EXHIBIT NO. _____
DOCKET NO. 010001-EI
TAMPA ELECTRIC COMPANY
(JDJ-1)

TAMPA ELECTRIC COMPANY

FUEL AND PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

DOCUMENT NO. DATE
17863-01 12/31/01
FPSC - COMMISSION CLERK

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 1
COMPANY/ WITNESS Jordan
DATE: 11-20-21-01

EXHIBIT NO. _____
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(JDJ-1)

FUEL AND PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

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DOCKET NO. 010001-EI
TAMPA ELECTRIC COMPANY
(JDJ-1)
DOCUMENT NO. 1

EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 1

FINAL CAPACITY OVER/(UNDER) RECOVERY FOR

JANUARY 2000 - DECEMBER 2000

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2000 THROUGH DECEMBER 2000

1. End-of-Period True-up: Over/(Under) Recovery	$1,388,160
2. Less: Actual/ Estimated Over/(Under) Recovery Approved at the November 2000 Fuel Hearings for the January 2000 through December 2000 period	1,977,239
3. Net True-up: Over/(Under) Recovery to be carried forward to the January 2002 through December 2002 period	**($589,079)**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2000 THROUGH DECEMBER 2000

	(1) ACTUAL JANUARY	(2) ACTUAL FEBRUARY	(3) ACTUAL MARCH	(4) ACTUAL APRIL	(5) ACTUAL MAY	(6) TOTAL JAN-MAY	(7) ACTUAL JUNE	(8) ACTUAL JULY	(9) ACTUAL AUGUST	(10) ACTUAL SEPTEMBER	(11) ACTUAL OCTOBER	(12) ACTUAL NOVEMBER	(13) ACTUAL DECEMBER	(14) TOTAL JUN-DEC
1. UNIT POWER CAPACITY CHARGES	$1,126,097	$1,126,097	$1,126,097	$1,126,097	$1,800,295	$6,304,683	$1,577,647	$1,558,153	$1,635,357	$1,635,357	$1,635,357	$1,455,917	$1,635,357	$11,133,145
2. CAPACITY PAYMENTS TO COGENERATORS	920,920	920,920	920,920	943,690	943,690	4,650,140	920,920	966,460	943,690	943,690	943,690	943,690	943,690	6,605,830
3. EMERGENCY CAPACITY CHARGES	1,065,000	1,065,000	760,000	(305,239)	579,504	3,164,265	1,259,211	1,530,580	1,711,396	471,104	131,781	130,491	132,237	5,366,800
4. (CAPACITY REVENUES)	(982,899)	(1,024,341)	(953,315)	(970,955)	(968,011)	(4,899,521)	(946,070)	(951,455)	(888,558)	(839,463)	(897,548)	(850,285)	(912,866)	(6,286,245)
5. TOTAL CAPACITY CHARGES - CURRENT PERIOD	$2,129,118	$2,087,676	$1,853,702	$793,593	$2,355,478	$9,219,567	$2,811,708	$3,103,738	$3,401,885	$2,210,688	$1,813,280	$1,679,813	$1,798,418	$16,819,(
6. JURISDICTIONAL PERCENTAGE	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	-
7. JURISDICTIONAL CAPACITY PAYMENTS	$2,090,713	$2,050,019	$1,820,265	$779,278	$2,312,990	$9,053,265	$2,760,991	$3,047,753	$3,340,522	$2,170,812	$1,780,572	$1,649,513	$1,765,978	$16,516,141
8. CAPACITY COST RECOVERY REVENUES (NET OF REVENUE TAXES)	1,847,953	1,836,890	1,606,361	1,721,931	1,935,439	8,948,574	2,867,247	3,226,989	3,259,257	3,331,593	3,000,959	2,421,954	2,606,421	20,714,420
9. PRIOR PERIOD TRUE-UP PROVISION	(252,146)	(252,146)	(252,146)	(252,146)	(252,146)	(1,260,730)	(839,889)	(839,889)	(839,889)	(839,889)	(839,889)	(839,889)	(839,892)	(5,879,226)
10. CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (NET OF REVENUE TAXES)	$1,595,807	$1,584,744	$1,354,215	$1,469,785	$1,683,293	$7,687,844	$2,027,358	$2,387,100	$2,419,368	$2,491,704	$2,161,070	$1,582,065	$1,766,529	$14,835,194
11. TRUE-UP PROVISION FOR MONTH - OVER/ (UNDER) RECOVERY (LINE 10 - LINE 7)	($494,906)	($465,275)	($466,050)	$690,507	($629,697)	($1,365,421)	($733,633)	($660,653)	($921,154)	$320,892	$380,498	($67,448)	$551	($1,680,947)
12. INTEREST PROVISION FOR MONTH	(12,845)	(14,224)	(15,705)	(14,402)	(13,572)	(70,748)	(14,824)	(14,045)	(13,753)	(10,908)	(4,526)	851	5,275	(51,930)
13. TRUE-UP & INTEREST PROVISION BEGINNING OF MONTH - OVER/(UNDER) RECOVERY	(3,025,749)	(3,281,354)	(3,508,707)	(3,738,316)	(2,810,065)	(3,025,749)	(5,879,226)	(5,787,794)	(5,622,603)	(5,717,621)	(4,567,748)	(3,351,887)	(2,578,595)	(5,879,226)
14. DEFERRED TRUE-UP - OVER/(UNDER) RECOVERY	442,999	442,999	442,999	442,999	442,999	442,999	3,121,037	3,121,037	3,121,037	3,121,037	3,121,037	3,121,037	3,121,037	3,121,037
15. PRIOR PERIOD TRUE-UP PROVISION - COLLECTED/(REFUNDED) THIS MONTH	252,146	252,146	252,146	252,146	252,146	1,260,730	839,889	839,889	839,889	839,889	839,889	839,889	839,892	5,879,226
16. END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 11 - 15)	($2,838,355)	($3,065,708)	($3,295,317)	($2,367,066)	($2,758,189)	($2,758,189)	($2,666,757)	($2,501,566)	($2,596,584)	($1,446,711)	($230,850)	$542,442	$1,388,160	$1,388,160

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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD JANUARY 2000 THROUGH DECEMBER 2000

	(1) ACTUAL JANUARY	(2) ACTUAL FEBRUARY	(3) ACTUAL MARCH	(4) ACTUAL APRIL	(5) ACTUAL MAY	(6) TOTAL JAN-MAY	(7) ACTUAL JUNE	(8) ACTUAL JULY	(9) ACTUAL AUGUST	(10) ACTUAL SEPTEMBER	(11) ACTUAL OCTOBER	(12) ACTUAL NOVEMBER	(13) ACTUAL DECEMBER	(14) TOTA JUN-DEC
1. BEGINNING TRUE-UP AMOUNT	(2,582,750)	(2,838,355)	(3,065,708)	(3,295,317)	(2,367,066)	N/A	(2,758,189)	(2,666,757)	(2,501,566)	(2,596,584)	(1,446,711)	(230,850)	542,442	N/A
2. ENDING TRUE-UP AMOUNT BEFORE INTEREST	(2,825,510)	(3,051,484)	(3,279,612)	(2,352,664)	(2,744,617)	N/A	(2,651,933)	(2,487,521)	(2,582,831)	(1,435,803)	(226,324)	541,591	1,382,885	N/A
3. TOTAL BEGINNING & ENDING TRUE-UP AMOUNT (LINES 1 + 2)	(5,408,260)	(5,889,839)	(6,345,320)	(5,647,981)	(5,111,683)	N/A	(5,410,122)	(5,154,278)	(5,084,397)	(4,032,387)	(1,673,035)	310,741	1,925,327	N/A
4. AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(2,704,130)	(2,944,920)	(3,172,660)	(2,823,991)	(2,555,842)	N/A	(2,705,061)	(2,577,139)	(2,542,199)	(2,016,194)	(836,518)	155,371	962,664	N/A
5. INT. RATE % - FIRST DAY REP. BUS. MONTH	5.600	5.800	5.800	6.070	6.180	N/A	6.570	6.580	6.500	6.480	6.500	6.490	6.650	N/A
6. INT. RATE % - FIRST DAY SUBSEQUENT MONTH	5.800	5.800	6.070	6.180	6.570	N/A	6.580	6.500	6.480	6.500	6.490	6.650	6.500	N/A
7. TOTAL (LINE 5 + LINE 6)	11.400	11.600	11.870	12.250	12.750	N/A	13.150	13.080	12.980	12.980	12.990	13.140	13.150	N/A
8. AVERAGE INT. RATE % (50% OF LINE 7)	5.700	5.800	5.935	6.125	6.375	N/A	6.575	6.540	6.490	6.490	6.495	6.570	6.575	N/A
9. MONTHLY AVG. INT. RATE % (LINE 8/12)	0.475	0.483	0.495	0.510	0.531	N/A	0.548	0.545	0.541	0.541	0.541	0.548	0.548	N/A
10. INT. PROVISION (LINE 4 X LINE 9)	($12,845)	($14,224)	($15,705)	($14,402)	($13,572)	($70,748)	($14,824)	($14,045)	($13,753)	($10,908)	($4,526)	$851	$5,275	($51,930)

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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2000 THROUGH DECEMBER 2000

	(1) ACTUAL	(2) ACTUAL/ ESTIMATED	(3) VARIANCE (1)-(2)	(4) % CHANGE (3)/(2)
1. UNIT POWER CAPACITY CHARGES	$ 17,437,828	$ 25,829,039	$ (8,391,211)	-32.49%
2. CAPACITY PAYMENTS TO COGENERATORS	11,255,970	11,256,020	(50)	0.00%
3. EMERGENCY CAPACITY CHARGES	8,531,065	0	8,531,065	0.00%
4. CAPACITY REVENUES	(11,185,766)	(11,637,547)	451,781	-3.88%
5. TOTAL CAPACITY CHARGES - CURRENT PERIOD	$ 26,039,097	$ 25,447,512	$ 591,585	2.32%
6. JURISDICTIONAL PERCENTAGE	98.19621%	98.19621%	0.00000%	0.00%
7. JURISDICTIONAL CAPACITY PAYMENTS	$ 25,569,406	$ 24,988,493	$ 580,913	2.32%
8. CAPACITY COST RECOVERY REVENUES (NET OF REVENUE TAXES)	29,662,994	29,657,287	5,707	0.02%
9. PRIOR PERIOD TRUE-UP PROVISION	(7,139,956)	(7,139,956)	0	0.00%
10. CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (NET OF REVENUE TAXES)	$ 22,523,038	$ 22,517,331	$ 5,707	0.03%
11. TRUE-UP PROVISION FOR PERIOD - OVER/ (UNDER) RECOVERY (LINE 10 - LINE 7)	$ (3,046,368)	$ (2,471,162)	$ (575,206)	23.28%
12. INTEREST PROVISION FOR PERIOD	(122,678)	(108,805)	(13,873)	12.75%
13. TRUE-UP & INTEREST PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	(3,025,749)	(3,025,749)	0	0.00%
14. DEFERRED TRUE-UP - OVER/(UNDER) RECOVERY	442,999	442,999	0	0.00%
15. PRIOR PERIOD TRUE-UP PROVISION - COLLECTED/(REFUNDED) THIS PERIOD	7,139,956	7,139,956	0	0.00%
16. END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 11 - 15)	$ 1,388,160	$ 1,977,239	$ (589,079)	-29.79%

EXHIBIT NO. _____
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TAMPA ELECTRIC COMPANY
(JDJ-1)
DOCUMENT NO. 2

EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 2

FINAL FUEL AND PURCHASED POWER OVER/(UNDER) RECOVERY

FOR

JANUARY 2000 - DECEMBER 2000

EXHIBIT NO._____
DOCKET NO. 010001-EI
TAMPA ELECTRIC COMPANY
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PAGE 1 OF 1

TAMPA ELECTRIC COMPANY
FINAL FUEL OVER/(UNDER)-RECOVERY
FOR THE PERIOD
JANUARY 2000 THROUGH DECEMBER 2000

1 TOTAL FUEL COSTS FOR THE PERIOD	$460,988,973
2 JURISDICTIONAL FUEL COSTS (INCL. PEABODY AND ALL ADJUSTMENTS)	444,626,080
3 JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD	372,629,320
4 ACTUAL OVER/(UNDER)-RECOVERED FUEL COSTS FOR THE PERIOD (LINE 3 - LINE 2)	(71,996,760)
5 INTEREST	(1,842,961)
6 TRUE-UP COLLECTED	20,318,467
7 PRIOR PERIOD TRUE-UP (ACTUAL ENDING 12/99)	(12,329,543)
8 ACTUAL OVER/(UNDER)-RECOVERY FOR THE PERIOD (LINE 4 + LINE 5 + LINE 6 + LINE 7)	(65,850,797)
9 PROJECTED UNDER-RECOVERY PER PROJECTION FILED 9/21/00 (SCHEDULE E1-A LINE 3)	(42,721,321)
10 FINAL FUEL OVER/(UNDER)-RECOVERY (LINE 8 - LINE 9)	**($23,129,476)**

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TAMPA ELECTRIC COMPANY
(JDJ-1)
DOCUMENT NO. 3

EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 3

ACTUAL FUEL AND PURCHASED POWER TRUE-UP

VS.

ORIGINAL ESTIMATES

JANUARY 2000 - DECEMBER 2000

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TAMPA ELECTRIC COMPANY
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TAMPA ELECTRIC COMPANY
CALCULATION OF TRUE-UP AMOUNT
ACTUAL vs. ORIGINAL ESTIMATES
FOR THE PERIOD:
JANUARY 2000 THROUGH DECEMBER 2000

		ACTUAL	ESTIMATED	VARIANCE AMOUNT	%
A	1. FUEL COST OF SYSTEM NET GENERATION	$ 364,767,743	$ 369,255,503	(4,487,760)	(1.2)
	2. FUEL COST OF POWER SOLD	39,135,568	41,669,768	(2,534,200)	(6.1)
	3. FUEL COST OF PURCHASED POWER	126,110,088	56,276,800	69,833,288	124.1
	a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0
	b. PAYMENT TO QUALIFIED FACILITIES	9,305,817	9,225,300	80,517	0.9
	4. ENERGY COST OF ECONOMY PURCHASES	(10,512)	14,546,700	(14,557,212)	(100.1)
	6a. ADJUSTMENTS TO FUEL COST (FT. MEADE)	(48,516)	(48,000)	(516)	1.1
	6b. ADJUSTMENTS TO FUEL COST 1	0	0	0	0.0
	6c. ADJUSTMENTS TO FUEL COST 2	(79)	0	(79)	0.0
	7. ADJUSTED TOTAL FUEL & NET PWR.TRANS. SUM OF LINES A1 THRU 6C	$ 460,988,973	$ 407,586,535	53,402,438	13.1
C	1. JURISDICTIONAL FUEL REVENUE	$ 392,671,085	$ 381,827,086	10,843,999	2.8
	2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0
	a. TRUE-UP PROVISION	(20,318,467)	(3,666,883)	(16,651,584)	454.1
	b. INCENTIVE PROVISION	276,702	276,702	0	0.0
	3. JURISDIC. FUEL REVENUE-THIS PERIOD (Sum of Lines C1 through C2b)	372,629,320	378,436,905	(5,807,585)	(1.5)
	6B.JURISDICTIONAL FUEL COST	440,465,924	398,658,786	41,807,138	10.5
	6D.PEABODY CONTRACT BUY OUT AMORT. JURISD.	4,160,156	4,256,925	(96,769)	(2.3)
	6E.OTHER	0	0	0	0.0
	6F.OTHER	0	0	0	0.0
	6G.OTHER	0	0	0	0.0
	6H.JURISD. TOTAL FUEL & NET PWR. TRANS. (INCL. PEABODY AND ALL ADJUSTMENTS)	444,626,080	402,915,711	41,710,369	10.4
	7. TRUE-UP PROV.- THIS PER. (LINE C3-C6H)	(71,996,760)	(24,478,806)	(47,517,954)	194.1
	8. INTEREST PROVISION - THIS PERIOD	(1,842,961)	(1,162,026)	(680,935)	58.6
	9.TOTAL TRUE-UP AMOUNT FOR PERIOD	$ (73,839,721)	$ (25,640,832)	(48,198,889)	188.0

Line numbers reference Schedule A-2 included in Document No. 4

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TAMPA ELECTRIC COMPANY
(JDJ-1)
DOCUMENT NO. 4

EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 4

FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2000 - DECEMBER 2000

SCHEDULES A1 THROUGH A9

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

JANUARY 2000

SCHEDULE A1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF : JANUARY , 2000

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	IFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	28,341,744	28,107,340	234,404	0.8	1,367,635	1,406,517	(38,882)	(2.8)	2.07232	1.99836	0.07396	3.7
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (FtMeade/Wauch. Wheeling Losses)	(3,480)	(4,000)	520	(13.0)	1,367,635 a)	1,406,517 a)	(38,882)	(2.8)	(0.00025)	(0.00028)	0.00003	(10.7)
4b. Adjustments to Fuel Cost (1)	0	0	0	0.0	1,367,635 a)	1,406,517 a)	(38,882)	(2.8)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost (2)	(80)	0	(80)	0.0	1,367,635 a)	1,406,517 a)	(38,882)	(2.8)	(0.00001)	0.00000	(0.00001)	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	28,338,184	28,103,340	234,844	0.8	1,367,635	1,406,517	(38,882)	(2.8)	2.07206	1.99808	0.07398	3.7
6. Fuel Cost of Purchased Power - Firm (A7)	4,534,549	1,496,900	3,037,649	202.9	117,149	39,964	77,185	193.1	3.87075	3.74562	0.12513	3.3
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	259,400	(259,400)	(100.0)	0	6,965	(6,965)	(100.0)	0.00000	3.72434	(3.72434)	(100.0)
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 a)	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	582,947	569,300	13,647	2.4	28,220	33,049	(4,829)	(14.6)	2.06572	1.72259	0.34313	19.9
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	5,117,496	2,325,600	2,791,896	120.1	145,369	79,978	65,391	81.8	3.52035	2.90780	0.61255	21.1
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,513,004	1,486,495	26,509	1.8				
TS												
14. Fuel Cost of Economy Sales (A6)	0	5,600	(5,600)	(100.0)	0	190	(190)	(100.0)	0.00000	2.94737	(2.94737)	(100.0)
15. Gain on Economy Sales - 80% (A6)	0	1,040	(1,040)	(100.0)	0 a)	190 a)	(190)	(100.0)	0.00000	0.54737	(0.54737)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	99,156	152,600	(53,444)	(35.0)	6,336	9,896	(3,560)	(36.0)	1.56496	1.54204	0.02292	1.5
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	120,659	104,600	16,059	15.4	6,022	5,724	298	5.2	2.00364	1.82739	0.17625	9.6
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	466,953	229,700	237,253	103.3	17,339	9,961	7,378	74.1	2.69308	2.30599	0.38709	16.8
21. Fuel Cost of Other Power Sales (A6)	2,461,433	2,014,564	446,869	22.2	124,820	111,600	13,220	11.8	1.97199	1.80516	0.16683	9.2
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	3,148,201	2,508,104	640,097	25.5	154,517	137,371	17,146	12.5	2.03745	1.82579	0.21166	11.6
23. Net Inadvertant Interchange					(308)	0	(308)	0.0				
24. Wheeling Rec'd. less Wheeling Del'd.					636	0	636	0.0				
25. Interchange and Wheeling Losses					3,414	2,100	1,314	62.6				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	30,307,479	27,920,836	2,386,643	8.5	1,355,401	1,347,024	8,377	0.6	2.23605	2.07278	0.16327	7.9
27. Net Unbilled	(487,727) (a)	(1,526,167) (a)	1,038,440	(68.0)	(21,812)	(73,629)	51,817	(70.4)	(0.03596)	(0.11330)	0.07732	(68.2)
28. Company Use	96,530 (a)	82,911 (a)	13,619	16.4	4,317	4,000	317	7.9	0.00730	0.00613	0.00117	19.1
29. T & D Losses	1,150,604 (a)	1,323,574 (a)	(172,970)	(13.1)	51,457	63,855	(12,398)	(19.4)	0.08707	0.09784	(0.01077)	(11.0)
30. System KWH Sales	30,307,479	27,920,836	2,386,643	8.5	1,321,439	1,352,798	(31,359)	(2.3)	2.29352	2.06393	0.22959	11.1
31. Wholesale KWH Sales	(735,146)	(262,799)	(472,347)	179.7	(32,053)	(12,733)	(19,320)	151.7	2.29353	2.06392	0.22961	11.1
32. Jurisdictional KWH Sales	29,572,333	27,658,037	1,914,296	6.9	1,289,386	1,340,065	(50,679)	(3.8)	2.29352	2.06393	0.22959	11.1
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	29,592,442	27,676,844	1,915,598	6.9	1,289,386	1,340,065	(50,679)	(3.8)	2.29508	2.06534	0.22974	11.1
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	366,847	372,427	(5,580)	(1.5)	1,289,386	1,340,065	(50,679)	(3.8)	0.02845	0.02779	0.00066	2.4
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	1,289,386	1,340,065	(50,679)	(3.8)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	1,289,386	1,340,065	(50,679)	(3.8)	0.00000	0.00000	0.00000	0.0
36. True-up *	305,574	305,574	0	0.0	1,289,386	1,340,065	(50,679)	(3.8)	0.02370	0.02280	0.00090	3.9
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	30,264,863	28,354,845	1,910,018	6.7	1,289,386	1,340,065	(50,679)	(3.8)	2.34723	2.11593	0.23130	10.9
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.34892	2.11745	0.23147	10.9
40. GPIF * (Already Adjusted for Taxes)	(23,059)	(23,059)	0	0.0	1,289,386	1,340,065	(50,679)	(3.8)	(0.00179)	(0.00172)	(0.00007)	4.1
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	30,241,804	28,331,786	1,910,018	6.7	1,289,386	1,340,065	(50,679)	(3.8)	2.34713	2.11573	0.23140	10.9
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.347	2.116	0.231	10.9

* Based on Jurisdictional Sales (a) Included for informational purposes only

SCHEDULE A1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: JANUARY , 2000

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	28,341,744	28,107,340	234,404	0.8	1,367,635	1,406,517	(38,882)	(2.8)	2.07232	1.99838	0.07396	3.7
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(3,480)	(4,000)	520	(13.0)	1,367,635 a)	1,406,517 a)	(38,882)	(2.8)	(0.00025)	(0.00028)	0.00003	(10.7)
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,367,635 a)	1,406,517 a)	(38,882)	(2.8)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	(80)	0	(80)	0.0	1,367,635 a)	1,406,517 a)	(38,882)	(2.8)	(0.00001)	0.00000	(0.00001)	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	28,338,184	28,103,340	234,844	0.8	1,367,635	1,406,517	(38,882)	(2.8)	2.07206	1.99808	0.07398	3.7
6. Fuel Cost of Purchased Power - Firm (A7)	4,534,549	1,496,900	3,037,649	202.9	117,149	39,964	77,185	193.1	3.87075	3.74562	0.12513	3.3
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	259,400	(259,400)	(100.0)	0	6,965	(6,965)	(100.0)	0.00000	3.72434	(3.72434)	(100.0)
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 a)	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	582,947	569,300	13,647	2.4	28,220	33,049	(4,829)	(14.6)	2.06572	1.72259	0.34313	19.9
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	5,117,496	2,325,600	2,791,896	120.1	145,369	79,978	65,391	81.8	3.52035	2.90780	0.61255	21.1
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,513,004	1,486,495	26,509	1.8				
14. Fuel Cost of Economy Sales (A6)	0	5,600	(5,600)	(100.0)	0	190	(190)	(100.0)	0.00000	2.94737	(2.94737)	(100.0)
15. Gain on Economy Sales - 80% (A6)	0	1,040	(1,040)	(100.0)	0 a)	190 a)	(190)	(100.0)	0.00000	0.54737	(0.54737)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	99,158	152,600	(53,444)	(35.0)	6,336	9,896	(3,560)	(36.0)	1.56496	1.54204	0.02292	1.5
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	120,659	104,600	16,059	15.4	6,022	5,724	298	5.2	2.00364	1.82739	0.17625	9.6
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	466,953	229,700	237,253	103.3	17,339	9,961	7,378	74.1	2.69308	2.30599	0.38709	16.8
21. Fuel Cost of Other Power Sales (A6)	2,461,433	2,014,564	446,869	22.2	124,820	111,600	13,220	11.8	1.97199	1.80516	0.16683	9.2
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	3,148,201	2,508,104	640,097	25.5	154,517	137,371	17,146	12.5	2.03745	1.82579	0.21166	11.6
23. Net Inadvertant Interchange					(308)	0	(308)	0.0				
24. Wheeling Rec'd. less Wheeling Del'd.					636	0	636	0.0				
25. Interchange and Wheeling Losses					3,414	2,100	1,314	62.6				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	30,307,479	27,920,836	2,386,643	8.5	1,355,401	1,347,024	8,377	0.6	2.23605	2.07278	0.16327	7.9
27. Net Unbilled	(487,727) (a)	(1,526,167) (a)	1,038,440	(68.0)	(21,812)	(73,629)	51,817	(70.4)	(0.03596)	(0.11330)	0.07732	(68.2)
28. Company Use	96,530 (a)	82,911 (a)	13,619	16.4	4,317	4,000	317	7.9	0.00730	0.00613	0.00117	19.1
29. T & D Losses	1,150,604 (a)	1,323,574 (a)	(172,970)	(13.1)	51,457	63,855	(12,398)	(19.4)	0.08707	0.09784	(0.01077)	(11.0)
30. System KWH Sales	30,307,479	27,920,836	2,386,643	8.5	1,321,439	1,352,798	(31,359)	(2.3)	2.29352	2.06393	0.22959	11.1
31. Wholesale KWH Sales	(735,146)	(262,799)	(472,347)	179.7	(32,053)	(12,733)	(19,320)	151.7	2.29353	2.06392	0.22961	11.1
32. Jurisdictional KWH Sales	29,572,333	27,658,037	1,914,296	6.9	1,289,386	1,340,065	(50,679)	(3.8)	2.29352	2.06393	0.22959	11.1
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	29,592,442	27,676,844	1,915,598	6.9	1,289,386	1,340,065	(50,679)	(3.8)	2.29508	2.06534	0.22974	11.1
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	368,847	372,427	(5,580)	(1.5)	1,289,386	1,340,065	(50,679)	(3.8)	0.02845	0.02779	0.00066	2.4
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	1,289,386	1,340,065	(50,679)	(3.8)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	1,289,386	1,340,065	(50,679)	(3.8)	0.00000	0.00000	0.00000	0.0
36. True-up *	305,574	305,574	0	0.0	1,289,386	1,340,065	(50,679)	(3.8)	0.02370	0.02280	0.00090	3.9
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	30,264,863	28,354,845	1,910,018	6.7	1,289,386	1,340,065	(50,679)	(3.8)	2.34723	2.11593	0.23130	10.9
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.34892	2.11745	0.23147	10.9
40. GPIF * (Already Adjusted for Taxes)	(23,059)	(23,059)	0	0.0	1,289,386	1,340,065	(50,679)	(3.8)	(0.00179)	(0.00172)	(0.00007)	4.1
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	30,241,804	28,331,786	1,910,018	6.7	1,289,386	1,340,065	(50,679)	(3.8)	2.34713	2.11573	0.23140	10.9
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.347	2.116	0.231	10.9

* Based on Jurisdictional Sales (a) Included for informational purposes only

SCHEDULE A2
PAGE 1 OF 3

TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	28,341,744	28,107,340	234,404	0.8	28,341,744	28,107,340	234,404	0.8
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD (INCLUDES ECONOMY SALES PROFITS) (80%)	3,148,201	2,508,104	640,097	25.5	3,148,201	2,508,104	640,097	25.5
3. FUEL COST OF PURCHASED POWER	4,534,549	1,496,900	3,037,649	202.9	4,534,549	1,496,900	3,037,649	202.9
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	582,947	569,300	13,647	2.4	582,947	569,300	13,647	2.4
4. ENERGY COST OF ECONOMY PURCHASES	0	259,400	(259,400)	0.0	0	259,400	(259,400)	0.0
5. TOTAL FUEL & NET POWER TRANSACTION	30,311,039	27,924,836	2,386,203	8.5	30,311,039	27,924,836	2,386,203	8.5
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(3,480)	(4,000)	520	(13.0)	(3,480)	(4,000)	520	(13.0)
6b. ADJ. TO FUEL COST (Gatliff Coal)	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST 2	(80)	0	(80)	0.0	(80)	0	(80)	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	30,307,479	27,920,836	2,386,643	8.5	30,307,479	27,920,836	2,386,643	8.5
B. MWH SALES								
1. JURISDICTIONAL SALES	1,289,386	1,340,065	(50,679)	(3.8)	1,289,386	1,340,065	(50,679)	(3.8)
2. NONJURISDICTIONAL SALES	32,053	12,733	19,320	151.7	32,053	12,733	19,320	151.7
3. TOTAL SALES	1,321,439	1,352,798	(31,359)	(2.3)	1,321,439	1,352,798	(31,359)	(2.3)
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9757439	0.9905877	(0.0148438)	(1.5)	0.9757439	0.9905877	(0.0148438)	(1.5)

SCHEDULE A2
PAGE 2 OF 3

TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATE	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	29,384,573	30,823,807	(1,439,234)	(4.7)	29,384,573	30,823,807	(1,439,234)	(4.7)
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	(305,574)	(305,574)	0	0.0	(305,574)	(305,574)	0	0.0
b. INCENTIVE PROVISION	23,059	23,059	0	0.0	23,059	23,059	0	0.0
c. TRANSITION ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
d. OTHER ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	29,102,058	30,541,292	(1,439,234)	(4.7)	29,102,058	30,541,292	(1,439,234)	(4.7)
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	30,307,479	27,920,836	2,386,643	8.5	30,307,479	27,920,836	2,386,643	8.5
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B-4)	0.9757439	0.9905877	(0.0148438)	(1.5)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	29,572,333	27,658,037	1,914,296	6.9	29,572,333	27,658,037	1,914,296	6.9
6A.JURISDIC. LOSS MULTIPLIER	1.00068	1.00068	0.0000	0.0	NA	NA	-	-
6B. (LINE 6 x LINE 6A)	29,592,442	27,676,844	1,915,598	6.9	29,592,442	27,676,844	1,915,598	6.9
6C.PEABODY COAL CONTR. BUY-OUT AMORT.	375,966	375,966	0	0.0	375,966	375,966	0	0.0
6D.(LINE 6C x LINE 5) PB. JURISD.	366,847	372,427	(5,580)	(1.5)	366,847	372,427	(5,580)	(1.5)
6E.OTHER (SPARE INPUT #1)	0	0	0	0.0	0	0	0	0.0
6F. OIL BELOW THE DISCHARGE VALVE	0	0	0	0.0	0	0	0	0.0
6G. OTHER (SPARE INPUT #2)	0	0	0	0.0	0	0	0	0.0
6H. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. 6B+6D+6E+6F+6G)	29,959,289	28,049,271	1,910,018	6.8	29,959,289	28,049,271	1,910,018	6.8
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6H)	(857,231)	2,492,021	(3,349,252)	(134.4)	(857,231)	2,492,021	(3,349,252)	(134.4)
8. INTEREST PROVISION FOR THE MONTH	(59,876)	(10,864)	(49,012)	451.1	(59,876)	(10,864)	(49,012)	451.1
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(20,209,479)	(11,546,819)	(8,662,660)	75.0	NOT APPLICABLE			
9a.DEFERRED TRUE-UP BEGINNING OF PERIO	7,879,936	7,879,936	0	0.0	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	305,574	305,574	0	0.0	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	(12,941,076)	(880,152)	(12,060,924)	1,370.3	NOT APPLICABLE			

TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	(12,329,543)	(3,666,883)	(8,662,660)	236.2	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	(12,881,200)	(869,288)	(12,011,912)	1,381.8	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(25,210,743)	(4,536,171)	(20,674,572)	455.8	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	(12,605,372)	(2,268,086)	(10,337,287)	455.8	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.600	5.750	(0.150)	(2.6)	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	5.800	5.750	0.050	0.9	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	11.400	11.500	(0.100)	(0.9)	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	5.700	5.750	(0.050)	(0.9)	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.475	0.479	(0.004)	(0.8)	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	(59,876)	(10,864)	(49,012)	451.1	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JANUARY 2000

SCHEDULE A3
PAGE 1 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
FUEL COST OF SYSTEM NET GENERATION ($)								
1 HEAVY OIL	103,562	85,094	18,468	21.7	103,562	85,094	18,468	21.7
2 LIGHT OIL	570,419	530,656	39,763	7.5	570,419	530,656	39,763	7.5
3 COAL	27,667,763	27,491,590	176,173	0.6	27,667,763	27,491,590	176,173	0.6
4 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
5 NUCLEAR	0	0	0	0.0	0	0	0	0.0
6 OTHER	0	0	0	0.0	0	0	0	0.0
7 TOTAL ($)	28,341,744	28,107,340	234,404	0.8	28,341,744	28,107,340	234,404	0.8
SYSTEM NET GENERATION (MWH)								
8 HEAVY OIL	1,221	2,017	(796)	(39.5)	1,221	2,017	(796)	(39.5)
9 LIGHT OIL	9,150	14,843	(5,693)	(38.4)	9,150	14,843	(5,693)	(38.4)
10 COAL	1,357,264	1,389,657	(32,393)	(2.3)	1,357,264	1,389,657	(32,393)	(2.3)
11 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
12 NUCLEAR	0	0	0	0.0	0	0	0	0.0
13 OTHER	0	0	0	0.0	0	0	0	0.0
14 TOTAL (MWH)	1,367,635	1,406,517	(38,882)	(2.8)	1,367,635	1,406,517	(38,882)	(2.8)
UNITS OF FUEL BURNED								
15 HEAVY OIL (BBL)	5,459	5,084	375	7.4	5,459	5,084	375	7.4
16 LIGHT OIL (BBL)	20,291	22,397	(2,106)	(9.4)	20,291	22,397	(2,106)	(9.4)
17 COAL (TON)	637,460	630,429	7,031	1.1	637,460	630,429	7,031	1.1
18 NATURAL GAS (MCF)	0	0	0	0.0	0	0	0	0.0
19 NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20 OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
BTUS BURNED (MMBTU)								
21 HEAVY OIL	34,698	32,138	2,560	8.0	34,698	32,138	2,560	8.0
22 LIGHT OIL	118,004	130,160	(12,156)	(9.3)	118,004	130,160	(12,156)	(9.3)
23 COAL	14,187,516	14,452,965	(265,449)	(1.8)	14,187,516	14,452,965	(265,449)	(1.8)
24 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
25 NUCLEAR	0	0	0	0.0	0	0	0	0.0
26 OTHER	0	0	0	0.0	0	0	0	0.0
27 TOTAL (MMBTU)	14,340,218	14,615,263	(275,045)	(1.9)	14,340,218	14,615,263	(275,045)	(1.9)
GENERATION MIX (% MWH)								
28 HEAVY OIL	0.09	0.14	(0.05)	-	0.09	0.14	(0.05)	-
29 LIGHT OIL	0.67	1.06	(0.39)	-	0.67	1.06	(0.39)	-
30 COAL	99.24	98.80	0.44	-	99.24	98.80	0.44	-
31 NATURAL GAS	0.00	0.00	0.00	-	0.00	0.00	0.00	-
32 NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33 OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34 TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
FUEL COST PER UNIT								
35 HEAVY OIL ($/BBL)	18.97	16.74	2.23	13.3	18.97	16.74	2.23	13.3
36 LIGHT OIL ($/BBL)	28.11	23.69	4.42	18.7	28.11	23.69	4.42	18.7
37 COAL ($/TON)	43.40	43.61	(0.21)	(0.5)	43.40	43.61	(0.21)	(0.5)
38 NATURAL GAS ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40 OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
FUEL COST PER MMBTU ($/MMBTU)								
41 HEAVY OIL	2.98	2.65	0.33	12.5	2.98	2.65	0.33	12.5
42 LIGHT OIL	4.83	4.08	0.75	18.4	4.83	4.08	0.75	18.4
43 COAL	1.95	1.90	0.05	2.6	1.95	1.90	0.05	2.6
44 NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
45 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47 TOTAL ($/MMBTU)	1.98	1.92	0.06	3.1	1.98	1.92	0.06	3.1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JANUARY 2000

SCHEDULE A3
PAGE 2 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
BTU BURNED PER KWH (BTU/KWH)								
48 HEAVY OIL	28,418	15,934	12,484	78.3	28,418	15,934	12,484	78.3
49 LIGHT OIL	12,897	8,769	4,128	47.1	12,897	8,769	4,128	47.1
50 COAL	10,453	10,400	53	0.5	10,453	10,400	53	0.5
51 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
52 NUCLEAR	0	0	0	0.0	0	0	0	0.0
53 OTHER	0	0	0	0.0	0	0	0	0.0
54 TOTAL (BTU/KWH)	10,485	10,391	94	0.9	10,485	10,391	94	0.9
GENERATED FUEL COST PER KWH (cents/KWH)								
55 HEAVY OIL	8.48	4.22	4.26	100.9	8.48	4.22	4.26	100.9
56 LIGHT OIL	6.23	3.58	2.65	74.0	6.23	3.58	2.65	74.0
57 COAL	2.04	1.98	0.06	3.0	2.04	1.98	0.06	3.0
58 NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
59 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61 TOTAL (cents/KWH)	2.07	2.00	0.07	3.5	2.07	2.00	0.07	3.5

SCHEDULE A4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD/MONTH OF: JANUARY 2000

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPC. FACTO (%)	EQUIV. AVAIL. FACTO (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COS PER KWH (cents /KWH)	COST OF FUEL ($/UNIT)
H.P.#1	32	303	1.3	93.6	37.1	-	HVY.OIL	-	-	-	-	-	-
H.P.#2	32	330	1.4	91.3	36.8	-	HVY.OIL	-	-	-	-	-	-
H.P.#3	32	350	1.5	93.6	32.5	-	HVY.OIL	-	-	-	-	-	-
H.P.#4	41	387	1.3	24.9	34.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#5	52	34	0.1	97.4	6.6	-	HVY.OIL	-	-	-	-	-	-
H.P. STATION	189	1,404	1.0	79.4	27.2	23,844	HVY.OIL	5,264	6,359,260	33,476.8	99,799	7.11	18.96
GAN.#1	114	13,010	15.3	23.2	66.1	11,248	COAL	6,237	23,461,793	146,331.2	260,999	2.01	41.85
GAN.#2	88	44,531	68.0	96.8	82.1	12,743	COAL	24,027	23,617,281	567,452.4	1,005,457	2.26	41.85
GAN.#3	155	65,051	56.4	88.3	67.3	12,528	COAL	39,833	20,459,659	814,969.6	1,666,890	2.56	41.85
GAN.#4	169	64,562	51.3	77.9	55.7	12,396	COAL	39,681	20,169,041	800,327.7	1,660,529	2.57	41.85
GAN.#5	242	86,882	48.3	68.5	64.3	11,176	COAL	41,139	23,602,820	970,996.4	1,721,542	1.98	41.85
GAN.#6	392	41,389	14.2	19.4	68.2	10,759	COAL	18,795	23,691,700	445,285.5	786,514	1.90	41.85
GANNON STA.	1160	315,425	36.5	53.6	66.3	11,874	COAL	169,712	22,068,933	3,745,362.8	7,101,931	2.25	41.85
B.B.#1	426	224,848	70.9	88.9	76.5	9,696	COAL	97,123	22,446,600	2,180,081.1	4,144,158	1.84	42.67
B.B.#2	426	233,094	73.5	89.6	77.7	9,969	COAL	101,503	22,894,000	2,323,809.7	4,331,048	1.86	42.67
B.B.#3	443	165,334	50.2	61.8	76.6	9,922	COAL	73,052	22,454,820	1,640,369.5	3,117,068	1.89	42.67
B.B. 1 - 3	1295	623,276	64.7	79.9	76.9	9,858	COAL	271,678	22,615,966	6,144,260.3	11,592,274	1.86	42.67
B.B.#4	447	264,969	79.7	88.7	89.1	9,836	COAL	123,239	21,147,319	2,606,174.4	6,013,084	2.27	48.79
B.B. STA.	1742	888,245	68.5	82.1	80.1	9,851	COAL	394,917	22,157,655	8,750,434.7	17,605,358	1.98	44.58
SEB-PHIL. #1(HVY OIL)	17	(92)	0.0	0.0	0.0	0	HVY.OIL	195	6,260,513	1,220.8	3,763	0.00	19.30
SEB-PHIL. #2(HVY OIL)	17	(91)	0.0	0.0	0.0	0	HVY.OIL	0	-	-	-	0.00	0.00
SEB-PHILLIPS TOTAL	34	(183)	0.0	0.0	0.0	0	HVY.OIL	195	6,260,513	1,220.8	3,763	0.00	19.30
POLK COAL	250	153,594	82.6	86.7	94.5	11,014	COAL	72,831	23,228,000	1,691,718.5	2,960,474	1.93	40.65
POLK OIL	245	4,087	2.2	95.5	50.0	8,957	LGT.OIL	6,297	5,813,560	36,607.0	185,691	4.54	29.49
POLK TOTAL	250	157,681	84.8	94.7	-	10,961	-	-	-	1,728,325.5	3,146,165	2.00	-
GAN.C.T.#1	17	147	1.2	100.0	50.9	20,352	LGT.OIL	514	5,818,811	2,991.8	14,135	9.62	27.49
B.B.C.T.#1	17	146	1.2	100.0	61.3	20,129	LGT.OIL	506	5,811,548	2,938.9	13,903	9.52	27.49
B.B.C.T.#2	80	2,046	3.4	100.0	52.2	16,910	LGT.OIL	5,948	5,816,619	34,597.6	163,524	7.99	27.49
B.B.C.T.#3	80	2,724	4.6	100.0	58.7	15,003	LGT.OIL	7,026	5,816,619	40,868.9	193,166	7.09	27.49
C.T. TOTAL	194	5,063	3.5	100.0	55.6	16,077	LGT.OIL	13,994	5,816,516	81,397.2	384,728	7.60	27.49
TOT. COAL (GN,BB,POLK)	3152	1,357,264	57.9	72.0	76.1	10,453	COAL	637,460	22,256,324	14,187,516.0	27,667,763	2.04	43.40
SYSTEM	3569	1,367,635	51.5	73.8	70.2	10,485	-	-	-	14,340,217.8	28,341,744	2.07	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS

NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2000

	CURRENT MONTH				PERIOD TO DATE			
HEAVY OIL (1)	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1 PURCHASES:								
2 UNITS (BBL)	0	5,084	(5,084)	(100.0)	0	5,084	(5,084)	(100.0)
3 UNIT COST ($/BBL)	0.00	15.96	(15.96)	(100.0)	0.00	15.96	(15.96)	(100.0)
4 AMOUNT ($)	21,875	81,141	(59,266)	(73.0)	21,875	81,141	(59,266)	(73.0)
5 BURNED:								
6 UNITS (BBL)	5,459	5,084	375	7.4	5,459	5,084	375	7.4
7 UNIT COST ($/BBL)	18.97	16.74	2.23	13.3	18.97	16.74	2.23	13.3
8 AMOUNT ($)	103,562	85,094	18,468	21.7	103,562	85,094	18,468	21.7
9 ENDING INVENTORY:								
10 UNITS (BBL)	84,801	175,493	(90,692)	(51.7)	84,801	175,493	(90,692)	(51.7)
11 UNIT COST ($/BBL)	19.17	16.90	2.27	13.4	19.17	16.90	2.27	13.4
12 AMOUNT ($)	1,625,684	2,965,844	(1,340,160)	(45.2)	1,625,684	2,965,844	(1,340,160)	(45.2)
13								
14 DAYS SUPPLY:	89	185	(96)	(51.9)	-	-	-	-
LIGHT OIL (2)								
15 PURCHASES:								
16 UNITS (BBL)	41,646	34,566	7,080	20.5	41,646	34,566	7,080	20.5
17 UNIT COST ($/BBL)	31.16	23.45	7.71	32.9	31.16	23.45	7.71	32.9
18 AMOUNT ($)	1,297,835	810,665	487,170	60.1	1,297,835	810,665	487,170	60.1
19 BURNED:								
20 UNITS (BBL)	20,291	22,397	(2,106)	(9.4)	20,291	22,397	(2,106)	(9.4)
21 UNIT COST ($/BBL)	28.11	23.69	4.42	18.7	28.11	23.69	4.42	18.7
22 AMOUNT ($)	570,419	530,656	39,763	7.5	570,419	530,656	39,763	7.5
23 ENDING INVENTORY:								
24 UNITS (BBL)	79,707	110,358	(30,651)	(27.8)	79,707	110,358	(30,651)	(27.8)
25 UNIT COST ($/BBL)	28.40	23.26	5.14	22.1	28.40	23.26	5.14	22.1
26 AMOUNT ($)	2,263,585	2,567,134	(303,549)	(11.8)	2,263,585	2,567,134	(303,549)	(11.8)
27								
28 DAYS SUPPLY: NORMAL	69	95	(26)	(27.4)	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	11	16	(5)	(31.3)	-	-	-	-
COAL (3)								
30 PURCHASES:								
31 UNITS (TONS)	608,302	693,400	(85,098)	(12.3)	608,302	693,400	(85,098)	(12.3)
32 UNIT COST ($/TON)	39.41	42.64	(3.23)	(7.6)	39.41	42.64	(3.23)	(7.6)
33 AMOUNT ($)	23,975,966	29,563,801	(5,587,835)	(18.9)	23,975,966	29,563,801	(5,587,835)	(18.9)
34 BURNED:								
35 UNITS (TONS)	637,460	630,429	7,031	1.1	637,460	630,429	7,031	1.1
36 UNIT COST ($/TON)	43.40	43.61	(0.21)	(0.5)	43.40	43.61	(0.21)	(0.5)
37 AMOUNT ($)	27,667,763	27,491,590	176,173	0.6	27,667,763	27,491,590	176,173	0.6
38 ENDING INVENTORY:								
39 UNITS (TONS)	747,858	926,471	(178,613)	(19.3)	747,858	926,471	(178,613)	(19.3)
40 UNIT COST ($/TON)	42.30	43.41	(1.11)	(2.6)	42.30	43.41	(1.11)	(2.6)
41 AMOUNT ($)	31,636,351	40,214,438	(8,578,087)	(21.3)	31,636,351	40,214,438	(8,578,087)	(21.3)
42								
43 DAYS SUPPLY:	38	47	(9)	(19.1)	-	-	-	-
NATURAL GAS								
44 PURCHASES:								
45 UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
46 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
48 BURNED:								
49 UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
50 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
51 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
56								
57 DAYS SUPPLY:	0	0	0	0.0	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2000

OTHER	CURRENT MONTH ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	PERIOD TO DATE ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
74 DAYS SUPPLY:	0	0	0	0.0	-	-	-	-

* Reflects an adjustment to Phillips Station lube oil for June 1999.

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	866
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	866

(2)
RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(8,723)	(239,807)
OTHER USAGE	(1,965)	(56,172)
TOTAL	(10,688)	(295,979)

(3)
RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	13,878
IGNITION #2 OIL	238,941
IGNITION PROPANE	1,945
AERIAL SURVEY ADJ.	493,507
ADDITIVES	67,500
TOTAL	815,771

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JANUARY 2000

SCHEDULE A6
PAGE 1 OF 3

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	190.0	0.0	190.0	3.158	3.842	6,000.00	7,300.00	1,040.00
VARIOUS	JURISDICTIONAL	SCH. -D	5,724.0	0.0	5,724.0	1.827	1.827	104,600.00	104,600.00	
VARIOUS	SEPARATED	SCH. -D	9,896.0	0.0	9,896.0	1.725	1.899	170,700.00	187,900.00	
HARDEE POWER PARTNERS	SEPARATED	CONTRACT	9,961.0	0.0	9,961.0	2.306	3.194	229,700.00	318,200.00	
FMPA		SCH. -D	111,600.0	0.0	111,600.0	1.805	1.805	2,014,564.00	2,014,564.00	
VARIOUS	JURISDICTIONAL	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	137,371.0	0.0	137,371.0	1.838	1.916	2,525,564.00	2,632,564.00	1,040.00
LESS TRANSMISSION COSTS		-						(18,100.00)		
LESS VARIABLE O & M COSTS		-						(400.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS		-						1,040.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-	137,371.0	0.0	137,371.0	1.826	1.916	2,508,104.00	2,632,564.00	1,040.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENRGY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
OGLETHORPE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENN. VALLEY AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	6,336.0	0.0	6,336.0	1.869	2.020	118,427.87	128,003.10	
REEDY CREEK	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEP CONTRACT		17,339.0	0.0	17,339.0	2.639	3.380	457,576.21	586,058.20	
SEMINOLE ELECTRIC CO-OP PRE	JURISD.	SCH. -D	5,711.0	450.5	5,260.5	2.035	2.035	107,052.45	107,052.45	
SEMINOLE ELECTRIC CO-OP HAR	JURISD.	SCH. -D	761.0	0.0	761.0	1.788	1.788	13,606.10	13,606.10	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JANUARY 2000

SCHEDULE A6
PAGE 2 OF 3

(1)		(2)	(3)	(4)	(5)	(6)		(7)	(8)	(9)
SOLD TO		TYPE & SCHEDULE	TOTAL MWH SOLD	MWH WHEELED OTHER SYSTEM	MWH FROM OWN GENERATION	---cents/KWH--- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	TOTAL $ FOR TOTAL COST (5)X(6)(B)	80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA		SCH. -D	110,850.0	0.0	110,850.0	1.942	1.942	2,152,687.45	2,152,687.45	
HARDEE POWER PART. TO FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FLA. PWR.& LT.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO JACKSONVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO KISSIMMEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO ORLANDO		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO SEMINOLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FT. PIERCE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO LK. WORTH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO ENERGY AUTH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FPC		SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. CORP.		SCH. -MB	470.0	0.0	470.0	2.802	2.802	13,169.43	13,169.43	
FLA. PWR. & LIGHT		SCH. -MB	12,631.0	0.0	12,631.0	2.179	2.179	275,216.18	275,216.18	
CITY OF LAKELAND		SCH. -MB	533.0	0.0	533.0	2.366	2.366	12,611.70	12,611.70	
ORLANDO UTIL. COMM.		SCH. -MB	336.0	0.0	336.0	2.306	2.306	7,748.43	7,748.43	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JANUARY 2000

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)	(9)
SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	MWH WHEELED OTHER SYSTEM	MWH FROM OWN GENERATION	---cents/KWH--- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	TOTAL $ FOR TOTAL COST (5)X(6)(B)	80% GAIN ON ECONOMY ENERGY SALES
ADJUSTMENTS TO PREV. MONTHS MON/YR TYP	SCHED.								
HARDEE POWER PARTNERS EST. 12/99 SEPAR.	CONTRACT	(4,321.0)	0.0	(4,321.0)	2.304	3.019	(99,555.84)	(130,450.99)	
HARDEE POWER PARTNERS ACT. 12/99 SEPAR.	CONTRACT	4,321.0	0.0	4,321.0	2.521	3.380	108,932.41	146,049.80	
SUB-TOTAL ECONOMY POWER SALES		0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.		6,336.0	0.0	6,336.0	1.869	2.020	118,427.87	128,003.10	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.		6,472.0	450.5	6,021.5	2.004	2.004	120,658.55	120,658.55	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.		0.0	0.0	0.0	0.000	0.000	0.0	0.0	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.		17,339.0	0.0	17,339.0	2.693	3.470	466,952.78	601,657.01	
SUB-TOTAL FMPA D POWER SALES		110,850.0	0.0	110,850.0	1.942	1.942	2,152,687.45	2,152,687.45	
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.		0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE MB POWER SALES-JURISD.		13,970.0	0.0	13,970.0	2.210	2.210	308,745.74	308,745.74	
TOTAL INCLUDING VARIABLE O & M COSTS		154,967.0	450.5	154,516.5	2.050	2.143	3,167,472.39	3,311,751.85	0.00
LESS VARIABLE O & M COSTS							0.00		
LESS VARIABLE O & M COSTS - HARDEE							0.00		
LESS TRANSMISSION COSTS SCH. D (SEP.)							(19,271.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS	-						0.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS	-	154,967.0	450.5	154,516.5	2.037	2.143	3,148,201.39	3,311,751.85	0.00
CURRENT MONTH:									
DIFFERENCE	-	17,596.0	450.5	17,145.5	0.211	0.227	640,097.39	679,187.85	(1,040.00)
DIFFERENCE %	-	12.8	0.0	12.5	11.6	11.8	25.5	25.8	(100.0)
PERIOD TO DATE:									
ACTUAL	-	154,967.0	450.5	154,516.5	2.037	2.143	3,148,201.39	3,311,751.85	0.00
ESTIMATED	-	137,371.0	0.0	137,371.0	1.826	1.916	2,508,104.00	2,632,564.00	1,040.00
DIFFERENCE	-	17,596.0	450.5	17,145.5	0.211	0.227	640,097.39	679,187.85	(1,040.00)
DIFFERENCE %	-	12.8	0.0	12.5	11.6	11.8	25.5	25.8	(100.0)

* No Economy Sales to Hardee Power Partners for Others in the month of January 2000.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH JANUARY 2000

SCHEDULE A7

(1)		(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM		TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:									
VARIOUS		EMER.	4,440.0	0.0	2,161.0	2,279.0	7.372	7.372	168,000.00
HARDEE POWER PARTNERS		IPP	13,805.0	0.0	0.0	13,805.0	4.369	4.369	603,200.00
VARIOUS		OTHER	23,880.0	0.0	0.0	23,880.0	3.039	3.039	725,700.00
TOTAL		-	42,125.0	0.0	2,161.0	39,964.0	3.746	3.746	1,496,900.00
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	52,326.0	0.0	0.0	52,326.0	3.919	3.919	2,050,622.25
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH.-Ja	3,092.0	0.0	2,293.4	798.6	6.137	6.137	49,013.69
FLA. POWER CORP.		SCH.-Jc	24,116.0	0.0	0.0	24,116.0	2.912	2.912	702,258.00
FLA. POWER & LIGHT		SCH.-Ja	10,736.0	0.0	6,219.8	4,516.2	5.789	5.789	261,424.50
FLA. POWER & LIGHT		SCH.-Jc	16,581.0	0.0	0.0	16,581.0	3.857	3.857	639,523.75
CITY OF LAKELAND		SCH.-Ja	1,152.0	0.0	977.5	174.5	6.862	6.862	11,973.55
CITY OF LAKELAND		SCH.-Jc	309.0	0.0	0.0	309.0	2.805	2.805	8,668.00
ORLANDO		SCH.-Jc	2,075.0	0.0	0.0	2,075.0	3.390	3.390	70,350.50
THE ENERGY AUTH.		SCH.-Ja	518.0	0.0	348.7	169.3	8.645	8.645	14,635.60
THE ENERGY AUTH.		SCH.-Jc	2,142.0	0.0	0.0	2,142.0	5.198	5.198	111,340.86
CARGILL FERTILIZER, INC.		SCH.-Ja	112.0	0.0	57.0	55.0	7.000	7.000	3,850.00
CARGILL FERTILIZER, INC.		SCH.-Jc	33.0	0.0	0.0	33.0	4.670	4.670	1,541.16
RELIANT ENERGY		SCH.-Jc	33.0	0.0	0.0	33.0	4.000	4.000	1,320.00
REEDY CREEK		SCH.-Jc	327.0	0.0	0.0	327.0	3.405	3.405	11,135.00
AQUILLA		SCH.-Ja	944.0	0.0	944.0	0.0	0.000	0.000	0.00
AQUILLA		SCH.-Jc	384.0	0.0	0.0	384.0	9.086	9.086	34,891.35
KOCH ENERGY TRAD.		SCH.-Ja	280.0	0.0	280.0	0.0	0.000	0.000	0.00
KOCH ENERGY TRAD.		SCH.-Jc	93.0	0.0	0.0	93.0	12.316	12.316	11,454.00
TALLAHASSEE		SCH.-Jc	605.0	0.0	0.0	605.0	3.201	3.201	19,363.60
AUBURNDALE POWER PARTNERS		SCH.-Jc	4,981.0	0.0	0.0	4,981.0	2.334	2.334	116,259.57
OKEELANTA		SCH.-D	7,430.0	0.0	0.0	7,430.0	3.824	3.824	284,150.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIV	Dec-99	IPP	(574.0)	0.0	0.0	(574.0)	37.021	37.021	(212,500.90)
HARDEE PWR. PART.-NATIV	Dec-99	IPP	574.0	0.0	0.0	574.0	65.501	65.501	375,975.06
THE ENERGY AUTH.	Nov-99	SCH.-Jc	(1,577.0)	0.0	0.0	(1,577.0)	3.510	3.510	(55,360.00)
THE ENERGY AUTH.	Nov-99	SCH.-Jc	1,577.0	0.0	0.0	1,577.0	3.509	3.509	55,340.95
TALLAHASSEE	Nov-99	SCH.-Jc	(1,822.0)	0.0	0.0	(1,822.0)	5.530	5.530	(100,751.36)
TALLAHASSEE	Nov-99	SCH.-Jc	1,822.0	0.0	0.0	1,822.0	3.756	3.756	68,430.32
AQUILLA	Nov-99	SCH.-Jc	(4,254.0)	0.0	0.0	(4,254.0)	3.627	3.627	(154,286.66)
AQUILLA	Nov-99	SCH.-Jc	4,254.0	0.0	0.0	4,254.0	3.618	3.618	153,926.31
TOTAL			128,269.0	0.0	11,120.4	117,148.6	3.871	3.871	4,534,549.10
CURRENT MONTH:									
DIFFERENCE		-	86,144.0	0.0	8,959.4	77,184.6	0.125	0.125	3,037,649.10
DIFFERENCE %		-	204.5	0.0	414.6	193.1	3.3	3.3	202.9
PERIOD TO DATE:									
ACTUAL		-	128,269.0	0.0	11,120.4	117,148.6	3.871	3.871	4,534,549.1
ESTIMATED		-	42,125.0	0.0	2,161.0	39,964.0	3.746	3.746	1,496,900.00
DIFFERENCE		-	86,144.0	0.0	8,959.4	77,184.6	0.125	0.125	3,037,649.10
DIFFERENCE %		-	204.5	0.0	414.6	193.1	3.3	3.3	202.9

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY

SCHEDULE A8

FOR THE MONTH OF: JANUARY 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	---CENTS/KWH--- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	33,049.0	0.0	0.0	33,049.0	1.723	1.723	569,300.00
TOTAL	-	33,049.0	0.0	0.0	33,049.0	1.723	1.723	569,300.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	3,992.0	0.0	0.0	3,992.0	2.019	2.019	80,584.84
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	151.0	0.0	0.0	151.0	2.265	2.265	3,419.57
HILLSBOROUGH COUNTY	COGEN.	15,376.0	0.0	0.0	15,376.0	2.029	2.029	312,028.63
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	1,947.0	0.0	0.0	1,947.0	2.359	2.359	45,939.32
FARMLAND HYDRO LP	COGEN.	1,034.0	0.0	0.0	1,034.0	2.302	2.302	23,799.42
IMC-AGRICO-S. PIERCE	COGEN.	180.0	0.0	0.0	180.0	2.267	2.267	4,079.91
AUBURNDALE POWER PARTNERS	COGEN.	258.0	0.0	0.0	258.0	4.259	4.259	10,986.71
ORANGE COGENERATION L.P.	COGEN.	5,644.0	0.0	0.0	5,644.0	2.027	2.027	114,382.17
CUTRALE CITRUS	COGEN.	1.0	0.0	0.0	1.0	1.895	1.895	18.95
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	363.0	(363.0)	3.986	3.986	(14,470.16)
SUB-TOTAL FOR JANUARY 2000	-	28,583.0	0.0	363.0	28,220.0	2.058	2.058	580,771.36
ADJ. FOR NOV. 1999								
IMC-AGRICO-NICHOLS	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
McKAY BAY REFUSE	COGEN.	(4,607.0)	0.0	0.0	(4,607.0)	2.051	2.051	(94,499.31)
		4,607.0	0.0	0.0	4,607.0	2.058	2.058	94,801.90
MULBERRY PHOSPHATES INC.	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
CARGILL RIDGEWOOD	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
IMC-AGRICO-NEW WALES	COGEN.	(1,569.0)	0.0	0.0	(1,569.0)	2.337	2.337	(36,664.90)
		1,569.0	0.0	0.0	1,569.0	2.261	2.261	35,476.09
HILLSBOROUGH COUNTY	COGEN.	(19,255.0)	0.0	0.0	(19,255.0)	2.057	2.057	(396,008.91)
		19,255.0	0.0	0.0	19,255.0	2.067	2.067	397,970.97
CARGILL MILLPOINT	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
CF INDUSTRIES INC.	COGEN.	(1,419.0)	0.0	0.0	(1,419.0)	2.291	2.291	(32,503.09)
		1,419.0	0.0	0.0	1,419.0	2.174	2.174	30,848.62
FARMLAND HYDRO LP	COGEN.	(199.0)	0.0	0.0	(199.0)	2.272	2.272	(4,521.18)
		199.0	0.0	0.0	199.0	2.180	2.180	4,337.81
IMC-AGRICO-S. PIERCE	COGEN.	(286.0)	0.0	0.0	(286.0)	2.446	2.446	(6,996.96)
		286.0	0.0	0.0	286.0	2.351	2.351	6,723.84
AUBURNDALE POWER PARTNERS	COGEN.	(3,442.0)	0.0	0.0	(3,442.0)	2.179	2.179	(75,015.31)
		3,442.0	0.0	0.0	3,442.0	2.102	2.102	72,341.99
ORANGE COGENERATION L.P.	COGEN.	(4,406.0)	0.0	0.0	(4,406.0)	1.991	1.991	(87,731.08)
		4,406.0	0.0	0.0	4,406.0	2.126	2.126	93,669.23
CUTRALE CITRUS	COGEN.	(39.0)	0.0	0.0	(39.0)	2.421	2.421	(944.06)
		39.0	0.0	0.0	39.0	2.282	2.282	889.89
AS AVAILABLE ASSIGNMENT	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
SUB-TOTAL FOR Nov-99 ADJ.	-	0.0	0.0	0.0	0.0	0.000	0.000	2,175.54
GRAND TOTAL		28,583.0	0.0	363.0	28,220.0	2.066	2.066	582,946.90
CURRENT MONTH:								
DIFFERENCE	-	(4,466.0)	0.0	363.0	(4,829.0)	0.343	0.343	13,646.90
DIFFERENCE %	-	(13.5)	0.0	0.0	(14.6)	19.9	19.9	2.4
PERIOD TO DATE:								
ACTUAL		28,583.0	0.0	363.0	28,220.0	2.066	2.066	582,946.90
ESTIMATED		33,049.0	0.0	0.0	33,049.0	1.723	1.723	569,300.00
DIFFERENCE	-	(4,466.0)	0.0	363.0	(4,829.0)	0.343	0.343	13,646.90
DIFFERENCE %	-	(13.5)	0.0	0.0	(14.6)	19.9	19.9	2.4

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JANUARY 2000

SCHEDULE A9

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	COST IF GENERATED (A) cents/KWH	COST IF GENERATED (B) $	FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	6,965.0	3.724	259,400.00	4.886	340,300.00	80,900.00
TOTAL	-	6,965.0	3.724	259,400.00	4.886	340,300.00	80,900.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL	-	0.0	0.000	0.00	0.000	0.00	0.00
CURRENT MONTH:							
DIFFERENCE	-	(6,965.0)	(3.724)	(259,400.00)	(4.886)	(340,300.00)	(80,900.00)
DIFFERENCE %	-	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		6,965.0	3.724	259,400.00	4.886	340,300.00	80,900.00
DIFFERENCE	-	(6,965.0)	(3.724)	(259,400.00)	(4.886)	(340,300.00)	(80,900.00)
DIFFERENCE %	-	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

FEBRUARY 2000

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	25,140,483	25,441,708	(301,225)	(1.2)	1,279,454	1,283,585	(4,131)	(0.3)	1.96494	1.98208	(0.01714)	(0.9)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (FL Meade/Wauch. Wheeling Losses)	(4,500)	(4,000)	(500)	12.5	1,279,454 a)	1,283,585 a)	(4,131)	(0.3)	(0.00035)	(0.00031)	(0.00004)	12.9
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,279,454 a)	1,283,585 a)	(4,131)	(0.3)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	(78)	0	(78)	0.0	1,279,454 a)	1,283,585 a)	(4,131)	(0.3)	(0.00001)	0.00000	(0.00001)	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	25,135,905	25,437,708	(301,803)	(1.2)	1,279,454	1,283,585	(4,131)	(0.3)	1.96458	1.98177	(0.01719)	(0.9)
6. Fuel Cost of Purchased Power - Firm (A7)	2,077,762	1,323,100	754,662	57.0	59,508	36,296	23,212	64.0	3.49157	3.64531	(0.15374)	(4.2)
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	173,700	(173,700)	(100.0)	0	4,861	(4,861)	(100.0)	0.00000	3.57334	(3.57334)	(100.0)
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 a)	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	558,975	533,600	25,375	4.8	29,782	31,530	(1,748)	(5.5)	1.87689	1.69236	0.18453	10.9
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	2,636,737	2,030,400	606,337	29.9	89,290	72,687	16,603	22.8	2.95300	2.79335	0.15965	5.7
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,368,744	1,356,272	12,472	0.9				
14. Fuel Cost of Economy Sales (A6)	0	20,600	(20,600)	(100.0)	0	754	(754)	(100.0)	0.00000	2.73210	(2.73210)	(100.0)
15. Gain on Economy Sales - 80% (A6)	0	5,200	(5,200)	(100.0)	0 a)	754 a)	(754)	(100.0)	0.00000	0.68966	(0.68966)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	91,611	142,700	(51,089)	(35.8)	5,850	9,257	(3,407)	(36.8)	1.56600	1.54154	0.02446	1.6
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	111,366	102,700	8,666	8.4	6,390	5,644	746	13.2	1.74282	1.81960	(0.07681)	(4.2)
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	155,369	131,600	23,769	18.1	9,334	5,735	3,599	62.8	1.66455	2.29468	(0.63013)	(27.5)
21. Fuel Cost of Other Power Sales (A6)	2,031,088	1,873,324	157,764	8.4	97,527	104,400	(6,873)	(6.6)	2.08259	1.79437	0.28822	16.1
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	2,389,434	2,276,124	113,310	5.0	119,101	125,790	(6,689)	(5.3)	2.00622	1.80946	0.19676	10.9
23. Net Inadvertant Interchange					(112)	0	(112)	0.0				
24. Wheeling Rec'd. less Wheeling Del'd.					830	0	830	0.0				
25. Interchange and Wheeling Losses					2,767	1,900	867	46.7				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	25,383,208	25,191,984	191,224	0.8	1,247,574	1,228,582	18,992	1.5	2.03461	2.05049	(0.01588)	(0.8)
27. Net Unbilled	(1,574,951) (a)	(702,047) (a)	(872,904)	124.3	(77,408)	(34,238)	(43,170)	126.1	(0.12624)	(0.05714)	(0.06910)	120.9
28. Company Use	93,063 (a)	82,020 (a)	11,063	13.5	4,575	4,000	575	14.4	0.00727	0.00671	0.00056	8.3
29. T & D Losses	821,433 (a)	752,489 (a)	68,944	9.2	40,373	36,698	3,675	10.0	0.06417	0.06157	0.00260	4.2
30. System KWH Sales	25,383,208	25,191,984	191,224	0.8	1,280,034	1,222,122	57,912	4.7	1.98301	2.06133	(0.07832)	(3.8)
31. Wholesale KWH Sales	(454,664)	(190,283)	(264,381)	138.9	(22,928)	(9,231)	(13,697)	148.4	1.98301	2.06135	(0.07834)	(3.8)
32. Jurisdictional KWH Sales	24,928,544	25,001,701	(73,157)	(0.3)	1,257,106	1,212,891	44,215	3.6	1.98301	2.06133	(0.07832)	(3.8)
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	24,945,495	25,018,702	(73,207)	(0.3)	1,257,106	1,212,891	44,215	3.6	1.98436	2.06273	(0.07837)	(3.8)
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	366,746	370,814	(3,868)	(1.0)	1,257,106	1,212,891	44,215	3.6	0.02917	0.03056	(0.00139)	(4.5)
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	1,257,106	1,212,891	44,215	3.6	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	1,257,106	1,212,891	44,215	3.6	0.00000	0.00000	0.00000	0.0
36. True-up *	305,574	305,574	0	0.0	1,257,106	1,212,891	44,215	3.6	0.02431	0.02519	(0.00088)	(3.5)
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	25,617,815	25,694,890	(77,075)	(0.3)	1,257,106	1,212,891	44,215	3.6	2.03784	2.11848	(0.08064)	(3.8)
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.03931	2.12001	(0.08070)	(3.8)
40. GPIF * (Already Adjusted for Taxes)	(23,059)	(23,059)	0	0.0	1,257,106	1,212,891	44,215	3.6	(0.00183)	(0.00190)	0.00007	(3.7)
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	25,594,756	25,671,831	(77,075)	(0.3)	1,257,106	1,212,891	44,215	3.6	2.03748	2.11811	(0.08063)	(3.8)
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.037	2.118	(0.081)	(3.8)

* Based on Jurisdictional Sales (a) Included for Informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: FEBRUARY, 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	53,482,227	53,549,048	(66,821)	(0.1)	2,647,089	2,690,102	(43,013)	(1.6)	2.02042	1.99060	0.02982	1.5
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(7,980)	(8,000)	20	(0.3)	2,647,089 a)	2,690,102 a)	(43,013)	(1.6)	(0.00030)	(0.00030)	0.00000	0.0
4b. Adjustments to Fuel Cost	0	0	0	0.0	2,647,089 a)	2,690,102 a)	(43,013)	(1.6)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	(158)	0	(158)	0.0	2,647,089 a)	2,690,102 a)	(43,013)	(1.6)	(0.00001)	0.00000	(0.00001)	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	53,474,089	53,541,048	(66,959)	(0.1)	2,647,089	2,690,102	(43,013)	(1.6)	2.02011	1.99030	0.02981	1.5
6. Fuel Cost of Purchased Power - Firm (A7)	6,812,311	2,820,000	3,792,311	134.5	176,657	76,260	100,397	131.7	3.74302	3.69788	0.04514	1.2
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	433,100	(433,100)	(100.0)	0	11,826	(11,826)	(100.0)	0.00000	3.66227	(3.66227)	(100.0)
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	1,141,922	1,102,900	39,022	3.5	58,002	64,579	(6,577)	(10.2)	1.96876	1.70783	0.26093	15.3
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	7,754,233	4,356,000	3,398,233	78.0	234,659	152,665	81,994	53.7	3.30447	2.85331	0.45116	15.8
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					2,881,748	2,842,767	38,981	1.4				
14. Fuel Cost of Economy Sales (A6)	0	26,200	(26,200)	(100.0)	0	944	(944)	(100.0)	0.00000	2.77542	(2.77542)	(100.0)
15. Gain on Economy Sales - 80% (A6)	0	6,240	(6,240)	(100.0)	0	944 a)	(944)	(100.0)	0.00000	0.66102	(0.66102)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	190,767	295,300	(104,533)	(35.4)	12,186	19,153	(6,967)	(36.4)	1.56548	1.54180	0.02368	1.5
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	232,025	207,300	24,725	11.9	12,412	11,368	1,044	9.2	1.86936	1.82354	0.04582	2.5
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	622,322	361,300	261,022	72.2	26,673	15,696	10,977	69.9	2.33315	2.30186	0.03129	1.4
21. Fuel Cost of Other Power Sales (A6)	4,492,521	3,887,666	604,633	15.6	222,347	216,000	6,347	2.9	2.02050	1.79995	0.22055	12.3
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	5,537,635	4,784,226	753,407	15.7	273,618	263,161	10,457	4.0	2.02386	1.81799	0.20587	11.3
23. Net Inadvertant Interchange					(420)	0	(420)	0.0				
24. Wheeling Rec'd. less Wheeling Del'vd.					1,466	0	1,466	0.0				
25. Interchange and Wheeling Losses					6,201	4,000	2,201	55.0				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	55,690,687	53,112,820	2,577,867	4.9	2,602,975	2,575,606	27,369	1.1	2.13950	2.06215	0.07735	3.8
27. Net Unbilled	(2,122,812) (a)	(2,224,379) (a)	101,567	(4.6)	(99,220)	(107,867)	8,647	(8.0)	(0.08155)	(0.08636)	0.00481	(5.6)
28. Company Use	190,244 (a)	164,972 (a)	25,272	15.3	8,892	8,000	892	11.2	0.00731	0.00641	0.00090	14.0
29. T & D Losses	1,964,703 (a)	2,073,554 (a)	(108,851)	(5.2)	91,830	100,553	(8,723)	(8.7)	0.07552	0.08053	(0.00501)	(6.2)
30. System KWH Sales	55,690,687	53,112,820	2,577,867	4.9	2,601,473	2,574,920	26,553	1.0	2.14074	2.06270	0.07804	3.8
31. Wholesale KWH Sales	(1,189,810)	(453,082)	(736,728)	162.6	(54,981)	(21,964)	(33,017)	150.3	2.16404	2.06284	0.10120	4.9
32. Jurisdictional KWH Sales	54,500,877	52,659,738	1,841,139	3.5	2,546,492	2,552,956	(6,464)	(0.3)	2.14023	2.06270	0.07753	3.8
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	54,537,937	52,695,546	1,842,391	3.5	2,546,492	2,552,956	(6,464)	(0.3)	2.14169	2.06410	0.07759	3.8
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	733,593	743,041	(9,448)	(1.3)	2,546,492	2,552,956	(6,464)	(0.3)	0.02881	0.02911	(0.00030)	(1.0)
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	2,546,492	2,552,956	(6,464)	(0.3)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	2,546,492	2,552,956	(6,464)	(0.3)	0.00000	0.00000	0.00000	0.0
36. True-up *	611,148	611,148	0	0.0	2,546,492	2,552,956	(6,464)	(0.3)	0.02400	0.02394	0.00006	0.3
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	55,882,678	54,049,735	1,832,943	3.4	2,546,492	2,552,956	(6,464)	(0.3)	2.19450	2.11714	0.07736	3.7
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.19608	2.11866	0.07742	3.7
40. GPIF * (Already Adjusted for Taxes)	(46,118)	(46,118)	0	0.0	2,546,492	2,552,956	(6,464)	(0.3)	(0.00181)	(0.00181)	0.00000	0.0
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	55,836,560	54,003,617	1,832,943	3.4	2,546,492	2,552,956	(6,464)	(0.3)	2.19427	2.11685	0.07742	3.7
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.194	2.117	0.077	3.6

(a) Included for Informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2000

SCHEDULE A2
PAGE 1 OF 3

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	25,140,483	25,441,708	(301,225)	(1.2)	53,482,227	53,549,048	(66,821)	(0.1)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	2,389,434	2,276,124	113,310	5.0	5,537,635	4,784,228	753,407	15.7
3. FUEL COST OF PURCHASED POWER	2,077,762	1,323,100	754,662	57.0	6,612,311	2,820,000	3,792,311	134.5
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	558,975	533,600	25,375	4.8	1,141,922	1,102,900	39,022	3.5
4. ENERGY COST OF ECONOMY PURCHASES	0	173,700	(173,700)	0.0	0	433,100	(433,100)	0.0
5. TOTAL FUEL & NET POWER TRANSACTION	25,387,786	25,195,984	191,802	0.8	55,698,825	53,120,820	2,578,005	4.9
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(4,500)	(4,000)	(500)	12.5	(7,980)	(8,000)	20	(0.3)
6b. ADJ. TO FUEL COST (Gatliff Coal)	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST (Big Bend 1&2 FGD Proj.)	(78)	0	(78)	0.0	(158)	0	(158)	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	25,383,208	25,191,984	191,224	0.8	55,690,687	53,112,820	2,577,867	4.9
* INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,257,106	1,212,891	44,215	3.6	2,546,492	2,552,956	(6,464)	(0.3)
2. NONJURISDICTIONAL SALES	22,928	9,231	13,697	148.4	54,981	21,964	33,017	150.3
3. TOTAL SALES	1,280,034	1,222,122	57,912	4.7	2,601,473	2,574,920	26,553	1.0
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9820880	0.9924467	(0.0103587)	(1.0)	0.9788654	0.9914700	(0.0126046)	(1.3)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2000

Revised with March 2000 filing

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	28,817,039	27,885,922	931,117	3.3	58,201,612	58,709,729	(508,117)	(0.9)
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	(305,574)	(305,574)	0	0.0	(611,148)	(611,148)	0	0.0
b. INCENTIVE PROVISION	23,059	23,059	0	0.0	46,118	46,118	0	0.0
c. TRANSITION ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
d. OTHER ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	28,534,524	27,603,407	931,117	3.4	57,636,582	58,144,699	(508,117)	(0.9)
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	25,383,208	25,191,984	191,224	0.8	55,690,687	53,112,820	2,577,867	4.9
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B-4)	0.9820880	0.9924467	(0.0103587)	(1.0)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	24,928,544	25,001,701	(73,157)	(0.3)	54,500,877	52,659,738	1,841,139	3.5
6A.JURISDIC. LOSS MULTIPLIER	1.00068	1.00068	0.0000	0.0	NA	NA	-	-
6B. (LINE 6 x LINE 6A)	24,945,495	25,018,702	(73,207)	(0.3)	54,537,937	52,695,546	1,842,391	3.5
6C.PEABODY COAL CONTRACT BUY-OUT AMORT.	373,435	373,435	0	0.0	749,401	749,401	0	0.0
6D.(LINE 6C x LINE 5) PB. JURISD.	366,746	370,614	(3,868)	(1.0)	733,593	743,041	(9,448)	(1.3)
6E.OTHER (SPARE INPUT #1)	0	0	0	0.0	0	0	0	0.0
6F. OIL BELOW THE DISCHARGE VALVE	0	0	0	0.0	0	0	0	0.0
6G. OTHER (SPARE INPUT #2)	0	0	0	0.0	0	0	0	0.0
6H. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. 6B+6D+6E+6F+6G)	25,312,241	25,389,316	(77,075)	(0.3)	55,271,530	53,438,587	1,832,943	3.4
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6H)	3,222,283	2,214,091	1,008,192	45.5	2,365,052	4,706,112	(2,341,060)	(49.7)
8. INTEREST PROVISION FOR THE MONTH	(53,986)	1,739	(55,725)	(3,204.4)	(113,862)	(9,125)	(104,737)	1,147.8
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(20,821,012)	(8,760,088)	(12,060,924)	137.7	NOT APPLICABLE			
9a.DEFERRED TRUE-UP BEGINNING OF PERIOD	7,879,936	7,879,936	0	0.0	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	305,574	305,574	0	0.0	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	(9,467,205)	1,641,252	(11,108,457)	(676.8)	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2000

SCHEDULE A2
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Revised with March 2000 filing

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	(12,941,076)	(880,152)	(12,060,924)	1,370.3	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. *(LINES C-7 + C-9 + C-9a + C-10)*	(9,413,219)	1,639,513	(11,052,732)	(674.1)	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(22,354,295)	759,361	(23,113,656)	(3,043.8)	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	(11,177,148)	379,681	(11,556,829)	(3,043.8)	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.800	5.500	0.300	5.5	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	5.800	5.500	0.300	5.5	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	11.600	11.000	0.600	5.5	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	5.800	5.500	0.300	5.5	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.483	0.458	0.025	5.5	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	(53,986)	1,739	(55,725)	(3,204.4)	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: FEBRUARY 2000

SCHEDULE A3
PAGE 1 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
FUEL COST OF SYSTEM NET GENERATION ($)								
1 HEAVY OIL	70,071	81,553	(11,482)	(14.1)	173,633	166,647	6,986	4.2
2 LIGHT OIL	488,298	475,767	12,531	2.6	1,058,717	1,006,423	52,294	5.2
3 COAL	24,582,114	24,884,388	(302,274)	(1.2)	52,249,877	52,375,978	(126,101)	(0.2)
4 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
5 NUCLEAR	0	0	0	0.0	0	0	0	0.0
6 OTHER	0	0	0	0.0	0	0	0	0.0
7 TOTAL ($)	25,140,483	25,441,708	(301,225)	(1.2)	53,482,227	53,549,048	(66,821)	(0.1)
SYSTEM NET GENERATION (MWH)								
8 HEAVY OIL	483	1,938	(1,455)	(75.1)	1,704	3,955	(2,251)	(56.9)
9 LIGHT OIL	9,617	13,583	(3,966)	(29.2)	18,767	28,426	(9,659)	(34.0)
10 COAL	1,269,354	1,268,064	1,290	0.1	2,626,618	2,657,721	(31,103)	(1.2)
11 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
12 NUCLEAR	0	0	0	0.0	0	0	0	0.0
13 OTHER	0	0	0	0.0	0	0	0	0.0
14 TOTAL (MWH)	1,279,454	1,283,585	(4,131)	(0.3)	2,647,089	2,690,102	(43,013)	(1.6)
UNITS OF FUEL BURNED								
15 HEAVY OIL (BBL)	3,665	4,886	(1,221)	(25.0)	9,124	9,970	(846)	(8.5)
16 LIGHT OIL (BBL)	15,666	20,181	(4,515)	(22.4)	35,957	42,578	(6,621)	(15.6)
17 COAL (TON)	571,794	574,173	(2,379)	(0.4)	1,209,254	1,204,602	4,652	0.4
18 NATURAL GAS (MCF)	0	0	0	0.0	0	0	0	0.0
19 NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20 OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
BTUS BURNED (MMBTU)								
21 HEAVY OIL	23,304	30,886	(7,582)	(24.5)	58,002	63,024	(5,022)	(8.0)
22 LIGHT OIL	90,990	117,072	(26,082)	(22.3)	208,994	247,232	(38,238)	(15.5)
23 COAL	13,031,248	13,177,684	(146,436)	(1.1)	27,218,764	27,630,649	(411,885)	(1.5)
24 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
25 NUCLEAR	0	0	0	0.0	0	0	0	0.0
26 OTHER	0	0	0	0.0	0	0	0	0.0
27 TOTAL (MMBTU)	13,145,542	13,325,642	(180,100)	(1.4)	27,485,760	27,940,905	(455,145)	(1.6)
GENERATION MIX (% MWH)								
28 HEAVY OIL	0.04	0.15	(0.11)	-	0.06	0.15	(0.09)	-
29 LIGHT OIL	0.75	1.06	(0.31)	-	0.71	1.06	(0.35)	-
30 COAL	99.21	98.79	0.42	-	99.23	98.80	0.43	-
31 NATURAL GAS	0.00	0.00	0.00	-	0.00	0.00	0.00	-
32 NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33 OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34 TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
FUEL COST PER UNIT								
35 HEAVY OIL ($/BBL)	19.12	16.69	2.43	14.6	19.03	16.71	2.32	13.9
36 LIGHT OIL ($/BBL)	31.17	23.57	7.60	32.2	29.44	23.64	5.80	24.5
37 COAL ($/TON)	42.99	43.34	(0.35)	(0.8)	43.21	43.48	(0.27)	(0.6)
38 NATURAL GAS ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40 OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
FUEL COST PER MMBTU ($/MMBTU)								
41 HEAVY OIL	3.01	2.64	0.37	14.0	2.99	2.64	0.35	13.3
42 LIGHT OIL	5.37	4.06	1.31	32.3	5.07	4.07	1.00	24.6
43 COAL	1.89	1.89	0.00	0.0	1.92	1.90	0.02	1.1
44 NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
45 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47 TOTAL ($/MMBTU)	1.91	1.91	0.00	0.0	1.95	1.92	0.03	1.6

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: FEBRUARY 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
BTU BURNED PER KWH (BTU/KWH)								
48 HEAVY OIL	48,248	15,937	32,311	202.7	34,039	15,935	18,104	113.6
49 LIGHT OIL	9,461	8,619	842	9.8	11,136	8,697	2,439	28.0
50 COAL	10,266	10,392	(126)	(1.2)	10,363	10,396	(33)	(0.3)
51 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
52 NUCLEAR	0	0	0	0.0	0	0	0	0.0
53 OTHER	0	0	0	0.0	0	0	0	0.0
54 TOTAL (BTU/KWH)	10,274	10,382	(108)	(1.0)	10,383	10,387	(4)	0.0
GENERATED FUEL COST PER KWH (cents/KWH)								
55 HEAVY OIL	14.51	4.21	10.30	244.7	10.19	4.21	5.98	142.0
56 LIGHT OIL	5.08	3.50	1.58	45.1	5.64	3.54	2.10	59.3
57 COAL	1.94	1.96	(0.02)	(1.0)	1.99	1.97	0.02	1.0
58 NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
59 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61 TOTAL (cents/KWH)	1.96	1.98	(0.02)	(1.0)	2.02	1.99	0.03	1.5

SCHEDULE A4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD/MONTH OF: FEBRUARY 2000

(A) PLANT/UNIT	(B) NET CAPABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPC. FACTO (%)	(E) EQUIV. AVAIL. FACTO (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COS PER KWH (cents /KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	32	67	0.3	100.0	16.3	-	HVY.OIL	-	-	-	-	-	-
H.P.#2	32	0	0.0	0.0	0.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#3	32	120	0.5	100.0	20.9	-	HVY.OIL	-	-	-	-	-	-
H.P.#4	41	212	0.7	100.0	19.6	-	HVY.OIL	-	-	-	-	-	-
H.P.#5	52	255	0.7	45.8	23.9	-	HVY.OIL	-	-	-	-	-	-
H.P. STATION	189	654	0.5	68.2	17.1	35,398	HVY.OIL	3,640	6,359,271	23,150.1	69,595	10.64	19.12
GAN.#1	114	41,808	49.3	87.2	59.6	11,715	COAL	20,590	23,786,882	489,771.9	836,660	2.00	40.63
GAN.#2	88	38,359	58.6	87.9	71.8	12,443	COAL	20,097	23,750,560	477,315.0	816,628	2.13	40.63
GAN.#3	155	38,219	33.1	62.2	62.6	11,901	COAL	21,547	21,109,301	454,842.1	875,547	2.29	40.63
GAN.#4	169	54,453	43.3	72.8	61.1	11,891	COAL	31,527	20,537,679	647,491.4	1,281,078	2.35	40.63
GAN.#5	242	82,004	45.5	67.2	60.3	11,112	COAL	38,692	23,551,080	911,238.4	1,572,223	1.92	40.63
GAN.#6	392	58,684	20.1	27.3	72.4	10,615	COAL	25,948	24,008,001	622,959.6	1,054,379	1.80	40.63
GANNON STA.	1,160	313,527	36.3	57.4	65.6	11,494	COAL	158,401	22,749,973	3,603,618.4	6,436,515	2.05	40.63
B.B.#1	426	189,859	59.9	76.3	76.1	10,101	COAL	81,244	23,605,040	1,917,767.9	3,402,331	1.79	41.88
B.B.#2	426	172,033	54.3	69.9	78.4	9,579	COAL	70,972	23,218,220	1,647,843.5	2,972,160	1.73	41.88
B.B.#3	443	232,299	70.5	87.0	81.3	9,810	COAL	97,581	23,352,740	2,278,783.7	4,086,490	1.76	41.88
B.B. 1 - 3	1,295	594,190	61.7	77.9	78.6	9,836	COAL	249,797	23,396,578	5,844,395.1	10,460,981	1.76	41.88
B.B.#4	447	263,444	79.2	96.7	84.7	9,643	COAL	121,728	20,868,828	2,540,320.7	5,898,355	2.24	48.46
B.B. STA.	1,742	857,634	66.2	82.7	80.2	9,777	COAL	371,525	22,568,376	8,384,715.8	16,359,336	1.91	44.03
SEB-PHIL. #1(HVY OIL)	17	(85)	0.0	0.0	0.0	0	HVY.OIL	25	6,160,000	154.5	476	0.00	19.04
SEB-PHIL. #2(HVY OIL)	17	(86)	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
SEB-PHILLIPS TOTAL	34	(171)	0.0	0.0	0.0	0	HVY.OIL	25	6,160,000	154.5	476	0.00	19.04
POLK COAL	250	98,193	52.8	62.3	90.0	10,621	COAL	41,868	24,909,499	1,042,913.4	1,786,263	1.82	42.66
POLK OIL	245	9,286	5.1	76.2	43.1	9,135	LGT.OIL	14,609	5,806,544	84,825.3	456,218	4.91	31.23
POLK TOTAL	250	107,479	57.9	75.5	-	10,493	-	-	-	1,127,738.7	2,242,481	2.09	-
GAN.C.T.#1	17	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	17	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#2	80	151	0.3	100.0	47.2	18,048	LGT.OIL	467	5,831,550	2,725.2	14,181	9.39	30.35
B.B.C.T.#3	80	180	0.3	100.0	37.5	19,108	LGT.OIL	590	5,831,440	3,439.5	17,899	9.94	30.35
C.T. TOTAL	194	331	0.2	100.0	34.9	18,624	LGT.OIL	1,057	5,831,489	6,164.7	32,080	9.69	30.35
TOT. COAL (GN,BB,POLK)	3,152	1,269,354	54.1	71.8	75.6	10,266	COAL	571,794	22,790,105	13,031,247.6	24,582,114	1.94	42.99
SYSTEM	3,569	1,279,454	48.2	73.4	68.0	10,274	-	-	-	13,145,542.2	25,140,483	1.96	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS

NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2000

SCHEDULE A5
PAGE 1 OF 2

		CURRENT MONTH				PERIOD TO DATE			
	HEAVY OIL (1)	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	PURCHASES:								
2	UNITS (BBL)	0	4,886	(4,886)	(100.0)	0	9,970	(9,970)	(100.0)
3	UNIT COST ($/BBL)	0.00	15.18	(15.18)	(100.0)	0.00	15.58	(15.58)	(100.0)
4	AMOUNT ($)	0	74,169	(74,169)	(100.0)	21,875	155,310	(133,435)	(85.9)
5	BURNED:								
6	UNITS (BBL)	3,665	4,886	(1,221)	(25.0)	9,124	9,970	(846)	(8.5)
7	UNIT COST ($/BBL)	19.12	16.69	2.43	14.6	19.03	16.71	2.32	13.9
8	AMOUNT ($)	70,071	81,553	(11,482)	(14.1)	173,633	166,647	6,986	4.2
9	ENDING INVENTORY:								
10	UNITS (BBL)	81,136	175,493	(94,357)	(53.8)	81,136	175,493	(94,357)	(53.8)
11	UNIT COST ($/BBL)	19.19	16.86	2.33	13.8	19.19	16.86	2.33	13.8
12	AMOUNT ($)	1,556,794	2,958,713	(1,401,919)	(47.4)	1,556,794	2,958,713	(1,401,919)	(47.4)
13									
14	DAYS SUPPLY:	51	111	(60)	(54.1)	-	-	-	-
	LIGHT OIL (2)								
15	PURCHASES:								
16	UNITS (BBL)	30,831	30,508	323	1.1	72,477	65,074	7,403	11.4
17	UNIT COST ($/BBL)	36.86	23.08	13.78	59.7	33.59	23.28	10.31	44.3
18	AMOUNT ($)	1,136,542	704,199	432,343	61.4	2,434,377	1,514,864	919,513	60.7
19	BURNED:								
20	UNITS (BBL)	15,666	20,181	(4,515)	(22.4)	35,957	42,578	(6,621)	(15.6)
21	UNIT COST ($/BBL)	31.17	23.57	7.60	32.2	29.44	23.64	5.80	24.5
22	AMOUNT ($)	488,298	475,767	12,531	2.6	1,058,717	1,006,423	52,294	5.2
23	ENDING INVENTORY:								
24	UNITS (BBL)	86,596	110,358	(23,762)	(21.5)	86,596	110,358	(23,762)	(21.5)
25	UNIT COST ($/BBL)	30.71	23.19	7.52	32.4	30.71	23.19	7.52	32.4
26	AMOUNT ($)	2,659,373	2,558,726	100,647	3.9	2,659,373	2,558,726	100,647	3.9
27									
28	DAYS SUPPLY: NORMAL	80	102	(22)	(21.6)	-	-	-	-
29	DAYS SUPPLY: EMERGENCY	12	16	(4)	(25.0)	-	-	-	-
	COAL (3)								
30	PURCHASES:								
31	UNITS (TONS)	837,485	600,400	237,085	39.5	1,445,787	1,293,800	151,987	11.7
32	UNIT COST ($/TON)	41.93	42.50	(0.57)	(1.3)	40.87	42.57	(1.70)	(4.0)
33	AMOUNT ($)	35,113,645	25,514,373	9,599,272	37.6	59,089,611	55,078,174	4,011,437	7.3
34	BURNED:								
35	UNITS (TONS)	571,794	574,173	(2,379)	(0.4)	1,209,254	1,204,602	4,652	0.4
36	UNIT COST ($/TON)	42.99	43.34	(0.35)	(0.8)	43.21	43.48	(0.27)	(0.6)
37	AMOUNT ($)	24,582,114	24,884,388	(302,274)	(1.2)	52,249,877	52,375,978	(126,101)	(0.2)
38	ENDING INVENTORY:								
39	UNITS (TONS)	1,013,549	952,698	60,851	6.4	1,013,549	952,698	60,851	6.4
40	UNIT COST ($/TON)	42.06	43.24	(1.18)	(2.7)	42.06	43.24	(1.18)	(2.7)
41	AMOUNT ($)	42,633,680	41,195,775	1,437,905	3.5	42,633,680	41,195,775	1,437,905	3.5
42									
43	DAYS SUPPLY:	50	47	3	6.4	-	-	-	-
	NATURAL GAS								
44	PURCHASES:								
45	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
46	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
48	BURNED:								
49	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
50	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
51	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
52	ENDING INVENTORY:								
53	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
54	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
56									
57	DAYS SUPPLY:	0	0	0	0.0	-	-	-	-
	NUCLEAR								
58	BURNED:								
59	UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
60	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0	0.00	0.0
61	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2000

SCHEDULE A5
PAGE 2 OF 2

OTHER	CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH %	PERIOD TO DATE ACTUAL	PERIOD TO DATE ESTIMATED	PERIOD TO DATE DIFFERENCE AMOUNT	PERIOD TO DATE %
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
74 DAYS SUPPLY:	0	0	0	0.0	-	-	-	-

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	1,181
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	1,181

(2)
RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(6,310)	(191,500)
OTHER USAGE	(1,966)	(60,956)
TOTAL	(8,276)	(252,456)

(3)
RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	19,476
IGNITION	190,319
IGNITION PROPANE	9,879
AERIAL SURVEY ADJ.	192,136
ADDITIVES	53,988
TOTAL	465,798

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: FEBRUARY 2000

SCHEDULE A6
PAGE 1 OF 3

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	754.0	0.0	754.0	2.944	3.806	22,200.00	28,700.00	5,200.00
VARIOUS	JURISDICTIONAL	SCH. -D	5,644.0	0.0	5,644.0	1.820	1.820	102,700.00	102,700.00	
VARIOUS	SEPARATED	SCH. -D	9,257.0	0.0	9,257.0	1.737	1.912	160,800.00	177,000.00	
HARDEE POWER PARTNERS	SEPARATED	CONTRACT	5,735.0	0.0	5,735.0	2.295	3.184	131,600.00	182,600.00	
FMPA		SCH. -D	104,400.0	0.0	104,400.0	1.794	1.794	1,873,324.00	1,873,324.00	
VARIOUS	JURISDICTIONAL	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	125,790.0	0.0	125,790.0	1.821	1.880	2,290,624.00	2,364,324.00	5,200.00
LESS TRANSMISSION COSTS		-						(18,100.00)		
LESS VARIABLE O & M COSTS		-						(1,600.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS		-						5,200.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-	125,790.0	0.0	125,790.0	1.809	1.880	2,276,124.00	2,364,324.00	5,200.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		*ECON.-C*	*0.0*	*0.0*	*0.0*	0.000	0.000	0.00	0.00	0.00
CITY OF NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENRGY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
OGLETHORPE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENN. VALLEY AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPAR.	SCH. -D	*0.0*	*0.0*	*0.0*	*0.000*	*0.000*	*0.00*	*0.00*	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	5,850.0	0.0	5,850.0	1.875	2.025	109,694.26	118,475.65	
REEDY CREEK	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEP. CONTRACT		9,334.0	0.0	9,334.0	2.298	3.140	214,495.32	293,087.60	
SEMINOLE ELECTRIC CO-OP PRE	JURISD.	SCH. -D	5,355.0	60.4	5,294.6	1.738	1.738	92,004.85	92,004.85	
SEMINOLE ELECTRIC CO-OP HAR	JURISD.	SCH. -D	1,095.0	0.0	1,095.0	1.768	1.768	19,361.35	19,361.35	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: FEBRUARY 2000

SCHEDULE A6
PAGE 2 OF 3

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA		SCH. -D	65,980.0	0.0	65,980.0	1.927	1.927	1,271,187.31	1,271,187.31	
HARDEE POWER PART. TO FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FLA. PWR.& LT.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO JACKSONVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO KISSIMMEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO ORLANDO		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO SEMINOLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FT. PIERCE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO LK. WORTH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO ENERGY AUTHORI		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FPC		SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PART. TO FLA. PWR.& LT.		SCH. -MB	553.0	0.0	553.0	2.570	2.570	14,212.43	14,212.43	
SEMINOLE ELECTRIC CO-OP		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: FEBRUARY 2000

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	SCH.-MB	2,110.0	0.0	2,110.0	3.024	3.024	63,807.45	63,807.45	
FLA. PWR. & LIGHT	SCH.-MB	26,071.0	0.0	26,071.0	2.316	2.316	603,897.46	603,897.46	
CITY OF LAKELAND	SCH.-MB	297.0	0.0	297.0	2.489	2.489	7,392.87	7,392.87	
ORLANDO UTIL. COMM.	SCH.-MB	1,228.0	0.0	1,228.0	2.302	2.302	28,269.46	28,269.46	
REEDY CREEK	SCH.-MB	20.0	0.0	20.0	2.257	2.257	451.31	451.31	
THE ENERGY AUTHORITY	SCH.-MB	318.0	0.0	318.0	2.803	2.803	8,913.97	8,913.97	
SOUTHERN COMPANY	SCH.-MB	950.0	0.0	950.0	3.469	3.469	32,955.40	32,955.40	
ADJUSTMENTS TO PREVIOUS MO	MTH/YR	TYP SCHED.							
HARDEE POWER PARTNERS ES	JAN. 00	SEP CONTRACT	(17,339.0)	0.0	(17,339.0)	2.639	3.380	(457,576.21)	(586,058.20)	
HARDEE POWER PARTNERS ACT	JAN. 00	SEP CONTRACT	17,339.0	0.0	17,339.0	2.298	3.140	398,450.22	544,444.60	
CITY OF NEW SMYRNA BCH.	JAN. 00	SEP SCH. -D	(6,336.0)	0.0	(6,336.0)	1.869	2.020	(118,427.87)	(128,003.10)	
CITY OF NEW SMYRNA BCH.	JAN. 00	SEP SCH. -D	6,336.0	0.0	6,336.0	1.869	2.002	118,427.87	126,815.90	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.			5,850.0	0.0	5,850.0	1.875	2.005	109,694.26	117,288.45	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			6,450.0	60.4	6,389.6	1.743	1.743	111,366.20	111,366.20	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.			9,334.0	0.0	9,334.0	1.665	2.694	155,369.33	251,474.00	
SUB-TOTAL FMPA D POWER SALES			65,980.0	0.0	65,980.0	1.927	1.927	1,271,187.31	1,271,187.31	
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE MB POWER SALES-JURISD.			31,547.0	0.0	31,547.0	2.409	2.409	759,900.35	759,900.35	
TOTAL INCLUDING VARIABLE O & M COSTS			119,161.0	60.4	119,100.6	2.021	2.108	2,407,517.45	2,511,216.31	0.00
LESS VARIABLE O & M COSTS								0.00		
LESS VARIABLE O & M COSTS - HARDEE								0.00		
LESS TRANSMISSION COSTS SCH. D (SEP.)								(18,083.80)		
PLUS 80% OF ECON. ENERGY SALES PROFITS *								0.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS			119,161.0	60.4	119,100.6	2.006	2.108	2,389,433.65	2,511,216.31	0.00
CURRENT MONTH:										
DIFFERENCE			(6,629.0)	60.4	(6,689.4)	0.197	0.228	113,309.65	146,892.31	(5,200.00)
DIFFERENCE %			(5.3)	0.0	(5.3)	10.9	12.1	5.0	6.2	(100.0)
PERIOD TO DATE:										
ACTUAL			274,128.0	510.9	273,617.1	2.024	2.128	5,537,635.04	5,822,968.16	0.00
ESTIMATED			263,161.0	0.0	263,161.0	1.818	1.899	4,784,228.00	4,996,888.00	6,240.00
DIFFERENCE			10,967.0	510.9	10,456.1	0.206	0.229	753,407.04	826,080.16	(6,240.00)
DIFFERENCE %			4.2	0.0	4.0	11.3	12.1	15.7	16.5	(100.0)

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. SEC 60% OR $859.73 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH FEBRUARY 2000

SCHEDULE A7

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:									
VARIOUS		EMER.	3,472.0	0.0	1,925.0	1,547.0	7.369	7.369	114,000.00
HARDEE POWER PARTNERS		IPP	12,189.0	0.0	0.0	12,189.0	4.323	4.323	526,900.00
VARIOUS		OTHER	22,560.0	0.0	0.0	22,560.0	3.024	3.024	682,200.00
TOTAL		-	38,221.0	0.0	1,925.0	36,296.0	3.645	3.645	1,323,100.00
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	27,527.0	0.0	0.0	27,527.0	3.985	3.985	1,097,010.38
HARDEE PWR. PART.-OTHERS		IPP	553.0	0.0	0.0	553.0	2.466	2.466	13,639.27
OKEELANTA		SCH.-D	5,316.0	0.0	0.0	5,316.0	4.621	4.621	245,678.00
AUBURNDALE POWER PARTNERS		SCH.-D	5,021.0	0.0	0.0	5,021.0	2.334	2.334	117,191.31
FLA. POWER CORP.		SCH.-Ja	789.0	0.0	270.3	518.7	4.620	4.620	23,965.39
FLA. POWER CORP.		SCH.-Jc	9,952.0	0.0	0.0	9,952.0	3.212	3.212	319,707.00
FLA. POWER & LIGHT		SCH.-Ja	1,447.0	0.0	1,023.7	423.3	4.836	4.836	20,472.66
FLA. POWER & LIGHT		SCH.-Jc	5,986.0	0.0	0.0	5,986.0	4.464	4.464	267,186.50
CITY OF LAKELAND		SCH.-Ja	446.0	0.0	446.0	0.0	0.000	0.000	0.00
CITY OF LAKELAND		SCH.-Jc	654.0	0.0	0.0	654.0	3.815	3.815	24,947.50
ORLANDO		SCH.-Ja	183	0.0	48.0	135.0	4.826	4.826	6,515.41
ORLANDO		SCH.-Jc	692	0.0	0.0	692.0	5.400	5.400	37,368.00
THE ENERGY AUTHORITY		SCH.-Ja	40	0.0	0.0	40.0	4.000	4.000	1,600.00
THE ENERGY AUTHORITY		SCH.-Jc	2327	0.0	0.0	2,327.0	3.149	3.149	73,278.75
REEDY CREEK		SCH.-Jc	20	0.0	0.0	20.0	3.600	3.600	720.00
TALLAHASSEE		SCH.-Jc	343	0.0	0.0	343.0	3.585	3.585	12,296.15
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIV	Jan-00	IPP	(52,326.0)	0.0	0.0	(52,326.0)	3.919	3.919	(2,050,622.25)
HARDEE PWR. PART.-NATIV	Jan-00	IPP	52,326.0	0.0	0.0	52,326.0	3.522	3.522	1,843,092.34
OKEELANTA	Jan-00	SCH.-D	(7,430.0)	0.0	0.0	(7,430.0)	3.824	3.824	(284,150.00)
OKEELANTA	Jan-00	SCH.-D	7,430.0	0.0	0.0	7,430.0	4.174	4.174	310,155.00
THE ENERGY AUTHORITY	Dec-99	SCH.-Jc	(1,040.0)	0.0	0.0	(1,040.0)	3.847	3.847	(40,012.80)
THE ENERGY AUTHORITY	Dec-99	SCH.-Jc	1,040.0	0.0	0.0	1,040.0	3.639	3.639	37,846.42
TALLAHASSEE	Dec-99	SCH.-Jc	(59.0)	0.0	0.0	(59.0)	3.038	3.038	(1,792.28)
TALLAHASSEE	Dec-99	SCH.-Jc	59.0	0.0	0.0	59.0	2.829	2.829	1,669.38
TOTAL			61,296.0	0.0	1,788.0	59,508.0	3.492	3.492	2,077,762.33
CURRENT MONTH:									
DIFFERENCE		-	23,075.0	0.0	(137.0)	23,212.0	(0.153)	(0.153)	754,662.33
DIFFERENCE %		-	60.4	0.0	(7.1)	64.0	(4.2)	(4.2)	57.0
PERIOD TO DATE:									
ACTUAL		-	189,565.00	0.00	12,908.40	176,656.6	3.743	3.743	6,612,311.43
ESTIMATED		-	80,346.0	0.0	4,086.0	76,260.0	3.698	3.698	2,820,000.0
DIFFERENCE		-	109,219.0	0.0	8,822.4	100,396.6	0.045	0.045	3,792,311.43
DIFFERENCE %		-	135.9	0.0	215.9	131.7	1.2	1.2	134.5

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY

SCHEDULE A8

FOR THE MONTH OF: FEBRUARY 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	—CENTS/KWH— (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	31,530.0	0.0	0.0	31,530.0	1.692	1.692	533,600.00
TOTAL	-	31,530.0	0.0	0.0	31,530.0	1.692	1.692	533,600.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	3,961.0	0.0	0.0	3,961.0	1.914	1.914	75,824.62
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	17.0	0.0	0.0	17.0	2.006	2.006	341.02
HILLSBOROUGH COUNTY	COGEN.	17,785.0	0.0	0.0	17,785.0	1.929	1.929	342,998.82
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	1,457.0	0.0	0.0	1,457.0	2.252	2.252	32,806.91
FARMLAND HYDRO LP	COGEN.	709.0	0.0	0.0	709.0	2.130	2.130	15,104.10
IMC-AGRICO-S. PIERCE	COGEN.	483.0	0.0	0.0	483.0	2.324	2.324	11,222.99
AUBURNDALE POWER PARTNERS	COGEN.	57.0	0.0	0.0	57.0	2.069	2.069	1,179.11
ORANGE COGENERATION L.P.	COGEN.	5,336.0	0.0	0.0	5,336.0	1.949	1.949	104,000.60
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	23.0	(23.0)	2.922	2.922	(671.99)
SUB-TOTAL FOR FEBRUARY 2000	-	29,805.0	0.0	23.0	29,782.0	1.957	1.957	582,806.18
ADJ. FOR DECEMBER 1999								
IMC-AGRICO-NICHOLS	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
McKAY BAY REFUSE	COGEN.	(4,892.0)	0.0	0.0	(4,892.0)	2.114	2.114	(103,403.38)
		4,892.0	0.0	0.0	4,892.0	2.057	2.057	100,643.57
MULBERRY PHOSPHATES INC.	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
CARGILL RIDGEWOOD	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
IMC-AGRICO-NEW WALES	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
HILLSBOROUGH COUNTY	COGEN.	(17,383.0)	0.0	0.0	(17,383.0)	2.122	2.122	(368,808.95)
		17,383.0	0.0	0.0	17,383.0	2.058	2.058	357,671.66
CARGILL MILLPOINT	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
CF INDUSTRIES INC.	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
FARMLAND HYDRO LP	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
IMC-AGRICO-S. PIERCE	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
AUBURNDALE POWER PARTNERS	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
ORANGE COGENERATION L.P.	COGEN.	(5,693.0)	0.0	0.0	(5,693.0)	2.222	2.222	(126,524.45)
		5,693.0	0.0	0.0	5,693.0	2.048	2.048	116,590.26
CUTRALE CITRUS	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
AS AVAILABLE ASSIGNMENT	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
SUB-TOTAL FOR Dec-99 ADJ.	-	0.0	0.0	0.0	0.0	0.000	0.000	(23,831.27)
GRAND TOTAL		29,805.0	0.0	23.0	29,782.0	1.877	1.877	558,974.91
CURRENT MONTH:								
DIFFERENCE	-	(1,725.0)	0.0	23.0	(1,748.0)	0.185	0.185	25,374.91
DIFFERENCE %	-	(5.5)	0.0	0.0	(5.5)	10.9	10.9	4.8
PERIOD TO DATE:								
ACTUAL		58,388.0	0.0	386.0	58,002.0	1.969	1.969	1,141,921.81
ESTIMATED		64,579.0	0.0	0.0	64,579.0	1.708	1.708	1,102,900.00
DIFFERENCE	-	(6,191.0)	0.0	386.0	(6,577.0)	0.261	0.261	39,021.81
DIFFERENCE %	-	(9.6)	0.0	0.0	(10.2)	15.3	15.3	3.5

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: FEBRUARY 2000

SCHEDULE A9

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	COST IF GENERATED (A) cents/KWH	COST IF GENERATED (B) $	FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	4,861.0	3.573	173,700.00	4.618	224,500.00	50,800.00
TOTAL	-	4,861.0	3.573	173,700.00	4.618	224,500.00	50,800.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL	-	0.0	0.000	0.00	0.000	0.00	0.00
CURRENT MONTH:							
DIFFERENCE	-	(4,861.0)	(3.573)	(173,700.00)	(4.618)	(224,500.00)	(50,800.00)
DIFFERENCE %	-	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		11,826.0	3.662	433,100.00	4.776	564,800.00	131,700.00
DIFFERENCE	-	(11,826.0)	(3.662)	(433,100.00)	(4.776)	(564,800.00)	(131,700.00)
DIFFERENCE %	-	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

MARCH 2000

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH , 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	23,644,591	27,216,137	(3,571,546)	(13.1)	1,279,981	1,364,781	(84,800)	(6.2)	1.84726	1.99418	(0.14692)	(7.4)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(3,265)	(4,000)	735	(18.4)	1,279,981 a)	1,364,781 a)	(84,800)	(6.2)	(0.00026)	(0.00029)	0.00003	(10.3)
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,279,981 a)	1,364,781 a)	(84,800)	(6.2)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	79	0	79	0.0	1,279,981 a)	1,364,781 a)	(84,800)	(6.2)	0.00001	0.00000	0.00001	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	23,641,405	27,212,137	(3,570,732)	(13.1)	1,279,981	1,364,781	(84,800)	(6.2)	1.84701	1.99388	(0.14687)	(7.4)
6. Fuel Cost of Purchased Power - Firm (A7)	5,679,254	1,646,700	4,032,554	244.9	137,587	50,157	87,430	174.3	4.12775	3.28309	0.84466	25.7
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	(10,512)	388,100	(398,612)	(102.7)	0	10,307	(10,307)	(100.0)	#DIV/0!	3.76540	#DIV/0!	#DIV/0!
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 a)	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	564,812	588,800	(23,988)	(4.1)	27,449	31,813	(4,364)	(13.7)	2.05768	1.85082	0.20686	11.2
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	6,233,554	2,623,600	3,609,954	137.6	165,036	92,277	72,759	78.8	3.77709	2.84318	0.93391	32.8
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,445,017	1,457,058	(12,041)	(0.8)				
14. Fuel Cost of Economy Sales (A6)	(1,687)	259,900	(261,587)	(100.6)	0	12,790	(12,790)	(100.0)	#DIV/0!	2.03206	#DIV/0!	#DIV/0!
15. Gain on Economy Sales - 80% (A6)	0	66,480	(66,480)	(100.0)	0 a)	12,790 a)	(12,790)	(100.0)	0.00000	0.51978	(0.51978)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	1	0	1	0.0	0	0	0	0.0	#DIV/0!	0.00000	#DIV/0!	0.0
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	81,887	107,600	(25,713)	(23.9)	4,426	5,773	(1,347)	(23.3)	1.85014	1.86385	(0.01371)	(0.7)
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	229,885	231,400	(1,515)	(0.7)	10,225	10,087	138	1.4	2.24826	2.29404	(0.04578)	(2.0)
21. Fuel Cost of Other Power Sales (A6)	2,544,038	2,014,564	529,474	26.3	124,593	111,600	12,993	11.6	2.04188	1.80516	0.23672	13.1
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	2,854,124	2,679,944	174,180	6.5	139,244	140,250	(1,006)	(0.7)	2.04973	1.91083	0.13890	7.3
23. Net Inadvertant Interchange					1,330	0	1,330	0.0				
24. Wheeling Rec'd. less Wheeling Del'v'd.					21	0	21	0.0				
25. Interchange and Wheeling Losses					3,103	2,100	1,003	47.8				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	27,020,835	27,155,793	(134,958)	(0.5)	1,304,021	1,314,708	(10,687)	(0.8)	2.07212	2.06554	0.00658	0.3
27. Net Unbilled	1,231,087 (a)	794,489 (a)	436,578	55.0	59,411	38,464	20,947	54.5	0.09441	0.06043	0.03398	56.2
28. Company Use	72,835 (a)	82,622 (a)	(9,787)	(11.8)	3,515	4,000	(485)	(12.1)	0.00624	0.00686	(0.00062)	(9.0)
29. T & D Losses	1,526,448 (a)	1,399,899 (a)	126,549	9.0	73,666	67,774	5,892	8.7	0.13075	0.11623	0.01452	12.5
30. System KWH Sales	27,020,835	27,155,793	(134,958)	(0.5)	1,167,429	1,204,470	(37,041)	(3.1)	2.31456	2.25458	0.05998	2.7
31. Wholesale KWH Sales	(1,052,870)	(197,118)	(855,752)	434.1	(45,489)	(8,743)	(36,746)	420.3	2.31456	2.25458	0.05998	2.7
32. Jurisdictional KWH Sales	25,967,965	26,958,675	(990,710)	(3.7)	1,121,940	1,195,727	(73,787)	(6.2)	2.31456	2.25458	0.05998	2.7
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	25,985,623	26,977,007	(991,384)	(3.7)	1,121,940	1,195,727	(73,787)	(6.2)	2.31613	2.25612	0.06001	2.7
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	356,452	368,212	(11,760)	(3.2)	1,121,940	1,195,727	(73,787)	(6.2)	0.03177	0.03079	0.00098	3.2
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	1,121,940	1,195,727	(73,787)	(6.2)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	1,121,940	1,195,727	(73,787)	(6.2)	0.00000	0.00000	0.00000	0.0
36. True-up *	305,574	305,574	0	0.0	1,121,940	1,195,727	(73,787)	(6.2)	0.02724	0.02556	0.00168	6.6
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	26,647,649	27,650,793	(1,003,144)	(3.6)	1,121,940	1,195,727	(73,787)	(6.2)	2.37514	2.31247	0.06267	2.7
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.37685	2.31413	0.06272	2.7
40. GPIF * (Already Adjusted for Taxes)	(23,059)	(23,059)	0	0.0	1,121,940	1,195,727	(73,787)	(6.2)	(0.00206)	(0.00193)	(0.00013)	6.7
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	26,624,590	27,627,734	(1,003,144)	(3.6)	1,121,940	1,195,727	(73,787)	(6.2)	2.37479	2.31220	0.06259	2.7
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.375	2.312	0.063	2.7

* Based on Jurisdictional Sales (a) Included for Informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: MARCH, 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	77,126,818	80,765,185	(3,638,367)	(4.5)	3,927,070	4,054,883	(127,813)	(3.2)	1.96398	1.99180	(0.02782)	(1.4)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (FLMeade/Wauch. Wheeling Losses)	(11,245)	(12,000)	755	(6.3)	3,927,070 a)	4,054,883 a)	(127,813)	(3.2)	(0.00029)	(0.00030)	0.00001	(3.3)
4b. Adjustments to Fuel Cost	0	0	0	0.0	3,927,070 a)	4,054,883 a)	(127,813)	(3.2)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	(79)	0	(79)	0.0	3,927,070 a)	4,054,883 a)	(127,813)	(3.2)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	77,115,494	80,753,185	(3,637,691)	(4.5)	3,927,070	4,054,883	(127,813)	(3.2)	1.96369	1.99150	(0.02781)	(1.4)
6. Fuel Cost of Purchased Power - Firm (A7)	12,291,565	4,466,700	7,824,865	175.2	314,244	126,417	187,827	148.6	3.91147	3.53331	0.37816	10.7
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	(10,512)	821,200	(831,712)	(101.3)	0	22,133	(22,133)	(100.0)	#DIV/0!	3.71030	#DIV/0!	#DIV/0!
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	1,706,734	1,691,700	15,034	0.9	85,451	96,392	(10,941)	(11.4)	1.99732	1.75502	0.24230	13.8
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	13,987,787	6,979,600	7,008,187	100.4	399,695	244,942	154,753	63.2	3.49962	2.84949	0.65013	22.8
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					4,326,765	4,299,825	26,940	0.6				
14. Fuel Cost of Economy Sales (A6)	(1,687)	286,100	(287,787)	(100.6)	0	13,734	(13,734)	(100.0)	#DIV/0!	2.08315	#DIV/0!	#DIV/0!
15. Gain on Economy Sales - 80% (A6)	0	72,720	(72,720)	(100.0)	0	13,734 a)	(13,734)	(100.0)	0.00000	0.52949	(0.52949)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	190,768	295,300	(104,532)	(35.4)	12,186	19,153	(6,967)	(36.4)	1.56547	1.54180	0.02367	1.5
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	313,912	314,900	(988)	(0.3)	16,838	17,141	(303)	(1.8)	1.86431	1.83712	0.02719	1.5
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	852,207	592,700	259,507	43.8	36,898	25,783	11,115	43.1	2.30963	2.29880	0.01083	0.5
21. Fuel Cost of Other Power Sales (A6)	7,036,559	5,902,452	1,134,107	19.2	346,940	327,600	19,340	5.9	2.02818	1.80173	0.22645	12.6
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	8,391,759	7,464,172	927,587	12.4	412,862	403,411	9,451	2.3	2.03258	1.85026	0.18232	9.9
23. Net Inadvertant Interchange					910	0	910	0.0				
24. Wheeling Rec'd. less Wheeling Deliv'd.					1,487	0	1,487	0.0				
25. Interchange and Wheeling Losses					9,304	6,100	3,204	52.5				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	82,711,522	80,268,613	2,442,909	3.0	3,906,996	3,890,314	16,682	0.4	2.11701	2.06329	0.05372	2.6
27. Net Unbilled	(842,761) (a)	(1,431,985) (a)	589,224	(41.1)	(39,809)	(69,403)	29,594	(42.6)	(0.02157)	(0.03681)	0.01524	(41.4)
28. Company Use	262,657 (a)	247,595 (a)	15,062	6.1	12,407	12,000	407	3.4	0.00697	0.00655	0.00042	6.4
29. T & D Losses	3,503,567 (a)	3,473,074 (a)	30,493	0.9	165,496	168,327	(2,831)	(1.7)	0.09298	0.09190	0.00106	1.2
30. System KWH Sales	82,711,522	80,268,613	2,442,909	3.0	3,768,902	3,779,390	(10,488)	(0.3)	2.19458	2.12385	0.07073	3.3
31. Wholesale KWH Sales	(2,242,680)	(650,200)	(1,592,480)	244.9	(100,470)	(30,707)	(69,763)	227.2	2.23219	2.11743	0.11476	5.4
32. Jurisdictional KWH Sales	80,468,842	79,618,413	850,429	1.1	3,668,432	3,748,683	(80,251)	(2.1)	2.19355	2.12390	0.06965	3.3
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	80,523,560	79,672,553	851,007	1.1	3,668,432	3,748,683	(80,251)	(2.1)	2.19504	2.12535	0.06969	3.3
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	1,090,045	1,111,253	(21,208)	(1.9)	3,668,432	3,748,683	(80,251)	(2.1)	0.02971	0.02964	0.00007	0.2
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	3,668,432	3,748,683	(80,251)	(2.1)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	3,668,432	3,748,683	(80,251)	(2.1)	0.00000	0.00000	0.00000	0.0
36. True-up *	916,722	916,722	0	0.0	3,668,432	3,748,683	(80,251)	(2.1)	0.02499	0.02445	0.00054	2.2
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	82,530,327	81,700,528	829,799	1.0	3,668,432	3,748,683	(80,251)	(2.1)	2.24974	2.17945	0.07029	3.2
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.25136	2.18102	0.07034	3.2
40. GPIF * (Already Adjusted for Taxes)	(69,177)	(69,177)	0	0.0	3,668,432	3,748,683	(80,251)	(2.1)	(0.00189)	(0.00185)	(0.00004)	2.2
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	82,461,150	81,631,351	829,799	1.0	3,668,432	3,748,683	(80,251)	(2.1)	2.24947	2.17917	0.07030	3.2
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.249	2.179	0.070	3.2

* Based on Jurisdictional Sales (a) Included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	23,644,591	27,216,137	(3,571,546)	(13.1)	77,126,818	80,765,185	(3,638,367)	(4.5)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	2,854,124	2,679,944	174,180	6.5	8,391,759	7,464,172	927,587	12.4
3. FUEL COST OF PURCHASED POWER	5,679,254	1,646,700	4,032,554	244.9	12,291,565	4,466,700	7,824,865	175.2
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	564,812	588,800	(23,988)	(4.1)	1,706,734	1,691,700	15,034	0.9
4. ENERGY COST OF ECONOMY PURCHASES	(10,512)	388,100	(398,612)	(102.7)	(10,512)	821,200	(831,712)	(101.3)
5. TOTAL FUEL & NET POWER TRANSACTION	27,024,021	27,159,793	(135,772)	(0.5)	82,722,846	80,280,613	2,442,233	3.0
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(3,265)	(4,000)	735	(18.4)	(11,245)	(12,000)	755	(6.3)
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST (Big Bend 1&2 FGD Proj.)	79	0	79	0.0	(79)	0	(79)	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	27,020,835	27,155,793	(134,958)	(0.5)	82,711,522	80,268,613	2,442,909	3.0
* INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,121,940	1,195,727	(73,787)	(6.2)	3,668,432	3,748,683	(80,251)	(2.1)
2. NONJURISDICTIONAL SALES	45,489	8,743	36,746	420.3	100,470	30,707	69,763	227.2
3. TOTAL SALES	1,167,429	1,204,470	(37,041)	(3.1)	3,768,902	3,779,390	(10,488)	(0.3)
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9610349	0.9927412	(0.0317063)	(3.2)	0.9733424	0.9918751	(0.0185327)	(1.9)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	25,705,635	27,481,214	(1,775,579)	(6.5)	83,907,247	86,190,943	(2,283,696)	(2.6)
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	(305,574)	(305,574)	0	0.0	(916,722)	(916,722)	0	0.0
b. INCENTIVE PROVISION	23,059	23,059	0	0.0	69,177	69,177	0	0.0
c. TRANSITION ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
d. OTHER ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	25,423,120	27,198,699	(1,775,579)	(6.5)	83,059,702	85,343,398	(2,283,696)	(2.7)
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	27,020,835	27,155,793	(134,958)	(0.5)	82,711,522	80,268,613	2,442,909	3.0
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B-4)	0.9610349	0.9927412	(0.0317063)	(3.2)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	25,967,965	26,958,675	(990,710)	(3.7)	80,468,842	79,618,413	850,429	1.1
6A.JURISDIC. LOSS MULTIPLIER	1.00068	1.00068	0.0000	0.0	NA	NA	-	-
6B. (LINE 6 x LINE 6A)	25,985,623	26,977,007	(991,384)	(3.7)	80,523,560	79,672,553	851,007	1.1
6C.PEABODY COAL CONTR. BUY-OUT AMORT.	370,904	370,904	0	0.0	1,120,305	1,120,305	0	0.0
6D.(LINE 6C x LINE 5) PB. JURISD.	356,452	368,212	(11,760)	(3.2)	1,090,045	1,111,253	(21,208)	(1.9)
6E.OTHER (SPARE INPUT #1)	0	0	0	0.0	0	0	0	0.0
6F. OIL BELOW THE DISCHARGE VALVE	0	0	0	0.0	0	0	0	0.0
6G. OTHER (SPARE INPUT #2)	0	0	0	0.0	0	0	0	0.0
6H. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. 6B+6D+6E+6F+6G)	26,342,075	27,345,219	(1,003,144)	(3.7)	81,613,605	80,783,806	829,799	1.0
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6H)	(918,955)	(146,520)	(772,435)	527.2	1,446,097	4,559,592	(3,113,495)	(68.3)
8. INTEREST PROVISION FOR THE MONTH	(48,381)	7,881	(56,262)	(713.9)	(162,243)	(1,244)	(160,999)	12,942.0
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(17,347,141)	(6,238,684)	(11,108,457)	178.1	NOT APPLICABLE			
9a.DEFERRED TRUE-UP BEGINNING OF PERIO	7,879,936	7,879,936	0	0.0	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	305,574	305,574	0	0.0	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	(10,128,967)	1,808,187	(11,937,154)	(660.2)	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	(9,467,205)	1,641,252	(11,108,457)	(676.8)	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	(10,080,586)	1,800,306	(11,880,892)	(659.9)	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(19,547,791)	3,441,558	(22,989,349)	(668.0)	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	(9,773,896)	1,720,779	(11,494,675)	(668.0)	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.800	5.500	0.300	5.5	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	6.070	5.500	0.570	10.4	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	11.870	11.000	0.870	7.9	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	5.935	5.500	0.435	7.9	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.495	0.458	0.037	8.1	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	(48,381)	7,881	(56,262)	(713.9)	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: MARCH 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
FUEL COST OF SYSTEM NET GENERATION ($)								
1 HEAVY OIL	0	266,304	(266,304)	(100.0)	173,633	432,951	(259,318)	(59.9)
2 LIGHT OIL	158,406	544,612	(386,206)	(70.9)	1,217,123	1,551,035	(333,912)	(21.5)
3 COAL	23,486,185	26,405,221	(2,919,036)	(11.1)	75,736,062	78,781,199	(3,045,137)	(3.9)
4 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
5 NUCLEAR	0	0	0	0.0	0	0	0	0.0
6 OTHER	0	0	0	0.0	0	0	0	0.0
7 TOTAL ($)	23,644,591	27,216,137	(3,571,546)	(13.1)	77,126,818	80,765,185	(3,638,367)	(4.5)
SYSTEM NET GENERATION (MWH)								
8 HEAVY OIL	(173)	6,305	(6,478)	(102.7)	1,531	10,260	(8,729)	(85.1)
9 LIGHT OIL	3,852	15,246	(11,394)	(74.7)	22,619	43,672	(21,053)	(48.2)
10 COAL	1,276,302	1,343,230	(66,928)	(5.0)	3,902,920	4,000,951	(98,031)	(2.5)
11 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
12 NUCLEAR	0	0	0	0.0	0	0	0	0.0
13 OTHER	0	0	0	0.0	0	0	0	0.0
14 TOTAL (MWH)	1,279,981	1,364,781	(84,800)	(6.2)	3,927,070	4,054,883	(127,813)	(3.2)
UNITS OF FUEL BURNED								
15 HEAVY OIL (BBL)	0	16,034	(16,034)	(100.0)	9,124	26,004	(16,880)	(64.9)
16 LIGHT OIL (BBL)	4,878	23,219	(18,341)	(79.0)	40,835	65,797	(24,962)	(37.9)
17 COAL (TON)	586,781	610,428	(23,647)	(3.9)	1,796,035	1,815,030	(18,995)	(1.0)
18 NATURAL GAS (MCF)	0	0	0	0.0	0	0	0	0.0
19 NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20 OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
BTUS BURNED (MMBTU)								
21 HEAVY OIL	0	101,356	(101,356)	(100.0)	58,002	164,380	(106,378)	(64.7)
22 LIGHT OIL	28,394	134,876	(106,482)	(78.9)	237,388	382,108	(144,720)	(37.9)
23 COAL	13,095,926	13,970,005	(874,079)	(6.3)	40,314,690	41,600,654	(1,285,964)	(3.1)
24 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
25 NUCLEAR	0	0	0	0.0	0	0	0	0.0
26 OTHER	0	0	0	0.0	0	0	0	0.0
27 TOTAL (MMBTU)	13,124,320	14,206,237	(1,081,917)	(7.6)	40,610,080	42,147,142	(1,537,062)	(3.6)
GENERATION MIX (% MWH)								
28 HEAVY OIL	(0.01)	0.46	(0.47)	-	0.04	0.25	(0.21)	-
29 LIGHT OIL	0.30	1.12	(0.82)	-	0.58	1.08	(0.50)	-
30 COAL	99.71	98.42	1.29	-	99.39	98.67	0.72	-
31 NATURAL GAS	0.00	0.00	0.00	-	0.00	0.00	0.00	-
32 NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33 OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34 TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
FUEL COST PER UNIT								
35 HEAVY OIL ($/BBL)	0.00	16.61	(16.61)	(100.0)	19.03	16.65	2.38	14.3
36 LIGHT OIL ($/BBL)	32.47	23.46	9.01	38.4	29.81	23.57	6.24	26.5
37 COAL ($/TON)	40.03	43.26	(3.23)	(7.5)	42.17	43.40	(1.23)	(2.8)
38 NATURAL GAS ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40 OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
FUEL COST PER MMBTU ($/MMBTU)								
41 HEAVY OIL	0.00	2.63	(2.63)	(100.0)	2.99	2.63	0.36	13.7
42 LIGHT OIL	5.58	4.04	1.54	38.1	5.13	4.06	1.07	26.4
43 COAL	1.79	1.89	(0.10)	(5.3)	1.88	1.89	(0.01)	(0.5)
44 NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
45 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47 TOTAL ($/MMBTU)	1.80	1.92	(0.12)	(6.2)	1.90	1.92	(0.02)	(1.0)

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: MARCH 2000

SCHEDULE A3
PAGE 2 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
BTU BURNED PER KWH (BTU/KWH)								
48 HEAVY OIL	0	16,075	(16,075)	(100.0)	37,885	16,021	21,864	136.5
49 LIGHT OIL	7,371	8,847	(1,476)	(16.7)	10,495	8,749	1,746	20.0
50 COAL	10,261	10,400	(139)	(1.3)	10,329	10,398	(69)	(0.7)
51 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
52 NUCLEAR	0	0	0	0.0	0	0	0	0.0
53 OTHER	0	0	0	0.0	0	0	0	0.0
54 TOTAL (BTU/KWH)	10,254	10,409	(155)	(1.5)	10,341	10,394	(53)	(0.5)
GENERATED FUEL COST PER KWH (cents/KWH)								
55 HEAVY OIL	0.00	4.22	(4.22)	(100.0)	11.34	4.22	7.12	168.7
56 LIGHT OIL	4.11	3.57	0.54	15.1	5.38	3.55	1.83	51.5
57 COAL	1.84	1.97	(0.13)	(6.6)	1.94	1.97	(0.03)	(1.5)
58 NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
59 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61 TOTAL (cents/KWH)	1.85	1.99	(0.14)	(7.0)	1.96	1.99	(0.03)	(1.5)

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4

ACTUAL FOR THE PERIOD/MONTH OF: MARCH 2000

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPC. FACTO (%)	EQUIV. AVAIL. FACTO (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RAT BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COS PER KWH (cents /KWH)	COST OF FUEL ($/UNIT)
H.P.#1	32	0	0.0	100.0	0.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#2	32	0	0.0	1.3	0.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#3	32	0	0.0	73.2	0.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#4	41	0	0.0	100.0	0.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#5	52	0	0.0	1.3	0.0	-	HVY.OIL	-	-	-	-	-	-
H.P. STATION	189	0	0.0	51.6	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN.#1	114	57,342	67.6	98.3	68.0	11,130	COAL	27,214	23,451,742	638,215.7	937,316	1.63	34.44
GAN.#2	88	46,423	70.9	88.6	79.7	12,586	COAL	24,500	23,847,261	584,257.9	843,840	1.82	34.44
GAN.#3	155	43,496	37.7	49.4	71.2	12,397	COAL	27,929	19,306,180	539,202.3	961,943	2.21	34.44
GAN.#4	169	83,994	66.8	95.2	69.0	11,540	COAL	50,563	19,170,560	969,321.0	1,741,513	2.07	34.44
GAN.#5	242	23,534	13.1	14.3	66.1	10,167	COAL	10,012	23,898,102	239,267.8	344,838	1.47	34.44
GAN.#6	392	151,683	52.0	62.1	75.6	10,810	COAL	68,737	23,855,400	1,639,748.6	2,367,470	1.56	34.44
GANNON STA.	1160	406,472	47.1	60.8	71.6	11,342	COAL	208,955	22,062,230	4,610,013.3	7,196,920	1.77	34.44
B.B.#1	426	248,745	78.5	92.2	78.5	9,808	COAL	106,832	22,837,620	2,439,788.6	4,189,246	1.68	39.21
B.B.#2	426	250,853	79.1	90.0	79.8	9,634	COAL	104,945	23,027,880	2,416,660.9	4,115,250	1.64	39.21
B.B.#3	443	86,677	26.3	31.2	81.1	8,788	COAL	33,393	22,809,780	761,687.0	1,309,453	1.51	39.21
B.B. 1 - 3	1295	586,275	60.8	70.6	79.8	9,583	COAL	245,170	22,915,269	5,618,136.5	9,613,949	1.64	39.21
B.B.#4	447	286,271	86.1	96.2	86.1	9,791	COAL	129,847	21,586,178	2,802,900.4	6,443,946	2.25	49.63
B.B. STA.	1742	872,546	67.3	77.2	81.4	9,651	COAL	375,017	22,455,080	8,421,036.9	16,057,895	1.84	42.82
SEB-PHIL. #1(HVY OIL)	17	(87)	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
SEB-PHIL. #2(HVY OIL)	17	(86)	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
SEB-PHILLIPS TOTAL	34	(173)	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
POLK COAL	250	(2,716)	0.0	7.4	0.0	0	COAL	2,809	23,098,017	64,875.4	231,370	0.00	82.38
POLK OIL	245	3,561	2.0	50.4	52.1	6,508	LGT.OIL	3,981	5,821,903	23,174.9	130,266	3.66	32.72
POLK TOTAL	250	845	2.0	49.3	-	104,202	-	-	-	88,050.3	361,636	42.80	-
GAN.C.T.#1	17	166	1.3	100.0	65.1	18,188	LGT.OIL	519	5,818,911	3,019.2	16,278	9.81	31.37
B.B.C.T.#1	17	125	1.0	100.0	73.5	17,599	LGT.OIL	378	5,818,456	2,199.9	11,862	9.49	31.37
B.B.C.T.#2	80	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	80	0	0.0	1.1	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	194	291	0.2	18.0	12.1	17,935	LGT.OIL	897	5,818,719	5,219.1	28,140	9.67	31.37
TOT. COAL (GN,BB,POLK)	3152	1,276,302	54.4	65.6	71.4	10,261	COAL	586,781	22,318,262	13,095,925.6	23,486,185	1.84	40.03
SYSTEM	3569	1,279,981	48.2	64.6	65.5	10,254	-	-	-	13,124,319.6	23,644,591	1.85	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS

NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2000

SCHEDULE A5
PAGE 1 OF 2

	CURRENT MONTH				PERIOD TO DATE			
HEAVY OIL (1)	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1 PURCHASES:								
2 UNITS (BBL)	0	16,034	(16,034)	(100.0)	0	26,004	(26,004)	(100.0)
3 UNIT COST ($/BBL)	0.00	15.43	(15.43)	(100.0)	0.00	15.49	(15.49)	(100.0)
4 AMOUNT ($)	0	247,405	(247,405)	(100.0)	21,875	402,715	(380,840)	(94.6)
5 BURNED:								
6 UNITS (BBL)	0	16,034	(16,034)	(100.0)	9,124	26,004	(16,880)	(64.9)
7 UNIT COST ($/BBL)	0.00	16.61	(16.61)	(100.0)	19.03	16.65	2.38	14.3
8 AMOUNT ($)	0	266,304	(266,304)	(100.0)	173,633	432,951	(259,318)	(59.9)
9 ENDING INVENTORY:								
10 UNITS (BBL)	81,135	175,493	(94,358)	(53.8)	81,135	175,493	(94,358)	(53.8)
11 UNIT COST ($/BBL)	19.19	16.76	2.43	14.5	19.19	16.76	2.43	14.5
12 AMOUNT ($)	1,556,794	2,941,074	(1,384,280)	(47.1)	1,556,794	2,941,074	(1,384,280)	(47.1)
13								
14 DAYS SUPPLY:	32	69	(37)	(53.6)	-	-	-	-
LIGHT OIL (2)								
15 PURCHASES:								
16 UNITS (BBL)	24,867	33,512	(8,645)	(25.8)	97,344	98,586	(1,242)	(1.3)
17 UNIT COST ($/BBL)	36.18	23.10	13.08	56.6	34.25	23.22	11.03	47.5
18 AMOUNT ($)	899,737	774,137	125,600	16.2	3,334,114	2,289,001	1,045,113	45.7
19 BURNED:								
20 UNITS (BBL)	4,878	23,219	(18,341)	(79.0)	40,835	65,797	(24,962)	(37.9)
21 UNIT COST ($/BBL)	32.47	23.46	9.01	38.4	29.81	23.57	6.24	26.5
22 AMOUNT ($)	158,406	544,612	(386,206)	(70.9)	1,217,123	1,551,035	(333,912)	(21.5)
23 ENDING INVENTORY:								
24 UNITS (BBL)	97,057	110,358	(13,301)	(12.1)	97,057	110,358	(13,301)	(12.1)
25 UNIT COST ($/BBL)	31.91	23.13	8.78	38.0	31.91	23.13	8.78	38.0
26 AMOUNT ($)	3,096,724	2,552,724	544,000	21.3	3,096,724	2,552,724	544,000	21.3
27								
28 DAYS SUPPLY: NORMAL	80	91	(11)	(12.1)	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	14	16	(2)	(12.5)	-	-	-	-
COAL (3)								
30 PURCHASES:								
31 UNITS (TONS)	817,578	639,400	178,178	27.9	2,263,365	1,933,200	330,165	17.1
32 UNIT COST ($/TON)	42.40	42.63	(0.23)	(0.5)	41.42	42.59	(1.17)	(2.7)
33 AMOUNT ($)	34,662,559	27,255,790	7,406,769	27.2	93,752,170	82,333,964	11,418,206	13.9
34 BURNED:								
35 UNITS (TONS)	586,781	610,428	(23,647)	(3.9)	1,796,035	1,815,030	(18,995)	(1.0)
36 UNIT COST ($/TON)	40.03	43.26	(3.23)	(7.5)	42.17	43.40	(1.23)	(2.8)
37 AMOUNT ($)	23,486,185	26,405,221	(2,919,036)	(11.1)	75,736,062	78,781,199	(3,045,137)	(3.9)
38 ENDING INVENTORY:								
39 UNITS (TONS)	1,244,346	981,670	262,676	26.8	1,244,346	981,670	262,676	26.8
40 UNIT COST ($/TON)	41.96	43.17	(1.21)	(2.8)	41.96	43.17	(1.21)	(2.8)
41 AMOUNT ($)	52,218,179	42,383,024	9,835,155	23.2	52,218,179	42,383,024	9,835,155	23.2
42								
43 DAYS SUPPLY:	57	45	12	26.7	-	-	-	-
NATURAL GAS								
44 PURCHASES:								
45 UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
46 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
48 BURNED:								
49 UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
50 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
51 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
56								
57 DAYS SUPPLY:	0	0	0	0.0	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2000

SCHEDULE A5
PAGE 2 OF 2

OTHER	CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH %	PERIOD TO DATE ACTUAL	PERIOD TO DATE ESTIMATED	PERIOD TO DATE DIFFERENCE AMOUNT	PERIOD TO DATE %
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
74 DAYS SUPPLY:	0	0	0	0.0	-	-	-	-

* Rounding adjustment of (1).

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	0
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	0

(2)
RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(5,099)	(159,977)
OTHER USAGE	(4,429)	(144,003)
TOTAL	(9,528)	(303,980)

(3)
RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	47,424
IGNITION #2 OIL	159,977
IGNITION PROPANE	10,435
AERIAL SURVEY ADJ.	(1,848,833)
ADDITIVES	39,122
TOTAL	(1,591,875)

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: MARCH 2000

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:									
VARIOUS	ECON.	12,790.0	0.0	12,790.0	2.242	2.892	286,800.00	369,900.00	66,480.00
VARIOUS JURISDICTIONAL	SCH. -D	5,773.0	0.0	5,773.0	1.864	1.864	107,600.00	107,600.00	
VARIOUS SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS SEPARATED	CONTRACT	10,087.0	0.0	10,087.0	2.294	3.183	231,400.00	321,100.00	
FMPA	SCH. -D	111,600.0	0.0	111,600.0	1.805	1.805	2,014,564.00	2,014,564.00	
VARIOUS JURISDICTIONAL	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS	-	140,250.0	0.0	140,250.0	1.883	2.006	2,640,364.00	2,813,164.00	66,480.00
LESS TRANSMISSION COSTS	-						0.00		
LESS VARIABLE O & M COSTS	-						(26,900.00)		
PLUS 80% OF ECON. ENERGY SALES PROFI	-						66,480.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INC	-								
80% OF ECON. ENERGY SALES PROFITS	-	140,250.0	0.0	140,250.0	1.911	2.006	2,679,944.00	2,813,164.00	66,480.00
ACTUAL:									
FLA. PWR. CORP.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF ST. CLOUD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SONAT	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY, INC.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENRGY, INC.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENN. VALLEY AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL. SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH. SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS SEP.	CONTRACT	10,225.0	0.0	10,225.0	2.272	3.121	232,312.00	319,122.25	
SEMINOLE ELECTRIC CO-OP PRE JURISD.	SCH. -D	4,662.0	1,004.6	3,657.4	1.860	1.860	68,033.11	68,033.11	
SEMINOLE ELECTRIC CO-OP HAR JURISD.	SCH. -D	769.0	0.0	769.0	1.802	1.802	13,854.36	13,854.36	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: MARCH 2000

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	*JURISD.*	*SCH. -J*	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA		SCH. -D	93,575.0	0.0	93,575.0	1.900	1.900	1,777,912.45	1,777,912.45	
HARDEE POWER PART. TO FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR.& LT.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO JACKSONVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KISSIMMEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ORLANDO		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO SEMINOLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FT. PIERCE		*ECON.-C*	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LK. WORTH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ENERGY AUTHORI		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FPC		*SCH. -J*	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PART. TO FLA. PWR.& LT.		SCH. -MB	146.0	0.0	146.0	2.572	2.572	3,754.63	3,754.63	
HARDEE POWER PART. TO ORLANDO		SCH. -MB	64.0	0.0	64.0	3.001	3.001	1,920.58	1,920.58	
SEMINOLE ELECTRIC CO-OP		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. CORP.		SCH. -MB	845.0	0.0	845.0	2.913	2.913	24,615.57	24,615.57	
FLA. PWR. & LIGHT		SCH. -MB	25,021.0	0.0	25,021.0	2.459	2.459	615,230.72	615,230.72	
CITY OF LAKELAND		SCH. -MB	4,602.0	0.0	4,602.0	2.355	2.355	108,385.16	108,385.16	
ORLANDO UTIL. COMM.		SCH. -MB	290.0	0.0	290.0	3.729	3.729	10,813.39	10,813.39	
THE ENERGY AUTHORITY		SCH. -MB	20.0	0.0	20.0	3.350	3.350	670.06	670.06	
TALLAHASSEE		SCH. -MB	30.0	0.0	30.0	2.450	2.450	735.09	735.09	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: MARCH 2000

SCHEDULE A6
PAGE 3 OF 3

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(6) (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ADJUSTMENTS TO PREVIOUS MO MON/YR TYP SCHED.									
HARDEE POWER PARTNERS ES 2/00 SEPAR.	CONTRACT	(9,334.0)	0.0	(9,334.0)	2.298	3.140	(214,495.32)	(293,087.60)	
HARDEE POWER PARTNERS ACT 2/00 SEPAR.	CONTRACT	9,334.0	0.0	9,334.0	2.272	3.121	212,068.48	291,314.14	
KOCH 8/98	ECON.-C	(885.0)	0.0	(885.0)	3.125	8.032	(27,656.25)	(71,083.20)	(34,741.56)
KOCH 8/98	ECON.-C	885.0	0.0	885.0	2.934	7.841	25,969.53	69,396.48	34,741.56
SUB-TOTAL ECONOMY POWER SALES		0.0	0.0	0.0	0.000	0.000	(1,686.72)	(1,686.72)	0.00
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.		0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.		5,431.0	1,004.6	4,426.4	1.850	1.850	81,887.47	81,887.47	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.		0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.		10,225.0	0.0	10,225.0	2.248	3.104	229,885.16	317,348.79	
SUB-TOTAL FMPA D POWER SALES		93,575.0	0.0	93,575.0	1.900	1.900	1,777,912.45	1,777,912.45	
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.		0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE MB POWER SALES-JURISD.		31,018.0	0.0	31,018.0	2.470	2.470	766,125.20	766,125.20	
TOTAL INCLUDING VARIABLE O & M COSTS		140,249.0	1,004.6	139,244.4	2.050	2.113	2,854,123.56	2,941,587.19	0.00
LESS VARIABLE O & M COSTS							0.00		
LESS VARIABLE O & M COSTS - HARDEE							0.00		
LESS TRANSMISSION COSTS SCH. D (SEP.)							0.00		
PLUS 80% OF ECON. ENERGY SALES PROFITS *							0.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS	-	140,249.0	1,004.6	139,244.4	2.050	2.113	2,854,123.56	2,941,587.19	0.00
CURRENT MONTH:									
DIFFERENCE	-	(1.0)	1,004.6	(1,005.6)	0.139	0.107	174,179.56	128,423.19	(66,480.00)
DIFFERENCE %	-	0.0	0.0	(0.7)	7.3	5.3	6.5	4.6	(100.0)
PERIOD TO DATE:									
ACTUAL	-	414,377.0	1,515.5	412,861.5	2.033	2.123	8,391,758.60	8,764,555.35	0.00
ESTIMATED	-	403,411.0	0.0	403,411.0	1.850	1.936	7,464,172.00	7,810,052.00	72,720.00
DIFFERENCE	-	10,966.0	1,515.5	9,450.5	0.183	0.187	927,586.60	954,503.35	(72,720.00)
DIFFERENCE %	-	2.7	0.0	2.3	9.9	9.7	12.4	12.2	(100.0)

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. SEC 60% OR $1,190.82 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH MARCH 2000

SCHEDULE A7

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) ----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	10,446.0	0.0	6,328.0	4,118.0	5.250	5.250	216,200.00
HARDEE POWER PARTNERS	IPP	24,983.0	0.0	0.0	24,983.0	3.148	3.148	786,400.00
VARIOUS	OTHER	21,056.0	0.0	0.0	21,056.0	3.059	3.059	644,100.00
TOTAL	-	56,485.0	0.0	6,328.0	50,157.0	3.283	3.283	1,646,700.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	61,999.0	0.0	0.0	61,999.0	4.014	4.014	2,488,377.38
HARDEE PWR. PART.-OTHERS	IPP	210.0	0.0	0.0	210.0	2.324	2.324	4,881.33
FLA. POWER CORP.	SCH.-Ja	14,265.0	0.0	9,693.4	4,571.6	5.647	5.647	258,159.20
FLA. POWER CORP.	SCH.-Jc	16,092.0	0.0	0.0	16,092.0	3.140	3.140	505,216.50
FLA. POWER & LIGHT	SCH.-Ja	5,807.0	0.0	5,613.7	193.3	5.665	5.665	10,949.48
FLA. POWER & LIGHT	SCH.-Jc	2,400.0	0.0	0.0	2,400.0	4.083	4.083	97,984.00
CITY OF LAKELAND	SCH.-Ja	16,661.0	0.0	6,072.6	10,588.4	5.600	5.600	592,958.66
CITY OF LAKELAND	SCH.-Jc	4,652.0	0.0	0.0	4,652.0	4.488	4.488	208,805.00
ORLANDO	SCH.-Ja	4,065.0	0.0	2,594.2	1,470.8	5.652	5.652	83,135.48
ORLANDO	SCH.-Jc	200.0	0.0	0.0	200.0	5.200	5.200	10,400.00
ENTERGY MARKETING	SCH.-Ja	818.0	0.0	818.0	0.0	0.000	0.000	0.00
THE ENERGY AUTH.	SCH.-Ja	5,794.0	0.0	1,152.9	4,641.1	5.236	5.236	243,014.65
THE ENERGY AUTH.	SCH.-Jc	8,144.0	0.0	0.0	8,144.0	3.887	3.887	316,547.94
RELIANT	SCH.-Ja	3,401.0	0.0	1,647.6	1,753.4	4.960	4.960	86,969.89
RELIANT	SCH.-Jc	2,312.0	0.0	0.0	2,312.0	3.829	3.829	88,533.14
REEDY CREEK	SCH.-Jc	370.0	0.0	0.0	370.0	3.467	3.467	12,827.50
TALLAHASSEE	SCH.-Ja	334.0	0.0	325.9	8.1	4.783	4.783	387.43
TALLAHASSEE	SCH.-Jc	186.0	0.0	0.0	186.0	3.953	3.953	7,352.86
AQUILLA	SCH.-Ja	3,280.0	0.0	3,280.0	0.0	0.000	0.000	0.00
OKEELANTA	SCH.-Ja	1,278.0	0.0	419.2	858.8	4.187	4.187	35,958.05
OKEELANTA	SCH.-Jc	390.0	0.0	0.0	390.0	4.013	4.013	15,650.00
KOCH ENERGY TRAD.	SCH.-Ja	2,731.0	0.0	1,682.5	1,048.5	6.302	6.302	66,073.54
KOCH ENERGY TRAD.	SCH.-Jc	2,540.0	0.0	0.0	2,540.0	5.832	5.832	148,140.00
OKEELANTA	SCH.-D	8,570.0	0.0	0.0	8,570.0	3.050	3.050	261,385.00
AUBURNDALE POWER PARTNERS	SCH.-D	4,388.0	0.0	0.0	4,388.0	4.238	4.238	185,947.75
ADJUSTMENTS TO PRIOR MONTHS:								
HARDEE PWR. PART.-NATIVE	Feb-00 IPP	(27,527.0)	0.0	0.0	(27,527.0)	3.985	3.985	(1,097,010.38)
HARDEE PWR. PART.-NATIVE	Feb-00 IPP	27,527.0	0.0	0.0	27,527.0	3.805	3.805	1,047,303.54
THE ENERGY AUTH.	Jan-00 SCH.-Ja	(518.0)	0.0	(348.7)	(169.3)	8.645	8.645	(14,635.60)
THE ENERGY AUTH.	Jan-00 SCH.-Ja	518.0	0.0	348.7	169.3	8.638	8.638	14,623.89
THE ENERGY AUTH.	Jan-00 SCH.-Jc	(2,142.0)	0.0	0.0	(2,142.0)	5.198	5.198	(111,340.86)
THE ENERGY AUTH.	Jan-00 SCH.-Jc	2,142.0	0.0	0.0	2,142.0	5.191	5.191	111,190.15
TALLAHASSEE	Jan-00 SCH.-Jc	(605.0)	0.0	0.0	(605.0)	3.201	3.201	(19,363.60)
TALLAHASSEE	Jan-00 SCH.-Jc	605.0	0.0	0.0	605.0	3.144	3.144	19,021.17
AQUILLA	Jan-00 SCH.-Jc	(384.0)	0.0	0.0	(384.0)	9.086	9.086	(34,891.35)
AQUILLA	Jan-00 SCH.-Jc	384.0	0.0	0.0	384.0	9.037	9.037	34,702.70
TOTAL		170,887.0	0.0	33,300.0	137,587.0	4.128	4.128	5,679,254.44
CURRENT MONTH:								
DIFFERENCE	-	114,402.0	0.0	26,972.0	87,430.0	4.612	4.612	4,032,554.44
DIFFERENCE %	-	202.5	0.0	426.2	174.3	140.5	140.5	244.9
PERIOD TO DATE:								
ACTUAL	-	360,452.0	0.0	46,208.4	314,243.6	3.911	3.911	12,291,565.87
ESTIMATED	-	136,831.0	0.0	10,414.0	126,417.0	3.533	3.533	4,466,700.00
DIFFERENCE	-	223,621.0	0.0	35,794.4	187,826.6	0.378	0.378	7,824,865.87
DIFFERENCE %	-	163.4	0.0	343.7	148.6	10.7	10.7	175.2

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY

SCHEDULE A8

FOR THE MONTH OF: MARCH 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	31,813.0	0.0	0.0	31,813.0	1.851	1.851	588,800.00
TOTAL	-	31,813.0	0.0	0.0	31,813.0	1.851	1.851	588,800.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	5,034.0	0.0	0.0	5,034.0	2.018	2.018	101,570.55
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	9.0	0.0	0.0	9.0	3.897	3.897	350.74
HILLSBOROUGH COUNTY	COGEN.	13,815.0	0.0	0.0	13,815.0	1.993	1.993	275,351.76
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	1,495.0	0.0	0.0	1,495.0	2.731	2.731	40,826.60
FARMLAND HYDRO LP	COGEN.	1,212.0	0.0	0.0	1,212.0	2.545	2.545	30,847.99
IMC-AGRICO-S. PIERCE	COGEN.	454.0	0.0	0.0	454.0	2.503	2.503	11,365.71
AUBURNDALE POWER PARTNERS	COGEN.	56.0	0.0	0.0	56.0	2.390	2.390	1,338.18
ORANGE COGENERATION L.P.	COGEN.	5,532.0	0.0	0.0	5,532.0	1.981	1.981	109,583.34
CUTRALE CITRUS	COGEN.	6.0	0.0	0.0	6.0	2.461	2.461	147.66
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	164.5	(164.5)	3.250	3.250	(5,346.69)
SUB-TOTAL FOR MARCH 2000	-	27,613.0	0.0	164.5	27,448.5	2.062	2.062	566,035.84
ADJ. FOR JANUARY 2000								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	3,075.00
McKAY BAY REFUSE	COGEN.	(3,992.0)	0.0	0.0	(3,992.0)	2.019	2.019	(80,584.84)
		3,992.0	0.0	0.0	3,992.0	2.004	2.004	79,995.47
MULBERRY PHOSPHATES INC.	COGEN.							
CARGILL RIDGEWOOD	COGEN.							
IMC-AGRICO-NEW WALES	COGEN.	(151.0)	0.0	0.0	(151.0)	2.265	2.265	(3,419.57)
		151.0	0.0	0.0	151.0	2.265	2.265	3,419.61
HILLSBOROUGH COUNTY	COGEN.	(15,376.0)	0.0	0.0	(15,376.0)	2.029	2.029	(312,028.63)
		15,376.0	0.0	0.0	15,376.0	2.014	2.014	309,692.10
CARGILL MILLPOINT	COGEN.							
CF INDUSTRIES INC.	COGEN.	(1,947.0)	0.0	0.0	(1,947.0)	2.359	2.359	(45,939.32)
		1,947.0	0.0	0.0	1,947.0	2.358	2.358	45,919.30
FARMLAND HYDRO LP	COGEN.	(1,034.0)	0.0	0.0	(1,034.0)	2.302	2.302	(23,799.42)
		1,034.0	0.0	0.0	1,034.0	2.301	2.301	23,793.63
IMC-AGRICO-S. PIERCE	COGEN.							
AUBURNDALE POWER PARTNERS	COGEN.	(258.0)	0.0	0.0	(258.0)	4.259	4.259	(10,988.71)
		258.0	0.0	0.0	258.0	4.259	4.259	10,987.38
ORANGE COGENERATION L.P.	COGEN.	(5,644.0)	0.0	0.0	(5,644.0)	2.027	2.027	(114,382.17)
		5,644.0	0.0	0.0	5,644.0	2.003	2.003	113,036.55
CUTRALE CITRUS	COGEN.							
AS AVAILABLE ASSIGNMENT	COGEN.	363.0	0.0	0.0	363.0	3.986	3.986	14,470.16
		(363.0)	0.0	0.0	(363.0)	3.986	3.986	(14,470.29)
SUB-TOTAL FOR January-00 ADJ.	-	0.0	0.0	0.0	0.0	0.000	0.000	(1,223.75)
GRAND TOTAL		27,613.0	0.0	164.5	27,448.5	2.058	2.058	564,812.09
CURRENT MONTH:								
DIFFERENCE	-	(4,200.0)	0.0	164.5	(4,364.5)	0.207	0.207	(23,987.91)
DIFFERENCE %	-	(13.2)	0.0	0.0	(13.7)	11.2	11.2	(4.1)
PERIOD TO DATE:								
ACTUAL		86,001.0	0.0	550.5	85,450.5	1.997	1.997	1,706,733.90
ESTIMATED		96,392.0	0.0	0.0	96,392.0	1.755	1.755	1,691,700.00
DIFFERENCE	-	(10,391.0)	0.0	550.5	(10,941.5)	0.242	0.242	15,033.90
DIFFERENCE %	-	(10.8)	0.0	0.0	(11.4)	13.8	13.8	0.9

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: MARCH 2000

SCHEDULE A9

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	COST IF GENERATED (A) cents/KWH	COST IF GENERATED (B) $	FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	10,307.0	3.765	388,100.00	4.723	486,800.00	98,700.00
TOTAL	-	10,307.0	3.765	388,100.00	4.723	486,800.00	98,700.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ADJUSTMENTS TO PRIOR MONTHS							
FLA. PWR. CORP.	ECON.-C *	0.0	0.000	(10,512.45)	0.000	0.00	10,512.45
TOTAL	-	0.0	0.000	(10,512.45)	0.000	0.00	10,512.45
CURRENT MONTH:							
DIFFERENCE	-	(10,307.0)	(3.765)	(398,612.45)	(4.723)	(486,800.00)	(88,187.55)
DIFFERENCE %	-	(100.0)	(100.0)	(102.7)	(100.0)	(100.0)	(89.3)
PERIOD TO DATE:							
ACTUAL		0.0	0.000	(10,512.45)	0.000	0.00	10,512.45
ESTIMATED		22,133.0	3.710	821,200.00	4.751	1,051,600.00	230,400.00
DIFFERENCE	-	(22,133.0)	(3.710)	(831,712.45)	(4.751)	(1,051,600.00)	(219,887.55)
DIFFERENCE %	-	(100.0)	(100.0)	(101.3)	(100.0)	(100.0)	(95.4)

* Adjustment to transmission service for November 1997 thru January 1999

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

APRIL 2000

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL , 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	23,843,179	26,039,477	(2,196,298)	(8.4)	1,210,177	1,287,330	(77,153)	(6.0)	1.97022	2.02275	(0.05253)	(2.6)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(3,243)	(4,000)	757	(18.9)	1,210,177 a)	1,287,330 a)	(77,153)	(6.0)	(0.00027)	(0.00031)	0.00004	(12.9)
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,210,177 a)	1,287,330 a)	(77,153)	(6.0)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,210,177 a)	1,287,330 a)	(77,153)	(6.0)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	23,839,936	26,035,477	(2,195,541)	(8.4)	1,210,177	1,287,330	(77,153)	(6.0)	1.96995	2.02244	(0.05249)	(2.6)
6. Fuel Cost of Purchased Power - Firm (A7)	6,775,449	3,166,300	3,609,149	114.0	172,878	84,679	88,199	104.2	3.91921	3.73918	0.18003	4.8
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	1,005,600	(1,005,600)	(100.0)	0	23,659	(23,659)	(100.0)	0.00000	4.25039	(4.25039)	(100.0)
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 a)	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	676,517	756,500	(79,983)	(10.6)	32,598	33,678	(1,080)	(3.2)	2.07533	2.24627	(0.17094)	(7.6)
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	7,451,966	4,928,400	2,523,566	51.2	205,476	142,016	63,460	44.7	3.62668	3.47031	0.15637	4.5
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,415,653	1,429,346	(13,693)	(1.0)				
14. Fuel Cost of Economy Sales (A6)	0	36,800	(36,800)	(100.0)	0	1,512	(1,512)	(100.0)	0.00000	2.43386	(2.43386)	(100.0)
15. Gain on Economy Sales - 80% (A6)	0	7,500	(7,500)	(100.0)	0 a)	1,512 a)	(1,512)	(100.0)	0.00000	0.49603	(0.49603)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
17. Fuel Cost of Sch. D Jurisd. Sales (A8)	124,302	122,700	1,602	1.3	5,595	5,675	(80)	(1.4)	2.22166	2.16211	0.05955	2.8
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A8)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	585,000	442,200	142,800	32.3	25,622	19,801	5,821	29.4	2.28319	2.23322	0.04997	2.2
21. Fuel Cost of Other Power Sales (A6)	1,847,916	1,943,944	(96,028)	(4.9)	92,980	108,000	(15,020)	(13.9)	1.98743	1.79995	0.18748	10.4
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	2,557,218	2,553,144	4,074	0.2	124,197	134,988	(10,791)	(8.0)	2.05900	1.89139	0.16761	8.9
23. Net Inadvertant Interchange					(676)	0	(676)	0.0				
24. Wheeling Rec'd. less Wheeling Del'd.					(591)	0	(591)	0.0				
25. Interchange and Wheeling Losses					2,607	2,000	607	30.4				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	28,734,684	28,410,733	323,951	1.1	1,287,582	1,292,358	(4,776)	(0.4)	2.23168	2.19838	0.03332	1.5
27. Net Unbilled	(315,470) (a)	(5,716) (a)	(309,754)	5,419.1	(14,136)	(260)	(13,876)	5,336.9	(0.02450)	(0.00044)	(0.02406)	5,468.2
28. Company Use	84,246 (a)	87,934 (a)	(3,688)	(4.2)	3,775	4,000	(225)	(5.6)	0.00680	0.00718	(0.00038)	(5.3)
29. T & D Losses	1,308,479 (a)	1,411,721 (a)	(103,242)	(7.3)	58,632	64,217	(5,585)	(8.7)	0.10558	0.11530	(0.00972)	(8.4)
30. System KWH Sales	28,734,684	28,410,733	323,951	1.1	1,239,311	1,224,401	14,910	1.2	2.31860	2.32038	(0.00178)	(0.1)
31. Wholesale KWH Sales	(866,412)	(360,078)	(506,334)	140.6	(37,368)	(15,518)	(21,850)	140.8	2.31859	2.32039	(0.00180)	(0.1)
32. Jurisdictional KWH Sales	27,868,272	28,050,655	(182,383)	(0.7)	1,201,943	1,208,883	(6,940)	(0.6)	2.31860	2.32038	(0.00178)	(0.1)
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	27,887,222	28,069,729	(182,507)	(0.7)	1,201,943	1,208,883	(6,940)	(0.6)	2.32018	2.32196	(0.00178)	(0.1)
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	357,266	363,704	(6,438)	(1.8)	1,201,943	1,208,883	(6,940)	(0.6)	0.02972	0.03009	(0.00037)	(1.2)
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	1,201,943	1,208,883	(6,940)	(0.6)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	1,201,943	1,208,883	(6,940)	(0.6)	0.00000	0.00000	0.00000	0.0
36. True-up *	305,574	305,574	0	0.0	1,201,943	1,208,883	(6,940)	(0.6)	0.02542	0.02528	0.00014	0.6
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	28,550,062	28,739,007	(188,945)	(0.7)	1,201,943	1,208,883	(6,940)	(0.6)	2.37533	2.37732	(0.00199)	(0.1)
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.37704	2.37903	(0.00199)	(0.1)
40. GPIF * (Already Adjusted for Taxes)	(23,059)	(23,059)	0	0.0	1,201,943	1,208,883	(6,940)	(0.6)	(0.00192)	(0.00191)	(0.00001)	0.5
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	28,527,003	28,715,948	(188,945)	(0.7)	1,201,943	1,208,883	(6,940)	(0.6)	2.37512	2.37712	(0.00200)	(0.1)
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.375	2.377	(0.002)	(0.1)

* Based on Jurisdictional Sales (a) Included for Informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: APRIL, 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	100,969,997	106,804,662	(5,834,665)	(5.5)	5,137,247	5,342,213	(204,966)	(3.8)	1.96545	1.99928	(0.03381)	(1.7)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (FLMeade/Wauch. Wheeling Losses)	(14,488)	(16,000)	1,512	(9.5)	5,137,247 a)	5,342,213 a)	(204,966)	(3.8)	(0.00028)	(0.00030)	0.00002	(6.7)
4b. Adjustments to Fuel Cost	0	0	0	0.0	5,137,247 a)	5,342,213 a)	(204,966)	(3.8)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	(79)	0	(79)	0.0	5,137,247 a)	5,342,213 a)	(204,966)	(3.8)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	100,955,430	106,788,662	(5,833,232)	(5.5)	5,137,247	5,342,213	(204,966)	(3.8)	1.96517	1.99896	(0.03379)	(1.7)
6. Fuel Cost of Purchased Power - Firm (A7)	19,067,014	7,833,000	11,434,014	149.8	487,122	211,096	276,026	130.8	3.91422	3.61589	0.29833	8.3
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	(10,512)	1,826,800	(1,837,312)	(100.6)	0	45,792	(45,792)	(100.0)	#DIV/0!	3.98934	#DIV/0!	#DIV/0!
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	2,383,251	2,448,200	(64,949)	(2.7)	118,049	130,070	(12,021)	(9.2)	2.01887	1.88222	0.13665	7.3
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	21,439,753	11,908,000	9,531,753	80.0	605,171	386,958	218,213	56.4	3.54276	3.07734	0.46542	15.1
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					5,742,418	5,729,171	13,247	0.2				
14. Fuel Cost of Economy Sales (A6)	(1,687)	322,900	(324,587)	(100.5)	0	15,246	(15,246)	(100.0)	#DIV/0!	2.11793	#DIV/0!	#DIV/0!
15. Gain on Economy Sales - 80% (A6)	0	80,220	(80,220)	(100.0)	0	15,246 a)	(15,246)	(100.0)	0.00000	0.52617	(0.52617)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	190,768	295,300	(104,532)	(35.4)	12,186	19,153	(6,967)	(36.4)	1.56547	1.54180	0.02367	1.5
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	438,214	437,600	614	0.1	22,433	22,816	(383)	(1.7)	1.95343	1.91795	0.03548	1.8
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	1,437,207	1,034,900	402,307	38.9	62,520	45,584	16,936	37.2	2.29880	2.27031	0.02849	1.3
21. Fuel Cost of Other Power Sales (A6)	8,884,475	7,846,396	1,038,079	13.2	439,920	435,600	4,320	1.0	2.01957	1.80128	0.21829	12.1
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	10,948,977	10,017,316	931,661	9.3	537,059	538,399	(1,340)	(0.2)	2.03869	1.86057	0.17812	9.6
23. Net Inadvertant Interchange					234	0	234	0.0				
24. Wheeling Rec'd. less Wheeling Del'd.					896	0	896	0.0				
25. Interchange and Wheeling Losses					11,911	8,100	3,811	47.0				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	111,446,206	108,679,346	2,766,860	2.5	5,194,578	5,182,872	11,906	0.2	2.14543	2.09698	0.04845	2.3
27. Net Unbilled	(1,157,352) (a)	(1,460,819) (a)	303,467	(20.8)	(53,945)	(69,663)	15,718	(22.6)	(0.02228)	(0.02819)	0.00591	(21.0)
28. Company Use	347,173 (a)	335,517 (a)	11,656	3.5	16,182	16,000	182	1.1	0.00693	0.00671	0.00022	3.3
29. T & D Losses	4,808,509 (a)	4,876,401 (a)	(67,892)	(1.4)	224,128	232,544	(8,416)	(3.6)	0.09601	0.09745	(0.00144)	(1.5)
30. System KWH Sales	111,446,206	108,679,346	2,766,860	2.5	5,008,213	5,003,791	4,422	0.1	2.22527	2.17194	0.05333	2.5
31. Wholesale KWH Sales	(3,109,092)	(1,010,278)	(2,098,814)	207.7	(137,838)	(46,225)	(91,613)	198.2	2.25561	2.18557	0.07004	3.2
32. Jurisdictional KWH Sales	108,337,114	107,669,068	668,046	0.6	4,870,375	4,957,566	(87,191)	(1.8)	2.22441	2.17181	0.05260	2.4
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	108,410,782	107,742,282	668,500	0.6	4,870,375	4,957,566	(87,191)	(1.8)	2.22592	2.17329	0.05263	2.4
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	1,447,311	1,474,957	(27,646)	(1.9)	4,870,375	4,957,566	(87,191)	(1.8)	0.02972	0.02975	(0.00003)	(0.1)
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	4,870,375	4,957,566	(87,191)	(1.8)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	4,870,375	4,957,566	(87,191)	(1.8)	0.00000	0.00000	0.00000	0.0
36. True-up *	1,222,296	1,222,296	0	0.0	4,870,375	4,957,566	(87,191)	(1.8)	0.02510	0.02466	0.00044	1.8
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	111,080,389	110,439,535	640,854	0.6	4,870,375	4,957,566	(87,191)	(1.8)	2.28074	2.22770	0.05304	2.4
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.28238	2.22930	0.05308	2.4
40. GPIF * (Already Adjusted for Taxes)	(92,236)	(92,236)	0	0.0	4,870,375	4,957,566	(87,191)	(1.8)	(0.00189)	(0.00186)	(0.00003)	1.6
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	110,988,153	110,347,299	640,854	0.6	4,870,375	4,957,566	(87,191)	(1.8)	2.28049	2.22744	0.05305	2.4
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.280	2.227	0.053	2.4

* Based on Jurisdictional Sales (a) Included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	23,843,179	26,039,477	(2,196,298)	(8.4)	100,969,997	106,804,662	(5,834,665)	(5.5)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD •	2,557,218	2,553,144	4,074	0.2	10,948,977	10,017,316	931,661	9.3
3. FUEL COST OF PURCHASED POWER	6,775,449	3,166,300	3,609,149	114.0	19,067,014	7,633,000	11,434,014	149.8
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	676,517	756,500	(79,983)	(10.6)	2,383,251	2,448,200	(64,949)	(2.7)
4. ENERGY COST OF ECONOMY PURCHASES	0	1,005,600	(1,005,600)	0.0	(10,512)	1,826,800	(1,837,312)	(100.6)
5. TOTAL FUEL & NET POWER TRANSACTION	28,737,927	28,414,733	323,194	1.1	111,460,773	108,695,346	2,765,427	2.5
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(3,243)	(4,000)	757	(18.9)	(14,488)	(16,000)	1,512	(9.5)
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST	0	0	0	0.0	(79)	0	(79)	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	28,734,684	28,410,733	323,951	1.1	111,446,206	108,679,346	2,766,860	2.5
• INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,201,943	1,208,883	(6,940)	(0.6)	4,870,375	4,957,566	(87,191)	(1.8)
2. NONJURISDICTIONAL SALES	37,368	15,518	21,850	140.8	137,838	46,225	91,613	198.2
3. TOTAL SALES	1,239,311	1,224,401	14,910	1.2	5,008,213	5,003,791	4,422	0.1
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9698478	0.9873260	(0.0174782)	(1.8)	0.9724776	0.9907620	(0.0182844)	(1.8)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2000
CURRENT MONTH

SCHEDULE A2
PAGE 2 OF 3
REVISED WITH JULY 2000 FILING
PERIOD TO DATE

	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	27,403,682	27,803,981	(400,299)	(1.4)	111,310,929	113,994,924	(2,683,995)	(2.4)
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	(305,574)	(305,574)	0	0.0	(1,222,296)	(1,222,296)	0	0.0
b. INCENTIVE PROVISION	23,059	23,059	0	0.0	92,236	92,236	0	0.0
c. TRANSITION ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
d. OTHER ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	27,121,167	27,521,466	(400,299)	(1.5)	110,180,869	112,864,864	(2,683,995)	(2.4)
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	28,734,684	28,410,733	323,951	1.1	111,446,206	108,679,346	2,766,860	2.5
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B-4)	0.9698478	0.9873260	(0.0174782)	(1.8)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	27,866,272	28,050,655	(182,383)	(0.7)	108,337,114	107,669,068	668,046	0.6
6A.JURISDIC. LOSS MULTIPLIER	1.00068	1.00068	0.0000	0.0	NA	NA	-	-
6B. (LINE 6 x LINE 6A)	27,887,222	28,069,729	(182,507)	(0.7)	108,410,782	107,742,282	668,500	0.6
6C.PEABODY COAL CONTR. BUY-OUT AMORT.	368,373	368,373	0	0.0	1,488,678	1,488,678	0	0.0
6D.(LINE 6C x LINE 5) PB. JURISD.	357,266	363,704	(6,438)	(1.8)	1,447,311	1,474,957	(27,646)	(1.9)
6E.OTHER (SPARE INPUT #1)	0	0	0	0.0	0	0	0	0.0
6F. OIL BELOW THE DISCHARGE VALVE	0	0	0	0.0	0	0	0	0.0
6G. OTHER (SPARE INPUT #2)	0	0	0	0.0	0	0	0	0.0
6H. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. 6B+6D+6E+6F+6G)	28,244,488	28,433,433	(188,945)	(0.7)	109,858,093	109,217,239	640,854	0.6
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6H)	(1,123,321)	(911,967)	(211,354)	23.2	322,776	3,647,625	(3,324,849)	(91.2)
8. INTEREST PROVISION FOR THE MONTH	(53,743)	(50,283)	(3,460)	6.9	(215,986)	(51,527)	(164,459)	319.2
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(18,008,903)	(18,008,903)	0	0.0	NOT APPLICABLE			
9a.DEFERRED TRUE-UP BEGINNING OF PERIO	7,879,936	7,879,936	0	0.0	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	305,574	305,574	0	0.0	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	(11,000,457)	(10,785,643)	(214,814)	2.0	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2000
CURRENT MONTH

REVISED WITH JULY 2000 FILING
PERIOD TO DATE

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	(10,128,967)	(10,128,967)	0	0.0	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	(10,946,714)	(10,735,360)	(211,354)	2.0	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(21,075,681)	(20,864,327)	(211,354)	1.0	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	(10,537,841)	(10,432,164)	(105,678)	1.0	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	6.070	6.070	0.000	0.0	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	6.180	5.500	0.680	12.4	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	12.250	11.570	0.680	5.9	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	6.125	5.785	0.340	5.9	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.510	0.482	0.028	5.8	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	(53,743)	(50,283)	(3,460)	6.9	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: APRIL 2000

SCHEDULE A3
PAGE 1 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
FUEL COST OF SYSTEM NET GENERATION ($)								
1 HEAVY OIL	811,197	882,874	(71,677)	(8.1)	984,830	1,315,825	(330,995)	(25.2)
2 LIGHT OIL	141,095	692,309	(551,214)	(79.6)	1,358,218	2,243,344	(885,126)	(39.5)
3 COAL	22,890,887	24,464,294	(1,573,407)	(6.4)	98,626,949	103,245,493	(4,618,544)	(4.5)
4 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
5 NUCLEAR	0	0	0	0.0	0	0	0	0.0
6 OTHER	0	0	0	0.0	0	0	0	0.0
7 TOTAL ($)	23,843,179	26,039,477	(2,196,298)	(8.4)	100,969,997	106,804,662	(5,834,665)	(5.5)
SYSTEM NET GENERATION (MWH)								
8 HEAVY OIL	14,792	18,434	(3,642)	(19.8)	16,323	28,694	(12,371)	(43.1)
9 LIGHT OIL	4,445	88	4,357	4,951.1	27,064	43,760	(16,696)	(38.2)
10 COAL	1,190,940	1,268,808	(77,868)	(6.1)	5,093,860	5,269,759	(175,899)	(3.3)
11 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
12 NUCLEAR	0	0	0	0.0	0	0	0	0.0
13 OTHER	0	0	0	0.0	0	0	0	0.0
14 TOTAL (MWH)	1,210,177	1,287,330	(77,153)	(6.0)	5,137,247	5,342,213	(204,966)	(3.8)
UNITS OF FUEL BURNED								
15 HEAVY OIL (BBL)	37,826	49,826	(12,000)	(24.1)	46,950	75,830	(28,880)	(38.1)
16 LIGHT OIL (BBL)	4,240	19,772	(15,532)	(78.6)	45,075	85,569	(40,494)	(47.3)
17 COAL (TON)	540,606	562,626	(22,020)	(3.9)	2,336,641	2,377,656	(41,015)	(1.7)
18 NATURAL GAS (MCF)	0	0	0	0.0	0	0	0	0.0
19 NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20 OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
BTUS BURNED (MMBTU)								
21 HEAVY OIL	240,545	314,948	(74,403)	(23.6)	298,547	479,328	(180,781)	(37.7)
22 LIGHT OIL	24,666	1,576	23,090	1,465.1	262,054	383,684	(121,630)	(31.7)
23 COAL	12,589,981	13,157,970	(567,989)	(4.3)	52,904,671	54,758,624	(1,853,953)	(3.4)
24 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
25 NUCLEAR	0	0	0	0.0	0	0	0	0.0
26 OTHER	0	0	0	0.0	0	0	0	0.0
27 TOTAL (MMBTU)	12,855,192	13,474,494	(619,302)	(4.6)	53,465,272	55,621,636	(2,156,364)	(3.9)
GENERATION MIX (% MWH)								
28 HEAVY OIL	1.22	1.43	(0.21)	-	0.32	0.54	(0.22)	-
29 LIGHT OIL	0.37	0.01	0.36	-	0.53	0.82	(0.29)	-
30 COAL	98.41	98.56	(0.15)	-	99.16	98.64	0.52	-
31 NATURAL GAS	0.00	0.00	0.00	-	0.00	0.00	0.00	-
32 NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33 OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34 TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
FUEL COST PER UNIT								
35 HEAVY OIL ($/BBL)	21.45	17.72	3.73	21.0	20.98	17.35	3.63	20.9
36 LIGHT OIL ($/BBL)	33.28	35.01	(1.73)	(4.9)	30.13	26.22	3.91	14.9
37 COAL ($/TON)	42.34	43.48	(1.14)	(2.6)	42.21	43.42	(1.21)	(2.8)
38 NATURAL GAS ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40 OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
FUEL COST PER MMBTU ($/MMBTU)								
41 HEAVY OIL	3.37	2.80	0.57	20.4	3.30	2.75	0.55	20.0
42 LIGHT OIL	5.72	439.28	(433.56)	(98.7)	5.18	5.85	(0.67)	(11.5)
43 COAL	1.82	1.86	(0.04)	(2.2)	1.86	1.89	(0.03)	(1.6)
44 NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
45 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47 TOTAL ($/MMBTU)	1.85	1.93	(0.08)	(4.1)	1.89	1.92	(0.03)	(1.6)

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: APRIL 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
BTU BURNED PER KWH (BTU/KWH)								
48 HEAVY OIL	16,262	17,085	(823)	(4.8)	18,290	16,705	1,585	9.5
49 LIGHT OIL	5,549	17,909	(12,360)	(69.0)	9,683	8,768	915	10.4
50 COAL	10,571	10,370	201	1.9	10,386	10,391	(5)	0.0
51 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
52 NUCLEAR	0	0	0	0.0	0	0	0	0.0
53 OTHER	0	0	0	0.0	0	0	0	0.0
54 TOTAL (BTU/KWH)	10,623	10,467	156	1.5	10,407	10,412	(5)	0.0
GENERATED FUEL COST PER KWH (cents/KWH)								
55 HEAVY OIL	5.48	4.79	0.69	14.4	6.03	4.59	1.44	31.4
56 LIGHT OIL	3.17	786.71	(783.54)	(99.6)	5.02	5.13	(0.11)	(2.1)
57 COAL	1.92	1.93	(0.01)	(0.5)	1.94	1.96	(0.02)	(1.0)
58 NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
59 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61 TOTAL (cents/KWH)	1.97	2.02	(0.05)	(2.5)	1.97	2.00	(0.03)	(1.5)

SCHEDULE A4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD/MONTH OF: APRIL 2000

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPC. FACTO (%)	EQUIV. AVAIL. FACTO (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COS PER KWH (cents /KWH)	COST OF FUEL ($/UNIT)
H.P.#1	30	2,515	11.3	100.0	65.8	-	HVY.OIL	-	-	-	-	-	-
H.P.#2	30	2,606	11.7	100.0	62.6	-	HVY.OIL	-	-	-	-	-	-
H.P.#3	30	2,608	11.7	96.5	63.7	-	HVY.OIL	-	-	-	-	-	-
H.P.#4	39	3,993	13.8	100.0	60.6	-	HVY.OIL	-	-	-	-	-	-
H.P.#5	67	3,112	6.2	56.3	58.1	-	HVY.OIL	-	-	-	-	-	-
H.P. STATION	196	14,834	10.2	84.5	61.3	16,216	HVY.OIL	37,826	6,359,253	240,545.1	810,554	5.46	21.43
GAN.#1	114	50,688	59.8	89.6	68.6	11,528	COAL	24,596	23,756,139	584,306.0	909,626	1.79	36.98
GAN.#2	98	34,799	47.7	72.2	68.2	10,816	COAL	15,909	23,659,017	376,391.3	588,358	1.69	36.98
GAN.#3	145	75,902	70.4	95.0	76.1	11,882	COAL	46,535	19,380,980	901,893.9	1,720,990	2.27	36.98
GAN.#4	159	1,862	1.6	2.0	60.9	28,237	COAL	2,720	19,330,000	52,577.6	100,593	5.40	36.98
GAN.#5	232	40,373	23.4	30.5	75.4	10,268	COAL	16,361	25,337,718	414,550.4	605,074	1.50	36.98
GAN.#6	372	152,524	55.1	63.1	74.3	10,687	COAL	68,206	23,899,620	1,630,097.5	2,522,442	1.65	36.98
GANNON STA.	1120	358,148	42.7	55.3	71.7	11,118	COAL	174,327	22,714,879	3,959,816.7	6,447,083	1.81	36.98
B.B.#1	416	162,278	52.4	52.0	73.4	10,627	COAL	70,091	24,603,500	1,724,489.1	2,923,921	1.80	41.72
B.B.#2	416	255,056	82.4	97.7	85.3	9,901	COAL	104,585	24,144,980	2,525,202.7	4,362,862	1.71	41.72
B.B.#3	433	39,525	12.3	16.5	65.6	11,578	COAL	19,006	24,076,681	457,606.7	792,862	2.01	41.72
B.B. 1 - 3	1265	456,859	48.5	54.9	74.6	10,304	COAL	193,682	24,304,210	4,707,298.5	8,079,645	1.77	41.72
B.B.#4	442	281,073	85.5	97.9	88.4	9,717	COAL	126,011	21,674,161	2,731,181.8	6,390,793	2.27	50.72
B.B. STA.	1707	737,932	58.1	66.0	78.2	10,080	COAL	319,693	23,267,545	7,438,480.3	14,470,438	1.96	45.26
SEB-PHIL. #1(HVY OIL)	17	(21)	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	321	0.00	0.00
SEB-PHIL. #2(HVY OIL)	17	(21)	0.0	1.4	0.0	0	HVY.OIL	0	0	0.0	322	0.00	0.00
SEB-PHILLIPS TOTAL	34	(42)	0.0	0.7	0.0	0	HVY.OIL	0	0	0.0	643	0.00	0.00
POLK COAL	250	96,860	52.1	59.6	89.6	12,303	COAL	46,586	25,580,459	1,191,683.6	1,973,366	2.04	42.36
POLK OIL	225	4,445	2.7	67.0	86.0	5,549	LGT.OIL	4,240	5,818,045	24,666.3	141,095	3.17	33.28
POLK TOTAL	250	101,305	54.8	65.7	-	12,007	-	-	-	1,216,349.9	2,114,461	2.09	-
GAN.C.T.#1	12	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#2	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	156	0	0.0	15.4	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
TOT. COAL (GN,BB,POLK)	3077	1,190,940	52.0	61.6	76.8	10,571	COAL	540,606	23,288,640	12,589,980.6	22,890,887	1.92	42.34
SYSTEM	3463	1,210,177	47.0	60.7	71.6	10,623	-	-	-	12,855,192.0	23,843,179	1.97	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS

NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2000

		CURRENT MONTH				PERIOD TO DATE			
	HEAVY OIL (1)	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	PURCHASES:								
2	UNITS (BBL)	97,202	3,738	93,464	2,500.4	97,202	29,742	67,460	226.8
3	UNIT COST ($/BBL)	23.06	27.51	(4.45)	(16.2)	23.28	17.00	6.28	36.9
4	AMOUNT ($)	2,241,124	102,836	2,138,288	2,079.3	2,262,999	505,551	1,757,448	347.6
5	BURNED:								
6	UNITS (BBL)	37,826	49,826	(12,000)	(24.1)	46,950	75,830	(28,880)	(38.1)
7	UNIT COST ($/BBL)	21.45	17.72	3.73	21.0	20.98	17.35	3.63	20.9
8	AMOUNT ($)	811,197	882,874	(71,677)	(8.1)	984,830	1,315,825	(330,995)	(25.2)
9	ENDING INVENTORY:								
10	UNITS (BBL)	140,511	81,135	59,376	73.2	140,511	81,135	59,376	73.2
11	UNIT COST ($/BBL)	21.29	17.86	3.43	19.2	21.29	17.86	3.43	19.2
12	AMOUNT ($)	2,992,009	1,449,051	1,542,958	106.5	2,992,009	1,449,051	1,542,958	106.5
13									
14	DAYS SUPPLY:	46	27	19	70.4	-	-	-	-
	LIGHT OIL (2)								
15	PURCHASES:								
16	UNITS (BBL)	12,387	34,952	(22,565)	(64.6)	109,731	133,538	(23,807)	(17.8)
17	UNIT COST ($/BBL)	32.19	39.83	(7.64)	(19.2)	34.02	27.57	6.45	23.4
18	AMOUNT ($)	398,738	1,392,044	(993,306)	(71.4)	3,732,852	3,681,045	51,807	1.4
19	BURNED:								
20	UNITS (BBL)	4,240	19,772	(15,532)	(78.6)	45,075	85,569	(40,494)	(47.3)
21	UNIT COST ($/BBL)	33.28	35.01	(1.73)	(4.9)	30.13	26.22	3.91	14.9
22	AMOUNT ($)	141,095	692,309	(551,214)	(79.6)	1,358,218	2,243,344	(885,126)	(39.5)
23	ENDING INVENTORY:								
24	UNITS (BBL)	97,308	97,057	251	0.3	97,308	97,057	251	0.3
25	UNIT COST ($/BBL)	31.93	33.94	(2.01)	(5.9)	31.93	33.94	(2.01)	(5.9)
26	AMOUNT ($)	3,107,107	3,293,646	(186,539)	(5.7)	3,107,107	3,293,646	(186,539)	(5.7)
27									
28	DAYS SUPPLY: NORMAL	70	69	1	1.4	-	-	-	-
29	DAYS SUPPLY: EMERGENCY	14	14	0	0.0	-	-	-	-
	COAL (3)								
30	PURCHASES:								
31	UNITS (TONS)	579,711	486,000	93,711	19.3	2,843,076	2,419,200	423,876	17.5
32	UNIT COST ($/TON)	43.19	43.42	(0.23)	(0.5)	41.78	42.76	(0.98)	(2.3)
33	AMOUNT ($)	25,037,220	21,100,405	3,936,815	18.7	118,789,390	103,434,369	15,355,021	14.8
34	BURNED:								
35	UNITS (TONS)	540,606	562,626	(22,020)	(3.9)	2,336,641	2,377,656	(41,015)	(1.7)
36	UNIT COST ($/TON)	42.34	43.48	(1.14)	(2.6)	42.21	43.42	(1.21)	(2.8)
37	AMOUNT ($)	22,890,887	24,464,294	(1,573,407)	(6.4)	98,626,949	103,245,493	(4,618,544)	(4.5)
38	ENDING INVENTORY:								
39	UNITS (TONS)	1,283,451	1,167,719	115,732	9.9	1,283,451	1,167,719	115,732	9.9
40	UNIT COST ($/TON)	42.03	42.20	(0.17)	(0.4)	42.03	42.20	(0.17)	(0.4)
41	AMOUNT ($)	53,946,374	49,281,886	4,664,488	9.5	53,946,374	49,281,886	4,664,488	9.5
42									
43	DAYS SUPPLY:	55	50	5	10.0	-	-	-	-
	NATURAL GAS								
44	PURCHASES:								
45	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
46	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
48	BURNED:								
49	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
50	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
51	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
52	ENDING INVENTORY:								
53	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
54	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
56									
57	DAYS SUPPLY:	0	0	0	0.0	-	-	-	-
	NUCLEAR								
58	BURNED:								
59	UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
60	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2000

OTHER	CURRENT MONTH ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	PERIOD TO DATE ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
74 DAYS SUPPLY:	0	0	0	0.0	-	-	-	-

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	5,288
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	5,288

(2) RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(6,958)	(218,283)
OTHER USAGE	(938)	(28,977)
TOTAL	(7,896)	(247,260)

(3) RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	28,879
IGNITION #2 OIL	165,671
IGNITION PROPANE	7,611
AERIAL SURVEY ADJ.	(695,507)
ADDITIVES	75,208
TOTAL	(418,138)

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: APRIL 2000

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	1,512.0	0.0	1,512.0	2.646	3.267	40,000.00	49,400.00	7,500.00
VARIOUS	JURISDICTIONAL	SCH. -D	5,675.0	0.0	5,675.0	2.162	2.162	122,700.00	122,700.00	
VARIOUS	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPARATED	CONTRACT	19,801.0	0.0	19,801.0	2.233	3.176	442,200.00	628,800.00	
FMPA		SCH. -D	108,000.0	0.0	108,000.0	1.800	1.800	1,943,944.00	1,943,944.00	
VARIOUS	JURISDICTIONAL	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	134,988.0	0.0	134,988.0	1.868	2.033	2,548,844.00	2,744,844.00	7,500.00
LESS TRANSMISSION COSTS		-						0.00		
LESS VARIABLE O & M COSTS		-						(3,200.00)		
PLUS 80% OF ECON. ENERGY SALES PROFI		-						7,500.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INC		-								
80% OF ECON. ENERGY SALES PROFITS		-	134,988.0	0.0	134,988.0	1.891	2.033	2,553,144.00	2,744,844.00	7,500.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENRGY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
OGLETHORPE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENN, VALLEY AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEP. CONTRACT		25,622.0	0.0	25,622.0	2.280	3.094	584,181.60	792,744.68	
SEMINOLE ELECTRIC CO-OP PRE	JURISD.	SCH. -D	5,701.0	898.6	4,802.4	2.300	2.300	110,447.61	110,447.61	
SEMINOLE ELECTRIC CO-OP HAR	JURISD.	SCH. -D	793.0	0.0	793.0	1.747	1.747	13,854.36	13,854.36	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: APRIL 2000

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA		SCH. -D	82,670.0	0.0	82,670.0	1.908	1.908	1,577,241.76	1,577,241.76	
HARDEE POWER PART. TO FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR.& LT.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO JACKSONVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KISSIMMEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ORLANDO		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO SEMINOLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FT. PIERCE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LK. WORTH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ENERGY AUTHORI		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FPL		SCH. -MB	55.0	0.0	55.0	2.581	2.581	1,419.57	1,419.57	
SEMINOLE ELECTRIC CO-OP		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. CORP.		SCH. -MB	325.0	0.0	325.0	2.479	2.479	8,057.49	8,057.49	
FLA. PWR. & LIGHT		SCH. -MB	9,210.0	0.0	9,210.0	2.626	2.626	241,865.93	241,865.93	
ORLANDO UTIL. COMM.		SCH. -MB	50.0	0.0	50.0	2.897	2.897	1,448.65	1,448.65	
REEDY CREEK		SCH. -MB	65.0	0.0	65.0	2.112	2.112	1,372.70	1,372.70	
THE ENERGY AUTHORITY		SCH. -MB	605.0	0.0	605.0	2.732	2.732	16,530.84	16,530.84	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: APRIL 2000

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ADJUSTMENTS TO PREVIOUS MO MON/YR TYP SCHED.									
HARDEE POWER PARTNERS ES 3/00 SEPAR.	CONTRACT	(10,225.0)	0.0	(10,225.0)	2.272	3.121	(232,312.00)	(319,122.25)	
HARDEE POWER PARTNERS ACT 3/00 SEPAR.	CONTRACT	10,225.0	0.0	10,225.0	2.280	3.094	233,130.00	316,361.50	
HARDEE POWER PART. TO ORLA 3/00 JURISD.	SCH. -MB	(64.0)	0.0	(64.0)	3.001	3.001	(1,920.58)	(1,920.58)	
HARDEE POWER PART. TO ORLA 3/00 JURISD.	SCH. -MB	64.0	0.0	64.0	2.968	2.968	1,899.62	1,899.62	
SUB-TOTAL ECONOMY POWER SALES		0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.		0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.		6,494.0	898.6	5,595.4	2.222	2.222	124,301.97	124,301.97	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.		0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.		25,622.0	0.0	25,622.0	2.283	3.083	584,999.60	789,983.93	
SUB-TOTAL FMPA D POWER SALES		82,670.0	0.0	82,670.0	1.908	1.908	1,577,241.76	1,577,241.76	
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.		0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE MB POWER SALES-JURISD.		10,310.0	0.0	10,310.0	2.625	2.625	270,674.22	270,674.22	
TOTAL INCLUDING VARIABLE O & M COSTS		125,096.0	898.6	124,197.4	2.059	2.224	2,557,217.55	2,762,201.88	0.00
LESS VARIABLE O & M COSTS							0.00		
LESS VARIABLE O & M COSTS - HARDEE							0.00		
LESS TRANSMISSION COSTS SCH. D (SEP.)							0.00		
PLUS 80% OF ECON. ENERGY SALES PROFITS -							0.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS -		125,096.0	898.6	124,197.4	2.059	2.224	2,557,217.55	2,762,201.88	0.00
CURRENT MONTH:									
DIFFERENCE	-	(9,892.0)	898.6	(10,790.6)	0.168	0.191	4,073.55	17,357.88	(7,500.00)
DIFFERENCE %	-	(7.3)	0.0	(8.0)	8.9	9.4	0.2	0.6	(100.0)
PERIOD TO DATE:									
ACTUAL	-	539,473.0	2,414.1	537,058.9	2.039	2.146	10,948,976.15	11,526,757.23	0.00
ESTIMATED	-	538,399.0	0.0	538,399.0	1.861	1.960	10,017,316.00	10,554,896.00	80,220.00
DIFFERENCE	-	1,074.0	2,414.1	(1,340.1)	0.178	0.186	931,660.15	971,861.23	(80,220.00)
DIFFERENCE %	-	0.2	0.0	(0.2)	9.6	9.5	9.3	9.2	(100.0)

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. SEC 60% OR $88.09 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH APRIL 2000

SCHEDULE A7

(1)		(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM		TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:									
VARIOUS		EMER.	47,999.0	0.0	24,581.0	23,418.0	5.250	5.250	1,229,500.00
HARDEE POWER PARTNERS		IPP	41,101.0	0.0	0.0	41,101.0	3.368	3.368	1,384,200.00
VARIOUS		OTHER	20,160.0	0.0	0.0	20,160.0	2.741	2.741	552,600.00
TOTAL		-	109,260.0	0.0	24,581.0	84,679.0	3.739	3.739	3,166,300.00
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	63,561.0	0.0	0.0	63,561.0	3.972	3.972	2,524,368.25
HARDEE PWR. PART.-OTHERS		IPP	55.0	0.0	0.0	55.0	2.474	2.474	1,360.85
FLA. POWER CORP.		SCH.-Ja	8,601.0	0.0	8,069.2	531.8	5.189	5.189	27,597.27
FLA. POWER CORP.		SCH.-Jc	23,047.0	0.0	0.0	23,047.0	3.587	3.587	826,689.00
FLA. POWER & LIGHT		SCH.-Ja	16,075.0	0.0	12,468.7	3,606.3	4.942	4.942	178,206.07
FLA. POWER & LIGHT		SCH.-Jc	14,018.0	0.0	0.0	14,018.0	4.293	4.293	601,802.50
CITY OF LAKELAND		SCH.-Ja	6,599.0	0.0	2,407.1	4,191.9	4.821	4.821	202,071.30
CITY OF LAKELAND		SCH.-Jc	3,166.0	0.0	0.0	3,166.0	4.396	4.396	139,174.00
ORLANDO		SCH.-Ja	10,600.0	0.0	2,654.0	7,946.0	4.730	4.730	375,846.92
ORLANDO		SCH.-Jc	7,755.0	0.0	0.0	7,755.0	4.334	4.334	336,088.50
ENTERGY MARKETING		SCH.-Ja	50.0	0.0	50.0	0.0	0.000	0.000	0.00
ENTERGY MARKETING		SCH.-Jc	101.0	0.0	0.0	101.0	4.789	4.789	4,837.05
THE ENERGY AUTH.		SCH.-Ja	4,807.0	0.0	1,212.4	3,594.6	4.894	4.894	175,907.08
THE ENERGY AUTH.		SCH.-Jc	10,433.0	0.0	0.0	10,433.0	4.362	4.362	455,112.91
RELIANT		SCH.-Ja	1,111.0	0.0	4.0	1,107.0	4.344	4.344	48,091.98
RELIANT		SCH.-Jc	1,219.0	0.0	0.0	1,219.0	4.408	4.408	53,731.16
TALLAHASSEE		SCH.-Ja	835.0	0.0	36.5	798.5	4.413	4.413	35,237.81
TALLAHASSEE		SCH.-Jc	6,706.0	0.0	0.0	6,706.0	3.979	3.979	266,854.55
AQUILA		SCH.-Ja	730.0	0.0	730.0	0.0	0.000	0.000	0.00
AQUILA		SCH.-Jc	992.0	0.0	0.0	992.0	3.653	3.653	36,233.25
OKEELANTA		SCH.-Ja	32.0	0.0	32.0	0.0	0.000	0.000	0.00
OKEELANTA		SCH.-Jc	1,688.0	0.0	0.0	1,688.0	4.579	4.579	77,291.08
KOCH ENERGY TRAD.		SCH.-Ja	358.0	0.0	358.0	0.0	0.000	0.000	0.00
KOCH ENERGY TRAD.		SCH.-Jc	561.0	0.0	0.0	561.0	4.930	4.930	27,660.00
SEMPRA		SCH.-Jc	100.0	0.0	0.0	100.0	4.900	4.900	4,900.00
OKEELANTA		SCH.-D	15,195.0	0.0	0.0	15,195.0	3.361	3.361	510,670.40
AUBURNDALE POWER PARTNERS		SCH.-D	2,505.0	0.0	0.0	2,505.0	2.334	2.334	58,455.73
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	Mar-00	IPP	(61,999.0)	0.0	0.0	(61,999.0)	4.014	4.014	(2,488,377.38)
HARDEE PWR. PART.-NATIVE	Mar-00	IPP	61,999.0	0.0	0.0	61,999.0	3.701	3.701	2,294,880.87
OKEELANTA	Mar-00	SCH.-Jc	(390.0)	0.0	0.0	(390.0)	4.013	4.013	(15,650.00)
OKEELANTA	Mar-00	SCH.-Jc	390.0	0.0	0.0	390.0	4.207	4.207	16,408.00
TOTAL			200,900.0	0.0	28,021.9	172,878.1	3.919	3.919	6,775,449.15
CURRENT MONTH:									
DIFFERENCE		-	91,640.0	0.0	3,440.9	88,199.1	4.092	4.092	3,609,149.15
DIFFERENCE %		-	83.9	0.0	14.0	104.2	109.4	109.4	114.0
PERIOD TO DATE:									
ACTUAL		-	561,352.00	0.00	74,230.30	487,121.7	3.914	3.914	19,067,015.02
ESTIMATED		-	246,091.0	0.0	34,995.0	211,096.0	3.616	3.616	7,633,000.0
DIFFERENCE		-	315,261.0	0.0	39,235.3	276,025.7	0.298	0.298	11,434,015.02
DIFFERENCE %		-	128.1	0.0	112.1	130.8	8.2	8.2	149.8

ENERGY PAYMENT TO QUALIFYING FACILITIES — SCHEDULE A8

TAMPA ELECTRIC COMPANY

FOR THE MONTH OF: APRIL 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	—CENTS/KWH— (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	33,678.0	0.0	0.0	33,678.0	2.246	2.246	756,500.00
TOTAL	-	33,678.0	0.0	0.0	33,678.0	2.246	2.246	756,500.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	3,876.0	0.0	0.0	3,876.0	2.005	2.005	77,726.37
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	43.0	0.0	0.0	43.0	3.428	3.428	1,474.25
HILLSBOROUGH COUNTY	COGEN.	17,947.0	0.0	0.0	17,947.0	2.009	2.009	360,488.09
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	1,796.0	0.0	0.0	1,796.0	2.475	2.475	44,450.44
FARMLAND HYDRO LP	COGEN.	580.0	0.0	0.0	580.0	2.763	2.763	16,025.58
IMC-AGRICO-S. PIERCE	COGEN.	481.0	0.0	0.0	481.0	2.543	2.543	12,232.38
AUBURNDALE POWER PARTNERS	COGEN.	463.0	0.0	0.0	463.0	2.370	2.370	10,972.98
ORANGE COGENERATION L.P.	COGEN.	7,590.0	0.0	0.0	7,590.0	2.015	2.015	152,932.03
CUTRALE CITRUS	COGEN.	2.0	0.0	0.0	2.0	2.639	2.639	52.77
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	180.1	(180.1)	3.171	3.171	(5,710.91)
SUB-TOTAL FOR APRIL 2000	-	32,778.0	0.0	180.1	32,597.9	2.057	2.057	670,643.98
ADJ. FOR FEBRUARY 2000								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	3,075.00
McKAY BAY REFUSE	COGEN.	(3,961.0)	0.0	0.0	(3,961.0)	1.914	1.914	(75,824.62)
		3,961.0	0.0	0.0	3,961.0	1.926	1.926	76,294.92
MULBERRY PHOSPHATES INC.	COGEN.		0.0	0.0	0.0	0.000	0.000	
			0.0	0.0	0.0	0.000	0.000	
CARGILL RIDGEWOOD	COGEN.		0.0	0.0	0.0	0.000	0.000	
			0.0	0.0	0.0	0.000	0.000	
IMC-AGRICO-NEW WALES	COGEN.		0.0	0.0	0.0	0.000	0.000	
			0.0	0.0	0.0	0.000	0.000	
HILLSBOROUGH COUNTY	COGEN.	(17,785.0)	0.0	0.0	(17,785.0)	1.929	1.929	(342,998.82)
		17,785.0	0.0	0.0	17,785.0	1.939	1.939	344,765.95
CARGILL MILLPOINT	COGEN.		0.0	0.0	0.0	0.000	0.000	
			0.0	0.0	0.0	0.000	0.000	
CF INDUSTRIES INC.	COGEN.	(1,457.0)	0.0	0.0	(1,457.0)	2.252	2.252	(32,806.91)
		1,457.0	0.0	0.0	1,457.0	2.253	2.253	32,827.66
FARMLAND HYDRO LP	COGEN.	(709.0)	0.0	0.0	(709.0)	2.130	2.130	(15,104.10)
		709.0	0.0	0.0	709.0	2.143	2.143	15,192.86
IMC-AGRICO-S. PIERCE	COGEN.	(483.0)	0.0	0.0	(483.0)	2.324	2.324	(11,222.99)
		483.0	0.0	0.0	483.0	2.324	2.324	11,225.83
AUBURNDALE POWER PARTNERS	COGEN.	(57.0)	0.0	0.0	(57.0)	2.069	2.069	(1,179.11)
		57.0	0.0	0.0	57.0	2.081	2.081	1,186.44
ORANGE COGENERATION L.P.	COGEN.	(5,336.0)	0.0	0.0	(5,336.0)	1.949	1.949	(104,000.60)
		5,336.0	0.0	0.0	5,336.0	1.957	1.957	104,441.08
CUTRALE CITRUS	COGEN.		0.0	0.0	0.0	0.000	0.000	
			0.0	0.0	0.0	0.000	0.000	
AS AVAILABLE ASSIGNMENT	COGEN.		0.0	0.0	0.0	0.000	0.000	
			0.0	0.0	0.0	0.000	0.000	
SUB-TOTAL FOR Feb-00 ADJ.	-	0.0	0.0	0.0	0.0	0.000	0.000	5,872.59
GRAND TOTAL		32,778.0	0.0	180.1	32,597.9	2.075	2.075	676,516.57
CURRENT MONTH:								
DIFFERENCE	-	(900.0)	0.0	180.1	(1,080.1)	(0.171)	(0.171)	(79,983.43)
DIFFERENCE %	-	(2.7)	0.0	0.0	(3.2)	(7.6)	(7.6)	(10.6)
PERIOD TO DATE:								
ACTUAL		118,779.0	0.0	730.6	118,048.4	2.019	2.019	2,383,250.47
ESTIMATED		130,070.0	0.0	0.0	130,070.0	1.882	1.882	2,448,200.00
DIFFERENCE	-	(11,291.0)	0.0	730.6	(12,021.6)	0.137	0.137	(64,949.53)
DIFFERENCE %	-	(8.7)	0.0	0.0	(9.2)	7.3	7.3	(2.7)

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH APRIL 2000

SCHEDULE A9

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	COST IF GENERATED (A) cents/KWH	(B) $	FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	23,659.0	4.250	1,005,600.00	5.731	1,356,000.00	350,400.00
TOTAL	-	23,659.0	4.250	1,005,600.00	5.731	1,356,000.00	350,400.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL	-	0.0	0.000	0.00	0.000	0.00	0.00
CURRENT MONTH:							
DIFFERENCE	-	(23,659.0)	(4.250)	(1,005,600.00)	(5.731)	(1,356,000.00)	(350,400.00)
DIFFERENCE %	-	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)
PERIOD TO DATE:							
ACTUAL		0.0	0.000	(10,512.45)	0.000	0.00	10,512.45
ESTIMATED		45,792.0	3.989	1,826,800.00	5.258	2,407,600.00	580,800.00
DIFFERENCE	-	(45,792.0)	(3.989)	(1,837,312.45)	(5.258)	(2,407,600.00)	(570,287.55)
DIFFERENCE %	-	(100.0)	(100.0)	(100.6)	(100.0)	(100.0)	(98.2)

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

MAY 2000

SCHEDULE A1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: MAY , 2000

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	31,421,038	31,239,727	181,309	0.6	1,618,076	1,543,035	75,041	4.9	1.94188	2.02458	(0.08268)	(4.1)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(4,183)	(4,000)	(183)	4.1	1,618,076 a)	1,543,035 a)	75,041	4.9	(0.00026)	(0.00026)	0.00000	0.0
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,618,076 a)	1,543,035 a)	75,041	4.9	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,618,076 a)	1,543,035 a)	75,041	4.9	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	31,416,873	31,235,727	181,146	0.6	1,618,076	1,543,035	75,041	4.9	1.94182	2.02430	(0.08268)	(4.1)
6. Fuel Cost of Purchased Power - Firm (A7)	8,257,482	5,865,900	2,371,582	40.3	176,553	110,492	66,061	59.8	4.67706	5.32699	(0.64993)	(12.2)
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	1,856,700	(1,856,700)	(100.0)	0	47,513	(47,513)	(100.0)	0.00000	3.90777	(3.90777)	(100.0)
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 a)	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	665,957	881,600	(195,643)	(22.7)	29,878	35,005	(5,127)	(14.6)	2.22892	2.46136	(0.23244)	(9.4)
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	8,923,439	8,604,200	319,239	3.7	206,431	193,010	13,421	7.0	4.32272	4.45790	(0.13518)	(3.0)
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,824,507	1,736,045	88,462	5.1				
14. Fuel Cost of Economy Sales (A6)	0	169,700	(169,700)	(100.0)	0	7,573	(7,573)	(100.0)	0.00000	2.24086	(2.24086)	(100.0)
15. Gain on Economy Sales - 80% (A6)	0	38,700	(38,700)	(100.0)	0 a)	7,573 a)	(7,573)	(100.0)	0.00000	0.51103	(0.51103)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	155,462	132,300	23,162	17.5	6,981	5,966	1,015	17.0	2.22693	2.21757	0.00936	0.4
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	1,172,132	823,600	348,532	88.0	50,640	27,800	22,840	82.2	2.31484	2.24317	0.07147	3.2
21. Fuel Cost of Other Power Sales (A6)	2,352,998	2,014,564	338,434	16.8	106,081	111,600	(5,519)	(4.9)	2.21811	1.80516	0.41295	22.9
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	3,680,592	2,978,864	701,728	23.6	163,702	152,939	10,763	7.0	2.24835	1.94775	0.30060	15.4
23. Net Inadvertant Interchange					702	0	702	0.0				
24. Wheeling Rec'd. less Wheeling Del'd.					1,507	0	1,507	0.0				
25. Interchange and Wheeling Losses					(1,520)	2,300	(3,820)	(166.1)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	36,659,720	36,861,063	(201,343)	(0.5)	1,664,534	1,580,806	83,728	5.3	2.20240	2.33179	(0.12939)	(5.5)
27. Net Unbilled	4,350,489 (a)	3,141,781 (a)	1,208,728	38.5	197,534	134,736	62,798	46.6	0.26136	0.19874	0.06262	31.5
28. Company Use	89,858 (a)	93,272 (a)	(3,414)	(3.7)	4,090	4,000	90	2.0	0.00652	0.00681	(0.00029)	(4.3)
29. T & D Losses	1,867,107 (a)	1,699,245 (a)	167,862	9.9	84,776	72,873	11,903	16.3	0.13548	0.12411	0.01137	9.2
30. System KWH Sales	36,659,720	36,861,063	(201,343)	(0.5)	1,378,144	1,389,197	8,947	0.7	2.66008	2.69217	(0.03209)	(1.2)
31. Wholesale KWH Sales	(1,294,047)	(843,967)	(450,080)	53.3	(48,647)	(31,349)	(17,298)	55.2	2.66008	2.69217	(0.03209)	(1.2)
32. Jurisdictional KWH Sales	35,365,673	36,017,096	(651,423)	(1.8)	1,329,497	1,337,848	(8,351)	(0.6)	2.66008	2.69217	(0.03209)	(1.2)
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	35,389,722	36,041,588	(651,866)	(1.8)	1,329,497	1,337,848	(8,351)	(0.6)	2.66189	2.69400	(0.03211)	(1.2)
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	352,928	357,466	(4,538)	(1.3)	1,329,497	1,337,848	(8,351)	(0.6)	0.02655	0.02672	(0.00017)	(0.6)
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	1,329,497	1,337,848	(8,351)	(0.6)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	1,329,497	1,337,848	(8,351)	(0.6)	0.00000	0.00000	0.00000	0.0
36. True-up *	305,574	305,574	0	0.0	1,329,497	1,337,848	(8,351)	(0.6)	0.02298	0.02284	0.00014	0.6
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	36,048,224	36,704,628	(656,404)	(1.8)	1,329,497	1,337,848	(8,351)	(0.6)	2.71142	2.74356	(0.03214)	(1.2)
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.71337	2.74554	(0.03217)	(1.2)
40. GPIF * (Already Adjusted for Taxes)	(23,059)	(23,059)	0	0.0	1,329,497	1,337,848	(8,351)	(0.6)	(0.00173)	(0.00172)	(0.00001)	0.6
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	36,025,165	36,681,569	(656,404)	(1.8)	1,329,497	1,337,848	(8,351)	(0.6)	2.71164	2.74382	(0.03218)	(1.2)
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.712	2.744	(0.032)	(1.2)

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: MAY, 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	132,391,033	138,044,389	(5,653,356)	(4.1)	6,755,323	6,885,248	(129,925)	(1.9)	1.95980	2.00493	(0.04513)	(2.3)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (FLMeade/Wauch. Wheeling Losses)	(18,651)	(20,000)	1,349	(6.7)	6,755,323 a)	6,885,248 a)	(129,925)	(1.9)	(0.00028)	(0.00029)	0.00001	(3.4)
4b. Adjustments to Fuel Cost	0	0	0	0.0	6,755,323 a)	6,885,248 a)	(129,925)	(1.9)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	(79)	0	(79)	0.0	6,755,323 a)	6,885,248 a)	(129,925)	(1.9)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	132,372,303	138,024,389	(5,652,086)	(4.1)	6,755,323	6,885,248	(129,925)	(1.9)	1.95953	2.00464	(0.04511)	(2.3)
6. Fuel Cost of Purchased Power - Firm (A7)	27,324,496	13,518,900	13,805,596	102.1	663,675	321,588	342,087	106.4	4.11715	4.20379	(0.08664)	(2.1)
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	(10,512)	3,683,500	(3,694,012)	(100.3)	0	93,305	(93,305)	(100.0)	0.00000	3.94781	(3.94781)	(100.0)
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	3,049,208	3,309,800	(260,592)	(7.9)	147,927	165,075	(17,148)	(10.4)	2.06129	2.00503	0.05626	2.8
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	30,363,192	20,512,200	9,850,992	48.0	811,602	579,968	231,634	39.9	3.74114	3.53678	0.20436	5.8
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					7,566,925	7,465,216	101,709	1.4				
14. Fuel Cost of Economy Sales (A6)	(1,687)	492,600	(494,287)	(100.3)	0	22,819	(22,819)	(100.0)	0.00000	2.15873	(2.15873)	(100.0)
15. Gain on Economy Sales - 80% (A6)	0	118,920	(118,920)	(100.0)	0	22,819 a)	(22,819)	(100.0)	0.00000	0.52114	(0.52114)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	190,788	295,300	(104,532)	(35.4)	12,186	19,153	(6,967)	(36.4)	1.56547	1.54180	0.02367	1.5
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	593,876	569,900	23,776	4.2	29,414	28,782	632	2.2	2.01835	1.98006	0.03829	1.9
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	2,609,339	1,658,500	950,839	57.3	113,160	73,384	39,776	54.2	2.30588	2.26003	0.04585	2.0
21. Fuel Cost of Other Power Sales (A6)	11,237,473	9,860,960	1,376,513	14.0	546,001	547,200	(1,199)	(0.2)	2.05814	1.80208	0.25606	14.2
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	14,629,569	12,996,180	1,633,389	12.6	700,761	691,338	9,423	1.4	2.08767	1.87986	0.20781	11.1
23. Net Inadvertant Interchange					936	0	936	0.0				
24. Wheeling Rec'd. less Wheeling Del'd.					2,403	0	2,403	0.0				
25. Interchange and Wheeling Losses					10,391	10,400	(9)	(0.1)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	146,105,926	145,540,409	2,565,517	1.8	6,859,112	6,763,478	95,634	1.4	2.15926	2.15186	0.00740	0.3
27. Net Unbilled	3,100,460 (a)	1,400,280 (a)	1,700,180	121.4	143,589	65,073	78,516	120.7	0.04520	0.02070	0.02450	118.4
28. Company Use	437,509 (a)	430,372 (a)	7,137	1.7	20,262	20,000	262	1.3	0.00685	0.00675	0.00010	1.5
29. T & D Losses	6,670,041 (a)	6,572,146 (a)	97,895	1.5	308,904	305,417	3,487	1.1	0.10444	0.10313	0.00131	1.3
30. System KWH Sales	146,105,926	145,540,409	2,565,517	1.8	6,386,357	6,372,968	13,389	0.2	2.31910	2.28371	0.03539	1.5
31. Wholesale KWH Sales	(4,403,139)	(1,854,245)	(2,548,894)	137.5	(186,485)	(77,574)	(108,911)	140.4	2.36112	2.39029	(0.02917)	(1.2)
32. Jurisdictional KWH Sales	143,702,787	143,686,164	16,623	0.0	6,199,872	6,295,414	(95,542)	(1.5)	2.31783	2.28239	0.03544	1.6
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	143,800,504	143,783,870	16,634	0.0	6,199,872	6,295,414	(95,542)	(1.5)	2.31941	2.28395	0.03546	1.6
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	1,800,239	1,832,423	(32,184)	(1.8)	6,199,872	6,295,414	(95,542)	(1.5)	0.02904	0.02911	(0.00007)	(0.2)
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	6,199,872	6,295,414	(95,542)	(1.5)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	6,199,872	6,295,414	(95,542)	(1.5)	0.00000	0.00000	0.00000	0.0
36. True-up *	1,527,870	1,527,870	0	0.0	6,199,872	6,295,414	(95,542)	(1.5)	0.02464	0.02427	0.00037	1.5
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	147,128,613	147,144,163	(15,550)	0.0	6,199,872	6,295,414	(95,542)	(1.5)	2.37309	2.33732	0.03577	1.5
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.37480	2.33900	0.03580	1.5
40. GPIF * (Already Adjusted for Taxes)	(115,295)	(115,295)	0	0.0	6,199,872	6,295,414	(95,542)	(1.5)	(0.00186)	(0.00183)	(0.00003)	1.6
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	147,013,318	147,028,868	(15,550)	0.0	6,199,872	6,295,414	(95,542)	(1.5)	2.37294	2.33717	0.03577	1.5
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.373	2.337	0.036	1.5

* Based on Jurisdictional Sales (a) Included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2000

SCHEDULE A2
PAGE 1 OF 3

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	31,421,036	31,239,727	181,309	0.6	132,391,033	138,044,389	(5,653,356)	(4.1)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	3,680,592	2,978,864	701,728	23.6	14,629,569	12,996,180	1,633,389	12.6
3. FUEL COST OF PURCHASED POWER	8,257,482	5,885,900	2,371,582	40.3	27,324,496	13,518,900	13,805,596	102.1
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	665,957	861,600	(195,643)	(22.7)	3,049,208	3,309,800	(260,592)	(7.9)
4. ENERGY COST OF ECONOMY PURCHASES	0	1,856,700	(1,856,700)	0.0	(10,512)	3,683,500	(3,694,012)	(100.3)
5. TOTAL FUEL & NET POWER TRANSACTION	36,663,883	36,865,063	(201,180)	(0.5)	148,124,656	145,560,409	2,564,247	1.8
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(4,163)	(4,000)	(163)	4.1	(18,651)	(20,000)	1,349	(6.7)
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST	0	0	0	0.0	(79)	0	(79)	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	36,659,720	36,861,063	(201,343)	(0.5)	148,105,926	145,540,409	2,565,517	1.8
* INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,329,497	1,337,848	(8,351)	(0.6)	6,199,872	6,295,414	(95,542)	(1.5)
2. NONJURISDICTIONAL SALES	48,647	31,349	17,298	55.2	186,485	77,574	108,911	140.4
3. TOTAL SALES	1,378,144	1,369,197	8,947	0.7	6,386,357	6,372,988	13,369	0.2
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9647011	0.9771041	(0.0124030)	(1.3)	0.9707995	0.9878277	(0.0170282)	(1.7)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2000
CURRENT MONTH

SCHEDULE A2
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REVISED WITH JULY 2000 FILING
PERIOD TO DATE

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	30,383,700	30,777,840	(394,140)	(1.3)	141,694,629	144,772,764	(3,078,135)	(2.1)
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	(305,574)	(305,574)	0	0.0	(1,527,870)	(1,527,870)	0	0.0
b. INCENTIVE PROVISION	23,059	23,059	0	0.0	115,295	115,295	0	0.0
c. TRANSITION ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
d. OTHER ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	30,101,185	30,495,325	(394,140)	(1.3)	140,282,054	143,360,189	(3,078,135)	(2.1)
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	36,659,720	36,861,063	(201,343)	(0.5)	148,105,926	145,540,409	2,565,517	1.8
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B-4)	0.9647011	0.9771041	(0.0124030)	(1.3)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	35,365,673	36,017,096	(651,423)	(1.8)	143,702,787	143,686,164	16,623	0.0
6A.JURISDIC. LOSS MULTIPLIER	1.00068	1.00068	0.0000	0.0	NA	NA	-	-
6B. (LINE 6 x LINE 6A)	35,389,722	36,041,588	(651,866)	(1.8)	143,800,504	143,783,870	16,634	0.0
6C.PEABODY COAL CONTR. BUY-OUT AMORT.	365,842	365,842	0	0.0	1,854,520	1,854,520	0	0.0
6D.(LINE 6C x LINE 5) PB. JURISD.	352,928	357,466	(4,538)	(1.3)	1,800,239	1,832,423	(32,184)	(1.8)
6E.OTHER (SPARE INPUT #1)	0	0	0	0.0	0	0	0	0.0
6F. OIL BELOW THE DISCHARGE VALVE	0	0	0	0.0	0	0	0	0.0
6G. OTHER (SPARE INPUT #2)	0	0	0	0.0	0	0	0	0.0
6H. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. 6B+6D+6E+6F+6G)	35,742,650	36,399,054	(656,404)	(1.8)	145,600,743	145,616,293	(15,550)	0.0
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6H)	(5,641,465)	(5,903,729)	262,264	(4.4)	(5,318,689)	(2,256,104)	(3,062,585)	135.7
8. INTEREST PROVISION FOR THE MONTH	(72,579)	(62,218)	(10,361)	16.7	(288,565)	(113,745)	(174,820)	153.7
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(18,880,393)	(18,665,579)	(214,814)	1.2	NOT APPLICABLE			
9a.DEFERRED TRUE-UP BEGINNING OF PERIO	7,879,936	7,879,936	0	0.0	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	305,574	305,574	0	0.0	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	(16,408,927)	(16,446,016)	37,089	(0.2)	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2000
CURRENT MONTH

SCHEDULE A2
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REVISED WITH JULY 2000 FILING
PERIOD TO DATE

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	(11,000,457)	(10,785,643)	(214,814)	2.0	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	(16,336,348)	(16,383,798)	47,450	(0.3)	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(27,336,805)	(27,169,441)	(167,364)	0.6	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	(13,668,403)	(13,584,721)	(83,683)	0.6	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	6.180	5.500	0.680	12.4	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	6.570	5.500	1.070	19.5	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	12.750	11.000	1.750	15.9	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	6.375	5.500	0.875	15.9	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.531	0.458	0.073	15.9	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	(72,579)	(62,218)	(10,361)	16.7	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: MAY 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
FUEL COST OF SYSTEM NET GENERATION ($)								
1 HEAVY OIL	1,551,395	1,178,767	372,628	31.6	2,536,225	2,494,592	41,633	1.7
2 LIGHT OIL	173,125	751,743	(578,618)	(77.0)	1,531,343	2,995,087	(1,463,744)	(48.9)
3 COAL	29,696,516	29,309,217	387,299	1.3	128,323,465	132,554,710	(4,231,245)	(3.2)
4 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
5 NUCLEAR	0	0	0	0.0	0	0	0	0.0
6 OTHER	0	0	0	0.0	0	0	0	0.0
7 TOTAL ($)	31,421,036	31,239,727	181,309	0.6	132,391,033	138,044,389	(5,653,356)	(4.1)
SYSTEM NET GENERATION (MWH)								
8 HEAVY OIL	31,547	23,855	7,692	32.2	47,870	52,549	(4,679)	(8.9)
9 LIGHT OIL	1,169	181	988	545.9	28,233	43,941	(15,708)	(35.7)
10 COAL	1,585,360	1,518,999	66,361	4.4	6,679,220	6,788,758	(109,538)	(1.6)
11 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
12 NUCLEAR	0	0	0	0.0	0	0	0	0.0
13 OTHER	0	0	0	0.0	0	0	0	0.0
14 TOTAL (MWH)	1,618,076	1,543,035	75,041	4.9	6,755,323	6,885,248	(129,925)	(1.9)
UNITS OF FUEL BURNED								
15 HEAVY OIL (BBL)	71,163	70,469	694	1.0	118,113	146,299	(28,186)	(19.3)
16 LIGHT OIL (BBL)	5,424	20,642	(15,218)	(73.7)	50,499	106,211	(55,712)	(52.5)
17 COAL (TON)	705,556	677,685	27,871	4.1	3,042,197	3,055,341	(13,144)	(0.4)
18 NATURAL GAS (MCF)	0	0	0	0.0	0	0	0	0.0
19 NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20 OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
BTUS BURNED (MMBTU)								
21 HEAVY OIL	451,469	445,435	6,034	1.4	750,016	924,763	(174,747)	(18.9)
22 LIGHT OIL	23,294	3,138	20,156	642.3	285,348	386,822	(101,474)	(26.2)
23 COAL	16,374,571	15,756,670	617,901	3.9	69,279,242	70,515,294	(1,236,052)	(1.8)
24 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
25 NUCLEAR	0	0	0	0.0	0	0	0	0.0
26 OTHER	0	0	0	0.0	0	0	0	0.0
27 TOTAL (MMBTU)	16,849,334	16,205,243	644,091	4.0	70,314,606	71,826,879	(1,512,273)	(2.1)
GENERATION MIX (% MWH)								
28 HEAVY OIL	1.95	1.55	0.40	-	0.71	0.76	(0.05)	-
29 LIGHT OIL	0.07	0.01	0.06	-	0.42	0.64	(0.22)	-
30 COAL	97.98	98.44	(0.46)	-	98.87	98.60	0.27	-
31 NATURAL GAS	0.00	0.00	0.00	-	0.00	0.00	0.00	-
32 NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33 OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34 TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
FUEL COST PER UNIT								
35 HEAVY OIL ($/BBL)	21.80	16.73	5.07	30.3	21.47	17.05	4.42	25.9
36 LIGHT OIL ($/BBL)	31.92	36.42	(4.50)	(12.4)	30.32	28.20	2.12	7.5
37 COAL ($/TON)	42.09	43.25	(1.16)	(2.7)	42.18	43.38	(1.20)	(2.8)
38 NATURAL GAS ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40 OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
FUEL COST PER MMBTU ($/MMBTU)								
41 HEAVY OIL	3.44	2.65	0.79	29.8	3.38	2.70	0.68	25.2
42 LIGHT OIL	7.43	239.56	(232.13)	(96.9)	5.37	7.74	(2.37)	(30.6)
43 COAL	1.81	1.86	(0.05)	(2.7)	1.85	1.88	(0.03)	(1.6)
44 NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
45 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47 TOTAL ($/MMBTU)	1.86	1.93	(0.07)	(3.6)	1.88	1.92	(0.04)	(2.1)

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: MAY 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
BTU BURNED PER KWH (BTU/KWH)								
48 HEAVY OIL	14,311	18,673	(4,362)	(23.4)	15,668	17,598	(1,930)	(11.0)
49 LIGHT OIL	19,926	17,337	2,589	14.9	10,107	8,803	1,304	14.8
50 COAL	10,329	10,373	(44)	(0.4)	10,372	10,387	(15)	(0.1)
51 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
52 NUCLEAR	0	0	0	0.0	0	0	0	0.0
53 OTHER	0	0	0	0.0	0	0	0	0.0
54 TOTAL (BTU/KWH)	10,413	10,502	(89)	(0.8)	10,409	10,432	(23)	(0.2)
GENERATED FUEL COST PER KWH (cents/KWH)								
55 HEAVY OIL	4.92	4.94	(0.02)	(0.4)	5.30	4.75	0.55	11.6
56 LIGHT OIL	14.81	415.33	(400.52)	(96.4)	5.42	6.82	(1.40)	(20.5)
57 COAL	1.87	1.93	(0.06)	(3.1)	1.92	1.95	(0.03)	(1.5)
58 NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
59 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61 TOTAL (cents/KWH)	1.94	2.02	(0.08)	(4.0)	1.96	2.00	(0.04)	(2.0)

SCHEDULE A4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD/MONTH OF: MAY 2000

(A) PLANT/UNIT	(B) NET CAPABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPC. FACTO (%)	(E) EQUIV. AVAIL. FACTO (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COS PER KWH (cents /KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	30	6,271	28.1	100.0	63.5	-	HVY.OIL	-	-	-	-	-	-
H.P.#2	30	5,512	24.7	91.9	62.8	-	HVY.OIL	-	-	-	-	-	-
H.P.#3	30	5,311	23.8	81.0	67.3	-	HVY.OIL	-	-	-	-	-	-
H.P.#4	39	690	2.4	11.5	50.8	-	HVY.OIL	-	-	-	-	-	-
H.P.#5	67	5,295	10.6	51.6	56.6	-	HVY.OIL	-	-	-	-	-	-
H.P. STATION	196	23,079	15.8	61.7	59.1	16,161	HVY.OIL	58,650	6,359,258	372,970.5	1,250,448	5.42	21.32
GAN.#1	114	52,081	61.4	90.3	64.2	11,499	COAL	24,961	23,992,821	598,884.8	942,251	1.81	37.75
GAN.#2	98	6,464	8.9	12.5	70.0	16,653	COAL	4,451	24,184,004	107,643.0	168,020	2.60	37.75
GAN.#3	145	69,955	64.8	85.2	75.1	11,710	COAL	42,749	19,162,561	819,180.3	1,613,729	2.31	37.75
GAN.#4	159	91,819	77.6	95.8	79.0	11,415	COAL	54,256	19,318,461	1,048,142.4	2,048,105	2.23	37.75
GAN.#5	232	116,478	67.5	80.1	78.5	10,606	COAL	48,576	25,432,780	1,235,422.7	1,833,692	1.57	37.75
GAN.#6	372	136,059	49.2	60.2	77.8	10,295	COAL	56,866	24,631,259	1,400,681.2	2,146,630	1.58	37.75
GANNON STA.	1120	472,856	56.7	71.5	75.7	11,018	COAL	231,859	22,470,357	5,209,954.4	8,752,427	1.85	37.75
B.B.#1	416	175,967	56.9	66.5	79.0	10,575	COAL	76,162	24,432,440	1,860,816.2	3,200,276	1.82	42.02
B.B.#2	416	243,138	78.6	89.7	78.6	10,253	COAL	102,280	24,374,100	2,492,982.9	4,297,753	1.77	42.02
B.B.#3	433	230,168	71.4	80.6	86.4	9,697	COAL	93,039	23,990,300	2,232,033.5	3,909,451	1.70	42.02
B.B. 1 - 3	1265	649,273	69.0	79.0	81.4	10,143	COAL	271,481	24,258,935	6,585,832.6	11,407,480	1.76	42.02
B.B.#4	442	283,614	86.2	96.8	86.2	9,833	COAL	130,968	21,294,076	2,788,842.6	6,458,460	2.28	49.31
B.B. STA.	1707	932,887	73.5	83.6	82.6	10,049	COAL	402,449	23,294,087	9,374,675.2	17,865,940	1.92	44.39
SEB-PHIL. #1(HVY OIL)	17	4,132	32.7	99.8	62.4	9,499	HVY.OIL	6,256	6,273,689	39,248.2	150,461	3.64	24.05
SEB-PHIL. #2(HVY OIL)	17	4,336	34.3	89.2	69.1	9,052	HVY.OIL	6,257	6,272,894	39,249.5	150,486	3.47	24.05
SEB-PHILLIPS TOTAL	34	8,468	33.5	94.5	75.8	9,270	HVY.OIL	12,513	6,273,292	78,497.7	300,947	3.55	24.05
POLK COAL	250	179,617	96.6	97.6	96.6	9,965	COAL	71,249	25,122,480	1,789,941.3	3,078,149	1.71	43.20
POLK OIL	225	0	0.0	100.0	0.0	0	LGT.OIL	1,422	-	0.0	47,324	0.00	33.28
POLK TOTAL	250	179,617	96.6	97.6	-	9,965	-	-	-	1,789,941.3	3,125,473	1.74	-
GAN.C.T.#1	12	507	5.7	99.6	75.4	19,894	LGT.OIL	1,733	5,818,848	10,086.1	54,489	10.75	31.44
B.B.C.T.#1	12	390	4.4	100.0	75.6	19,684	LGT.OIL	1,318	5,824,273	7,676.8	41,434	10.62	31.44
B.B.C.T.#2	66	88	0.2	10.3	1.8	25,547	LGT.OIL	386	5,819,872	2,246.1	12,143	13.80	31.44
B.B.C.T.#3	66	184	0.4	6.4	5.9	17,845	LGT.OIL	564	5,819,774	3,283.4	17,735	9.64	31.44
C.T. TOTAL	156	1,169	1.0	22.4	14.9	19,927	LGT.OIL	4,002	5,820,864	23,294.4	125,801	10.76	31.44
TOT. COAL (GN,BB,POLK)	3077	1,585,360	69.3	80.3	81.2	10,329	COAL	705,556	23,208,029	16,374,570.9	29,696,516	1.87	42.09
SYSTEM	3463	1,618,076	62.8	76.8	73.6	10,413	-	-	-	16,849,333.5	31,421,036	1.94	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS

NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2000

SCHEDULE A5
PAGE 1 OF 2

	CURRENT MONTH				PERIOD TO DATE			
HEAVY OIL (1)	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1 PURCHASES:								
2 UNITS (BBL)	7,537	70,469	(62,932)	(89.3)	104,739	100,211	4,528	4.5
3 UNIT COST ($/BBL)	26.50	15.62	10.88	69.7	23.51	16.03	7.48	46.7
4 AMOUNT ($)	199,756	1,100,438	(900,682)	(81.8)	2,462,755	1,605,989	856,766	53.3
5 BURNED:								
6 UNITS (BBL)	71,163	70,469	694	1.0	116,113	146,299	(28,186)	(19.3)
7 UNIT COST ($/BBL)	21.80	16.73	5.07	30.3	21.47	17.05	4.42	25.9
8 AMOUNT ($)	1,551,395	1,178,767	372,628	31.6	2,536,225	2,494,592	41,633	1.7
9 ENDING INVENTORY:								
10 UNITS (BBL)	76,885	81,135	(4,250)	(5.2)	76,885	81,135	(4,250)	(5.2)
11 UNIT COST ($/BBL)	21.51	17.21	4.30	25.0	21.51	17.21	4.30	25.0
12 AMOUNT ($)	1,653,880	1,396,670	257,210	18.4	1,653,880	1,396,670	257,210	18.4
13								
14 DAYS SUPPLY:	22	23	(1)	(4.3)	-	-	-	-
LIGHT OIL (2)								
15 PURCHASES:								
16 UNITS (BBL)	32,533	40,578	(8,045)	(19.8)	142,264	174,116	(31,852)	(18.3)
17 UNIT COST ($/BBL)	32.28	39.28	(7.00)	(17.8)	33.62	30.30	3.32	11.0
18 AMOUNT ($)	1,050,284	1,593,867	(543,583)	(34.1)	4,783,136	5,274,912	(491,776)	(9.3)
19 BURNED:								
20 UNITS (BBL)	5,424	20,642	(15,218)	(73.7)	50,499	106,211	(55,712)	(52.5)
21 UNIT COST ($/BBL)	31.92	36.42	(4.50)	(12.4)	30.32	28.20	2.12	7.5
22 AMOUNT ($)	173,125	751,743	(578,618)	(77.0)	1,531,343	2,995,087	(1,463,744)	(48.9)
23 ENDING INVENTORY:								
24 UNITS (BBL)	117,524	97,057	20,467	21.1	117,524	97,057	20,467	21.1
25 UNIT COST ($/BBL)	32.09	35.47	(3.38)	(9.5)	32.09	35.47	(3.38)	(9.5)
26 AMOUNT ($)	3,770,969	3,442,558	328,411	9.5	3,770,969	3,442,558	328,411	9.5
27								
28 DAYS SUPPLY: NORMAL	73	60	13	21.7	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	17	14	3	21.4	-	-	-	-
COAL (3)								
30 PURCHASES:								
31 UNITS (TONS)	484,488	460,000	24,488	5.3	3,327,564	2,879,200	448,364	15.6
32 UNIT COST ($/TON)	42.11	42.27	(0.16)	(0.4)	41.83	42.68	(0.85)	(2.0)
33 AMOUNT ($)	20,403,387	19,442,932	960,455	4.9	139,192,777	122,877,301	16,315,476	13.3
34 BURNED:								
35 UNITS (TONS)	705,556	677,685	27,871	4.1	3,042,197	3,055,341	(13,144)	(0.4)
36 UNIT COST ($/TON)	42.09	43.25	(1.16)	(2.7)	42.18	43.38	(1.20)	(2.8)
37 AMOUNT ($)	29,696,516	29,309,217	387,299	1.3	128,323,465	132,554,710	(4,231,245)	(3.2)
38 ENDING INVENTORY:								
39 UNITS (TONS)	1,062,383	950,034	112,349	11.8	1,062,383	950,034	112,349	11.8
40 UNIT COST ($/TON)	41.79	42.09	(0.30)	(0.7)	41.79	42.09	(0.30)	(0.7)
41 AMOUNT ($)	44,395,113	39,982,689	4,412,424	11.0	44,395,113	39,982,689	4,412,424	11.0
42								
43 DAYS SUPPLY:	43	38	5	13.2	-	-	-	-
NATURAL GAS								
44 PURCHASES:								
45 UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
46 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
48 BURNED:								
49 UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
50 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
51 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
56								
57 DAYS SUPPLY:	0	0	0	0.0	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2000

OTHER	CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH %	PERIOD TO DATE ACTUAL	PERIOD TO DATE ESTIMATED	PERIOD TO DATE DIFFERENCE AMOUNT	PERIOD TO DATE %
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
74 DAYS SUPPLY:	0	0	0	0.0	-	-	-	-

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	13,510
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	13,510

(2) RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
POLK IGNITION	1,422	47,324
IGNITION	(7,083)	(221,901)
OTHER USAGE	(1,232)	(38,720)
TOTAL	(6,893)	(213,297)

(3) RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	47,923
IGNITION #2 OIL	208,391
IGNITION PROPANE	1,870
AERIAL SURVEY ADJ.	(695,507)
ADDITIVES	179,191
TOTAL	(258,132)

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: MAY 2000

SCHEDULE A6
PAGE 1 OF 3

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	7,573.0	0.0	7,573.0	2.451	3.090	185,600.00	234,000.00	38,700.00
VARIOUS	JURISDICTIONAL	SCH. -D	5,966.0	0.0	5,966.0	2.218	2.218	132,300.00	132,300.00	
VARIOUS	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPARATED	CONTRACT	27,800.0	0.0	27,800.0	2.243	3.186	623,600.00	885,600.00	
FMPA		SCH. -D	111,600.0	0.0	111,600.0	1.805	1.805	2,014,564.00	2,014,564.00	
VARIOUS	JURISDICTIONAL	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	152,939.0	0.0	152,939.0	1.933	2.136	2,956,064.00	3,266,464.00	38,700.00
LESS TRANSMISSION COSTS		-						0.00		
LESS VARIABLE O & M COSTS		-						(15,900.00)		
PLUS 80% OF ECON. ENERGY SALES PROFI		-						38,700.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INC		-								
80% OF ECON. ENERGY SALES PROFITS		-	152,939.0	0.0	152,939.0	1.948	2.136	2,978,864.00	3,266,464.00	38,700.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENRGY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
OGLETHORPE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENN. VALLEY AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEP. CONTRACT		50,640.0	0.0	50,640.0	2.303	3.116	1,166,239.20	1,577,942.40	
SEMINOLE ELECTRIC CO-OP PRE	JURISD.	SCH. -D	6,883.0	1,031.4	5,851.6	2.422	2.422	141,730.53	141,730.53	
SEMINOLE ELECTRIC CO-OP HAR	JURISD.	SCH. -D	1,129.0	0.0	1,129.0	1.227	1.227	13,854.36	13,854.36	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: MAY 2000

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA		SCH. -D	90,250.0	0.0	90,250.0	1.946	1.946	1,756,105.67	1,756,105.67	
HARDEE POWER PART. TO FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR.& LT.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO JACKSONVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KISSIMMEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ORLANDO		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO SEMINOLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FT. PIERCE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LK. WORTH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ENERGY AUTHORI		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FPC		SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR.& LT.		SCH. -MB	537.0	0.0	537.0	2.753	2.753	14,783.77	14,783.77	
HARDEE POWER PART. TO KOCH ENERGY		SCH. -MB	550.0	0.0	550.0	6.318	6.318	34,748.11	34,748.11	
SEMINOLE ELECTRIC CO-OP		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT		SCH. -MB	11,534.0	0.0	11,534.0	2.599	2.599	299,726.62	299,726.62	
CITY OF LAKELAND		SCH. -MB	975.0	0.0	975.0	2.723	2.723	26,552.63	26,552.63	
SOUTHERN COMPANY		SCH. -MB	474.0	0.0	474.0	11.546	11.546	54,728.96	54,728.96	
KOCH ENERGY		SCH. -MB	1,761.0	0.0	1,761.0	9.446	9.446	166,352.25	166,352.25	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: MAY 2000

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)	(9)
SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	MWH WHEELED OTHER SYSTEM	MWH FROM OWN GENERATION	—cents/KWH— (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	TOTAL $ FOR TOTAL COST (5)X(6)(B)	80% GAIN ON ECONOMY ENERGY SALES
ADJUSTMENTS TO APRIL 2000	MON/YR TYP SCHED.								
HARDEE POWER PARTNERS ES	4/00 SEPA CONTRACT	(25,622.0)	0.0	(25,622.0)	2.280	3.094	(584,181.60)	(792,744.68)	
HARDEE POWER PARTNERS ACT	4/00 SEPA CONTRACT	25,622.0	0.0	25,622.0	2.303	3.116	590,074.66	798,381.52	
SEMINOLE ELECTRIC CO-OP HAR	4/00 JURIS SCH. -D	(793.0)	0.0	(793.0)	1.747	1.747	(13,854.36)	(13,854.36)	
SEMINOLE ELECTRIC CO-OP HAR	4/00 JURIS SCH. -D	793.0	0.0	793.0	1.732	1.732	13,731.09	13,731.09	
SUB-TOTAL ECONOMY POWER SALES		0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.		0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.		8,012.0	1,031.4	6,980.6	2.227	2.227	155,461.62	155,461.62	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.		0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.		50,640.0	0.0	50,640.0	2.315	3.127	1,172,132.26	1,583,579.24	
SUB-TOTAL OTHER D POWER SALES		90,250.0	0.0	90,250.0	1.946	1.946	1,756,105.67	1,756,105.67	
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.		0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE MB POWER SALES-JURISD.		15,831.0	0.0	15,831.0	3.770	3.770	596,892.34	596,892.34	
TOTAL INCLUDING VARIABLE O & M COSTS		164,733.0	1,031.4	163,701.6	2.248	2.500	3,680,591.89	4,092,038.87	0.00
LESS VARIABLE O & M COSTS							0.00		
LESS VARIABLE O & M COSTS - HARDEE							0.00		
LESS TRANSMISSION COSTS SCH. D (SEP.)							0.00		
PLUS 80% OF ECON. ENERGY SALES PROFITS	-						0.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS	-	164,733.0	1,031.4	163,701.6	2.248	2.500	3,680,591.89	4,092,038.87	0.00
CURRENT MONTH:									
DIFFERENCE	-	11,794.0	1,031.4	10,762.6	0.300	0.364	701,727.89	825,574.87	(38,700.00)
DIFFERENCE %	-	7.7	0.0	7.0	15.4	17.0	23.6	25.3	(100.0)
PERIOD TO DATE:									
ACTUAL	-	704,206.0	3,445.5	700,760.5	2.088	2.229	14,629,568.04	15,618,796.10	0.00
ESTIMATED	-	691,338.0	0.0	691,338.0	1.880	1.999	12,996,180.00	13,821,360.00	118,920.00
DIFFERENCE	-	12,868.0	3,445.5	9,422.5	0.208	0.230	1,633,388.04	1,797,436.10	(118,920.00)
DIFFERENCE %	-	1.9	0.0	1.4	11.1	11.5	12.6	13.0	(100.0)

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. SEC 60% OR $16,680.37 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH MAY 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	37,157.0	0.0	19,199.0	17,958.0	16.059	16.059	2,883,800.00
HARDEE POWER PARTNERS	IPP	68,044.0	0.0	0.0	68,044.0	3.305	3.305	2,248,900.00
VARIOUS	OTHER	24,490.0	0.0	0.0	24,490.0	3.076	3.076	753,200.00
TOTAL	-	129,691.0	0.0	19,199.0	110,492.0	5.327	5.327	5,885,900.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	102,941.0	0.0	0.0	102,941.0	4.622	4.622	4,758,321.12
HARDEE PWR. PART.-OTHERS	IPP	1,087.0	0.0	0.0	1,087.0	3.534	3.534	38,411.64
FLA. POWER CORP.	SCH.-Ja	5,956.0	0.0	5,660.6	295.4	8.513	8.513	25,147.64
FLA. POWER CORP.	SCH.-Jc	11,364.0	0.0	0.0	11,364.0	4.052	4.052	460,425.00
FLA. POWER & LIGHT	SCH.-Ja	1,419.0	0.0	934.4	484.6	5.399	5.399	26,161.23
FLA. POWER & LIGHT	SCH.-Jc	4,397.0	0.0	0.0	4,397.0	5.532	5.532	243,250.00
CITY OF LAKELAND	SCH.-Ja	7,229.0	0.0	5,979.9	1,249.1	8.159	8.159	101,916.04
CITY OF LAKELAND	SCH.-Jc	6,804.0	0.0	0.0	6,804.0	5.698	5.698	387,679.50
ORLANDO	SCH.-Ja	3,238.0	0.0	3,238.0	0.0	0.000	0.000	0.00
ORLANDO	SCH.-Jc	752.0	0.0	0.0	752.0	9.231	9.231	69,419.00
ENTERGY MARKETING	SCH.-Ja	4,105.0	0.0	2,816.0	1,289.0	7.562	7.562	97,475.96
ENTERGY MARKETING	SCH.-Jc	4,700.0	0.0	0.0	4,700.0	5.269	5.269	247,659.76
THE ENERGY AUTH.	SCH.-Ja	3,240.0	0.0	1,596.3	1,643.7	7.938	7.938	130,478.15
THE ENERGY AUTH.	SCH.-Jc	3,867.0	0.0	0.0	3,867.0	5.633	5.633	217,825.19
RELIANT	SCH.-Ja	883.0	0.0	559.3	323.7	7.067	7.067	22,875.24
RELIANT	SCH.-Jc	2,048.0	0.0	0.0	2,048.0	6.234	6.234	127,673.55
TALLAHASSEE	SCH.-Ja	724.0	0.0	302.9	421.1	7.558	7.558	31,828.72
TALLAHASSEE	SCH.-Jc	1,289.0	0.0	0.0	1,289.0	6.129	6.129	79,002.03
AQUILA	SCH.-Ja	1,962.0	0.0	1,363.0	599.0	8.479	8.479	50,789.36
AQUILA	SCH.-Jc	3,011.0	0.0	0.0	3,011.0	6.266	6.266	188,676.93
OKEELANTA	SCH.-Ja	851.0	0.0	423.6	427.4	5.955	5.955	25,453.63
OKEELANTA	SCH.-Jc	1,669.0	0.0	0.0	1,669.0	5.985	5.985	99,896.95
KOCH	SCH.-Ja	2,020.0	0.0	1,170.8	849.2	7.146	7.146	60,687.78
KOCH	SCH.-Jc	1,068.0	0.0	0.0	1,068.0	6.680	6.680	71,341.72
MORGAN STANLEY	SCH.-Ja	1,743.0	0.0	1,552.3	190.7	11.123	11.123	21,210.99
MORGAN STANLEY	SCH.-Jc	2,722.0	0.0	0.0	2,722.0	7.027	7.027	191,287.74
CARGILL ALLIANT	SCH.-Jc	137.0	0.0	0.0	137.0	4.907	4.907	6,722.00
FLORIDA POWER & LIGHT *	SCH.-Jc	0.0	0.0	0.0	0.0	0.000	0.000	11,595.00
RINGHAVER	SCH.-Jc	83.0	0.0	0.0	83.0	13.692	13.692	11,364.54
OKEELANTA	SCH.-D	18,640.0	0.0	0.0	18,640.0	3.293	3.293	613,814.00
ABURNDALE POWER PARTNERS	SCH.-D	2,201.0	0.0	0.0	2,201.0	2.334	2.334	51,366.44
ADJUSTMENTS TO PRIOR MONTHS (See Page 2 of 2 for detail)		0.0	0.0	0.0	0.0	0.000	0.000	(212,274.45)
TOTAL		202,150.0	0.0	25,597.1	176,552.9	4.677	4.677	8,257,482.40
CURRENT MONTH:								
DIFFERENCE	-	72,459.0	0.0	6,398.1	66,060.9	3.590	3.590	2,371,582.40
DIFFERENCE %	-	55.9	0.0	33.3	59.8	67.4	67.4	40.3
PERIOD TO DATE:								
ACTUAL	-	763,502.00	0.00	99,827.40	663,674.6	4.117	4.117	27,324,497.42
ESTIMATED	-	375,782.0	0.0	54,194.0	321,588.0	4.204	4.204	13,518,900.0
DIFFERENCE	-	387,720.0	0.0	45,633.4	342,086.6	(0.087)	(0.087)	13,805,597.42
DIFFERENCE %	-	103.2	0.0	84.2	106.4	(2.1)	(2.1)	102.1

* Transmission service charge for sale made to Southern Company.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH MAY 2000

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) ----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ADUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	APR.'00	IPP	(63,561.0)	0.0	0.0	(63,561.0)	3.972	3.972	(2,524,368.25)
HARDEE PWR. PART.-NATIVE	APR.'00	IPP	63,561.0	0.0	0.0	63,561.0	3.646	3.646	2,317,278.16
THE ENERGY AUTH.	MAR.'00	SCH.-Ja	(5,794.0)	0.0	(1,152.9)	(4,641.1)	5.236	5.236	(243,014.65)
THE ENERGY AUTH.	MAR.'00	SCH.-Ja	5,794.0	0.0	1,152.9	4,641.1	5.199	5.199	241,273.17
THE ENERGY AUTH.	MAR.'00	SCH.-Jc	(8,144.0)	0.0	0.0	(8,144.0)	3.887	3.887	(316,547.94)
THE ENERGY AUTH.	MAR.'00	SCH.-Jc	8,144.0	0.0	0.0	8,144.0	3.849	3.849	313,485.55
RELIANT	MAR.'00	SCH.-Ja	(3,401.0)	0.0	(1,647.6)	(1,753.4)	4.960	4.960	(86,969.89)
RELIANT	MAR.'00	SCH.-Ja	3,401.0	0.0	1,647.6	1,753.4	4.944	4.944	86,693.05
RELIANT	MAR.'00	SCH.-Jc	(2,312.0)	0.0	0.0	(2,312.0)	3.829	3.829	(88,533.14)
RELIANT	MAR.'00	SCH.-Jc	2,312.0	0.0	0.0	2,312.0	3.813	3.813	88,157.10
TALLAHASSEE	MAR.'00	SCH.-Ja	(334.0)	0.0	(325.9)	(8.1)	4.783	4.783	(387.43)
TALLAHASSEE	MAR.'00	SCH.-Ja	334.0	0.0	325.9	8.1	4.923	4.923	398.76
TALLAHASSEE	MAR.'00	SCH.-Jc	(186.0)	0.0	0.0	(186.0)	3.953	3.953	(7,352.86)
TALLAHASSEE	MAR.'00	SCH.-Jc	186.0	0.0	0.0	186.0	4.094	4.094	7,613.92
TOTAL ADJUSTMENTS TO PRIOR MONTHS			0.0	0.0	0.0	0.0	0.000	0.000	(212,274.45)

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: MAY 2000

SCHEDULE A8

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	¢/KWH (A) FUEL COST	¢/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	35,005.0	0.0	0.0	35,005.0	2.461	2.461	861,600.00
TOTAL	-	35,005.0	0.0	0.0	35,005.0	2.461	2.461	861,600.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	4,967.0	0.0	0.0	4,967.0	2.105	2.105	104,569.89
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	88.0	0.0	0.0	88.0	6.740	6.740	5,931.04
IMC-AGRICO-NEW WALES	COGEN.	1,307.0	0.0	0.0	1,307.0	3.587	3.587	46,875.62
HILLSBOROUGH COUNTY	COGEN.	15,873.0	0.0	0.0	15,873.0	2.123	2.123	337,050.46
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	912.0	0.0	0.0	912.0	2.756	2.756	25,136.97
FARMLAND HYDRO LP	COGEN.	822.0	0.0	0.0	822.0	3.223	3.223	26,496.21
IMC-AGRICO-S. PIERCE	COGEN.	211.0	0.0	0.0	211.0	3.215	3.215	6,783.42
AUBURNDALE POWER PARTNERS	COGEN.	1,116.0	0.0	0.0	1,116.0	3.781	3.781	42,195.57
ORANGE COGENERATION L.P.	COGEN.	5,359.0	0.0	0.0	5,359.0	2.162	2.162	115,842.35
CUTRALE CITRUS	COGEN.	1.0	0.0	0.0	1.0	3.809	3.809	38.09
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	778.0	(778.0)	4.797	4.797	(37,317.22)
SUB-TOTAL FOR MAY 2000	-	30,656.0	0.0	778.0	29,878.0	2.255	2.255	673,602.40
ADJ. FOR MARCH 2000								
IMC-AGRICO-NICHOLS	COGEN.		0.0		0.0	0.000	0.000	0.00
			0.0		0.0	0.000	0.000	(6,150.00)
McKAY BAY REFUSE	COGEN.	(5,034.0)	0.0	0.0	(5,034.0)	2.018	2.018	(101,570.55)
		5,034.0	0.0	0.0	5,034.0	2.012	2.012	101,263.77
MULBERRY PHOSPHATES INC.	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
CARGILL RIDGEWOOD	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
IMC-AGRICO-NEW WALES	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
HILLSBOROUGH COUNTY	COGEN.	(13,815.0)	0.0	0.0	(13,815.0)	1.993	1.993	(275,351.76)
		13,815.0	0.0	0.0	13,815.0	1.988	1.988	274,581.00
CARGILL MILLPOINT	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
CF INDUSTRIES INC.	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
FARMLAND HYDRO LP	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
IMC-AGRICO-S. PIERCE	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
AUBURNDALE POWER PARTNERS	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
ORANGE COGENERATION L.P.	COGEN.	(5,532.0)	0.0	0.0	(5,532.0)	1.981	1.981	(109,583.34)
		5,532.0	0.0	0.0	5,532.0	1.973	1.973	109,165.96
CUTRALE CITRUS	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
AS AVAILABLE ASSIGNMENT			0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
SUB-TOTAL FOR Mar-00 ADJ.	-	0.0	0.0	0.0	0.0	0.000	0.000	(7,644.92)
GRAND TOTAL		30,656.0	0.0	778.0	29,878.0	2.229	2.229	665,957.48
CURRENT MONTH:								
DIFFERENCE	-	(4,349.0)	0.0	778.0	(5,127.0)	(0.232)	(0.232)	(195,642.52)
DIFFERENCE %	-	(12.4)	0.0	0.0	(14.6)	(9.4)	(9.4)	(22.7)
PERIOD TO DATE:								
ACTUAL		149,435.0	0.0	1,508.6	147,926.4	2.061	2.061	3,049,207.95
ESTIMATED		165,075.0	0.0	0.0	165,075.0	2.005	2.005	3,309,800.00
DIFFERENCE	-	(15,640.0)	0.0	1,508.6	(17,148.6)	0.056	0.056	(260,592.05)
DIFFERENCE %	-	(9.5)	0.0	0.0	(10.4)	2.8	2.8	(7.9)

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: MAY 2000

SCHEDULE A9

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	COST IF GENERATED (A) cents/KWH	(B) $	FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	47,513.0	3.908	1,856,700.00	5.132	2,438,600.00	581,900.00
TOTAL	-	47,513.0	3.908	1,856,700.00	5.132	2,438,600.00	581,900.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL	-	0.0	0.000	0.00	0.000	0.00	0.00
CURRENT MONTH:							
DIFFERENCE	-	(47,513.0)	(3.908)	(1,856,700.00)	(5.132)	(2,438,600.00)	(581,900.00)
DIFFERENCE %	-	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)
PERIOD TO DATE:							
ACTUAL		0.0	0.000	(10,512.45)	0.000	0.00	10,512.45
ESTIMATED		93,305.0	3.948	3,683,500.00	5.194	4,846,200.00	1,162,700.00
DIFFERENCE	-	(93,305.0)	(3.948)	(3,694,012.45)	(5.194)	(4,846,200.00)	(1,152,187.55)
DIFFERENCE %	-	(100.0)	(100.0)	(100.3)	(100.0)	(100.0)	(99.1)

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

JUNE 2000

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE , 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	34,118,643	33,484,587	634,056	1.9	1,668,334	1,622,981	45,353	2.8	2.04507	2.06315	(0.01808)	(0.9)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(4,172)	(4,000)	(172)	4.3	1,668,334 a)	1,622,981 a)	45,353	2.8	(0.00025)	(0.00025)	0.00000	0.0
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,668,334 a)	1,622,981 a)	45,353	2.8	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,668,334 a)	1,622,981 a)	45,353	2.8	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	34,114,471	33,480,587	633,884	1.9	1,668,334	1,622,981	45,353	2.8	2.04482	2.06291	(0.01809)	(0.9)
6. Fuel Cost of Purchased Power - Firm (A7)	10,179,913	9,435,200	744,713	7.9	183,338	188,745	(5,407)	(2.8)	5.55254	5.05245	0.50009	9.9
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	1,803,600	(1,803,600)	(100.0)	0	30,371	(30,371)	(100.0)	0.00000	5.93856	(5.93856)	(100.0)
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 a)	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	830,371	843,200	(12,829)	(1.5)	33,883	33,875	8	0.0	2.45070	2.48915	(0.03845)	(1.5)
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	11,010,284	12,082,000	(1,071,716)	(8.9)	217,221	250,991	(33,770)	(13.5)	5.06870	4.81372	0.25498	5.3
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,885,555	1,873,972	11,583	0.6				
14. Fuel Cost of Economy Sales (A6)	0	1,132,800	(1,132,800)	(100.0)	0	43,194	(43,194)	(100.0)	0.00000	2.62259	(2.62259)	(100.0)
15. Gain on Economy Sales - 80% (A6)	0	353,500	(353,500)	(100.0)	0 a)	43,194 a)	(43,194)	(100.0)	0.00000	0.81840	(0.81840)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	159,299	143,800	15,499	10.8	6,171	5,999	172	2.9	2.58141	2.39707	0.18434	7.7
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	1,316,707	867,200	449,507	51.8	57,080	38,216	18,864	49.4	2.30677	2.26921	0.03756	1.7
21. Fuel Cost of Other Power Sales (A6)	2,430,282	1,944,944	485,338	25.0	110,047	108,000	2,047	1.9	2.20840	1.80087	0.40753	22.6
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	3,906,288	4,442,244	(535,956)	(12.1)	173,298	195,409	(22,111)	(11.3)	2.25409	2.27331	(0.01922)	(0.8)
23. Net Inadvertant Interchange					492	0	492	0.0				
24. Wheeling Rec'd. less Wheeling Del'vd.					758	0	758	0.0				
25. Interchange and Wheeling Losses					2,187	3,000	(813)	(27.1)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	41,218,467	41,120,343	98,124	0.2	1,711,320	1,675,563	35,757	2.1	2.40858	2.45412	(0.04554)	(1.9)
27. Net Unbilled	(690,853) (a)	850,205 (a)	(1,541,058)	(181.3)	(28,683)	34,644	(63,327)	(182.8)	(0.04129)	0.05413	(0.09542)	(176.3)
28. Company Use	103,762 (a)	98,165 (a)	5,597	5.7	4,308	4,000	308	7.7	0.00620	0.00625	(0.00005)	(0.8)
29. T & D Losses	1,504,929 (a)	1,623,057 (a)	(118,128)	(7.3)	62,482	66,136	(3,654)	(5.5)	0.08994	0.10333	(0.01339)	(13.0)
30. System KWH Sales	41,218,467	41,120,343	98,124	0.2	1,673,213	1,570,783	102,430	6.5	2.46343	2.61782	(0.15439)	(5.9)
31. Wholesale KWH Sales	(1,996,659)	(1,527,501)	(469,158)	30.7	(81,052)	(58,350)	(22,702)	38.9	2.46343	2.61783	(0.15440)	(5.9)
32. Jurisdictional KWH Sales	39,221,808	39,592,842	(371,034)	(0.9)	1,592,161	1,512,433	79,728	5.3	2.46343	2.61782	(0.15439)	(5.9)
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	39,248,479	39,619,765	(371,286)	(0.9)	1,592,161	1,512,433	79,728	5.3	2.46511	2.61960	(0.15449)	(5.9)
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	345,712	349,815	(4,103)	(1.2)	1,592,161	1,512,433	79,728	5.3	0.02171	0.02313	(0.00142)	(0.1)
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	1,592,161	1,512,433	79,728	5.3	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	1,592,161	1,512,433	79,728	5.3	0.00000	0.00000	0.00000	0.0
36. True-up *	2,684,371	305,574	2,378,797	778.5	1,592,161	1,512,433	79,728	5.3	0.16860	0.02020	0.14840	734.7
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	42,278,562	40,275,154	2,003,408	5.0	1,592,161	1,512,433	79,728	5.3	2.65542	2.66294	(0.00752)	(0.3)
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.65733	2.66486	(0.00753)	(0.3)
40. GPIF * (Already Adjusted for Taxes)	(23,059)	(23,059)	0	0.0	1,592,161	1,512,433	79,728	5.3	(0.00145)	(0.00152)	0.00007	(4.6)
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	42,255,503	40,252,095	2,003,408	5.0	1,592,161	1,512,433	79,728	5.3	2.65588	2.66334	(0.00746)	(0.3)
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.656	2.663	(0.007)	(0.3)

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: JUNE, 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUN	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	166,509,676	171,526,976	(5,019,300)	(2.9)	8,423,657	8,508,229	(84,573)	(1.0)	1.97669	2.01604	(0.03935)	(2.0)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (FLMeade/Wauch. Wheeling Losses	(22,823)	(24,000)	1,177	(4.9)	8,423,657 a)	8,508,229 a)	(84,573)	(1.0)	(0.00027)	(0.00028)	0.00001	(3.6)
4b. Adjustments to Fuel Cost	0	0	0	0.0	8,423,657 a)	8,508,229 a)	(84,573)	(1.0)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	(79)	0	(79)	0.0	8,423,657 a)	8,508,229 a)	(84,573)	(1.0)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	166,486,774	171,504,976	(5,018,202)	(2.9)	8,423,657	8,508,229	(84,573)	(1.0)	1.97642	2.01575	(0.03933)	(2.0)
6. Fuel Cost of Purchased Power - Firm (A7)	37,504,409	22,954,100	14,550,309	63.4	847,013	508,333	338,680	66.6	4.42784	4.51556	(0.08772)	(1.9)
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	(10,512)	5,467,100	(5,497,612)	(100.2)	0	123,676	(123,676)	(100.0)	#DIV/0!	4.43667	#DIV/0!	#DIV/0!
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	3,879,579	4,153,000	(273,421)	(6.6)	181,810	198,950	(17,140)	(8.6)	2.13386	2.08746	0.04640	2.2
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	41,373,476	32,594,200	8,779,276	26.9	1,028,823	830,959	197,864	23.8	4.02144	3.92248	0.09896	2.5
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					9,452,480	9,339,188	113,292	1.2				
14. Fuel Cost of Economy Sales (A6)	(1,687)	1,625,400	(1,627,087)	(100.1)	0	66,013	(66,013)	(100.0)	#DIV/0!	2.46224	#DIV/0!	#DIV/0!
15. Gain on Economy Sales - 80% (A6)	0	472,420	(472,420)	(100.0)	0	66,013 a)	(66,013)	(100.0)	0.00000	0.71565	(0.71565)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	190,768	295,300	(104,532)	(35.4)	12,166	19,153	(6,987)	(36.4)	1.56547	1.54180	0.02367	1.5
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	752,975	713,700	39,275	5.5	35,585	34,781	804	2.3	2.11599	2.05198	0.06401	3.1
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	3,926,046	2,525,700	1,400,346	55.4	170,240	111,600	58,640	52.5	2.30618	2.26317	0.04301	1.9
21. Fuel Cost of Other Power Sales (A6)	13,667,755	11,805,904	1,861,851	15.8	656,048	655,200	848	0.1	2.08335	1.80188	0.28147	15.6
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 +,18 + 19 + 20 + 21)	18,535,857	17,438,424	1,097,433	6.3	874,059	886,747	(12,688)	(1.4)	2.12066	1.96656	0.15410	7.8
23. Net Inadvertant Interchange					1,428	0	1,428	0.0				
24. Wheeling Rec'd. less Wheeling Del'd.					3,161	0	3,161	0.0				
25. Interchange and Wheeling Losses					12,578	13,400	(822)	(6.1)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	189,324,393	186,660,752	2,663,641	1.4	8,570,432	8,439,041	131,391	1.6	2.20904	2.21187	(0.00283)	(0.1)
27. Net Unbilled	2,538,320 (a)	2,205,610 (a)	332,710	15.1	114,906	99,717	15,189	15.2	0.03149	0.02777	0.00372	13.4
28. Company Use	542,761 (a)	530,849 (a)	11,912	2.2	24,570	24,000	570	2.4	0.00673	0.00668	0.00005	0.7
29. T & D Losses	8,204,065 (a)	8,218,269 (a)	(14,204)	(0.2)	371,386	371,553	(167)	0.0	0.10179	0.10346	(0.00167)	(1.6)
30. System KWH Sales	189,324,393	186,660,752	2,663,641	1.4	8,059,570	7,943,771	115,799	1.5	2.34906	2.34978	(0.00072)	0.0
31. Wholesale KWH Sales	(6,399,798)	(3,381,746)	(3,018,052)	89.2	(267,537)	(135,924)	(131,613)	96.8	2.39212	2.48797	(0.09585)	(3.9)
32. Jurisdictional KWH Sales	182,924,595	183,279,006	(354,411)	(0.2)	7,792,033	7,807,847	(15,815)	(0.2)	2.34759	2.34737	0.00022	0.0
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	183,048,983	183,403,635	(354,652)	(0.2)	7,792,033	7,807,847	(15,815)	(0.2)	2.34918	2.34897	0.00021	0.0
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	2,145,951	2,182,238	(36,287)	(1.7)	7,792,033	7,807,847	(15,815)	(0.2)	0.02754	0.02795	(0.00041)	(1.5)
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	7,792,033	7,807,847	(15,815)	(0.2)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	7,792,033	7,807,847	(15,815)	(0.2)	0.00000	0.00000	0.00000	0.0
36. True-up *	4,212,241	1,833,444	2,378,797	129.7	7,792,033	7,807,847	(15,815)	(0.2)	0.05406	0.02348	0.03058	130.2
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	189,407,175	187,419,317	1,987,858	1.1	7,792,033	7,807,847	(15,815)	(0.2)	2.43078	2.40040	0.03038	1.3
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.43253	2.40213	0.03040	1.3
40. GPIF * (Already Adjusted for Taxes)	(138,354)	(138,354)	0	0.0	7,792,033	7,807,847	(15,815)	(0.2)	(0.00178)	(0.00177)	(0.00001)	0.6
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	189,268,821	187,280,963	1,987,858	1.1	7,792,033	7,807,847	(15,815)	(0.2)	2.43075	2.40036	0.03039	1.3
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.431	2.400	0.031	1.3

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CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2000
CURRENT MONTH

SCHEDULE A2
PAGE 1 OF 3

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	34,118,643	33,484,587	634,056	1.9	166,509,676	171,528,976	(5,019,300)	(2.9)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	3,906,288	4,442,244	(535,956)	(12.1)	18,535,857	17,438,424	1,097,433	6.3
3. FUEL COST OF PURCHASED POWER	10,179,913	9,435,200	744,713	7.9	37,504,409	22,954,100	14,550,309	63.4
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	830,371	843,200	(12,829)	(1.5)	3,879,579	4,153,000	(273,421)	(6.6)
4. ENERGY COST OF ECONOMY PURCHASES	0	1,803,600	(1,803,600)	0.0	(10,512)	5,487,100	(5,497,612)	(100.2)
5. TOTAL FUEL & NET POWER TRANSACTION	41,222,639	41,124,343	98,296	0.2	189,347,295	186,684,752	2,662,543	1.4
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(4,172)	(4,000)	(172)	4.3	(22,823)	(24,000)	1,177	(4.9)
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST	0	0	0	0.0	(79)	0	(79)	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	41,218,467	41,120,343	98,124	0.2	189,324,393	186,660,752	2,663,641	1.4
* INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,592,161	1,512,433	79,728	5.3	7,792,033	7,807,847	(15,814)	(0.2)
2. NONJURISDICTIONAL SALES	81,052	58,350	22,702	38.9	267,537	135,924	131,613	96.8
3. TOTAL SALES	1,673,213	1,570,783	102,430	6.5	8,059,570	7,943,771	115,799	1.5
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9515591	0.9628529	(0.0112938)	(1.2)	0.9668051	0.9828892	(0.0160841)	(1.6)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2000
CURRENT MONTH

SCHEDULE A2
PAGE 2 OF 3
REVISED WITH JULY 2000 FILING
PERIOD TO DATE

C. TRUE-UP CALCULATION	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. JURISDICTIONAL FUEL REVENUE	37,985,326	34,828,923	3,156,403	9.1	179,679,955	179,601,687	78,268	0.0
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	(2,684,371)	(305,574)	(2,378,797)	778.5	(4,212,241)	(1,833,444)	(2,378,797)	129.7
b. INCENTIVE PROVISION	23,059	23,059	0	0.0	138,354	138,354	0	0.0
c. TRANSITION ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
d. OTHER ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	35,324,014	34,546,408	777,606	2.3	175,606,068	177,906,597	(2,300,529)	(1.3)
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	41,218,467	41,120,343	98,124	0.2	189,324,393	186,660,752	2,663,641	1.4
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B-4)	0.9515591	0.9628529	(0.0112938)	(1.2)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	39,221,808	39,592,842	(371,034)	(0.9)	182,924,595	183,279,006	(354,411)	(0.2)
6A.JURISDIC. LOSS MULTIPLIER	1.00068	1.00068	0.0000	0.0	NA	NA	-	-
6B. (LINE 6 x LINE 6A)	39,248,479	39,619,765	(371,286)	(0.9)	183,048,983	183,403,635	(354,652)	(0.2)
6C.PEABODY COAL CONTR. BUY-OUT AMORT.	363,311	363,311	0	0.0	2,217,831	2,217,831	0	0.0
6D.(LINE 6C x LINE 5) PB. JURISD.	345,712	349,815	(4,103)	(1.2)	2,145,951	2,182,238	(36,287)	(1.7)
6E.OTHER (SPARE INPUT #1)	0	0	0	0.0	0	0	0	0.0
6F. OIL BELOW THE DISCHARGE VALVE	0	0	0	0.0	0	0	0	0.0
6G. OTHER (SPARE INPUT #2)	0	0	0	0.0	0	0	0	0.0
6H. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. 6B+6D+6E+6F+6G)	39,594,191	39,969,580	(375,389)	(0.9)	185,194,934	185,585,873	(390,939)	(0.2)
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6H)	(4,270,177)	(5,423,172)	1,152,995	(21.3)	(9,588,866)	(7,679,276)	(1,909,590)	24.9
8. INTEREST PROVISION FOR THE MONTH	(94,266)	(87,042)	(7,224)	8.3	(382,831)	(200,787)	(182,044)	90.7
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(24,288,863)	(24,325,952)	37,089	(0.2)	NOT APPLICABLE			
9a.DEFERRED TRUE-UP BEGINNING OF PERIO	7,879,936	7,879,936	0	0.0	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	2,684,371	305,574	2,378,797	778.5	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	(18,068,999)	(21,650,656)	3,581,657	(16.5)	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2000
CURRENT MONTH

REVISED WITH JULY 2000 FILING
PERIOD TO DATE

	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	(16,408,927)	(16,446,016)	37,089	(0.2)	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	(17,994,733)	(21,563,614)	3,568,881	(16.6)	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(34,403,660)	(38,009,630)	3,605,970	(9.5)	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	(17,201,830)	(19,004,815)	1,802,985	(9.5)	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	6.570	5.500	1.070	19.5	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	6.580	5.500	1.080	19.6	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	13.150	11.000	2.150	19.5	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	6.575	5.500	1.075	19.5	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.548	0.458	0.090	19.7	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	(94,266)	(87,042)	(7,224)	8.3	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JUNE 2000

SCHEDULE A3
PAGE 1 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
FUEL COST OF SYSTEM NET GENERATION ($)								
1 HEAVY OIL	2,311,115	2,122,487	188,628	8.9	4,847,340	4,617,079	230,261	5.0
2 LIGHT OIL	648,534	1,296,066	(647,532)	(50.0)	2,179,877	4,291,153	(2,111,276)	(49.2)
3 COAL	31,158,994	30,066,034	1,092,960	3.6	159,482,459	162,620,744	(3,138,285)	(1.9)
4 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
5 NUCLEAR	0	0	0	0.0	0	0	0	0.0
6 OTHER	0	0	0	0.0	0	0	0	0.0
7 TOTAL ($)	34,118,643	33,484,587	634,056	1.9	166,509,676	171,528,976	(5,019,300)	(2.9)
SYSTEM NET GENERATION (MWH)								
8 HEAVY OIL	40,457	50,750	(10,293)	(20.3)	88,327	103,299	(14,972)	(14.5)
9 LIGHT OIL	8,279	5,302	2,977	56.1	36,512	49,243	(12,731)	(25.9)
10 COAL	1,619,598	1,566,929	52,669	3.4	8,298,818	8,355,687	(56,870)	(0.7)
11 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
12 NUCLEAR	0	0	0	0.0	0	0	0	0.0
13 OTHER	0	0	0	0.0	0	0	0	0.0
14 TOTAL (MWH)	1,668,334	1,622,981	45,353	2.8	8,423,657	8,508,229	(84,573)	(1.0)
UNITS OF FUEL BURNED								
15 HEAVY OIL (BBL)	90,894	125,236	(34,342)	(27.4)	209,007	271,535	(62,528)	(23.0)
16 LIGHT OIL (BBL)	20,276	35,201	(14,925)	(42.4)	70,775	141,412	(70,637)	(50.0)
17 COAL (TON)	734,449	709,378	25,071	3.5	3,776,646	3,764,719	11,927	0.3
18 NATURAL GAS (MCF)	0	0	0	0.0	0	0	0	0.0
19 NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20 OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
BTUS BURNED (MMBTU)								
21 HEAVY OIL	576,682	791,615	(214,933)	(27.2)	1,326,698	1,716,378	(389,680)	(22.7)
22 LIGHT OIL	113,203	89,908	23,295	25.9	398,551	476,730	(78,179)	(16.4)
23 COAL	16,958,094	16,486,930	471,164	2.9	86,237,336	87,002,224	(764,888)	(0.9)
24 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
25 NUCLEAR	0	0	0	0.0	0	0	0	0.0
26 OTHER	0	0	0	0.0	0	0	0	0.0
27 TOTAL (MMBTU)	17,647,979	17,368,453	279,526	1.6	87,962,585	89,195,332	(1,232,747)	(1.4)
GENERATION MIX (% MWH)								
28 HEAVY OIL	2.42	3.13	(0.71)	-	1.05	1.21	(0.16)	-
29 LIGHT OIL	0.50	0.33	0.17	-	0.43	0.58	(0.15)	-
30 COAL	97.08	96.55	0.53	-	98.52	98.21	0.31	-
31 NATURAL GAS	0.00	0.00	0.00	-	0.00	0.00	0.00	-
32 NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33 OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34 TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
FUEL COST PER UNIT								
35 HEAVY OIL ($/BBL)	25.43	16.95	8.48	50.0	23.19	17.00	6.19	36.4
36 LIGHT OIL ($/BBL)	31.99	36.82	(4.83)	(13.1)	30.80	30.35	0.45	1.5
37 COAL ($/TON)	42.42	42.38	0.04	0.1	42.23	43.20	(0.97)	(2.2)
38 NATURAL GAS ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40 OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
FUEL COST PER MMBTU ($/MMBTU)								
41 HEAVY OIL	4.01	2.68	1.33	49.6	3.65	2.69	0.96	35.7
42 LIGHT OIL	5.73	14.42	(8.69)	(60.3)	5.47	9.00	(3.53)	(39.2)
43 COAL	1.84	1.82	0.02	1.1	1.85	1.87	(0.02)	(1.1)
44 NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
45 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47 TOTAL ($/MMBTU)	1.93	1.93	0.00	0.0	1.89	1.92	(0.03)	(1.6)

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JUNE 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
BTU BURNED PER KWH (BTU/KWH)								
48 HEAVY OIL	14,254	15,598	(1,344)	(8.6)	15,020	16,616	(1,596)	(9.6)
49 LIGHT OIL	13,674	16,957	(3,283)	(19.4)	10,916	9,681	1,235	12.8
50 COAL	10,471	10,522	(51)	(0.5)	10,392	10,412	(20)	(0.2)
51 NATURAL GAS	0	0	0	0.0	0	0	0	0.0
52 NUCLEAR	0	0	0	0.0	0	0	0	0.0
53 OTHER	0	0	0	0.0	0	0	0	0.0
54 TOTAL (BTU/KWH)	10,578	10,702	(124)	(1.2)	10,442	10,483	(41)	(0.4)
GENERATED FUEL COST PER KWH (cents/KWH)								
55 HEAVY OIL	5.71	4.18	1.53	36.6	5.49	4.47	1.02	22.8
56 LIGHT OIL	7.83	24.44	(16.61)	(68.0)	5.97	8.71	(2.74)	(31.5)
57 COAL	1.92	1.92	0.00	0.0	1.92	1.95	(0.03)	(1.5)
58 NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
59 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61 TOTAL (cents/KWH)	2.05	2.06	(0.01)	(0.5)	1.98	2.02	(0.04)	(2.0)

SCHEDULE A4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD/MONTH OF: JUNE 2000

(A) PLANT/UNIT	(B) NET CAPABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPC. FACTO (%)	(E) EQUIV. AVAIL. FACTO (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COS PER KWH (cents /KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	30	5,205	23.3	100.0	60.5	-	HVY.OIL	-	-	-	-	-	-
H.P.#2	30	4,212	18.9	92.1	55.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#3	30	5,788	25.9	95.9	63.8	-	HVY.OIL	-	-	-	-	-	-
H.P.#4	39	4,246	14.6	65.6	53.8	-	HVY.OIL	-	-	-	-	-	-
H.P.#5	67	10,392	20.8	88.9	60.5	-	HVY.OIL	-	-	-	-	-	-
H.P. STATION	196	29,843	20.5	87.5	58.8	16,049	HVY.OIL	75,313	6,359,278	478,936.3	1,867,272	6.26	24.79
GAN.#1	114	45,592	53.8	82.6	64.3	11,121	COAL	21,227	23,885,038	507,007.7	811,510	1.78	38.23
GAN.#2	98	35,122	48.2	65.8	76.9	12,624	COAL	18,720	23,685,540	443,393.3	715,667	2.04	38.23
GAN.#3	145	72,222	66.9	93.7	71.7	11,696	COAL	43,577	19,384,519	844,719.2	1,665,952	2.31	38.23
GAN.#4	159	78,857	66.7	92.7	71.7	11,848	COAL	48,306	19,341,419	934,306.6	1,846,743	2.34	38.23
GAN.#5	232	120,173	69.6	89.2	79.6	10,492	COAL	53,056	23,765,280	1,260,890.7	2,028,335	1.69	38.23
GAN.#6	372	171,091	61.8	74.8	83.0	10,214	COAL	70,238	24,879,300	1,747,472.3	2,685,205	1.57	38.23
GANNON STA.	1120	523,057	62.8	82.8	76.8	10,970	COAL	255,124	22,490,200	5,737,789.8	9,753,412	1.86	38.23
B.B.#1	416	228,545	73.8	86.0	79.5	10,703	COAL	101,192	24,172,720	2,446,085.9	4,269,523	1.87	42.19
B.B.#2	416	228,193	73.7	86.7	81.2	10,313	COAL	97,941	24,029,200	2,353,443.9	4,132,356	1.81	42.19
B.B.#3	433	259,979	80.7	95.0	83.4	9,698	COAL	105,107	23,988,500	2,521,359.3	4,434,706	1.71	42.19
B.B. 1 - 3	1265	716,717	76.2	89.3	81.4	10,214	COAL	304,240	24,062,875	7,320,889.1	12,836,585	1.79	42.19
B.B.#4	442	247,524	75.3	86.7	87.5	9,907	COAL	112,840	21,730,787	2,452,107.4	5,860,504	2.37	51.94
B.B. STA	1707	964,241	75.9	88.6	83.0	10,135	COAL	417,080	23,431,933	9,772,996.5	18,697,089	1.94	44.83
SEB-PHIL. #1(HVY OIL)	17	5,027	39.7	99.6	84.8	9,722	HVY.OIL	7,791	6,273,007	48,873.0	221,936	4.41	28.49
SEB-PHIL. #2(HVY OIL)	17	5,587	44.2	99.7	98.1	8,748	HVY.OIL	7,790	6,273,813	48,873.0	221,907	3.97	28.49
SEB-PHILLIPS TOTAL	34	10,614	42.0	99.7	91.5	9,209	HVY.OIL	15,581	6,273,410	97,746.0	443,843	4.18	28.49
POLK COAL	250	132,300	71.1	73.9	91.5	10,940	COAL	62,244	23,252,000	1,447,307.7	2,708,493	2.05	43.51
POLK OIL	225	1,479	0.9	86.9	63.2	7,589	LGT.OIL	2,732	4,107,587	11,223.9	90,302	6.11	33.05
POLK TOTAL	250	133,779	72.0	79.8	-	10,903	-	-	-	1,458,531.6	2,798,795	2.09	-
GAN.C.T.#1	12	516	5.8	99.5	81.4	1,913	LGT.OIL	170	5,818,696	987.2	5,399	1.05	31.82
B.B.C.T.#1	12	505	5.7	100.0	93.8	17,646	LGT.OIL	1,530	5,822,574	8,911.1	48,698	9.64	31.82
B.B.C.T.#2	66	4,551	9.3	87.6	69.2	15,886	LGT.OIL	12,440	5,811,876	72,298.4	395,830	8.70	31.82
B.B.C.T.#3	66	1,228	2.5	27.0	66.1	16,109	LGT.OIL	3,404	5,811,864	19,781.9	108,305	8.82	31.82
C.T. TOTAL	156	6,800	5.9	63.8	70.7	14,997	LGT.OIL	17,544	5,812,873	101,978.6	558,232	8.21	31.82
TOT. COAL (GN,BB,POLK)	3077	1,819,598	70.7	85.3	81.4	10,471	COAL	734,449	23,089,556	16,958,094.0	31,158,994	1.92	42.43
SYSTEM	3463	1,868,334	64.8	85.0	78.8	10,578	-	-	-	17,647,978.8	34,118,643	2.05	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS

NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2000

	CURRENT MONTH				PERIOD TO DATE			
HEAVY OIL (1)	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1 PURCHASES:								
2 UNITS (BBL)	117,141	125,236	(8,095)	(6.5)	221,880	225,447	(3,567)	(1.6)
3 UNIT COST ($/BBL)	27.77	16.37	11.40	69.6	25.76	16.22	9.54	58.8
4 AMOUNT ($)	3,252,724	2,050,176	1,202,548	58.7	5,715,479	3,656,165	2,059,314	56.3
5 BURNED:								
6 UNITS (BBL)	90,894	125,236	(34,342)	(27.4)	209,007	271,535	(62,528)	(23.0)
7 UNIT COST ($/BBL)	25.43	16.95	8.48	50.0	23.19	17.00	6.19	36.4
8 AMOUNT ($)	2,311,115	2,122,487	188,628	8.9	4,847,340	4,617,079	230,261	5.0
9 ENDING INVENTORY:								
10 UNITS (BBL)	103,132	81,135	21,997	27.1	103,132	81,135	21,997	27.1
11 UNIT COST ($/BBL)	25.32	17.03	8.29	48.7	25.32	17.03	8.29	48.7
12 AMOUNT ($)	2,611,797	1,381,330	1,230,467	89.1	2,611,797	1,381,330	1,230,467	89.1
13								
14 DAYS SUPPLY:	36	28	8	28.6	-	-	-	-
LIGHT OIL (2)								
15 PURCHASES:								
16 UNITS (BBL)	17,335	54,941	(37,606)	(68.4)	159,599	229,057	(69,458)	(30.3)
17 UNIT COST ($/BBL)	33.61	38.82	(5.21)	(13.4)	33.62	32.34	1.28	4.0
18 AMOUNT ($)	582,616	2,132,759	(1,550,143)	(72.7)	5,365,752	7,407,671	(2,041,919)	(27.6)
19 BURNED:								
20 UNITS (BBL)	20,276	35,201	(14,925)	(42.4)	70,775	141,412	(70,637)	(50.0)
21 UNIT COST ($/BBL)	31.99	36.82	(4.83)	(13.1)	30.80	30.35	0.45	1.5
22 AMOUNT ($)	648,534	1,296,066	(647,532)	(50.0)	2,179,877	4,291,153	(2,111,276)	(49.2)
23 ENDING INVENTORY:								
24 UNITS (BBL)	106,381	97,057	9,324	9.6	106,381	97,057	9,324	9.6
25 UNIT COST ($/BBL)	32.36	36.69	(4.33)	(11.8)	32.36	36.69	(4.33)	(11.8)
26 AMOUNT ($)	3,442,141	3,561,047	(118,906)	(3.3)	3,442,141	3,561,047	(118,906)	(3.3)
27								
28 DAYS SUPPLY: NORMAL	69	63	6	9.5	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	15	14	1	7.1	-	-	-	-
COAL (3)								
30 PURCHASES:								
31 UNITS (TONS)	678,947	691,000	(12,053)	(1.7)	4,006,511	3,570,200	436,311	12.2
32 UNIT COST ($/TON)	43.54	42.26	1.28	3.0	42.12	42.60	(0.48)	(1.1)
33 AMOUNT ($)	29,560,771	29,204,488	356,283	1.2	168,753,548	152,081,789	16,671,759	11.0
34 BURNED:								
35 UNITS (TONS)	734,449	709,378	25,071	3.5	3,776,646	3,764,719	11,927	0.3
36 UNIT COST ($/TON)	42.42	42.38	0.04	0.1	42.23	43.20	(0.97)	(2.2)
37 AMOUNT ($)	31,158,994	30,066,034	1,092,960	3.6	159,482,459	162,620,744	(3,138,285)	(1.9)
38 ENDING INVENTORY:								
39 UNITS (TONS)	1,006,881	931,656	75,225	8.1	1,006,881	931,656	75,225	8.1
40 UNIT COST ($/TON)	42.32	42.10	0.22	0.5	42.32	42.10	0.22	0.5
41 AMOUNT ($)	42,615,867	39,224,954	3,390,913	8.6	42,615,867	39,224,954	3,390,913	8.6
42								
43 DAYS SUPPLY:	41	38	3	7.9	-	-	-	-
NATURAL GAS								
44 PURCHASES:								
45 UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
46 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
48 BURNED:								
49 UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
50 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
51 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
56								
57 DAYS SUPPLY:	0	0	0	0.0	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2000

OTHER	CURRENT MONTH ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	PERIOD TO DATE ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
74 DAYS SUPPLY:	0	0	0	0.0	-	-	-	-

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	16,189
LUBE OIL	0
FUEL ANALYSIS	119
TOTAL	16,308

(2) RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(6,909)	(220,818)
OTHER USAGE	(1,293)	(42,092)
TOTAL	(8,202)	(262,910)

(3) RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	25,455
IGNITION #2 OIL	204,629
IGNITION PROPANE	4,482
AERIAL SURVEY ADJ.	(695,507)
ADDITIVES	279,918
TOTAL	(181,023)

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JUNE 2000

SCHEDULE A6
PAGE 1 OF 3

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:									
VARIOUS	ECON.	43,194.0	0.0	43,194.0	2.833	3.856	1,223,500.00	1,665,400.00	353,500.00
VARIOUS JURISDICTIONAL	SCH. -D	5,999.0	0.0	5,999.0	2.397	2.397	143,800.00	143,800.00	
VARIOUS SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS SEPARATED	CONTRACT	38,216.0	0.0	38,216.0	2.269	3.211	867,200.00	1,227,300.00	
FMPA	SCH. -D	108,000.0	0.0	108,000.0	1.801	1.801	1,944,944.00	1,944,944.00	
VARIOUS JURISDICTIONAL	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS	-	195,409.0	0.0	195,409.0	2.139	2.549	4,179,444.00	4,981,444.00	353,500.00
LESS TRANSMISSION COSTS	-						0.00		
LESS VARIABLE O & M COSTS	-						(90,700.00)		
PLUS 80% OF ECON. ENERGY SALES PROFI	-						353,500.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INC 80% OF ECON. ENERGY SALES PROFITS	-	195,409.0	0.0	195,409.0	2.273	2.549	4,442,244.00	4,981,444.00	353,500.00
ACTUAL:									
FLA. PWR. CORP.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF ST. CLOUD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SONAT	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY, INC.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENRGY, INC.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENN, VALLEY AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL. SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH. SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS SEP. CONTRACT		57,080.0	0.0	57,080.0	2.305	3.123	1,315,694.00	1,782,608.40	
SEMINOLE ELECTRIC CO-OP PRE JURISD.	SCH. -D	6,154.0	987.9	5,166.1	2.710	2.710	139,998.42	139,998.42	
SEMINOLE ELECTRIC CO-OP HAR JURISD.	SCH. -D	992.0	0.0	992.0	1.946	1.946	19,300.40	19,300.40	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JUNE 2000

SCHEDULE A6
PAGE 2 OF 3

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA		SCH. -D	89,755.0	0.0	89,755.0	1.909	1.909	1,713,217.32	1,713,217.32	
HARDEE POWER PART. TO FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR.& LT.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO JACKSONVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KISSIMMEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ORLANDO		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO SEMINOLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FT. PIERCE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LK. WORTH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ENERGY AUTHORI		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FPC		SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR. CORP.		SCH. -MB	318.0	0.0	318.0	6.187	6.187	19,673.55	19,673.55	
HARDEE POWER PART. TO FLA. PWR.& LT.		SCH. -MB	441.0	0.0	441.0	4.145	4.145	18,277.93	18,277.93	
HARDEE POWER PART. TO LAKELAND		SCH. -MB	31.0	0.0	31.0	4.488	4.488	1,391.13	1,391.13	
HARDEE POWER PART. TO ORLANDO		SCH. -MB	44.0	0.0	44.0	3.625	3.625	1,594.79	1,594.79	
HARDEE POWER PART. TO ENERGY AUTHORI		SCH. -MB	360.0	0.0	360.0	4.000	4.000	14,400.87	14,400.87	
HARDEE POWER PART. TO TALLAHASSEE		SCH. -MB	140.0	0.0	140.0	3.784	3.784	5,297.77	5,297.77	
HARDEE POWER PART. TO AQUILA		SCH. -MB	440.0	0.0	440.0	4.368	4.368	19,217.09	19,217.09	
SEMINOLE ELECTRIC CO-OP		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. CORP.		SCH. -MB	2,130.0	0.0	2,130.0	4.960	4.960	105,647.20	105,647.20	
FLA. PWR.& LIGHT		SCH. -MB	13,107.0	0.0	13,107.0	2.998	2.998	392,953.24	392,953.24	
CITY OF LAKELAND		SCH. -MB	520.0	0.0	520.0	4.606	4.606	23,952.28	23,952.28	
ORLANDO UTIL. COMM.		SCH. -MB	685.0	0.0	685.0	3.278	3.278	22,452.68	22,452.68	
THE ENERGY AUTHORITY		SCH. -MB	1,984.0	0.0	1,984.0	4.089	4.089	81,121.62	81,121.62	
TALLAHASSEE		SCH. -MB	50.0	0.0	50.0	4.347	4.347	2,173.65	2,173.65	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JUNE 2000

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(6) (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ADJUSTMENTS TO PREVIOUS MO MON/YR TYP SCH.									
HARDEE POWER PARTNERS ES 5/00 SEPAR.	CONTRACT	(50,640.0)	0.0	(50,640.0)	2.303	3.116	(1,166,239.20)	(1,577,942.40)	
HARDEE POWER PARTNERS ACT 5/00 SEPAR.	CONTRACT	50,640.0	0.0	50,640.0	2.305	3.123	1,167,252.00	1,581,487.20	
SOUTHERN COMPANY 5/00	SCH. -MB	(474.0)	0.0	(474.0)	11.546	11.546	(54,728.96)	(54,728.96)	
SOUTHERN COMPANY 5/00	SCH. -MB	455.0	0.0	455.0	11.540	11.540	52,505.96	52,505.96	
KOCH ENERGY 5/00	SCH. -MB	(1,761.0)	0.0	(1,761.0)	9.446	9.446	(166,352.25)	(166,352.25)	
KOCH ENERGY 5/00	SCH. -MB	1,772.0	0.0	1,772.0	9.452	9.452	167,486.25	167,486.25	
FLORIDA POWER & LIGHT 5/00	STEAM -A	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLORIDA POWER & LIGHT 5/00	STEAM -A	50.0	0.0	50.0	20.000	20.000	10,000.00	10,000.00	
SEMINOLE ELECTRIC CO-OP PRE 4/00 JURIS	SCH. -D	(5,701.0)	(898.6)	(4,802.4)	2.300	2.300	(110,447.61)	(110,447.61)	
SEMINOLE ELECTRIC CO-OP PRE 4/00 JURIS	SCH. -D	5,701.0	885.3	4,815.7	2.293	2.293	110,447.61	110,447.61	
SEMINOLE ELECTRIC CO-OP PRE 5/00 JURIS	SCH. -D	(6,883.0)	(1,031.4)	(5,851.6)	2.422	2.422	(141,730.53)	(141,730.53)	
SEMINOLE ELECTRIC CO-OP PRE 5/00 JURIS	SCH. -D	6,883.0	1,031.9	5,851.1	2.422	2.422	141,730.53	141,730.53	
SUB-TOTAL ECONOMY POWER SALES		0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.		0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.		7,146.0	975.1	6,170.9	2.581	2.581	159,298.82	159,298.82	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.		0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.		57,080.0	0.0	57,080.0	2.307	3.129	1,316,706.80	1,786,153.20	
SUB-TOTAL OTHER D POWER SALES		89,755.0	0.0	89,755.0	1.909	1.909	1,713,217.32	1,713,217.32	
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.		0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE MB POWER SALES-JURISD.		20,242.0	0.0	20,242.0	3.493	3.493	707,064.70	707,064.70	
SUB-TOTAL OTHER POWER SALES		50.0	0.0	50.0	20.000	20.000	10,000.00	10,000.00	
TOTAL INCLUDING VARIABLE O & M COSTS		174,273.0	975.1	173,297.9	2.254	2.525	3,906,287.64	4,375,734.04	0.00
LESS VARIABLE O & M COSTS							0.00		
LESS VARIABLE O & M COSTS - HARDEE							0.00		
LESS TRANSMISSION COSTS SCH. D (SEP.)							0.00		
PLUS 80% OF ECON. ENERGY SALES PROFITS -							0.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS -		174,273.0	975.1	173,297.9	2.254	2.525	3,906,287.64	4,375,734.04	0.00
CURRENT MONTH:									
DIFFERENCE -		(21,136.0)	975.1	(22,111.1)	(0.019)	(0.024)	(535,956.36)	(605,709.96)	(353,500.00)
DIFFERENCE % -		(10.8)	0.0	(11.3)	(0.8)	(0.9)	(12.1)	(12.2)	(100.0)
PERIOD TO DATE:									
ACTUAL -		878,479.0	4,420.6	874,058.4	2.121	2.288	18,535,855.68	19,994,530.14	0.00
ESTIMATED -		886,747.0	0.0	886,747.0	1.967	2.120	17,438,424.00	18,802,804.00	472,420.00
DIFFERENCE -		(8,268.0)	4,420.6	(12,688.6)	0.154	0.168	1,097,431.68	1,191,726.14	(472,420.00)
DIFFERENCE % -		(0.9)	0.0	(1.4)	7.8	7.9	6.3	6.3	(100.0)

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. SEC 60% OR $15,560.19 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH JUNE 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	42,016.0	0.0	22,804.0	19,212.0	16.059	16.059	3,085,300.00
HARDEE POWER PARTNERS	IPP	129,852.0	0.0	0.0	129,852.0	3.509	3.509	4,556,000.00
VARIOUS	OTHER	37,681.0	0.0	0.0	37,681.0	4.761	4.761	1,793,900.00
TOTAL	-	209,549.0	0.0	22,804.0	186,745.0	5.052	5.052	9,435,200.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	94,031.0	0.0	0.0	94,031.0	5.116	5.116	4,810,892.84
HARDEE PWR. PART.-OTHERS	IPP	1,774.0	0.0	0.0	1,774.0	3.917	3.917	69,479.67
FLA. POWER CORP.	SCH.-Ja	409.0	0.0	127.4	281.6	9.448	9.448	26,605.41
FLA. POWER CORP.	SCH.-Jc	2,416.0	0.0	0.0	2,416.0	4.298	4.298	103,843.00
FLA. POWER & LIGHT	SCH.-Ja	5,724.0	0.0	4,353.8	1,370.2	7.243	7.243	99,244.28
FLA. POWER & LIGHT	SCH.-Jc	15,706.0	0.0	0.0	15,706.0	5.916	5.916	929,163.68
CITY OF LAKELAND	SCH.-Ja	5,888.0	0.0	3,682.3	2,205.7	9.063	9.063	199,901.54
CITY OF LAKELAND	SCH.-Jc	4,950.0	0.0	0.0	4,950.0	7.699	7.699	381,083.50
ORLANDO	SCH.-Ja	7,247.0	0.0	5,215.8	2,031.2	7.994	7.994	162,370.68
ORLANDO	SCH.-Jc	9,210.0	0.0	0.0	9,210.0	6.913	6.913	636,704.00
THE ENERGY AUTH.	SCH.-Ja	4,667.0	0.0	3,723.2	943.8	8.587	8.587	81,046.73
THE ENERGY AUTH.	SCH.-Jc	5,823.0	0.0	0.0	5,823.0	6.827	6.827	397,549.84
ENTERGY	SCH.-Ja	1,206.0	0.0	612.4	593.6	9.830	9.830	58,353.40
ENTERGY	SCH.-Jc	1,677.0	0.0	0.0	1,677.0	8.956	8.956	150,197.27
RELIANT	SCH.-Ja	1,114.0	0.0	354.7	759.3	7.075	7.075	53,721.64
RELIANT	SCH.-Jc	1,673.0	0.0	0.0	1,673.0	7.580	7.580	126,813.70
REEDY CREEK	SCH.-Jc	75.0	0.0	0.0	75.0	5.300	5.300	3,975.00
AQUILA	SCH.-Ja	259.0	0.0	100.0	159.0	9.474	9.474	15,063.67
AQUILA	SCH.-Jc	1,107.0	0.0	0.0	1,107.0	6.040	6.040	66,863.14
TALLAHASSEE	SCH.-Ja	1,816.0	0.0	1,167.3	648.7	9.079	9.079	58,897.15
TALLAHASSEE	SCH.-Jc	1,548.0	0.0	0.0	1,548.0	8.983	8.983	139,051.16
KOCH	SCH.-Ja	760.0	0.0	522.3	237.7	8.537	8.537	20,293.04
KOCH	SCH.-Jc	2,078.0	0.0	0.0	2,078.0	8.273	8.273	171,920.04
ENRON	SCH.-Ja	590.0	0.0	507.7	82.3	6.962	6.962	5,730.11
ENRON	SCH.-Jc	811.0	0.0	0.0	811.0	6.481	6.481	52,562.40
MORGAN STANLEY	SCH.-Ja	84.0	0.0	0.0	84.0	7.993	7.993	6,713.84
MORGAN STANLEY	SCH.-Jc	972.0	0.0	0.0	972.0	7.284	7.284	70,800.88
FARMLAND	SCH.-Jc	232.0	0.0	0.0	232.0	3.507	3.507	8,135.11
CARGILL ALLIANT	SCH.-Jc	4,526.0	0.0	0.0	4,526.0	3.950	3.950	178,777.00
RINGHAVER	SCH.-Jc	83.0	0.0	0.0	83.0	12.003	12.003	9,962.20
AUBURNDALE POWER PARTNERS	SCH.-D	23,167.0	0.0	0.0	23,167.0	5.522	5.522	1,279,214.80
OKEELANTA	SCH.-D	2,291.0	0.0	0.0	2,291.0	2.334	2.334	53,464.94
ADJUSTMENTS TO PRIOR MONTHS: See Page 2 of 3 and Page 3 of 3 for details		(1,266.0)	0.0	(1,056.5)	(209.5)	118.607	118.607	(248,482.56)
TOTAL		202,648.0	0.0	19,310.4	183,337.6	5.553	5.553	10,179,913.10
CURRENT MONTH:								
DIFFERENCE	-	(6,901.0)	0.0	(3,493.6)	(3,407.4)	-21.856	-21.856	744,713.10
DIFFERENCE %	-	(3.3)	0.0	(15.3)	(1.8)	(432.6)	(432.6)	7.9
PERIOD TO DATE:								
ACTUAL	-	966,150.00	0.00	119,137.80	847,012.2	4.428	4.428	37,504,410.52
ESTIMATED	-	585,331.0	0.0	76,998.0	508,333.0	4.516	4.516	22,954,100.0
DIFFERENCE	-	380,819.0	0.0	42,139.8	338,679.2	(0.088)	(0.088)	14,550,310.52
DIFFERENCE %	-	65.1	0.0	54.7	66.6	(1.9)	(2.0)	63.4

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH JUNE 2000

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) ——CENTS/KWH—— (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ADUSTMENTS TO PRIOR MONTHS:								
FLA. POWER CORP.	Jun-99 SCH.-Jc	(22,262.0)	0.0	0.0	(22,262.0)	2.997	2.997	(667,299.26)
FLA. POWER CORP.	Jun-99 SCH.-Jc	22,262.0	0.0	0.0	22,262.0	2.771	2.771	616,899.26
ORLANDO	Jun-99 SCH.-Jc	(17,053.0)	0.0	0.0	(17,053.0)	4.360	4.360	(743,453.38)
ORLANDO	Jun-99 SCH.-Jc	17,053.0	0.0	0.0	17,053.0	4.186	4.186	713,853.38
FLA. POWER CORP.	Jul-99 SCH.-Jc	(22,667.0)	0.0	0.0	(22,667.0)	2.623	2.623	(594,610.10)
FLA. POWER CORP.	Jul-99 SCH.-Jc	22,667.0	0.0	0.0	22,667.0	2.590	2.590	587,077.10
FLA. POWER CORP.	Nov-99 SCH.-Jc	(2,877.0)	0.0	0.0	(2,877.0)	3.492	3.492	(100,464.00)
FLA. POWER CORP.	Nov-99 SCH.-Jc	2,877.0	0.0	0.0	2,877.0	3.243	3.243	93,314.00
FLA. POWER & LIGHT	Nov-99 SCH.-Jc	(2,044.0)	0.0	0.0	(2,044.0)	4.773	4.773	(97,551.75)
FLA. POWER & LIGHT	Nov-99 SCH.-Jc	2,044.0	0.0	0.0	2,044.0	4.577	4.577	93,551.75
ORLANDO	Nov-99 SCH.-Jc	(1,549.0)	0.0	0.0	(1,549.0)	4.642	4.642	(71,900.50)
ORLANDO	Nov-99 SCH.-Jc	1,549.0	0.0	0.0	1,549.0	3.873	3.873	59,985.50
THE ENERGY AUTH.	Nov-99 SCH.-Jc	(1,577.0)	0.0	0.0	(1,577.0)	3.509	3.509	(55,340.95)
THE ENERGY AUTH.	Nov-99 SCH.-Jc	1,577.0	0.0	0.0	1,577.0	3.448	3.448	54,380.95
REEDY CREEK	Nov-99 SCH.-Jc	(209.0)	0.0	0.0	(209.0)	3.380	3.380	(7,064.00)
REEDY CREEK	Nov-99 SCH.-Jc	209.0	0.0	0.0	209.0	2.543	2.543	5,314.00
TALLAHASSEE	Nov-99 SCH.-Jc	(1,822.0)	0.0	0.0	(1,822.0)	3.756	3.756	(68,430.32)
TALLAHASSEE	Nov-99 SCH.-Jc	1,822.0	0.0	0.0	1,822.0	3.122	3.122	56,882.32
OKEELANTA	Jan-00 SCH.-D	(7,430.0)	0.0	0.0	(7,430.0)	4.174	4.174	(310,155.00)
OKEELANTA	Jan-00 SCH.-D	7,262.0	0.0	0.0	7,262.0	4.271	4.271	310,155.00
OKEELANTA	Feb-00 SCH.-D	(5,316.0)	0.0	0.0	(5,316.0)	4.621	4.621	(245,678.00)
OKEELANTA	Feb-00 SCH.-D	5,194.0	0.0	0.0	5,194.0	4.730	4.730	245,678.00
OKEELANTA	Mar-00 SCH.-D	(8,570.0)	0.0	0.0	(8,570.0)	3.050	3.050	(261,385.00)
OKEELANTA	Mar-00 SCH.-D	8,373.0	0.0	0.0	8,373.0	3.122	3.122	261,385.00
OKEELANTA	Apr-00 SCH.-D	(15,195.0)	0.0	0.0	(15,195.0)	3.361	3.361	(510,670.40)
OKEELANTA	Apr-00 SCH.-D	14,846.0	0.0	0.0	14,846.0	3.440	3.440	510,670.40
OKEELANTA	May-00 SCH.-D	(18,640.0)	0.0	0.0	(18,640.0)	3.293	3.293	(613,814.00)
OKEELANTA	May-00 SCH.-D	18,210.0	0.0	0.0	18,210.0	3.371	3.371	613,814.00
HARDEE PWR. PART.-NATIVE	May-00 IPP	(102,941.0)	0.0	0.0	(102,941.0)	4.622	4.622	(4,758,321.12)
HARDEE PWR. PART.-NATIVE	May-00 IPP	102,941.0	0.0	0.0	102,941.0	4.448	4.448	4,578,708.85
FLA. POWER CORP.	Apr-00 SCH.-Ja	(8,601.0)	0.0	(8,069.2)	(531.8)	5.189	5.189	(27,597.27)
FLA. POWER CORP.	Apr-00 SCH.-Ja	8,693.0	0.0	8,086.2	606.8	5.179	5.179	31,425.79
FLA. POWER CORP.	Apr-00 SCH.-Jc	(23,047.0)	0.0	0.0	(23,047.0)	3.587	3.587	(826,689.00)
FLA. POWER CORP.	Apr-00 SCH.-Jc	22,955.0	0.0	0.0	22,955.0	3.585	3.585	822,825.00
FLA. POWER & LIGHT	Apr-00 SCH.-Ja	(16,075.0)	0.0	(12,468.7)	(3,606.3)	4.942	4.942	(178,206.07)
FLA. POWER & LIGHT	Apr-00 SCH.-Ja	14,999.0	0.0	11,481.5	3,517.5	4.950	4.950	174,130.79
FLA. POWER & LIGHT	Apr-00 SCH.-Jc	(14,018.0)	0.0	0.0	(14,018.0)	4.293	4.293	(601,802.50)
FLA. POWER & LIGHT	Apr-00 SCH.-Jc	15,094.0	0.0	0.0	15,094.0	4.330	4.330	653,639.50
ORLANDO	Apr-00 SCH.-Ja	(10,600.0)	0.0	(2,654.0)	(7,946.0)	4.730	4.730	(375,846.92)
ORLANDO	Apr-00 SCH.-Ja	10,495.0	0.0	2,654.0	7,841.0	4.719	4.719	370,055.98
ORLANDO	Apr-00 SCH.-Jc	(7,755.0)	0.0	0.0	(7,755.0)	4.334	4.334	(336,088.50)
ORLANDO	Apr-00 SCH.-Jc	7,860.0	0.0	0.0	7,860.0	4.353	4.353	342,158.50
THE ENERGY AUTH.	Apr-00 SCH.-Ja	(4,807.0)	0.0	(1,212.4)	(3,594.6)	4.894	4.894	(175,907.08)
THE ENERGY AUTH.	Apr-00 SCH.-Ja	4,807.0	0.0	1,188.6	3,618.4	4.854	4.854	175,637.44
THE ENERGY AUTH.	Apr-00 SCH.-Jc	(10,433.0)	0.0	0.0	(10,433.0)	4.362	4.362	(455,112.91)
THE ENERGY AUTH.	Apr-00 SCH.-Jc	10,433.0	0.0	0.0	10,433.0	4.322	4.322	450,959.93
RELIANT	Apr-00 SCH.-Ja	(1,111.0)	0.0	(4.0)	(1,107.0)	4.344	4.344	(48,091.98)
RELIANT	Apr-00 SCH.-Ja	1,111.0	0.0	4.0	1,107.0	4.298	4.298	47,579.66
RELIANT	Apr-00 SCH.-Jc	(1,219.0)	0.0	0.0	(1,219.0)	4.408	4.408	(53,731.16)
RELIANT	Apr-00 SCH.-Jc	1,219.0	0.0	0.0	1,219.0	4.362	4.362	53,167.00
AQUILA	Apr-00 SCH.-Jc	(992.0)	0.0	0.0	(992.0)	3.653	3.653	(36,233.25)
AQUILA	Apr-00 SCH.-Jc	992.0	0.0	0.0	992.0	3.625	3.625	35,957.77
TALLAHASSEE	Apr-00 SCH.-Ja	(835.0)	0.0	(36.5)	(798.5)	4.413	4.413	(35,237.81)
TALLAHASSEE	Apr-00 SCH.-Ja	835.0	0.0	36.5	798.5	4.358	4.358	34,795.12
TALLAHASSEE	Apr-00 SCH.-Jc	(6,706.0)	0.0	0.0	(6,706.0)	3.979	3.979	(266,854.55)
TALLAHASSEE	Apr-00 SCH.-Jc	6,706.0	0.0	0.0	6,706.0	3.924	3.924	263,131.04
ENTERGY	Apr-00 SCH.-Jc	(101.0)	0.0	0.0	(101.0)	4.789	4.789	(4,837.05)
ENTERGY	Apr-00 SCH.-Jc	101.0	0.0	0.0	101.0	4.733	4.733	4,780.41

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH JUNE 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	-----CENTS/KWH----- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ADUSTMENTS TO PRIOR MONTHS CONTINUED:								
FLA. POWER CORP.	May-00 SCH.-Ja	(5,956.0)	0.0	(5,660.6)	(295.4)	8.513	8.513	(25,147.64)
FLA. POWER CORP.	May-00 SCH.-Ja	5,956.0	0.0	4,846.6	1,109.4	9.077	9.077	100,698.12
FLA. POWER & LIGHT	May-00 SCH.-Ja	(1,419.0)	0.0	(934.4)	(484.6)	5.399	5.399	(26,161.23)
FLA. POWER & LIGHT	May-00 SCH.-Ja	1,419.0	0.0	1,052.6	366.4	5.248	5.248	19,229.50
CITY OF LAKELAND	May-00 SCH.-Ja	(7,229.0)	0.0	(5,979.9)	(1,249.1)	8.159	8.159	(101,916.04)
CITY OF LAKELAND	May-00 SCH.-Ja	7,229.0	0.0	6,464.7	764.3	8.182	8.182	62,533.59
ORLANDO UTIL. COMM.	May-00 SCH.-Ja	(3,238.0)	0.0	(3,238.0)	0.0	0.000	0.000	0.00
ORLANDO UTIL. COMM.	May-00 SCH.-Ja	3,238.0	0.0	2,827.0	411.0	7.898	7.898	32,461.29
ENTERGY	May-00 SCH.-Ja	(4,105.0)	0.0	(2,816.0)	(1,289.0)	7.562	7.562	(97,475.96)
ENTERGY	May-00 SCH.-Ja	4,105.0	0.0	2,621.5	1,483.5	7.406	7.406	109,870.44
THE ENERGY AUTHORITY	May-00 SCH.-Ja	(3,240.0)	0.0	(1,596.3)	(1,643.7)	7.938	7.938	(130,478.15)
THE ENERGY AUTHORITY	May-00 SCH.-Ja	3,240.0	0.0	2,335.8	904.2	9.481	9.481	85,730.96
RELIANT	May-00 SCH.-Ja	(883.0)	0.0	(559.3)	(323.7)	7.067	7.067	(22,875.24)
RELIANT	May-00 SCH.-Ja	883.0	0.0	444.3	438.7	6.535	6.535	28,667.35
TALLAHASSEE	May-00 SCH.-Ja	(724.0)	0.0	(302.9)	(421.1)	7.558	7.558	(31,828.72)
TALLAHASSEE	May-00 SCH.-Ja	724.0	0.0	414.4	309.6	9.566	9.566	29,615.71
AQUILA	May-00 SCH.-Ja	(1,962.0)	0.0	(1,363.0)	(599.0)	8.479	8.479	(50,789.36)
AQUILA	May-00 SCH.-Ja	1,962.0	0.0	1,273.6	688.4	7.795	7.795	53,658.02
OKEELANTA	May-00 SCH.-Ja	(851.0)	0.0	(423.6)	(427.4)	5.955	5.955	(25,453.63)
OKEELANTA	May-00 SCH.-Ja	851.0	0.0	656.5	194.5	7.778	7.778	15,127.68
KOCH	May-00 SCH.-Ja	(2,020.0)	0.0	(1,170.8)	(849.2)	7.146	7.146	(60,687.78)
KOCH	May-00 SCH.-Ja	2,020.0	0.0	1,144.3	875.7	6.016	6.016	52,681.92
MORGAN STANLEY	May-00 SCH.-Ja	(1,743.0)	0.0	(1,552.3)	(190.7)	11.123	11.123	(21,210.99)
MORGAN STANLEY	May-00 SCH.-Ja	1,743.0	0.0	1,453.3	289.7	7.500	7.500	21,727.99
TOTAL ADJUSTMENTS		(1,266.0)	0.0	(1,056.5)	(209.5)	118.607	118.607	(248,482.56)

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JUNE 2000

SCHEDULE A9

(1) URCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:									
VARIOUS		COGEN.	33,875.0	0.0	0.0	33,875.0	2.489	2.489	843,200.00
TOTAL		-	33,875.0	0.0	0.0	33,875.0	2.489	2.489	843,200.00
ACTUAL:									
IMC-AGRICO-NICHOLS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE		COGEN.	4,593.0	0.0	0.0	4,593.0	2.183	2.183	100,285.49
MULBERRY PHOSPHATES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	1,260.0	0.0	0.0	1,260.0	3.414	3.414	43,014.01
HILLSBOROUGH COUNTY		COGEN.	16,290.0	0.0	0.0	16,290.0	2.176	2.176	354,541.61
CARGILL MILLPOINT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.		COGEN.	2,056.0	0.0	0.0	2,056.0	3.444	3.444	70,801.10
FARMLAND HYDRO LP		COGEN.	749.0	0.0	0.0	749.0	3.083	3.083	23,091.78
IMC-AGRICO-S. PIERCE		COGEN.	184.0	0.0	0.0	184.0	4.354	4.354	8,012.02
AUBURNDALE POWER PARTNERS		COGEN.	3,957.0	0.0	0.0	3,957.0	3.683	3.683	145,751.58
ORANGE COGENERATION L.P.		COGEN.	5,543.0	0.0	0.0	5,543.0	2.166	2.166	120,070.88
CUTRALE CITRUS		COGEN.	9.0	0.0	0.0	9.0	2.843	2.843	255.85
AS AVAILABLE ASSIGNMENT		COGEN.	0.0	0.0	661.6	(661.6)	5.121	5.121	(33,879.41)
SUB-TOTAL FOR JUNE	2000	-	34,641.0	0.0	661.6	33,979.4	2.448	2.448	831,944.91
ADJUSTMENTS TO PRIOR MONTHS									
IMC-AGRICO-NICHOLS		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
McKAY BAY REFUSE	Apr-00	COGEN.	(3,876.0)	0.0	0.0	(3,876.0)	2.005	2.005	(77,726.37)
			3,876.0	0.0	0.0	3,876.0	2.018	2.018	78,205.20
MULBERRY PHOSPHATES INC.		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
CARGILL RIDGEWOOD		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
IMC-AGRICO-NEW WALES		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
HILLSBOROUGH COUNTY	Apr-00	COGEN.	(17,947.0)	0.0	0.0	(17,947.0)	2.009	2.009	(360,488.09)
			17,947.0	0.0	0.0	17,947.0	2.021	2.021	362,719.10
CARGILL MILLPOINT		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
CF INDUSTRIES INC.		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
FARMLAND HYDRO LP		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
IMC-AGRICO-S. PIERCE		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
AUBURNDALE POWER PARTNE	Apr-00	COGEN.	(463.0)	0.0	0.0	(463.0)	2.370	2.370	(10,972.98)
			431.0	0.0	0.0	431.0	2.254	2.254	9,716.53
ORANGE COGENERATION L.P.	Apr-00	COGEN.	(7,590.0)	0.0	0.0	(7,590.0)	2.015	2.015	(152,932.03)
			7,590.0	0.0	0.0	7,590.0	2.033	2.033	154,270.73
CUTRALE CITRUS		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
AS AVAILABLE ASSIGNMENT	Apr-00	COGEN.		0.0	(180.0)	180.0	3.173	3.173	5,710.91
				0.0	178.0	(178.0)	3.160	3.160	(5,624.85)
AS AVAILABLE ASSIGNMENT	May-00	COGEN.		0.0	(778.0)	778.0	4.797	4.797	37,317.22
				0.0	844.0	(844.0)	4.949	4.949	(41,769.16)
SUB-TOTAL FOR ADJUSTMENTS			(32.0)	0.0	64.0	(96.0)	1.639	1.639	(1,573.79)
GRAND TOTAL			34,609.0	0.0	725.6	33,883.4	2.451	2.451	830,371.12
CURRENT MONTH:									
DIFFERENCE		-	734.0	0.0	725.6	8.4	(0.038)	(0.038)	(12,828.88)
DIFFERENCE %		-	2.2	0.0	0.0	0.0	(1.5)	(1.5)	(1.5)
PERIOD TO DATE:									
ACTUAL			184,044.0	0.0	2,234.2	181,809.8	2.134	2.134	3,879,579.07
ESTIMATED			198,950.0	0.0	0.0	198,950.0	2.087	2.087	4,153,000.00
DIFFERENCE		-	(14,906.0)	0.0	2,234.2	(17,140.2)	0.047	0.047	(273,420.93)
DIFFERENCE %		-	(7.5)	0.0	0.0	(8.6)	2.3	2.3	(6.6)

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JUNE 2000

SCHEDULE A9

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	COST IF GENERATED (A) cents/KWH	COST IF GENERATED (B) $	FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	30,371.0	5.939	1,803,600.00	6.998	2,125,400.00	321,800.00
TOTAL	-	30,371.0	5.939	1,803,600.00	6.998	2,125,400.00	321,800.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL	-	0.0	0.000	0.00	0.000	0.00	0.00
CURRENT MONTH:							
DIFFERENCE	-	(30,371.0)	(5.939)	(1,803,600.00)	(6.998)	(2,125,400.00)	(321,800.00)
DIFFERENCE %	-	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)
PERIOD TO DATE:							
ACTUAL		0.0	0.000	(10,512.45)	0.000	0.00	10,512.45
ESTIMATED		123,676.0	4.437	5,487,100.00	5.637	6,971,600.00	1,484,500.00
DIFFERENCE	-	(123,676.0)	(4.437)	(5,497,612.45)	(5.637)	(6,971,600.00)	(1,473,987.55)
DIFFERENCE %	-	(100.0)	(100.0)	(100.2)	(100.0)	(100.0)	(99.3)

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

JULY 2000

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: JULY , 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	36,850,309	38,363,834	(1,513,525)	(3.9)	1,676,032	1,730,156	(54,124)	(3.1)	2.19866	2.21736	(0.01870)	(0.8)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (FLMeade/Wauch. Wheeling Losses)	(6,530)	(4,000)	(2,530)	63.3	1,676,032 a)	1,730,156 a)	(54,124)	(3.1)	(0.00039)	(0.00023)	(0.00016)	69.6
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,676,032 a)	1,730,156 a)	(54,124)	(3.1)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,676,032 a)	1,730,156 a)	(54,124)	(3.1)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	36,843,779	38,359,834	(1,516,055)	(4.0)	1,676,032	1,730,156	(54,124)	(3.1)	2.19827	2.21713	(0.01886)	(0.9)
6. Fuel Cost of Purchased Power - Firm (A7)	13,522,470	12,646,200	876,270	6.9	215,095	234,796	(19,701)	(8.4)	6.28674	5.38604	0.90070	16.7
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	323,800	(323,800)	(100.0)	0	4,925	(4,925)	(100.0)	0.00000	6.57462	(6.57462)	(100.0)
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 a)	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	1,077,356	974,800	102,556	10.5	37,787	36,871	1,116	3.0	2.85113	2.65823	0.19290	7.3
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	14,599,826	13,944,800	655,026	4.7	252,882	276,392	(23,510)	(8.5)	5.77337	5.04530	0.72807	14.4
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,928,914	2,006,548	(77,634)	(3.9)				
14. Fuel Cost of Economy Sales (A6)	0	2,568,600	(2,568,600)	(100.0)	0	64,490	(64,490)	(100.0)	0.00000	3.98294	(3.98294)	(100.0)
15. Gain on Economy Sales - 80% (A6)	0	1,744,900	(1,744,900)	(100.0)	0 a)	64,490 a)	(64,490)	(100.0)	0.00000	2.70569	(2.70569)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	1	0	1	0.0	0	0	0	0.0	#DIV/0!	0.00000	#DIV/0!	0.0
17. Fuel Cost of Sch. D Juriscl. Sales (A6)	98,448	137,300	(40,852)	(29.8)	4,185	5,750	(1,565)	(27.2)	2.30461	2.38783	(0.08322)	(3.5)
18. Fuel Cost of Sch. G Juriscl. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Juriscl. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	1,508,195	1,155,900	350,295	30.3	60,695	49,915	10,780	21.6	2.48156	2.31574	0.16584	7.2
21. Fuel Cost of Other Power Sales (A6)	2,756,924	2,014,564	742,360	36.8	120,475	111,600	8,875	8.0	2.28838	1.80516	0.48322	26.8
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	4,359,568	7,621,264	(3,261,696)	(42.8)	185,355	231,755	(46,400)	(20.0)	2.35201	3.28850	(0.93649)	(28.5)
23. Net Inadvertant Interchange					649	0	649	0.0				
24. Wheeling Rec'd. less Wheeling Del'd.					1,238	0	1,238	0.0				
25. Interchange and Wheeling Losses					2,331	3,500	(1,169)	(33.4)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	47,084,037	44,683,370	2,400,667	5.4	1,743,115	1,771,293	(28,178)	(1.6)	2.70114	2.52264	0.17850	7.1
27. Net Unbilled	1,086,005 (a)	1,233,416 (a)	(147,411)	(12.0)	45,089	50,259	(5,170)	(10.3)	0.06769	0.07427	(0.00658)	(8.9)
28. Company Use	108,315 (a)	98,165 (a)	8,150	8.3	4,414	4,000	414	10.4	0.00683	0.00591	0.00072	12.2
29. T & D Losses	2,148,381 (a)	1,380,884 (a)	767,497	55.6	89,197	56,268	32,929	58.5	0.13390	0.08315	0.05075	61.0
30. System KWH Sales	47,084,037	44,683,370	2,400,667	5.4	1,604,415	1,660,766	(56,351)	(3.4)	2.93465	2.69053	0.24412	9.1
31. Wholesale KWH Sales	(2,506,400)	(1,717,036)	(789,361)	46.0	(85,407)	(63,818)	(21,589)	33.8	2.93465	2.69052	0.24413	9.1
32. Jurisdictional KWH Sales	44,577,637	42,966,331	1,611,306	3.8	1,519,008	1,596,948	(77,940)	(4.9)	2.93485	2.69053	0.24412	9.1
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	44,607,950	42,995,548	1,612,402	3.8	1,519,008	1,596,948	(77,940)	(4.9)	2.93665	2.69236	0.24429	9.1
35. Peabody Coal Contract Buy-Out Amort. Juriscl.	341,575	346,916	(5,341)	(1.5)	1,519,008	1,596,948	(77,940)	(4.9)	0.02249	0.02172	0.00077	3.5
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	1,519,008	1,596,948	(77,940)	(4.9)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	1,519,008	1,596,948	(77,940)	(4.9)	0.00000	0.00000	0.00000	0.0
36. True-up *	2,684,371	305,574	2,378,797	778.5	1,519,008	1,596,948	(77,940)	(4.9)	0.17672	0.01913	0.15759	823.8
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	47,633,896	43,648,038	3,985,858	9.1	1,519,008	1,596,948	(77,940)	(4.9)	3.13586	2.73322	0.40264	14.7
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.13812	2.73519	0.40293	14.7
40. GPIF * (Already Adjusted for Taxes)	(23,059)	(23,059)	0	0.0	1,519,008	1,596,948	(77,940)	(4.9)	(0.00152)	(0.00144)	(0.00008)	5.8
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	47,610,837	43,624,979	3,985,858	9.1	1,519,008	1,596,948	(77,940)	(4.9)	3.13660	2.73375	0.40285	14.7
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									3.137	2.734	0.403	14.7

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: JULY, 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUN	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	203,359,985	209,892,810	(6,532,825)	(3.1)	10,099,689	10,238,385	(138,697)	(1.4)	2.01353	2.05006	(0.03653)	(1.8)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses	(29,353)	(28,000)	(1,353)	4.8	10,099,689	a) 10,238,385 a)	(138,697)	(1.4)	(0.00029)	(0.00027)	(0.00002)	7.4
4b. Adjustments to Fuel Cost	0	0	0	0.0	10,099,689	a) 10,238,385 a)	(138,697)	(1.4)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	(79)	0	(79)	0.0	10,099,689	a) 10,238,385 a)	(138,697)	(1.4)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	203,330,553	209,864,810	(6,534,257)	(3.1)	10,099,689	10,238,385	(138,697)	(1.4)	2.01324	2.04978	(0.03654)	(1.8)
6. Fuel Cost of Purchased Power - Firm (A7)	51,026,879	35,600,300	15,426,579	43.3	1,062,106	743,129	318,979	42.9	4.80430	4.79059	0.01371	0.3
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	(10,512)	5,810,900	(5,821,412)	(100.2)	0	126,601	(126,601)	(100.0)	#DIV/0!	4.51655	#DIV/0!	#DIV/0!
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	4,956,935	5,127,800	(170,865)	(3.3)	219,597	235,621	(16,024)	(6.8)	2.25729	2.17629	0.08100	3.7
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	55,973,302	46,539,000	9,434,302	20.3	1,281,705	1,107,351	174,354	15.7	4.36710	4.20273	0.16437	3.9
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					11,381,394	11,345,736	35,658	0.3				
14. Fuel Cost of Economy Sales (A6)	(1,667)	4,194,000	(4,195,667)	(100.0)	0	130,503	(130,503)	(100.0)	#DIV/0!	3.21372	#DIV/0!	#DIV/0!
15. Gain on Economy Sales - 80% (A6)	0	2,217,320	(2,217,320)	(100.0)	0	130,503 a)	(130,503)	(100.0)	0.00000	1.69906	(1.69906)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	190,769	295,300	(104,531)	(35.4)	12,186	19,153	(6,967)	(36.4)	1.56548	1.54160	0.02388	1.5
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	849,423	851,000	(1,577)	(0.2)	39,770	40,531	(761)	(1.9)	2.13584	2.09963	0.03621	1.7
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	5,432,241	3,681,800	1,750,641	47.6	230,935	161,515	69,420	43.0	2.35228	2.27942	0.07286	3.2
21. Fuel Cost of Other Power Sales (A6)	16,424,679	13,820,468	2,604,211	18.8	776,523	766,800	9,723	1.3	2.11516	1.80236	0.31280	17.4
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	22,695,425	25,059,688	(2,164,263)	(8.6)	1,059,414	1,118,502	(59,088)	(5.3)	2.16114	2.24047	(0.07933)	(3.5)
23. Net Inadvertant Interchange					2,077	0	2,077	0.0				
24. Wheeling Rec'd. less Wheeling Del'd.					4,399	0	4,399	0.0				
25. Interchange and Wheeling Losses					14,909	16,900	(1,991)	(11.8)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	236,408,430	231,344,122	5,064,308	2.2	10,313,547	10,210,334	103,213	1.0	2.29221	2.26578	0.02643	1.2
27. Net Unbilled	3,534,354 (a)	3,317,274 (a)	217,080	6.5	159,995	149,976	10,019	6.7	0.03657	0.03454	0.00203	5.9
28. Company Use	640,268 (a)	619,324 (a)	20,944	3.4	28,984	28,000	984	3.5	0.00663	0.00645	0.00018	2.8
29. T & D Losses	10,174,483 (a)	9,462,844 (a)	711,619	7.5	460,583	427,821	32,762	7.7	0.10528	0.09852	0.00676	6.9
30. System KWH Sales	236,408,430	231,344,122	5,064,308	2.2	9,683,985	9,604,537	59,448	0.6	2.44628	2.40870	0.03758	1.6
31. Wholesale KWH Sales	(8,906,196)	(5,098,785)	(3,807,413)	74.7	(352,944)	(199,742)	(153,202)	76.7	2.52340	2.55269	(0.02929)	(1.1)
32. Jurisdictional KWH Sales	227,502,232	226,245,337	1,256,895	0.6	9,311,041	9,404,795	(93,755)	(1.0)	2.44336	2.40564	0.03772	1.6
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	227,656,933	226,399,183	1,257,750	0.6	9,311,041	9,404,795	(93,755)	(1.0)	2.44502	2.40727	0.03775	1.6
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	2,487,526	2,529,154	(41,628)	(1.6)	9,311,041	9,404,795	(93,755)	(1.0)	0.02672	0.02689	(0.00017)	(0.6)
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	9,311,041	9,404,795	(93,755)	(1.0)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	9,311,041	9,404,795	(93,755)	(1.0)	0.00000	0.00000	0.00000	0.0
36. True-up *	6,896,612	2,139,018	4,757,594	222.4	9,311,041	9,404,795	(93,755)	(1.0)	0.07407	0.02274	0.05133	225.7
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	237,041,071	231,067,355	5,973,716	2.6	9,311,041	9,404,795	(93,755)	(1.0)	2.54581	2.45691	0.08890	3.6
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.54764	2.45868	0.08896	3.6
40. GPIF * (Already Adjusted for Taxes)	(161,413)	(161,413)	0	0.0	9,311,041	9,404,795	(93,755)	(1.0)	(0.00173)	(0.00172)	(0.00001)	0.6
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	236,879,658	230,905,942	5,973,716	2.6	9,311,041	9,404,795	(93,755)	(1.0)	2.54581	2.45696	0.08885	3.6
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.546	2.457	0.089	3.6

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2000

SCHEDULE A2
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	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	36,850,309	38,363,834	(1,513,525)	(3.9)	203,359,985	209,892,810	(6,532,825)	(3.1)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	4,359,568	7,621,264	(3,261,696)	(42.8)	22,895,425	25,059,688	(2,164,263)	(8.6)
3. FUEL COST OF PURCHASED POWER	13,522,470	12,646,200	876,270	6.9	51,026,879	35,600,300	15,426,579	43.3
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	1,077,356	974,800	102,556	10.5	4,956,935	5,127,800	(170,865)	(3.3)
4. ENERGY COST OF ECONOMY PURCHASES	0	323,800	(323,800)	0.0	(10,512)	5,810,900	(5,821,412)	(100.2)
5. TOTAL FUEL & NET POWER TRANSACTION	47,090,567	44,687,370	2,403,197	5.4	236,437,862	231,372,122	5,065,740	2.2
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(6,530)	(4,000)	(2,530)	63.3	(29,353)	(28,000)	(1,353)	4.8
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST	0	0	0	0.0	(79)	0	(79)	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	47,084,037	44,683,370	2,400,667	5.4	236,408,430	231,344,122	5,064,308	2.2
* INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,519,008	1,596,948	(77,940)	(4.9)	9,311,041	9,404,795	(93,754)	(1.0)
2. NONJURISDICTIONAL SALES	85,407	63,818	21,589	33.8	352,944	199,742	153,202	76.7
3. TOTAL SALES	1,604,415	1,660,766	(56,351)	(3.4)	9,663,985	9,604,537	59,448	0.6
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9467675	0.9615732	(0.0148057)	(1.5)	0.9634784	0.9792034	(0.0157250)	(1.6)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	37,552,801	36,793,509	759,292	2.1	217,232,756	216,395,196	837,560	0.4
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	(2,684,371)	(305,574)	(2,378,797)	778.5	(6,896,612)	(2,139,018)	(4,757,594)	222.4
b. INCENTIVE PROVISION	23,059	23,059	0	0.0	161,413	161,413	0	0.0
c. TRANSITION ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
d. OTHER ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	34,891,489	36,510,994	(1,619,505)	(4.4)	210,497,557	214,417,591	(3,920,034)	(1.8)
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	47,084,037	44,683,370	2,400,667	5.4	236,408,430	231,344,122	5,064,308	2.2
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B-4)	0.9467675	0.9615732	(0.0148057)	(1.5)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	44,577,637	42,966,331	1,611,306	3.8	227,502,232	226,245,337	1,256,895	0.6
6A.JURISDIC. LOSS MULTIPLIER	1.00068	1.00068	0.0000	0.0	NA	NA	-	-
6B. (LINE 6 x LINE 6A)	44,607,950	42,995,548	1,612,402	3.8	227,656,933	226,399,183	1,257,750	0.6
6C.PEABODY COAL CONTR. BUY-OUT AMORT.	360,780	360,780	0	0.0	2,578,611	2,578,611	0	0.0
6D.(LINE 6C x LINE 5) PB. JURISD.	341,575	346,916	(5,341)	(1.5)	2,487,526	2,529,154	(41,628)	(1.6)
6E.OTHER (SPARE INPUT #1)	0	0	0	0.0	0	0	0	0.0
6F. OIL BELOW THE DISCHARGE VALVE	0	0	0	0.0	0	0	0	0.0
6G. OTHER (SPARE INPUT #2)	0	0	0	0.0	0	0	0	0.0
6H. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. 6B+6D+6E+6F+6G)	44,949,525	43,342,464	1,607,061	3.7	230,144,459	228,928,337	1,216,122	0.5
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6H)	(10,058,036)	(6,831,470)	(3,226,566)	47.2	(19,646,902)	(14,510,746)	(5,136,156)	35.4
8. INTEREST PROVISION FOR THE MONTH	(118,678)	(114,104)	(4,574)	4.0	(501,509)	(314,891)	(186,618)	59.3
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(20,470,672)	(29,530,592)	9,059,920	(30.7)	NOT APPLICABLE			
9a.DEFERRED TRUE-UP BEGINNING OF PERIO	2,381,673	7,879,936	(5,498,263)	(69.8)	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	2,684,371	305,574	2,378,797	778.5	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	(25,581,342)	(28,290,656)	2,709,314	(9.6)	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	(18,088,999)	(21,650,656)	3,561,657	(16.5)	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	(25,462,664)	(28,176,552)	2,713,888	(9.6)	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(43,551,663)	(49,827,208)	6,275,545	(12.6)	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	(21,775,831)	(24,913,604)	3,137,773	(12.6)	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	6.580	5.500	1.080	19.6	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	6.500	5.500	1.000	18.2	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	13.080	11.000	2.080	18.9	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	6.540	5.500	1.040	18.9	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.545	0.458	0.087	19.0	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	(118,678)	(114,104)	(4,574)	4.0	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JULY 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
FUEL COST OF SYSTEM NET GENERATION ($)								
1 HEAVY OIL	2,129,077	3,118,918	(989,841)	(31.7)	6,976,417	7,735,997	(759,580)	(9.8)
2 LIGHT OIL	2,430,551	3,644,750	(1,214,199)	(33.3)	4,610,428	7,935,903	(3,325,475)	(41.9)
3 COAL	31,874,302	31,600,166	74,136	0.2	191,156,781	194,220,910	(3,064,149)	(1.6)
4 NATURAL GAS	616,379	0	616,379	0.0	616,379	0	616,379	0.0
5 NUCLEAR	0	0	0	0.0	0	0	0	0.0
6 OTHER	0	0	0	0.0	0	0	0	0.0
7 TOTAL ($)	36,850,309	38,363,834	(1,513,525)	(3.9)	203,359,985	209,892,810	(6,532,825)	(3.1)
SYSTEM NET GENERATION (MWH)								
8 HEAVY OIL	32,991	71,703	(38,712)	(54.0)	121,318	175,002	(53,684)	(30.7)
9 LIGHT OIL	30,074	26,034	4,040	15.5	66,586	75,277	(8,691)	(11.5)
10 COAL	1,605,567	1,632,419	(26,852)	(1.6)	9,904,385	9,988,106	(83,722)	(0.8)
11 NATURAL GAS	7,400	0	7,400	0.0	7,400	0	7,400	0.0
12 NUCLEAR	0	0	0	0.0	0	0	0	0.0
13 OTHER	0	0	0	0.0	0	0	0	0.0
14 TOTAL (MWH)	1,676,032	1,730,156	(54,124)	(3.1)	10,099,689	10,238,385	(138,697)	(1.4)
UNITS OF FUEL BURNED								
15 HEAVY OIL (BBL)	76,654	174,667	(98,013)	(56.1)	285,661	446,202	(160,541)	(36.0)
16 LIGHT OIL (BBL)	70,817	96,232	(25,415)	(26.4)	141,592	237,644	(96,052)	(40.4)
17 COAL (TON)	743,440	742,149	1,291	0.2	4,520,086	4,506,868	13,218	0.3
18 NATURAL GAS (MCF)	93,493	0	93,493	0.0	93,493	0	93,493	0.0
19 NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20 OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
BTUS BURNED (MMBTU)								
21 HEAVY OIL	486,289	1,104,068	(617,779)	(56.0)	1,812,987	2,820,446	(1,007,459)	(35.7)
22 LIGHT OIL	409,258	439,842	(30,584)	(7.0)	807,809	916,572	(108,763)	(11.9)
23 COAL	16,957,698	17,246,870	(289,172)	(1.7)	103,195,034	104,249,094	(1,054,060)	(1.0)
24 NATURAL GAS	90,902	0	90,902	0.0	90,902	0	90,902	0.0
25 NUCLEAR	0	0	0	0.0	0	0	0	0.0
26 OTHER	0	0	0	0.0	0	0	0	0.0
27 TOTAL (MMBTU)	17,944,147	18,790,780	(846,633)	(4.5)	105,906,732	107,986,112	(2,079,380)	(1.9)
GENERATION MIX (% MWH)								
28 HEAVY OIL	1.97	4.14	(2.17)	-	1.20	1.71	(0.51)	-
29 LIGHT OIL	1.79	1.50	0.29	-	0.66	0.74	(0.08)	-
30 COAL	95.80	94.35	1.45	-	98.07	97.56	0.51	-
31 NATURAL GAS	0.44	0.00	0.44	-	0.07	0.00	0.07	-
32 NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33 OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34 TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
FUEL COST PER UNIT								
35 HEAVY OIL ($/BBL)	27.78	17.86	9.92	55.5	24.42	17.34	7.08	40.8
36 LIGHT OIL ($/BBL)	34.32	37.87	(3.55)	(9.4)	32.56	33.39	(0.83)	(2.5)
37 COAL ($/TON)	42.61	42.58	0.03	0.1	42.29	43.09	(0.80)	(1.9)
38 NATURAL GAS ($/MCF)	6.59	0.00	6.59	0.0	6.59	0.00	6.59	0.0
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40 OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
FUEL COST PER MMBTU ($/MMBTU)								
41 HEAVY OIL	4.38	2.82	1.56	55.3	3.85	2.74	1.11	40.5
42 LIGHT OIL	5.94	8.29	(2.35)	(28.3)	5.71	8.66	(2.95)	(34.1)
43 COAL	1.87	1.83	0.04	2.2	1.85	1.86	(0.01)	(0.5)
44 NATURAL GAS	6.78	0.00	6.78	0.0	6.78	0.00	6.78	0.0
45 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47 TOTAL ($/MMBTU)	2.05	2.04	0.01	0.5	1.92	1.94	(0.02)	(1.0)

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JULY 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
BTU BURNED PER KWH (BTU/KWH)								
48 HEAVY OIL	14,740	15,398	(658)	(4.3)	14,944	16,117	(1,173)	(7.3)
49 LIGHT OIL	13,608	16,895	(3,287)	(19.5)	12,132	12,176	(44)	(0.4)
50 COAL	10,562	10,565	(3)	0.0	10,419	10,437	(18)	(0.2)
51 NATURAL GAS	12,284	0	12,284	0.0	12,284	0	12,284	0.0
52 NUCLEAR	0	0	0	0.0	0	0	0	0.0
53 OTHER	0	0	0	0.0	0	0	0	0.0
54 TOTAL (BTU/KWH)	10,706	10,861	(155)	(1.4)	10,486	10,547	(61)	(0.6)
GENERATED FUEL COST PER KWH (cents/KWH)								
55 HEAVY OIL	6.45	4.35	2.10	48.3	5.75	4.42	1.33	30.1
56 LIGHT OIL	8.08	14.00	(5.92)	(42.3)	6.92	10.54	(3.62)	(34.3)
57 COAL	1.97	1.94	0.03	1.5	1.93	1.94	(0.01)	(0.5)
58 NATURAL GAS	8.33	0.00	8.33	0.0	8.33	0.00	8.33	0.0
59 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61 TOTAL (cents/KWH)	2.20	2.22	(0.02)	(0.9)	2.01	2.05	(0.04)	(2.0)

SCHEDULE A4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD/MONTH OF: JULY 2000

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPC. FACTO (%)	EQUIV. AVAIL. FACTO (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COS PER KWH (cents /KWH)	COST OF FUEL ($/UNIT)
H.P.#1	30	4,532	20.3	100.0	56.6	-	HVY.OIL	-	-	-	-	-	-
H.P.#2	30	5,386	24.1	100.0	59.6	-	HVY.OIL	-	-	-	-	-	-
H.P.#3	30	374	1.7	10.8	56.5	-	HVY.OIL	-	-	-	-	-	-
H.P.#4	39	6,903	23.8	100.0	55.7	-	HVY.OIL	-	-	-	-	-	-
H.P.#5	67	6,326	12.7	64.8	54.5	-	HVY.OIL	-	-	-	-	-	-
H.P. STATION	196	23,521	16.1	74.3	56.1	17,027	HVY.OIL	62,977	6,359,293	400,489.2	1,735,005	7.38	27.55
GAN.#1	114	47,787	56.3	83.4	63.2	11,754	COAL	23,833	23,567,679	561,688.5	909,557	1.90	38.16
GAN.#2	98	48,190	66.1	88.8	73.3	12,259	COAL	25,579	23,095,461	590,758.8	976,191	2.03	38.16
GAN.#3	145	75,382	69.9	88.0	76.0	12,500	COAL	47,917	19,664,699	942,273.4	1,828,693	2.43	38.16
GAN.#4	159	87,113	73.6	94.6	76.6	12,093	COAL	54,678	19,266,780	1,053,469.0	2,086,718	2.40	38.16
GAN.#5	232	115,719	67.0	82.9	71.2	10,881	COAL	53,452	23,556,179	1,259,124.9	2,039,929	1.76	38.16
GAN.#6	372	124,711	45.1	54.8	77.8	10,789	COAL	54,693	24,510,460	1,345,452.7	2,094,924	1.68	38.16
GANNON STA.	1120	498,902	59.9	76.5	74.1	11,531	COAL	260,352	22,096,113	5,752,767.3	9,936,012	1.99	38.16
B.B.#1	416	186,220	60.2	70.4	80.6	10,510	COAL	79,390	24,651,700	1,957,098.5	3,398,057	1.82	42.80
B.B.#2	416	195,086	63.0	72.2	81.5	10,262	COAL	82,366	24,305,020	2,001,907.3	3,525,436	1.81	42.80
B.B.#3	433	258,674	80.3	93.1	83.4	9,912	COAL	106,697	24,029,440	2,563,869.2	4,566,853	1.77	42.80
B.B. 1 - 3	1265	639,980	68.0	78.8	81.9	10,192	COAL	268,453	24,298,015	6,522,875.0	11,490,346	1.80	42.80
B.B.#4	442	290,666	88.4	95.4	88.4	9,898	COAL	135,889	21,170,861	2,876,889.8	6,864,931	2.36	50.52
B.B. STA.	1707	930,646	73.3	83.1	83.5	10,100	COAL	404,342	23,247,065	9,399,764.8	18,355,277	1.97	45.40
SEB-PHIL. #1(HVY OIL)	17	4,400	34.8	90.9	81.6	9,750	HVY.OIL	6,839	6,272,891	42,900.3	197,050	4.48	28.81
SEB-PHIL. #2(HVY OIL)	17	5,070	40.1	91.5	93.0	8,462	HVY.OIL	6,838	6,273,808	42,900.3	197,022	3.89	28.81
SEB-PHILLIPS TOTAL	34	9,470	37.4	91.2	87.3	9,060	HVY.OIL	13,677	6,273,349	85,800.6	394,072	4.16	28.81
POLK #1 GASIFIER	250	176,019	94.6	96.4	98.0	10,256	COAL	78,746	22,924,000	1,805,165.5	3,383,013	1.92	42.96
POLK #1 CT (OIL)	225	2,199	1.3	100.0	51.2	8,760	LGT.OIL	3,671	5,395,295	19,263.9	123,141	5.60	34.49
POLK #1 TOTAL	250	178,218	95.9	99.5	96.9	10,237	-	-	-	1,824,429.4	3,506,154	1.97	-
POLK #2 CT (GAS)	150	7,400	6.6	71.8	30.3	12,284	GAS	93,493	972,290	90,902.0	616,379	8.33	6.59
POLK #2 CT (OIL)	150	10,632	9.5	87.4	69.6	12,947	LGT.OIL	23,869	5,767,090	137,652.7	823,196	7.74	34.49
POLK #2 TOTAL	150	18,032	16.1	79.6	45.5	12,675	-	-	-	228,554.7	1,439,575	7.98	-
POLK STATION TOTAL	400	196,250	65.9	92.0	77.6	10,461	-	-	-	2,052,984.1	4,945,729	2.52	-
GAN.C.T.#1	12	812	9.1	100.0	62.1	1,939	LGT.OIL	271	5,818,645	1,574.7	9,260	1.14	34.22
B.B.C.T.#1	12	857	9.6	100.0	65.0	18,648	LGT.OIL	2,747	5,818,700	15,981.7	93,979	10.97	34.22
B.B.C.T.#2	66	7,212	14.7	100.0	75.4	15,461	LGT.OIL	19,168	5,817,237	111,506.2	655,865	9.09	34.22
B.B.C.T.#3	66	8,362	17.0	100.0	79.2	14,743	LGT.OIL	21,192	5,817,234	123,278.6	725,110	8.67	34.22
C.T. TOTAL	156	17,243	14.9	100.0	76.7	14,634	LGT.OIL	43,377	5,817,337	252,341.2	1,484,214	8.61	34.22
TOT. COAL (GN,BB,POLK)	3077	1,605,567	70.1	81.7	81.3	10,562	COAL	743,440	22,809,783	16,957,697.6	31,674,302	1.97	42.61
SYSTEM	3,613	1,676,032	62.4	82.3	76.2	10,706	-	-	-	17,944,147.2	36,850,309	2.20	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS
NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2000

	CURRENT MONTH				PERIOD TO DATE			
HEAVY OIL (1)	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1 PURCHASES:								
2 UNITS (BBL)	102,613	174,667	(72,054)	(41.3)	324,493	400,114	(75,621)	(18.9)
3 UNIT COST ($/BBL)	30.25	18.01	12.24	68.0	27.18	17.00	10.18	59.9
4 AMOUNT ($)	3,103,542	3,145,543	(42,001)	(1.3)	8,819,021	6,801,708	2,017,313	29.7
5 BURNED:								
6 UNITS (BBL)	76,654	174,667	(98,013)	(56.1)	285,661	446,202	(160,541)	(36.0)
7 UNIT COST ($/BBL)	27.78	17.86	9.92	55.5	24.42	17.34	7.08	40.8
8 AMOUNT ($)	2,129,077	3,118,918	(989,841)	(31.7)	6,976,417	7,735,997	(759,580)	(9.8)
9 ENDING INVENTORY:								
10 UNITS (BBL)	129,091	81,135	47,956	59.1	129,091	81,135	47,956	59.1
11 UNIT COST ($/BBL)	27.89	18.16	9.73	53.6	27.89	18.16	9.73	53.6
12 AMOUNT ($)	3,600,590	1,473,758	2,126,832	144.3	3,600,590	1,473,758	2,126,832	144.3
13								
14 DAYS SUPPLY:	67	42	25	59.5	-	-	-	-
LIGHT OIL (2)								
15 PURCHASES:								
16 UNITS (BBL)	91,760	117,366	(25,606)	(21.8)	251,359	346,423	(95,064)	(27.4)
17 UNIT COST ($/BBL)	36.59	38.87	(2.28)	(5.9)	34.71	34.55	0.16	0.5
18 AMOUNT ($)	3,357,829	4,561,637	(1,203,808)	(26.4)	8,723,581	11,969,308	(3,245,727)	(27.1)
19 BURNED:								
20 UNITS (BBL)	70,817	96,232	(25,415)	(26.4)	141,592	237,644	(96,052)	(40.4)
21 UNIT COST ($/BBL)	34.32	37.87	(3.55)	(9.4)	32.56	33.39	(0.83)	(2.5)
22 AMOUNT ($)	2,430,551	3,644,750	(1,214,199)	(33.3)	4,610,428	7,935,903	(3,325,475)	(41.9)
23 ENDING INVENTORY:								
24 UNITS (BBL)	113,949	97,057	16,892	17.4	113,949	97,057	16,892	17.4
25 UNIT COST ($/BBL)	34.33	37.87	(3.54)	(9.3)	34.33	37.87	(3.54)	(9.3)
26 AMOUNT ($)	3,911,506	3,675,856	235,650	6.4	3,911,506	3,675,856	235,850	6.4
27								
28 DAYS SUPPLY: NORMAL	74	63	11	17.5	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	16	14	2	14.3	-	-	-	-
COAL (3)								
30 PURCHASES:								
31 UNITS (TONS)	696,961	796,000	(99,019)	(12.4)	4,705,492	4,368,200	337,292	7.7
32 UNIT COST ($/TON)	43.03	42.57	0.46	1.1	42.25	42.59	(0.34)	(0.8)
33 AMOUNT ($)	30,073,886	33,973,857	(3,899,971)	(11.5)	198,827,434	186,055,646	12,771,788	6.9
34 BURNED:								
35 UNITS (TONS)	743,440	742,149	1,291	0.2	4,520,086	4,506,868	13,218	0.3
36 UNIT COST ($/TON)	42.61	42.58	0.03	0.1	42.29	43.09	(0.80)	(1.9)
37 AMOUNT ($)	31,674,302	31,600,186	74,136	0.2	191,156,761	194,220,910	(3,064,149)	(1.6)
38 ENDING INVENTORY:								
39 UNITS (TONS)	962,422	987,507	(25,085)	(2.5)	962,422	987,507	(25,085)	(2.5)
40 UNIT COST ($/TON)	42.36	42.35	0.01	0.0	42.36	42.35	0.01	0.0
41 AMOUNT ($)	40,765,547	41,823,812	(1,058,265)	(2.5)	40,765,547	41,823,812	(1,058,265)	(2.5)
42								
43 DAYS SUPPLY:	41	42	(1)	(2.4)	-	-	-	-
NATURAL GAS								
44 PURCHASES:								
45 UNITS (MCF)	93,493	0	93,493	0.0	93,493	0	93,493	0.0
46 UNIT COST ($/MCF)	6.59	0.00	6.59	0.0	6.59	0.00	6.59	0.0
47 AMOUNT ($)	616,379	0	616,379	0.0	616,379	0	616,379	0.0
48 BURNED:								
49 UNITS (MCF)	93,493	0	93,493	0.0	0	0	0	0.0
50 UNIT COST ($/MCF)	6.59	0.00	6.59	0.0	0.00	0.00	0.00	0.0
51 AMOUNT ($)	616,379	0	616,379	0.0	0	0	0	0.0
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
56								
57 DAYS SUPPLY:	0	0	0	0.0	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2000

OTHER	CURRENT MONTH ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	PERIOD TO DATE ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
74 DAYS SUPPLY:	0	0	0	0.0	-	-	-	-

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	14,096
LUBE OIL	0
FUEL ANALYSIS	232
TOTAL	14,328

(2)
RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(12,710)	(435,062)
OTHER USAGE	(665)	(22,851)
TOTAL	(13,375)	(457,913)

(3)
RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	38,049
IGNITION #2 OIL	420,966
IGNITION PROPANE	3,192
AERIAL SURVEY ADJ.	(695,507)
ADDITIVES	(16,604)
TOTAL	(249,904)

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JULY 2000

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	64,490.0	0.0	64,490.0	4.183	7.575	2,704,000.00	4,886,100.00	1,744,900.00
VARIOUS	JURISDICTIONAL	SCH. -D	5,750.0	0.0	5,750.0	2.388	2.388	137,300.00	137,300.00	
VARIOUS	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPARATED	CONTRACT	49,915.0	0.0	49,915.0	2.316	3.258	1,155,900.00	1,626,400.00	
FMPA		SCH. -D	111,600.0	0.0	111,600.0	1.805	1.805	2,014,564.00	2,014,564.00	
VARIOUS	JURISDICTIONAL	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	231,755.0	0.0	231,755.0	2.694	3.738	6,011,764.00	8,663,364.00	1,744,900.00
LESS TRANSMISSION COSTS		-						0.00		
LESS VARIABLE O & M COSTS		-						(135,400.00)		
PLUS 80% OF ECON. ENERGY SALES PROFI		-						1,744,900.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INC		-								
80% OF ECON. ENERGY SALES PROFITS		-	231,755.0	0.0	231,755.0	3.289	3.738	7,621,264.00	8,663,364.00	1,744,900.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENRGY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
OGLETHORPE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENN. VALLEY AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEP. CONTRACT		60,695.0	0.0	60,695.0	2.366	3.231	1,454,252.20	1,961,055.45	
SEMINOLE ELECTRIC CO-OP PRE	JURISD.	SCH. -D	3,543.0	310.6	3,232.4	2.342	2.342	75,706.49	75,706.49	
SEMINOLE ELECTRIC CO-OP HAR	JURISD.	SCH. -D	953.0	0.0	953.0	2.176	2.176	20,741.83	20,741.83	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JULY 2000

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) ---cents/KWH--- (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
AQUILLA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
THE ENERGY AUTH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
MORGAN STANLEY	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA		SCH. -D	102,055.0	0.0	102,055.0	1.896	1.896	1,934,627.04	1,934,627.04	
HARDEE POWER PART. TO FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR.& LT.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO JACKSONVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KISSIMMEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ORLANDO		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO SEMINOLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FT. PIERCE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LK. WORTH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ENERGY AUTHORI		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO AQUILLA		SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PART. TO ORLANDO		SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PART. TO FLA. PWR. CORP.		SCH. -MB	353.0	0.0	353.0	5.218	5.218	18,419.20	18,419.20	
HARDEE POWER PART. TO FLA. PWR.& LT.		SCH. -MB	285.0	0.0	285.0	3.789	3.789	10,797.86	10,797.86	
SEMINOLE ELECTRIC CO-OP		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JULY 2000

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -MB	2,597.0	0.0	2,597.0	6.142	6.142	159,512.63	159,512.63	
FLA. PWR. & LIGHT	JURISD.	SCH. -MB	13,766.0	0.0	13,766.0	3.250	3.250	447,403.66	447,403.66	
CITY OF LAKELAND	JURISD.	SCH. -MB	500.0	0.0	500.0	2.509	2.509	12,542.62	12,542.62	
ORLANDO UTIL. COMM.	JURISD.	SCH. -MB	238.0	0.0	238.0	4.993	4.993	11,882.94	11,882.94	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -MB	92.0	0.0	92.0	9.772	9.772	8,990.26	8,990.26	
CARGILL ALLIANT	JURISD.	SCH. -MB	204.0	0.0	204.0	6.958	6.958	14,194.66	14,194.66	
CITY OF HOMESTEAD	JURISD.	SCH. -MB	10.0	0.0	10.0	17.360	17.360	1,736.03	1,736.03	
ORLANDO UTIL. COMM.	JURISD.	STEAM-A	373.0	0.0	373.0	36.681	36.681	136,818.36	136,818.36	
ADJ. TO PREVIOUS MONTHS	MON/YR TYP	SCHED.								
HARDEE POWER PARTNERS ES	6/00 SEPAR.	CONTRACT	(57,080.0)	0.0	(57,080.0)	2.305	3.123	(1,315,684.00)	(1,782,606.40)	
HARDEE POWER PARTNERS ACT	6/00 SEPAR.	CONTRACT	57,080.0	0.0	57,080.0	2.396	3.231	1,367,636.80	1,844,254.80	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			4,496.0	310.6	4,185.4	2.304	2.304	96,448.32	96,448.32	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.			60,695.0	0.0	60,695.0	2.482	3.333	1,506,195.00	2,022,701.85	
SUB-TOTAL OTHER D POWER SALES			102,055.0	0.0	102,055.0	1.896	1.896	1,934,627.04	1,934,627.04	
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE MB POWER SALES-JURISD.			18,047.0	0.0	18,047.0	3.798	3.798	685,478.78	685,478.78	
SUB-TOTAL OTHER POWER SALES			373.0	0.0	373.0	36.681	36.681	136,818.36	136,818.36	
TOTAL INCLUDING VARIABLE O & M COSTS			185,666.0	310.6	185,355.4	2.352	2.631	4,359,567.50	4,876,074.35	0.00
LESS VARIABLE O & M COSTS								0.00		
LESS VARIABLE O & M COSTS - HARDEE								0.00		
LESS TRANSMISSION COSTS SCH. D (SEP.)								0.00		
PLUS 80% OF ECON. ENERGY SALES PROFITS		-						0.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-	185,666.0	310.6	185,355.4	2.352	2.631	4,359,567.50	4,876,074.35	0.00
CURRENT MONTH:										
DIFFERENCE		-	(46,089.0)	310.6	(46,399.6)	(0.937)	(1.107)	(3,261,696.50)	(3,787,289.65)	(1,744,900.00)
DIFFERENCE %		-	(19.9)	0.0	(20.0)	(28.5)	(29.6)	(42.8)	(43.7)	(100.0)
PERIOD TO DATE:										
ACTUAL		-	1,064,145.0	4,731.2	1,059,413.8	2.161	2.348	22,895,423.18	24,870,604.49	0.00
ESTIMATED		-	1,118,502.0	0.0	1,118,502.0	2.240	2.456	25,059,688.00	27,466,168.00	2,217,320.00
DIFFERENCE		-	(54,357.0)	4,731.2	(59,088.2)	(0.079)	(0.108)	(2,164,264.82)	(2,595,563.51)	(2,217,320.00)
DIFFERENCE %		-	(4.9)	0.0	(5.3)	(3.5)	(4.4)	(8.6)	(9.5)	(100.0)

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. SEC 60% OR $8,436.86 HAS BEEN EXCLUDED.

SCHEDULE A7

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH JULY 2000

(1)		(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM		TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:									
VARIOUS		EMER.	57,625.0	0.0	27,675.0	29,950.0	16.059	16.059	4,809,700.00
HARDEE POWER PARTNERS		IPP	146,970.0	0.0	0.0	146,970.0	3.555	3.555	5,225,400.00
VARIOUS		OTHER	57,876.0	0.0	0.0	57,876.0	4.512	4.512	2,611,100.00
TOTAL		-	262,471.0	0.0	27,675.0	234,796.0	5.386	5.386	12,646,200.00
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	116,390.0	0.0	0.0	116,390.0	5.188	5.188	6,038,289.74
HARDEE PWR. PART.-OTHERS		IPP	638.0	0.0	0.0	638.0	3.698	3.698	23,592.49
FLA. POWER CORP.		SCH.-Ja	742.0	0.0	455.0	287.0	11.521	11.521	33,065.00
FLA. POWER CORP.		SCH.-Jc	8,985.0	0.0	0.0	8,985.0	4.650	4.650	417,772.00
FLA. POWER & LIGHT		SCH.-Ja	2,981.0	0.0	1,544.2	1,436.8	10.772	10.772	154,768.35
FLA. POWER & LIGHT		SCH.-Jc	12,734.0	0.0	0.0	12,734.0	5.485	5.485	698,481.00
CITY OF LAKELAND		SCH.-Ja	10,230.0	0.0	6,018.2	4,211.8	21.400	21.400	901,318.51
CITY OF LAKELAND		SCH.-Jc	8,934.0	0.0	0.0	8,934.0	7.176	7.176	641,117.50
ORLANDO		SCH.-Ja	3,801.0	0.0	1,679.0	2,122.0	11.131	11.131	236,202.88
ORLANDO		SCH.-Jc	15,649.0	0.0	0.0	15,649.0	8.915	8.915	1,395,097.50
ENTERGY MARKETING		SCH.-Jc	273.0	0.0	0.0	273.0	6.314	6.314	17,236.00
THE ENERGY AUTH.		SCH.-Ja	4,553.0	0.0	2,306.9	2,246.1	12.506	12.506	280,897.22
THE ENERGY AUTH.		SCH.-Jc	3,770.0	0.0	0.0	3,770.0	9.191	9.191	346,487.32
RELIANT		SCH.-Ja	30.0	0.0	30.0	0.0	0.000	0.000	0.00
RELIANT		SCH.-Jc	75.0	0.0	0.0	75.0	5.000	5.000	3,750.00
REEDY CREEK		SCH.-Ja	6.0	0.0	0.0	6.0	6.200	6.200	372.00
REEDY CREEK		SCH.-Jc	84.0	0.0	0.0	84.0	4.117	4.117	3,458.00
TALLAHASSEE		SCH.-Ja	810.0	0.0	472.4	337.6	15.137	15.137	51,102.53
TALLAHASSEE		SCH.-Jc	3,464.0	0.0	0.0	3,464.0	6.866	6.866	237,853.74
AQUILLA		SCH.-Ja	205.0	0.0	60.0	145.0	9.097	9.097	13,190.74
AQUILLA		SCH.-Jc	1,508.0	0.0	0.0	1,508.0	7.215	7.215	108,803.87
MORGAN STANLEY		SCH.-Ja	670.0	0.0	50.0	620.0	9.925	9.925	61,534.26
MORGAN STANLEY		SCH.-Jc	2,165.0	0.0	0.0	2,165.0	9.894	9.894	214,200.26
CARGILL FERTILIZER		SCH.-Ja	174.0	0.0	94.0	80.0	16.375	16.375	13,100.00
CARGILL FERTILIZER		SCH.-Jc	223.0	0.0	0.0	223.0	9.000	9.000	20,070.00
CORAL ENERGY		SCH.-Jc	281.0	0.0	0.0	281.0	6.435	6.435	18,081.00
FARMLAND HYDRO LP		SCH.-Jc	302.0	0.0	0.0	302.0	3.496	3.496	10,556.80
RINGHAVER		SCH.-Jc	258.0	0.0	0.0	258.0	8.415	8.415	21,710.79
OKEELANTA		SCH.-D	23,816.0	0.0	0.0	23,816.0	5.485	5.485	1,306,311.60
AUBURNDALE POWER PARTNERS		SCH.-D	4,029.0	0.0	0.0	4,029.0	2.625	2.625	105,769.91
FLA. POWER & LIGHT		STEAM-A	25.0	0.0	0.0	25.0	11.544	11.544	2,886.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	Jun-00	IPP	(94,031.0)	0.0	0.0	(94,031.0)	5.116	5.116	(4,810,892.84)
HARDEE PWR. PART.-NATIVE	Jun-00	IPP	94,031.0	0.0	0.0	94,031.0	5.271	5.271	4,956,144.36
CARGILL FERTILIZER	Jan-00	SCH.-Jc	(33.0)	0.0	0.0	(33.0)	4.670	4.670	(1,541.16)
CARGILL FERTILIZER	Jan-00	SCH.-Jc	33.0	0.0	0.0	33.0	5.098	5.098	1,682.32
TOTAL			227,805.0	0.0	12,709.7	215,095.3	6.287	6.287	13,522,469.69
CURRENT MONTH:									
DIFFERENCE		-	(34,666.0)	0.0	(14,965.3)	(19,700.7)	-4.448	-4.448	876,269.69
DIFFERENCE %		-	(13.2)	0.0	(54.1)	(8.4)	(82.6)	(82.6)	6.9
PERIOD TO DATE:									
ACTUAL		-	1,193,955.00	0.00	131,847.50	1,062,107.5	4.804	4.804	51,026,880.21
ESTIMATED		-	847,802.0	0.0	104,673.0	743,129.0	4.791	4.791	35,600,300.0
DIFFERENCE		-	346,153.0	0.0	27,174.5	318,978.5	0.013	0.013	15,426,580.21
DIFFERENCE %		-	40.8	0.0	26.0	42.9	0.3	0.3	43.3

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JULY 2000

SCHEDULE A8

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:									
VARIOUS		COGEN.	36,671.0	0.0	0.0	36,671.0	2.656	2.656	974,800.00
TOTAL		-	36,671.0	0.0	0.0	36,671.0	2.656	2.656	974,800.00
ACTUAL:									
IMC-AGRICO-NICHOLS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE		COGEN.	4,505.0	0.0	0.0	4,505.0	2.325	2.325	104,746.89
MULBERRY PHOSPHATES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD		COGEN.	125.0	0.0	0.0	125.0	8.205	8.205	10,255.93
IMC-AGRICO-NEW WALES		COGEN.	1,172.0	0.0	0.0	1,172.0	5.929	5.929	69,485.56
HILLSBOROUGH COUNTY		COGEN.	18,223.0	0.0	0.0	18,223.0	2.330	2.330	424,549.57
CARGILL MILLPOINT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.		COGEN.	1,823.0	0.0	0.0	1,823.0	4.551	4.551	82,956.06
FARMLAND HYDRO LP		COGEN.	736.0	0.0	0.0	736.0	3.819	3.819	28,111.02
IMC-AGRICO-S. PIERCE		COGEN.	1,824.0	0.0	0.0	1,824.0	7.326	7.326	133,617.95
AUBURNDALE POWER PARTNERS		COGEN.	2,132.0	0.0	0.0	2,132.0	3.953	3.953	84,262.78
ORANGE COGENERATION L.P.		COGEN.	7,820.0	0.0	0.0	7,820.0	2.289	2.289	178,986.92
CUTRALE CITRUS		COGEN.	29.0	0.0	0.0	29.0	3.347	3.347	970.70
AS AVAILABLE ASSIGNMENT		COGEN.	0.0	0.0	368.6	(368.6)	7.940	7.940	(29,266.36)
SUB-TOTAL FOR JULY	2000	-	38,389.0	0.0	368.6	38,020.4	2.863	2.863	1,088,697.00
ADJUSTMENTS TO PRIOR MONTHS									
IMC-AGRICO-NICHOLS		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
McKAY BAY REFUSE	May-00	COGEN.	(4,967.0)	0.0	0.0	(4,967.0)	2.105	2.105	(104,569.89)
			4,967.0	0.0	0.0	4,967.0	2.099	2.099	104,276.12
MULBERRY PHOSPHATES INC.		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
CARGILL RIDGEWOOD		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
IMC-AGRICO-NEW WALES		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
HILLSBOROUGH COUNTY	May-00	COGEN.	(15,873.0)	0.0	0.0	(15,873.0)	2.123	2.123	(337,050.46)
			15,873.0	0.0	0.0	15,873.0	2.117	2.117	336,059.49
CARGILL MILLPOINT		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
CF INDUSTRIES INC.		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
FARMLAND HYDRO LP	Jun-00	COGEN.	(749.0)	0.0	0.0	(749.0)	3.083	3.083	(23,091.78)
			516.0	0.0	0.0	516.0	2.625	2.625	13,543.95
IMC-AGRICO-S. PIERCE		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
AUBURNDALE POWER PARTNERS		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
ORANGE COGENERATION L.P.	May-00	COGEN.	(5,359.0)	0.0	0.0	(5,359.0)	2.162	2.162	(115,842.35)
			5,359.0	0.0	0.0	5,359.0	2.152	2.152	115,334.18
CUTRALE CITRUS		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
AS AVAILABLE ASSIGNMENT		COGEN.		0.0		0.0	0.000	0.000	
				0.0		0.0	0.000	0.000	
SUB-TOTAL FOR ADJUSTMENTS		-	(233.0)	0.0	0.0	(233.0)	4.867	4.867	(11,340.74)
GRAND TOTAL			38,156.0	0.0	368.6	37,787.4	2.851	2.851	1,077,356.26
CURRENT MONTH:									
DIFFERENCE		-	1,485.0	0.0	368.6	1,116.4	0.193	0.193	102,556.26
DIFFERENCE %		-	4.0	0.0	0.0	3.0	7.3	7.3	10.5
PERIOD TO DATE:									
ACTUAL			222,200.0	0.0	2,602.8	219,597.2	2.257	2.257	4,956,935.33
ESTIMATED			235,621.0	0.0	0.0	235,621.0	2.176	2.176	5,127,800.00
DIFFERENCE		-	(13,421.0)	0.0	2,602.8	(16,023.8)	0.081	0.081	(170,864.67)
DIFFERENCE %		-	(5.7)	0.0	0.0	(6.8)	3.7	3.7	(3.3)

SCHEDULE A9

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JULY 2000

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACT. COST cents/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	(6) COST IF GENERATED (A) cents/KWH	(6) COST IF GENERATED (B) $	(7) FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	4,925.0	6.575	323,800.00	7.222	355,700.00	31,900.00
TOTAL	-	4,925.0	6.575	323,800.00	7.222	355,700.00	31,900.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL	-	0.0	0.000	0.00	0.000	0.00	0.00
CURRENT MONTH:							
DIFFERENCE	-	(4,925.0)	(6.575)	(323,800.00)	(7.222)	(355,700.00)	(31,900.00)
DIFFERENCE %	-	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)
PERIOD TO DATE:							
ACTUAL		0.0	0.000	(10,512.45)	0.000	0.00	10,512.45
ESTIMATED		128,601.0	4.519	5,810,900.00	5.698	7,327,300.00	1,516,400.00
DIFFERENCE	-	(128,601.0)	(4.519)	(5,821,412.45)	(5.698)	(7,327,300.00)	(1,505,887.55)
DIFFERENCE %	-	(100.0)	(100.0)	(100.2)	(100.0)	(100.0)	(99.3)

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

AUGUST 2000

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST , 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
1. Fuel Cost of System Net Generation (A3)	37,338,972	40,705,505	(3,366,533)	(8.3)	1,612,421	1,756,112	(143,691)	(8.2)	2.31571	2.31793	(0.00222)	(0.1)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (FLMeade/Wauch. Wheeling Losses)	(4,484)	(4,000)	(484)	12.1	1,612,421 a)	1,756,112 a)	(143,691)	(8.2)	(0.00028)	(0.00023)	(0.00005)	21.7
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,612,421 a)	1,756,112 a)	(143,691)	(8.2)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,612,421 a)	1,756,112 a)	(143,691)	(8.2)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	37,334,488	40,701,505	(3,367,017)	(8.3)	1,612,421	1,756,112	(143,691)	(8.2)	2.31543	2.31771	(0.00228)	(0.1)
6. Fuel Cost of Purchased Power - Firm (A7)	19,144,629	10,455,200	8,689,429	83.1	309,803	220,288	89,515	40.6	6.17961	4.74615	1.43346	30.2
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	279,900	(279,900)	(100.0)	0	4,553	(4,553)	(100.0)	0.00000	6.14759	(6.14759)	(100.0)
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 a)	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	1,112,828	960,500	152,328	15.9	38,053	36,671	1,382	3.8	2.92442	2.61924	0.30518	11.7
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	20,257,457	11,695,600	8,561,857	73.2	347,856	261,512	86,344	33.0	5.82352	4.47230	1.35122	30.2
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,960,277	2,017,624	(57,347)	(2.8)				
14. Fuel Cost of Economy Sales (A6)	0	2,326,200	(2,326,200)	(100.0)	0	62,128	(62,128)	(100.0)	0.00000	3.74421	(3.74421)	(100.0)
15. Gain on Economy Sales - 80% (A6)	0	1,116,600	(1,116,600)	(100.0)	0 a)	62,128 a)	(62,128)	(100.0)	0.00000	1.79726	(1.79726)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	(63,286)	0	(63,286)	0.0	0	0	0	0.0	#DIV/0!	0.00000	#DIV/0!	0.0
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	133,813	144,700	(10,887)	(7.5)	4,826	5,864	(1,038)	(17.7)	2.77275	2.46760	0.30515	12.4
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	108,608	0	108,608	0.0	2,630	0	2,630	0.0	4.12958	0.00000	4.12958	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	2,701	0	2,701	0.0	55	0	55	0.0	4.91091	0.00000	4.91091	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	1,360,893	939,500	421,393	44.9	58,995	39,909	17,086	42.8	2.38774	2.35411	0.03363	1.4
21. Fuel Cost of Other Power Sales (A6)	1,849,485	2,014,564	(165,099)	(8.2)	95,830	111,600	(15,770)	(14.1)	1.92994	1.80516	0.12478	6.9
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	3,392,194	6,541,564	(3,149,370)	(48.1)	160,336	219,501	(59,165)	(27.0)	2.11568	2.98020	(0.86452)	(29.0)
23. Net Inadvertant Interchange					27	0	27	0.0				
24. Wheeling Rec'd. less Wheeling Del'd.					187	0	187	0.0				
25. Interchange and Wheeling Losses					1,593	3,300	(1,707)	(51.7)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	54,199,751	45,855,541	8,344,210	18.2	1,798,562	1,794,823	3,739	0.2	3.01350	2.55488	0.45862	18.0
27. Net Unbilled	2,157,510 (a)	1,772,930 (a)	384,580	21.7	89,576	72,243	17,333	24.0	0.13272	0.10813	0.02459	22.7
28. Company Use	108,193 (a)	98,165 (a)	10,028	10.2	4,492	4,000	492	12.3	0.00666	0.00599	0.00067	11.2
29. T & D Losses	1,900,998 (a)	1,936,399 (a)	(35,403)	(1.8)	78,926	78,904	22	0.0	0.11694	0.11810	(0.00116)	(1.0)
30. System KWH Sales	54,199,751	45,855,541	8,344,210	18.2	1,625,568	1,639,676	(14,108)	(0.9)	3.33420	2.79662	0.53758	19.2
31. Wholesale KWH Sales	(3,051,197)	(1,716,093)	(1,335,104)	77.8	(91,512)	(61,383)	(30,149)	49.1	3.33420	2.79663	0.53757	19.2
32. Jurisdictional KWH Sales	51,148,554	44,139,448	7,009,106	15.9	1,534,056	1,578,313	(44,257)	(2.8)	3.33420	2.79662	0.53758	19.2
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	51,183,335	44,169,483	7,013,872	15.9	1,534,056	1,578,313	(44,257)	(2.8)	3.33647	2.79852	0.53795	19.2
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	338,081	344,842	(6,761)	(2.0)	1,534,056	1,578,313	(44,257)	(2.8)	0.02204	0.02185	0.00019	0.9
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	1,534,056	1,578,313	(44,257)	(2.8)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	1,534,056	1,578,313	(44,257)	(2.8)	0.00000	0.00000	0.00000	0.0
36. True-up *	2,684,371	305,574	2,378,797	778.5	1,534,056	1,578,313	(44,257)	(2.8)	0.17499	0.01936	0.15563	803.9
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	54,205,787	44,819,879	9,385,908	20.9	1,534,056	1,578,313	(44,257)	(2.8)	3.53349	2.83973	0.69376	24.4
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.53603	2.84177	0.69426	24.4
40. GPIF * (Already Adjusted for Taxes)	(23,059)	(23,059)	0	0.0	1,534,056	1,578,313	(44,257)	(2.8)	(0.00150)	(0.00146)	(0.00004)	2.7
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	54,182,728	44,796,820	9,385,908	21.0	1,534,056	1,578,313	(44,257)	(2.8)	3.53453	2.84031	0.69422	24.4
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									3.535	2.840	0.695	24.5

* Based on Jurisdictional Sales (a) Included for informational purposes only

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COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: AUGUST, 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
1. Fuel Cost of System Net Generation (A3)	240,698,957	250,598,315	(9,899,358)	(4.0)	11,712,110	11,994,497	(282,388)	(2.4)	2.05513	2.08928	(0.03415)	(1.6)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses	(33,837)	(32,000)	(1,837)	5.7	11,712,110 a)	11,994,497 a)	(282,388)	(2.4)	*(0.00029)*	*(0.00027)*	*(0.00002)*	7.4
4b. Adjustments to Fuel Cost	0	0	0	0.0	11,712,110 a)	11,994,497 a)	(282,388)	(2.4)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	(79)	0	(79)	0.0	11,712,110 a)	11,994,497 a)	(282,388)	(2.4)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	240,665,041	250,566,315	(9,901,274)	(4.0)	11,712,110	11,994,497	(282,388)	(2.4)	2.05484	2.08901	(0.03417)	(1.6)
6. Fuel Cost of Purchased Power - Firm (A7)	*70,171,508*	*48,055,500*	24,116,008	52.4	1,371,911	963,417	408,494	42.4	5.11487	4.78043	0.33444	7.0
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	(10,512)	6,090,800	(6,101,312)	(100.2)	0	133,154	(133,154)	(100.0)	#DIV/0!	*4.57425*	#DIV/0!	#DIV/0!
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0								
11. Payments to Qualifying Facilities (A8)	6,069,763	6,088,300	(18,537)	(0.3)	257,650	272,292	(14,642)	(5.4)	2.35582	2.23595	0.11987	5.4
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	*76,230,759*	*58,234,800*	17,996,159	30.9	1,629,561	1,368,863	260,698	19.0	4.67799	4.25423	0.42376	10.0
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					13,341,671	13,363,360	(21,690)	(0.2)				
14. Fuel Cost of Economy Sales (A6)	(1,687)	6,520,200	(6,521,887)	(100.0)	0	*192,631*	(192,631)	*(100.0)*	#DIV/0!	3.38481	#DIV/0!	#DIV/0!
15. Gain on Economy Sales - 80% (A6)	0	3,333,920	(3,333,920)	(100.0)	0	192,631 a)	(192,631)	(100.0)	0.00000	1.73073	(1.73073)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	127,483	295,300	(167,817)	(56.8)	12,188	19,153	(6,967)	(36.4)	1.04614	1.54180	(0.49566)	(32.1)
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	*983,236*	*995,700*	*(12,464)*	*(1.3)*	44,596	46,395	(1,799)	(3.9)	2.20476	2.14614	0.05862	2.7
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	108,608	0	108,608	0.0	2,630	0	2,630	0.0	4.12958	0.00000	4.12958	*0.0*
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	2,701	0	2,701	0.0	55	0	55	0.0	4.91091	0.00000	4.91091	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	6,793,134	4,621,100	2,172,034	47.0	287,930	201,424	86,506	42.9	2.35930	2.29422	0.06508	2.8
21. Fuel Cost of Other Power Sales (A6)	18,274,144	15,835,032	2,439,112	15.4	872,353	878,400	*(6,047)*	*(0.7)*	*2.09481*	1.80271	0.29210	16.2
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	26,287,819	31,601,252	(5,313,433)	(16.8)	1,219,750	1,338,003	(118,253)	(8.8)	2.15516	2.36182	(0.20666)	(8.8)
23. Net Inadvertant Interchange					2,104	0	2,104	0.0				
24. Wheeling Rec'd. less Wheeling Del'd.					4,586	0	4,586	0.0				
25. Interchange and Wheeling Losses					16,502	20,200	(3,698)	(18.3)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	290,608,181	277,199,663	13,408,518	4.8	12,112,109	12,005,157	106,952	0.9	2.39932	2.30900	0.09032	3.9
27. Net Unbilled	5,513,123 (a)	4,915,195 (a)	*597,928*	12.2	*249,571*	*222,219*	27,352	12.3	0.04883	0.04371	0.00512	11.7
28. Company Use	739,498 (a)	707,798 (a)	31,700	4.5	33,478	32,000	1,478	4.6	0.00655	0.00629	0.00026	4.1
29. T & D Losses	11,917,970 (a)	11,208,098 (a)	709,872	6.3	539,509	506,725	32,784	6.5	0.10557	0.09966	0.00589	5.9
30. System KWH Sales	290,608,181	277,199,663	13,408,518	4.8	11,289,553	11,244,213	45,340	0.4	*2.57413*	*2.46527*	*0.10886*	4.4
31. Wholesale KWH Sales	(11,957,395)	(6,814,878)	(5,142,517)	75.5	(444,456)	(261,105)	(183,351)	70.2	2.69034	2.61001	0.08033	3.1
32. Jurisdictional KWH Sales	278,650,786	270,384,785	8,266,001	3.1	*10,845,097*	*10,983,108*	(138,012)	(1.3)	2.56937	2.46182	0.10755	4.4
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	*278,840,268*	*270,568,646*	8,271,622	3.1	10,845,097	10,983,108	(138,012)	(1.3)	2.57112	2.46350	0.10762	4.4
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	2,825,607	2,873,996	(48,389)	(1.7)	10,845,097	10,983,108	(138,012)	(1.3)	0.02605	0.02617	(0.00012)	(0.5)
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	10,845,097	*10,983,108*	(138,012)	(1.3)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	10,845,097	10,983,108	(138,012)	(1.3)	0.00000	0.00000	0.00000	0.0
36. True-up *	9,580,983	2,444,592	7,136,391	291.9	10,845,097	10,983,108	(138,012)	(1.3)	0.08834	0.02226	0.06608	*296.9*
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	291,246,858	275,887,234	15,359,624	5.6	10,845,097	10,983,108	(138,012)	(1.3)	2.68552	2.51192	0.17360	6.9
38. Revenue Tax Factor									*1.00072*	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.68745	2.51373	0.17372	6.9
40. GPIF * (Already Adjusted for Taxes)	(184,472)	(184,472)	0	0.0	10,845,097	10,983,108	(138,012)	(1.3)	(0.00170)	(0.00168)	(0.00002)	1.2
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	291,062,386	275,702,762	15,359,624	5.6	10,845,097	10,983,108	(138,012)	(1.3)	2.68575	2.51205	0.17370	6.9
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.686	2.512	0.174	6.9

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CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	37,338,972	40,705,505	(3,366,533)	(8.3)	240,698,957	250,598,315	(9,899,358)	(4.0)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	3,392,194	6,541,564	(3,149,370)	(48.1)	26,287,619	31,601,252	(5,313,633)	(16.8)
3. FUEL COST OF PURCHASED POWER	19,144,629	10,455,200	8,689,429	83.1	70,171,508	46,055,500	24,116,008	52.4
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	1,112,828	960,500	152,328	15.9	6,069,763	6,088,300	(18,537)	(0.3)
4. ENERGY COST OF ECONOMY PURCHASES	0	279,900	(279,900)	0.0	(10,512)	6,090,800	(6,101,312)	(100.2)
5. TOTAL FUEL & NET POWER TRANSACTION	54,204,235	45,859,541	8,344,694	18.2	290,642,097	277,231,663	13,410,434	4.8
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(4,484)	(4,000)	(484)	12.1	(33,837)	(32,000)	(1,837)	5.7
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST	0	0	0	0.0	(79)	0	(79)	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	54,199,751	45,855,541	8,344,210	18.2	290,608,181	277,199,663	13,408,518	4.8
* INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,534,056	1,578,313	(44,257)	(2.8)	10,845,097	10,983,108	(138,011)	(1.3)
2. NONJURISDICTIONAL SALES	91,512	61,363	30,149	49.1	444,456	261,105	183,351	70.2
3. TOTAL SALES	1,625,568	1,639,676	(14,108)	(0.9)	11,289,553	11,244,213	45,340	0.4
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9437046	0.9625761	(0.0188715)	(2.0)	0.9606312	0.9767787	(0.0161475)	(1.7)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	37,961,484	36,354,825	1,606,659	4.4	255,194,240	252,750,021	2,444,219	1.0
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	(2,684,371)	(305,574)	(2,378,797)	778.5	(9,580,983)	(2,444,592)	(7,136,391)	291.9
b. INCENTIVE PROVISION	23,059	23,059	0	0.0	184,472	184,472	0	0.0
c. TRANSITION ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
d. OTHER ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	35,300,172	36,072,310	(772,138)	(2.1)	245,797,729	250,489,901	(4,692,172)	(1.9)
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	54,199,751	45,855,541	8,344,210	18.2	290,608,181	277,199,663	13,408,518	4.8
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B-4)	0.9437046	0.9625761	(0.0188715)	(2.0)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	51,148,554	44,139,448	7,009,106	15.9	278,650,786	270,384,785	8,266,001	3.1
6A.JURISDIC. LOSS MULTIPLIER	1.00068	1.00068	0.0000	0.0	NA	NA	-	-
6B. (LINE 6 x LINE 6A)	51,183,335	44,169,463	7,013,872	15.9	278,840,268	270,568,646	8,271,622	3.1
6C.PEABODY COAL CONTR. BUY-OUT AMORT.	358,249	358,249	0	0.0	2,936,860	2,936,860	0	0.0
6D.(LINE 6C x LINE 5) PB. JURISD.	338,081	344,842	(6,761)	(2.0)	2,825,607	2,873,996	(48,389)	(1.7)
6E.OTHER (SPARE INPUT #1)	0	0	0	0.0	0	0	0	0.0
6F. OIL BELOW THE DISCHARGE VALVE	0	0	0	0.0	0	0	0	0.0
6G. OTHER (SPARE INPUT #2)	0	0	0	0.0	0	0	0	0.0
6H. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. 6B+6D+6E+6F+6G)	51,521,416	44,514,305	7,007,111	15.7	281,665,875	273,442,642	8,223,233	3.0
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6H)	(16,221,244)	(8,441,995)	(7,779,249)	92.1	(35,868,146)	(22,952,741)	(12,915,405)	56.3
8. INTEREST PROVISION FOR THE MONTH	(175,012)	(148,204)	(26,808)	18.1	(676,521)	(463,095)	(213,426)	46.1
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(27,963,015)	(36,170,592)	8,207,577	(22.7)	NOT APPLICABLE			
9a.DEFERRED TRUE-UP BEGINNING OF PERIO	2,381,673	7,879,936	(5,498,263)	(69.8)	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	2,684,371	305,574	2,378,797	778.5	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	(39,293,227)	(36,575,281)	(2,717,946)	7.4	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	(25,581,342)	(28,290,656)	2,709,314	(9.6)	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	(39,118,215)	(36,427,077)	(2,691,138)	7.4	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(64,699,557)	(64,717,733)	18,176	0.0	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	(32,349,778)	(32,358,867)	9,089	0.0	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	6.500	5.500	1.000	18.2	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	6.480	5.500	0.980	17.8	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	12.980	11.000	1.980	18.0	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	6.490	5.500	0.990	18.0	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.541	0.458	0.083	18.1	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	(175,012)	(148,204)	(26,808)	18.1	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: AUGUST 2000

SCHEDULE A3
PAGE 1 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
FUEL COST OF SYSTEM NET GENERATION ($)								
1 HEAVY OIL	2,459,270	3,466,404	(1,007,134)	(29.1)	9,435,687	11,202,401	(1,766,714)	(15.8)
2 LIGHT OIL	3,908,064	4,760,860	(852,796)	(17.9)	8,518,492	12,696,763	(4,178,271)	(32.9)
3 COAL	29,802,771	32,478,241	(2,675,470)	(8.2)	220,959,532	226,699,151	(5,739,619)	(2.5)
4 NATURAL GAS	1,168,867	0	1,168,867	0.0	1,785,246	0	1,785,246	0.0
5 NUCLEAR	0	0	0	0.0	0	0	0	0.0
6 OTHER	0	0	0	0.0	0	0	0	0.0
7 TOTAL ($)	37,338,972	40,705,505	(3,366,533)	(8.3)	240,698,957	250,598,315	(9,899,358)	(4.0)
SYSTEM NET GENERATION (MWH)								
8 HEAVY OIL	38,074	70,865	(32,791)	(46.3)	159,392	245,867	(86,475)	(35.2)
9 LIGHT OIL	50,012	43,147	6,865	15.9	116,598	118,424	(1,826)	(1.5)
10 COAL	1,499,805	1,642,100	(142,295)	(8.7)	11,404,190	11,630,206	(226,017)	(1.9)
11 NATURAL GAS	24,530	0	24,530	0.0	31,930	0	31,930	0.0
12 NUCLEAR	0	0	0	0.0	0	0	0	0.0
13 OTHER	0	0	0	0.0	0	0	0	0.0
14 TOTAL (MWH)	1,612,421	1,756,112	(143,691)	(8.2)	11,712,110	11,994,497	(282,388)	(2.4)
UNITS OF FUEL BURNED								
15 HEAVY OIL (BBL)	85,819	173,438	(87,619)	(50.5)	371,480	619,640	(248,160)	(40.0)
16 LIGHT OIL (BBL)	110,600	123,008	(12,408)	(10.1)	252,192	360,652	(108,460)	(30.1)
17 COAL (TON)	684,743	746,607	(61,864)	(8.3)	5,204,829	5,253,475	(48,646)	(0.9)
18 NATURAL GAS (MCF)	283,921	0	283,921	0.0	377,414	0	377,414	0.0
19 NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20 OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
BTUS BURNED (MMBTU)								
21 HEAVY OIL	544,142	1,096,305	(552,163)	(50.4)	2,357,129	3,916,751	(1,559,622)	(39.8)
22 LIGHT OIL	642,826	594,867	47,959	8.1	1,450,635	1,511,439	(60,804)	(4.0)
23 COAL	15,815,300	17,349,610	(1,534,310)	(8.8)	119,010,334	121,598,704	(2,588,370)	(2.1)
24 NATURAL GAS	276,053	0	276,053	0.0	366,955	0	366,955	0.0
25 NUCLEAR	0	0	0	0.0	0	0	0	0.0
26 OTHER	0	0	0	0.0	0	0	0	0.0
27 TOTAL (MMBTU)	17,278,321	19,040,782	(1,762,461)	(9.3)	123,185,053	127,026,894	(3,841,841)	(3.0)
GENERATION MIX (% MWH)								
28 HEAVY OIL	2.36	4.04	(1.68)	-	1.36	2.05	(0.69)	-
29 LIGHT OIL	3.10	2.46	0.64	-	1.00	0.99	0.01	-
30 COAL	93.02	93.51	(0.49)	-	97.37	96.96	0.41	-
31 NATURAL GAS	1.52	0.00	1.52	-	0.27	0.00	0.27	-
32 NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33 OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34 TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
FUEL COST PER UNIT								
35 HEAVY OIL ($/BBL)	28.66	19.99	8.67	43.4	25.40	18.08	7.32	40.5
36 LIGHT OIL ($/BBL)	35.34	38.70	(3.36)	(8.7)	33.78	35.21	(1.43)	(4.1)
37 COAL ($/TON)	43.52	43.50	0.02	0.0	42.45	43.15	(0.70)	(1.6)
38 NATURAL GAS ($/MCF)	4.12	0.00	4.12	0.0	4.73	0.00	4.73	0.0
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40 OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
FUEL COST PER MMBTU ($/MMBTU)								
41 HEAVY OIL	4.52	3.16	1.36	43.0	4.00	2.86	1.14	39.9
42 LIGHT OIL	6.08	8.00	(1.92)	(24.0)	5.87	8.40	(2.53)	(30.1)
43 COAL	1.88	1.87	0.01	0.5	1.86	1.86	0.00	0.0
44 NATURAL GAS	4.23	0.00	4.23	0.0	4.87	0.00	4.87	0.0
45 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47 TOTAL ($/MMBTU)	2.16	2.14	0.02	0.9	1.95	1.97	(0.02)	(1.0)

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: AUGUST 2000

SCHEDULE A3
PAGE 2 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
BTU BURNED PER KWH (BTU/KWH)								
48 HEAVY OIL	14,292	15,470	(1,178)	(7.6)	14,788	15,930	(1,142)	(7.2)
49 LIGHT OIL	12,853	13,787	(934)	(6.8)	12,441	12,763	(322)	(2.5)
50 COAL	10,545	10,566	(21)	(0.2)	10,436	10,455	(19)	(0.2)
51 NATURAL GAS	11,254	0	11,254	0.0	11,492	0	11,492	0.0
52 NUCLEAR	0	0	0	0.0	0	0	0	0.0
53 OTHER	0	0	0	0.0	0	0	0	0.0
54 TOTAL (BTU/KWH)	10,716	10,843	(127)	(1.2)	10,518	10,590	(72)	(0.7)
GENERATED FUEL COST PER KWH (cents/KWH)								
55 HEAVY OIL	6.46	4.89	1.57	32.1	5.92	4.56	1.36	29.8
56 LIGHT OIL	7.81	11.03	(3.22)	(29.2)	7.31	10.72	(3.41)	(31.8)
57 COAL	1.99	1.98	0.01	0.5	1.94	1.95	(0.01)	(0.5)
58 NATURAL GAS	4.77	0.00	4.77	0.0	5.59	0.00	5.59	0.0
59 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61 TOTAL (cents/KWH)	2.32	2.32	0.00	0.0	2.06	2.09	(0.03)	(1.4)

SCHEDULE A4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD/MONTH OF: AUGUST 2000

(A) PLANT/UNIT	(B) NET CAPABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPC. FACTO (%)	(E) EQUIV. AVAIL. FACTO (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COS PER KWH (cents /KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	30	2,729	12.2	97.2	37.1	-	HVY.OIL	-	-	-	-	-	-
H.P.#2	30	3,939	17.6	96.1	51.1	-	HVY.OIL	-	-	-	-	-	-
H.P.#3	30	5,383	24.1	100.0	55.9	-	HVY.OIL	-	-	-	-	-	-
H.P.#4	39	6,980	24.1	98.7	71.7	-	HVY.OIL	-	-	-	-	-	-
H.P.#5	67	6,306	12.7	54.0	52.9	-	HVY.OIL	-	-	-	-	-	-
H.P. STATION	196	25,337	17.4	83.0	50.3	16,845	HVY.OIL	67,117	6,359,253	426,814.0	1,929,482	7.62	28.75
GAN.#1	114	45,551	53.7	71.9	67.4	12,212	COAL	22,929	24,261,442	556,290.6	948,290	2.08	41.36
GAN.#2	98	43,751	60.0	74.6	75.3	12,510	COAL	22,905	23,894,822	547,310.9	947,298	2.17	41.36
GAN.#3	145	77,360	71.7	83.6	81.3	12,022	COAL	47,021	19,778,639	930,011.4	1,944,679	2.51	41.36
GAN.#4	159	86,380	73.0	88.8	79.0	12,313	COAL	53,087	20,034,219	1,063,556.6	2,195,555	2.54	41.36
GAN.#5	232	97,098	56.3	65.5	74.0	10,729	COAL	43,963	23,695,981	1,041,746.4	1,818,208	1.87	41.36
GAN.#6	372	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GANNON STA.	1,120	350,140	42.0	50.9	50.5	11,821	COAL	189,905	21,794,665	4,138,915.9	7,854,030	2.24	41.36
B.B.#1	416	247,258	79.9	89.9	79.9	10,596	COAL	105,870	24,745,860	2,619,844.2	4,426,715	1.79	41.81
B.B.#2	416	239,238	77.3	87.2	80.1	10,223	COAL	99,517	24,576,720	2,445,801.4	4,161,079	1.74	41.81
B.B.#3	433	256,864	79.7	89.0	81.7	9,814	COAL	103,921	24,258,080	2,520,923.9	4,345,222	1.69	41.81
B.B. 1 - 3	1,265	743,360	79.0	0.0	0.0	10,206	COAL	309,308	24,527,557	7,586,569.5	12,933,016	1.74	41.81
B.B.#4	442	247,101	75.1	84.8	85.9	9,928	COAL	114,496	21,425,959	2,453,182.3	6,188,693	2.50	54.05
B.B. STA.	1,707	990,461	78.0	0.0	0.0	10,136	COAL	423,804	23,689,622	10,039,751.8	19,121,709	1.93	45.12
SEB-PHIL. #1(HVY OIL)	17	6,082	48.1	99.7	84.5	9,646	HVY.OIL	9,351	6,273,586	58,664.3	264,894	4.36	28.33
SEB-PHIL. #2(HVY OIL)	17	6,655	52.6	99.8	92.5	8,815	HVY.OIL	9,351	6,273,586	58,664.3	264,894	3.98	28.33
SEB-PHILLIPS TOTAL	34	12737	50.4	99.8	88.5	9,212	HVY.OIL	18,702	6,273,586	117,328.6	529,788	4.16	28.33
POLK #1 GASIFIER	250	159,204	85.6	87.7	97.4	10,280	COAL	71,034	23,039,999	1,636,632.3	2,827,032	1.78	39.80
POLK #1 CT (OIL)	225	1,760	1.1	89.0	94.2	9,242	LGT.OIL	3,033	5,363,172	16,266.5	110,345	6.27	36.38
POLK #1 TOTAL	250	160,964	86.5	88.7	97.4	10,269	-	-	-	1,652,898.8	2,937,377	1.82	-
POLK #2 CT (GAS)	150	24,530	22.0	92.2	177.7	11,254	GAS	283,921	972,290	276,053.0	1,168,867	4.77	4.12
POLK #2 CT (OIL)	150	27,949	25.0	92.6	97.2	11,650	LGT.OIL	55,832	5,831,718	325,596.5	2,031,477	7.27	36.39
POLK #2 TOTAL	150	52,479	47.0	92.4	123.3	11,465	-	-	-	601,649.5	3,200,344	6.10	-
POLK STATION TOTAL	400	213,443	71.7	90.1	107.1	10,563	-	-	-	2,254,548.3	6,137,721	2.88	-
GAN.C.T.#1	12	860	9.6	93.2	75.4	1,967	LGT.OIL	291	5,812,715	1,691.5	9,925	1.15	34.11
B.B.C.T.#1	12	861	9.6	100.0	80.3	19,173	LGT.OIL	2,837	5,818,858	16,508.1	96,857	11.25	34.14
B.B.C.T.#2	66	8,718	17.8	100.0	72.7	15,582	LGT.OIL	23,351	5,817,323	135,840.3	797,210	9.14	34.14
B.B.C.T.#3	66	9,864	20.1	99.3	75.5	14,895	LGT.OIL	25,256	5,817,338	146,922.7	862,250	8.74	34.14
C.T. TOTAL	156	20,303	17.5	99.2	74.7	14,824	LGT.OIL	51,735	5,817,389	300,962.6	1,766,242	8.70	34.14
TOT. COAL (GN,BB,POLK)	3077	1,499,805	65.5	74.3	71.8	10,545	COAL	684,743	23,096,688	15,815,300.0	29,802,771	1.99	43.52
SYSTEM	3,613	1,612,421	60.0	76.9	73.0	10,716	-	-	-	17,278,321.2	37,338,972	2.32	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS
NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2000

SCHEDULE A5
PAGE 1 OF 2

		CURRENT MONTH				PERIOD TO DATE			
	HEAVY OIL (1)	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	PURCHASES:								
2	UNITS (BBL)	97,835	173,438	(75,603)	(43.6)	422,328	573,552	(151,224)	(26.4)
3	UNIT COST ($/BBL)	29.70	20.55	9.15	44.5	27.76	18.07	9.69	53.6
4	AMOUNT ($)	2,905,809	3,563,758	(657,949)	(18.5)	11,724,830	10,365,466	1,359,364	13.1
5	BURNED:								
6	UNITS (BBL)	85,819	173,438	(87,619)	(50.5)	371,480	619,640	(248,160)	(40.0)
7	UNIT COST ($/BBL)	28.66	19.99	8.67	43.4	25.40	18.08	7.32	40.5
8	AMOUNT ($)	2,459,270	3,466,404	(1,007,134)	(29.1)	9,435,687	11,202,401	(1,766,714)	(15.8)
9	ENDING INVENTORY:								
10	UNITS (BBL)	141,107	81,135	59,972	73.9	141,107	81,135	59,972	73.9
11	UNIT COST ($/BBL)	28.80	20.17	8.63	42.8	28.80	20.17	8.63	42.8
12	AMOUNT ($)	4,063,622	1,636,157	2,427,465	148.4	4,063,622	1,636,157	2,427,465	148.4
13									
14	DAYS SUPPLY:	644	89	555	623.6	-	-	-	-
	LIGHT OIL (2)								
15	PURCHASES:								
16	UNITS (BBL)	107,115	93,937	13,178	14.0	358,474	440,360	(81,886)	(18.6)
17	UNIT COST ($/BBL)	36.07	38.99	(2.92)	(7.5)	35.11	35.50	(0.39)	(1.1)
18	AMOUNT ($)	3,863,200	3,662,271	200,929	5.5	12,586,781	15,631,579	(3,044,798)	(19.5)
19	BURNED:								
20	UNITS (BBL)	110,600	123,008	(12,408)	(10.1)	252,192	360,652	(108,460)	(30.1)
21	UNIT COST ($/BBL)	35.34	38.70	(3.36)	(8.7)	33.78	35.21	(1.43)	(4.1)
22	AMOUNT ($)	3,908,064	4,760,860	(852,796)	(17.9)	8,518,492	12,696,763	(4,178,271)	(32.9)
23	ENDING INVENTORY:								
24	UNITS (BBL)	98,884	97,057	1,827	1.9	98,884	97,057	1,827	1.9
25	UNIT COST ($/BBL)	35.08	38.39	(3.31)	(8.6)	35.08	38.39	(3.31)	(8.6)
26	AMOUNT ($)	3,468,934	3,726,405	(257,471)	(6.9)	3,468,934	3,726,405	(257,471)	(6.9)
27									
28	DAYS SUPPLY: NORMAL	36	61	(25)	(41.0)	-	-	-	-
29	DAYS SUPPLY: EMERGENCY	14	14	0	0.0	-	-	-	-
	COAL (3)								
30	PURCHASES:								
31	UNITS (TONS)	743,740	729,000	14,740	2.0	5,449,232	5,097,200	352,032	6.9
32	UNIT COST ($/TON)	43.19	42.53	0.66	1.6	42.38	42.58	(0.20)	(0.5)
33	AMOUNT ($)	32,122,590	31,003,192	1,119,398	3.6	230,950,024	217,058,838	13,891,186	6.4
34	BURNED:								
35	UNITS (TONS)	684,743	746,607	(61,864)	(8.3)	5,204,829	5,253,475	(48,646)	(0.9)
36	UNIT COST ($/TON)	43.52	43.50	0.02	0.0	42.45	43.15	(0.70)	(1.6)
37	AMOUNT ($)	29,802,771	32,478,241	(2,675,470)	(8.2)	220,959,532	226,699,151	(5,739,619)	(2.5)
38	ENDING INVENTORY:								
39	UNITS (TONS)	1,021,419	969,900	51,519	5.3	1,021,419	969,900	51,519	5.3
40	UNIT COST ($/TON)	42.39	42.52	(0.13)	(0.3)	42.39	42.52	(0.13)	(0.3)
41	AMOUNT ($)	43,302,985	41,241,995	2,060,990	5.0	43,302,985	41,241,995	2,060,990	5.0
42									
43	DAYS SUPPLY:	54	45	9	20.0	-	-	-	-
	NATURAL GAS								
44	PURCHASES:								
45	UNITS (MCF)	283,921	0	283,921	0.0	377,414	0	377,414	0.0
46	UNIT COST ($/MCF)	4.75	0.00	4.75	0.0	5.21	0.00	5.21	0.0
47	AMOUNT ($)	1,349,830	0	1,349,830	0.0	1,966,209	0	1,966,209	0.0
48	BURNED:								
49	UNITS (MCF)	283,921	0	283,921	0.0	0	0	0	0.0
50	UNIT COST ($/MCF)	4.12	0.00	4.12	0.0	0.00	0.00	0.00	0.0
51	AMOUNT ($)	1,168,867	0	1,168,867	0.0	0	0	0	0.0
52	ENDING INVENTORY:								
53	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
54	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
56									
57	DAYS SUPPLY:	0	0	0	0.0	-	-	-	-
	NUCLEAR								
58	BURNED:								
59	UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
60	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2000

SCHEDULE A5
PAGE 2 OF 2

OTHER	CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH %	PERIOD TO DATE ACTUAL	PERIOD TO DATE ESTIMATED	PERIOD TO DATE DIFFERENCE AMOUNT	PERIOD TO DATE %
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
74 DAYS SUPPLY:	0	0	0	0.0	-	-	-	-

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	16,493
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	16,493

(2) RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(10,268)	(351,308)
OTHER USAGE	(1,312)	(46,400)
TOTAL	(11,580)	(397,708)

(3) RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	40
IGNITION #2 OIL	334,815
IGNITION PROPANE	2,319
AERIAL SURVEY ADJ.	(194,318)
ADDITIVES	74,763
TOTAL	217,619

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: AUGUST 2000

SCHEDULE A6
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(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(6) (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	62,128.0	0.0	62,128.0	3.954	6.201	2,456,700.00	3,852,500.00	1,116,600.00
VARIOUS	JURISDICTIONAL	SCH. -D	5,864.0	0.0	5,864.0	2.468	2.468	144,700.00	144,700.00	
VARIOUS	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPARATED	CONTRACT	39,909.0	0.0	39,909.0	2.354	3.296	939,500.00	1,315,600.00	
FMPA		SCH. -D	111,600.0	0.0	111,600.0	1.805	1.805	2,014,564.00	2,014,564.00	
VARIOUS	JURISDICTIONAL	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	219,501.0	0.0	219,501.0	2.531	3.338	5,555,464.00	7,327,364.00	1,116,600.00
LESS TRANSMISSION COSTS		-						0.00		
LESS VARIABLE O & M COSTS		-						(130,500.00)		
PLUS 80% OF ECON. ENERGY SALES PROFI		-						1,116,600.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INC 80% OF ECON. ENERGY SALES PROFITS		-	219,501.0	0.0	219,501.0	2.980	3.338	6,541,564.00	7,327,364.00	1,116,600.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENRGY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
OGLETHORPE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENN. VALLEY AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEP. CONTRACT		56,995.0	0.0	56,995.0	2.392	3.220	1,363,320.40	1,835,239.00	
SEMINOLE ELECTRIC CO-OP PRE	JURISD.	SCH. -D	5,510.0	1,416.7	4,093.3	2.883	2.883	118,029.50	118,029.50	
SEMINOLE ELECTRIC CO-OP HAR	JURISD.	SCH. -D	702.0	0.0	702.0	2.266	2.266	15,905.77	15,905.77	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: AUGUST 2000

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
THE ENERGY AUTHORITY	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA		SCH. -D	95,830.0	0.0	95,830.0	1.930	1.930	1,849,465.17	1,849,465.17	
HARDEE POWER PART. TO FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR.& LT.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO JACKSONVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KISSIMMEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ORLANDO		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO SEMINOLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FT. PIERCE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LK. WORTH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ENERGY AUTHORI		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR. CORP.		SCH. -J	55.0	0.0	55.0	4.911	4.911	2,701.01	2,701.01	
HARDEE POWER PART. TO FLA. PWR.& LT.		SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PART. TO FLA. PWR.& LT.		SCH. -MB	90.0	0.0	90.0	4.480	4.480	4,032.28	4,032.28	
HARDEE POWER PART. TO TALLAHASSEE		SCH. -MB	125.0	0.0	125.0	3.905	3.905	4,881.00	4,881.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: AUGUST 2000

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -MB	1,045.0	0.0	1,045.0	4.284	4.284	44,768.17	44,768.17	
FLA. PWR. & LIGHT	JURISD.	SCH. -MB	825.0	0.0	825.0	4.418	4.418	36,451.50	36,451.50	
CITY OF LAKELAND	JURISD.	SCH. -MB	95.0	0.0	95.0	2.849	2.849	2,706.29	2,706.29	
ORLANDO UTIL. COMM.	JURISD.	SCH. -MB	400.0	0.0	400.0	3.361	3.361	13,445.21	13,445.21	
TALLAHASSEE	JURISD.	SCH. -MB	50.0	0.0	50.0	4.647	4.647	2,323.65	2,323.65	
ADJUSTMENTS TO PREVIOUS MO	MON/YR	TYP SCHED.								
HARDEE POWER PARTNERS ES	7/00	SEPAR. CONTRACT	(60,695.0)	0.0	(60,695.0)	2.396	3.231	(1,454,252.20)	(1,961,056.45)	
HARDEE POWER PARTNERS ACT	7/00	SEPAR. CONTRACT	60,695.0	0.0	60,695.0	2.392	3.220	1,451,824.40	1,954,379.00	
SEMINOLE ELECTRIC CO-OP PRE	7/00	JURISD SCH. -D	(3,543.0)	(310.6)	(3,232.4)	2.342	2.342	(75,706.49)	(75,706.49)	
SEMINOLE ELECTRIC CO-OP PRE	7/00	JURISD SCH. -D	3,543.0	279.5	3,263.5	2.316	2.316	75,583.83	75,583.83	
ORLANDO UTIL. COMM.	7/00	JURISD STEAM-A	(373.0)	0.0	(373.0)	36.681	36.681	(136,818.36)	(136,818.36)	
ORLANDO UTIL. COMM.	7/00	JURISD STEAM-A	373.0	0.0	373.0	19.714	19.714	73,532.80	73,532.80	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			6,212.0	1,385.6	4,826.4	2.773	2.773	133,812.61	133,812.61	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.			55.0	0.0	55.0	4.911	4.911	2,701.01	2,701.01	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.			56,995.0	0.0	56,995.0	2.388	3.208	1,360,892.60	1,828,562.55	
SUB-TOTAL OTHER D POWER SALES			95,830.0	0.0	95,830.0	1.930	1.930	1,849,465.17	1,849,465.17	
SUB-TOTAL SCHEDULE MB POWER SALES-JURISD.			2,630.0	0.0	2,630.0	4.130	4.130	108,608.10	108,608.10	
SUB-TOTAL OTHER POWER SALES			0.0	0.0	0.0	0.000	0.000	(63,285.56)	(63,285.56)	
TOTAL INCLUDING VARIABLE O & M COSTS			161,722.0	1,385.6	160,336.4	2.116	2.407	3,392,193.93	3,859,863.88	0.00
LESS VARIABLE O & M COSTS								0.00		
LESS VARIABLE O & M COSTS - HARDEE								0.00		
LESS TRANSMISSION COSTS SCH. D (SEP.)								0.00		
PLUS 80% OF ECON. ENERGY SALES PROFITS	-							0.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS	-		161,722.0	1,385.6	160,336.4	2.116	2.407	3,392,193.93	3,859,863.88	0.00
CURRENT MONTH:										
DIFFERENCE	-		(57,779.0)	1,385.6	(59,164.6)	(0.864)	(0.931)	(3,149,370.07)	(3,467,500.12)	(1,116,600.00)
DIFFERENCE %	-		(26.3)	0.0	(27.0)	(29.0)	(27.9)	(48.1)	(47.3)	(100.0)
PERIOD TO DATE:										
ACTUAL	-		1,225,667.0	6,116.8	1,219,750.2	2.155	2.355	26,287,617.11	28,730,468.37	0.00
ESTIMATED	-		1,338,003.0	0.0	1,338,003.0	2.362	2.600	31,601,252.00	34,793,532.00	3,333,920.00
DIFFERENCE	-		(112,136.0)	6,116.8	(118,252.8)	(0.207)	(0.245)	(5,313,634.89)	(6,063,063.63)	(3,333,920.00)
DIFFERENCE %	-		(8.4)	0.0	(8.8)	(8.8)	(9.4)	(16.8)	(17.4)	(100.0)

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. SEC 60% OR $3,169.27 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH AUGUST 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	35,879.0	0.0	18,678.0	17,201.0	16.059	16.059	2,762,300.00
HARDEE POWER PARTNERS	IPP	148,252.0	0.0	0.0	148,252.0	3.562	3.562	5,280,700.00
VARIOUS	OTHER	54,835.0	0.0	0.0	54,835.0	4.399	4.399	2,412,200.00
TOTAL	-	238,966.0	0.0	18,678.0	220,288.0	4.746	4.746	10,455,200.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	125,833.0	0.0	0.0	125,833.0	5.693	5.693	7,164,087.55
HARDEE PWR. PART.-OTHERS	IPP	270.0	0.0	0.0	270.0	3.519	3.519	9,501.45
OKEELANTA	SCH.-D	25,723.0	0.0	0.0	25,723.0	5.493	5.493	1,412,846.80
AUBURNDALE POWER PARTNERS	SCH.-D	4,410.0	0.0	0.0	4,410.0	2.625	2.625	115,763.29
FLA. POWER CORP.	SCH.-Ja	1,317.0	0.0	1,127.3	189.7	11.544	11.544	21,898.32
FLA. POWER CORP.	SCH.-Jc	26,618.0	0.0	0.0	26,618.0	3.624	3.624	964,557.50
FLA. POWER & LIGHT	SCH.-Ja	14,744.0	0.0	6,838.9	7,905.1	9.027	9.027	713,602.01
FLA. POWER & LIGHT	SCH.-Jc	31,881.0	0.0	0.0	31,881.0	5.556	5.556	1,771,398.00
CITY OF LAKELAND	SCH.-Ja	15,644.0	0.0	10,697.5	4,946.5	8.599	8.599	425,365.17
CITY OF LAKELAND	SCH.-Jc	12,797.0	0.0	0.0	12,797.0	6.794	6.794	869,407.25
ORLANDO	SCH.-Ja	17,702.0	0.0	10,257.9	7,444.1	7.958	7.958	592,416.26
ORLANDO	SCH.-Jc	23,208.0	0.0	0.0	23,208.0	8.631	8.631	2,002,994.00
ENTERGY MARKETING	SCH.-Ja	692.0	0.0	530.1	161.9	12.497	12.497	20,232.03
ENTERGY MARKETING	SCH.-Jc	779.0	0.0	0.0	779.0	10.021	10.021	78,065.00
THE ENERGY AUTH.	SCH.-Ja	6,164.0	0.0	4,176.8	1,987.2	8.986	8.986	178,561.31
THE ENERGY AUTH.	SCH.-Jc	6,878.0	0.0	0.0	6,878.0	6.380	6.380	438,829.94
REEDY CREEK	SCH.-Jc	150.0	0.0	0.0	150.0	5.833	5.833	8,750.00
CORAL POWER	SCH.-Ja	4,191.0	0.0	1,423.3	2,767.7	9.466	9.466	261,985.82
CORAL POWER	SCH.-Jc	4,956.0	0.0	0.0	4,956.0	8.582	8.582	425,303.71
TALLAHASSEE	SCH.-Ja	29.0	0.0	29.0	0.0	0.000	0.000	0.00
TALLAHASSEE	SCH.-Jc	2,111.0	0.0	0.0	2,111.0	5.791	5.791	122,255.38
AQUILLA	SCH.-Ja	1,344.0	0.0	340.1	1,003.9	9.179	9.179	92,145.82
AQUILLA	SCH.-Jc	3,651.0	0.0	0.0	3,651.0	7.994	7.994	291,874.15
MORGAN STANLEY	SCH.-Ja	2,106.0	0.0	1,007.2	1,098.8	9.143	9.143	100,466.67
MORGAN STANLEY	SCH.-Jc	2,871.0	0.0	0.0	2,871.0	7.014	7.014	201,382.04
CARGILL ALLIANT	SCH.-Ja	1,213.0	0.0	755.5	457.5	11.329	11.329	51,831.30
CARGILL ALLIANT	SCH.-Jc	489.0	0.0	0.0	489.0	10.470	10.470	51,196.58
ENRON	SCH.-Ja	610.0	0.0	299.0	311.0	8.456	8.456	26,298.65
ENRON	SCH.-Jc	1,310.0	0.0	0.0	1,310.0	9.114	9.114	119,397.93
FARMLAND HYDRO LP	SCH.-Jc	358.0	0.0	0.0	358.0	3.502	3.502	12,537.78
CARGILL FERTILIZER	SCH.-Jc	4,055.0	0.0	0.0	4,055.0	3.138	3.138	127,229.50
RINGHAVER	SCH.-Jc	3,207.0	0.0	0.0	3,207.0	0.832	0.832	26,696.51
ADJUSTMENTS TO PRIOR MONTHS (See Pages 2, 3, and 4 for details)		(4.0)	0.0	21.0	(25.0)	(1,780.369)	(1,780.369)	445,751.02
TOTAL		347,307.0	0.0	37,503.6	309,803.4	6.180	6.180	19,144,628.74
CURRENT MONTH:								
DIFFERENCE	-	108,341.0	0.0	18,825.6	89,515.4	9.707	9.707	8,689,428.74
DIFFERENCE %	-	45.3	0.0	100.8	40.6	204.5	204.5	83.1
PERIOD TO DATE:								
ACTUAL	-	1,541,262.00	0.00	169,351.14	1,371,910.9	5.115	5.115	70,171,508.95
ESTIMATED	-	1,086,768.0	0.0	123,351.0	963,417.0	4.780	4.780	46,055,500.0
DIFFERENCE	-	454,494.0	0.0	46,000.1	408,493.9	0.335	0.335	24,116,008.95
DIFFERENCE %	-	41.8	0.0	37.3	42.4	7.0	7.0	52.4

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH AUGUST 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ADJUSTMENTS TO PRIOR MONTHS								
May 2000 :								
Fla. Pwr Corp	Schd. Ja (EST)	(5,956.0)	0.0	(4,846.6)	(1,109.4)	9.077	9.077	(100,698.12)
Fla. Pwr Corp	Schd. Ja (ACT)	5,956.0	0.0	4,794.8	1,161.2	9.079	9.079	105,419.79
Fla. Pwr & Lgt.	Schd. Ja (EST)	(1,419.0)	0.0	(1,052.6)	(366.4)	5.248	5.248	(19,229.50)
Fla. Pwr & Lgt.	Schd. Ja (ACT)	1,419.0	0.0	1,046.7	372.3	5.247	5.247	19,533.05
Entergy Power	Schd. Ja (EST)	(4,105.0)	0.0	(2,621.5)	(1,483.5)	7.406	7.406	(109,870.44)
Entergy Power	Schd. Ja (ACT)	4,105.0	0.0	2,606.6	1,498.4	7.018	7.018	105,154.25
Entergy Power	Schd. Jc (EST)	(4,700.0)	0.0	0.0	(4,700.0)	5.269	5.269	(247,659.76)
Entergy Power	Schd. Jc (ACT)	4,700.0	0.0	0.0	4,700.0	5.128	5.128	241,032.50
Tallahassee	Schd. Ja (EST)	(724.0)	0.0	(414.4)	(309.6)	9.566	9.566	(29,615.71)
Tallahassee	Schd. Ja (ACT)	724.0	0.0	406.8	317.2	8.740	8.740	27,724.24
		0.0						
Tallahassee	Schd. Jc (EST)	(1,289.0)	0.0	0.0	(1,289.0)	6.129	6.129	(79,002.03)
Tallahassee	Schd. Jc (ACT)	1,289.0	0.0	0.0	1,289.0	6.029	6.029	77,709.29
Koch	Schd. Ja (EST)	(2,020.0)	0.0	(1,144.3)	(875.7)	6.016	6.016	(52,681.92)
Koch	Schd. Ja (ACT)	2,020.0	0.0	1,142.1	877.9	6.847	6.847	60,111.28
Koch	Schd. Jc (EST)	(1,068.0)	0.0	0.0	(1,068.0)	6.680	6.680	(71,341.72)
Koch	Schd. Jc (ACT)	1,068.0	0.0	0.0	1,068.0	7.672	7.672	81,936.52
Energy Auth.	Schd. Ja (EST)	(3,240.0)	0.0	(2,335.8)	(904.2)	9.481	9.481	(85,730.96)
Energy Auth.	Schd. Ja (ACT)	3,240.0	0.0	2,310.5	929.5	7.298	7.298	67,835.00
Energy Auth.	Schd. Jc (EST)	(3,867.0)	0.0	0.0	(3,867.0)	5.633	5.633	(217,825.19)
Energy Auth.	Schd. Jc (ACT)	3,867.0	0.0	0.0	3,867.0	5.962	5.962	230,542.99
Aquila	Schd. Ja (EST)	(1,962.0)	0.0	(1,273.6)	(688.4)	7.794	7.794	(53,658.02)
Aquila	Schd. Ja (ACT)	1,964.0	0.0	1,270.5	693.5	9.021	9.021	62,563.46
Aquila	Schd. Jc (EST)	(3,011.0)	0.0	0.0	(3,011.0)	6.266	6.266	(188,676.93)
Aquila	Schd. Jc (ACT)	3,007.0	0.0	0.0	3,007.0	6.570	6.570	197,556.67
Morgan Stanley	Schd. Ja (EST)	(1,743.0)	0.0	(1,453.3)	(289.7)	7.500	7.500	(21,727.99)
Morgan Stanley	Schd. Ja (ACT)	1,743.0	0.0	1,426.5	316.5	10.115	10.115	32,011.85
		0.0						
Morgan Stanley	Schd. Jc (EST)	(2,722.0)	0.0	0.0	(2,722.0)	7.027	7.027	(191,287.74)
Morgan Stanley	Schd. Jc (ACT)	2,722.0	0.0	0.0	2,722.0	7.434	7.434	202,356.67
Reliant	Schd. Ja (EST)	(883.0)	0.0	(444.3)	(438.7)	6.535	6.535	(28,667.35)
Reliant	Schd. Ja (ACT)	883.0	0.0	426.4	456.6	5.647	5.647	25,785.19
Reliant	Schd. Jc (EST)	(2,048.0)	0.0	0.0	(2,048.0)	6.234	6.234	(127,673.55)
Reliant	Schd. Jc (ACT)	2,048.0	0.0	0.0	2,048.0	5.896	5.896	120,759.39
Lakeland	Schd. Ja (EST)	(7,229.0)	0.0	(6,464.7)	(764.3)	8.181	8.181	(62,533.59)
Lakeland	Schd. Ja (ACT)	7,229.0	0.0	6,418.1	810.9	8.121	8.121	65,852.57
Orlando	Schd. Ja (EST)	(3,238.0)	0.0	(2,827.0)	(411.0)	7.898	7.898	(32,461.29)
Orlando	Schd. Ja (ACT)	3,238.0	0.0	2,816.7	421.3	7.877	7.877	33,181.05
Okeelanta	Schd. Ja (EST)	(851.0)	0.0	(656.5)	(194.5)	7.777	7.777	(15,127.68)
Okeelanta	Schd. Ja (ACT)	851.0	0.0	647.0	204.0	7.671	7.671	15,647.86
Sub-Total for May 2000		(2.0)	0.0	(221.7)	219.7	16.949	16.949	37,244.13

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH AUGUST 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
June 2000:								
Aquila	Schd. Ja (EST)	(259.0)	0.0	(100.0)	(159.0)	9.471	9.471	(15,063.67)
Aquila	Schd. Ja (ACT)	259.0	0.0	100.0	159.0	9.585	9.585	15,244.45
Aquila	Schd. Jc (EST)	(1,107.0)	0.0	0.0	(1,107.0)	6.040	6.040	(66,863.14)
Aquila	Schd. Jc (ACT)	1,107.0	0.0	0.0	1,107.0	6.154	6.154	68,124.82
Entergy Power	Schd. Ja (EST)	(1,206.0)	0.0	(612.4)	(593.6)	9.830	9.830	(58,353.40)
Entergy Power	Schd. Ja (ACT)	1,206.0	0.0	612.4	593.6	9.854	9.854	58,498.13
Entergy Power	Schd. Jc (EST)	(1,677.0)	0.0	0.0	(1,677.0)	8.956	8.956	(150,197.27)
Entergy Power	Schd. Jc (ACT)	1,677.0	0.0	0.0	1,677.0	9.280	9.280	155,625.98
Enron	Schd. Ja (EST)	(590.0)	0.0	(507.7)	(82.3)	6.960	6.960	(5,730.11)
Enron	Schd. Ja (ACT)	590.0	0.0	528.7	61.3	6.235	6.235	3,824.15
Enron	Schd. Jc (EST)	(811.0)	0.0	0.0	(811.0)	6.481	6.481	(52,562.40)
Enron	Schd. Jc (ACT)	811.0	0.0	0.0	811.0	6.712	6.712	54,436.52
Fla. Pwr & Lgt.	Schd. Ja (EST)	(5,724.0)	0.0	(4,353.8)	(1,370.2)	7.243	7.243	(99,244.28)
Fla. Pwr & Lgt.	Schd. Ja (ACT)	5,724.0	0.0	4,360.8	1,363.2	7.212	7.212	98,312.22
Fla. Pwr & Lgt.	Schd. Jc (EST)	(15,706.0)	0.0	0.0	(15,706.0)	5.916	5.916	(929,163.68)
Fla. Pwr & Lgt.	Schd. Jc (ACT)	15,706.0	0.0	0.0	15,706.0	5.918	5.918	929,460.24
Koch	Schd. Ja (EST)	(760.0)	0.0	(522.3)	(237.7)	8.537	8.537	(20,293.04)
Koch	Schd. Ja (ACT)	760.0	0.0	522.3	237.7	8.582	8.582	20,399.99
Koch	Schd. Jc (EST)	(2,078.0)	0.0	0.0	(2,078.0)	8.273	8.273	(171,920.04)
Koch	Schd. Jc (ACT)	2,052.0	0.0	0.0	2,052.0	8.543	8.543	175,294.99
Morgan Stanley	Schd. Ja (EST)	(84.0)	0.0	0.0	(84.0)	7.993	7.993	(6,713.84)
Morgan Stanley	Schd. Ja (EST)	84.0	0.0	0.0	84.0	7.521	7.521	6,317.36
Morgan Stanley	Schd. Jc (EST)	(972.0)	0.0	0.0	(972.0)	7.284	7.284	(70,800.88)
Morgan Stanley	Schd. Jc (ACT)	972.0	0.0	0.0	972.0	7.813	7.813	75,938.64
Lakeland	Schd. Ja (EST)	(5,888.0)	0.0	(3,682.3)	(2,205.7)	9.063	9.063	(199,901.54)
Lakeland	Schd. Ja (EST)	5,888.0	0.0	3,697.3	2,190.7	9.064	9.064	198,551.54
Relient	Schd. Ja (EST)	(1,114.0)	0.0	(354.7)	(759.3)	7.075	7.075	(53,721.64)
Relient	Schd. Ja (EST)	1,114.0	0.0	354.7	759.3	7.085	7.085	53,794.38
Relient	Schd. Jc (EST)	(1,673.0)	0.0	0.0	(1,673.0)	7.580	7.580	(126,813.70)
Relient	Schd. Jc (ACT)	1,673.0	0.0	0.0	1,673.0	7.629	7.629	127,630.39
Tallahassee	Schd. Ja (EST)	(1,816.0)	0.0	(1,167.3)	(648.7)	9.080	9.080	(58,897.15)
Tallahassee	Schd. Ja (EST)	1,816.0	0.0	1,167.3	648.7	9.074	9.074	58,856.91
Tallahassee	Schd. Jc (EST)	(1,548.0)	0.0	0.0	(1,548.0)	8.983	8.983	(139,051.16)
Tallahassee	Schd. Jc (ACT)	1,548.0	0.0	0.0	1,548.0	9.030	9.030	139,788.57
Energy Auth.	Schd. Ja (EST)	(4,667.0)	0.0	(3,723.2)	(943.8)	8.588	8.588	(81,046.73)
Energy Auth.	Schd. Ja (EST)	4,707.0	0.0	3,723.2	983.8	8.037	8.037	79,065.23
Energy Auth.	Schd. Jc (EST)	(5,823.0)	0.0	0.0	(5,823.0)	6.827	6.827	(397,549.84)
Energy Auth.	Schd. Jc (ACT)	5,807.0	0.0	0.0	5,807.0	6.899	6.899	400,605.74
Sub-Total for June 2000		(2.0)	0.0	43.0	(45.0)	(35.295)	(35.295)	15,882.74

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH AUGUST 2000

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) ——CENTS/KWH—— (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
July 2000:								
HARDEE PWR. PART.-NATIVE	IPP (EST)	(116,390.0)	0.0	0.0	(116,390.0)	5.188	5.188	(6,038,289.74)
HARDEE PWR. PART.-OTHER	IPP (ACT)	116,390.0	0.0	0.0	116,390.0	5.555	5.555	6,465,755.13
Okeelanta	Schd. D (EST)	(23,816.0)	0.0	0.0	(23,816.0)	5.485	5.485	(1,306,311.60)
Okeelanta	Schd. D (ACT)	23,816.0	0.0	0.0	23,816.0	5.513	5.513	1,312,955.60
Aquila	Schd. Ja (EST)	(205.0)	0.0	(60.0)	(145.0)	9.097	9.097	(13,190.74)
Aquila	Schd. Ja (ACT)	205.0	0.0	60.0	145.0	9.069	9.069	13,150.00
Aquila	Schd. Jc (EST)	(1,508.0)	0.0	0.0	(1,508.0)	7.215	7.215	(108,803.87)
Aquila	Schd. Jc (ACT)	1,508.0	0.0	0.0	1,508.0	7.097	7.097	107,020.00
Cargill Fert.	Schd. Ja (EST)	(174.0)	0.0	(94.0)	(80.0)	16.375	16.375	(13,100.00)
Cargill Fert.	Schd. Ja (ACT)	154.0	0.0	94.0	60.0	18.833	18.833	11,300.00
Cargill Fert.	Schd. Jc (EST)	(223.0)	0.0	0.0	(223.0)	9.000	9.000	(20,070.00)
Cargill Fert.	Schd. Jc (ACT)	0.0	0.0	0.0	0.0	0.000	0.000	0.00
Cargill Alliant	Schd. Ja (EST)	0.0	0.0	0.0	0.0	0.000	0.000	0.00
Cargill Alliant	Schd. Ja (ACT)	20.0	0.0	0.0	20.0	9.000	9.000	1,800.00
Cargill Alliant	Schd. Jc (EST)	0.0	0.0	0.0	0.0	0.000	0.000	0.00
Cargill Alliant	Schd. Jc (ACT)	223.0	0.0	0.0	223.0	9.000	9.000	20,070.00
Fla. Pwr & Lgt.	Schd. Ja (EST)	(2,981.0)	0.0	(1,544.2)	(1,436.8)	10.772	10.772	(154,768.35)
Fla. Pwr & Lgt.	Schd. Ja (ACT)	2,981.0	0.0	1,545.5	1,435.5	10.437	10.437	149,822.24
Morgan Stanley	Schd. Ja (EST)	(670.0)	0.0	(50.0)	(620.0)	9.925	9.925	(61,534.26)
Morgan Stanley	Schd. Ja (ACT)	672.0	0.0	50.0	622.0	9.924	9.924	61,724.26
Morgan Stanley	Schd. Jc (EST)	(2,165.0)	0.0	0.0	(2,165.0)	9.894	9.894	(214,200.26)
Morgan Stanley	Schd. Jc (ACT)	2,163.0	0.0	0.0	2,163.0	10.194	10.194	220,499.26
Lakeland	Schd. Ja (EST)	(10,230.0)	0.0	(6,018.2)	(4,211.8)	21.400	21.400	(901,318.51)
Lakeland	Schd. Ja (ACT)	10,230.0	0.0	6,045.7	4,184.3	21.192	21.192	886,714.67
Orlando	Schd. Ja (EST)	(3,801.0)	0.0	(1,679.0)	(2,122.0)	11.131	11.131	(236,202.88)
Orlando	Schd. Ja (ACT)	3,801.0	0.0	1,737.3	2,063.7	11.112	11.112	229,307.59
Tallahassee	Schd. Ja (EST)	(810.0)	0.0	(472.4)	(337.6)	15.136	15.136	(51,102.53)
Tallahassee	Schd. Ja (ACT)	810.0	0.0	483.8	326.2	15.220	15.220	49,655.68
Tallahassee	Schd. Jc (EST)	(3,464.0)	0.0	0.0	(3,464.0)	6.866	6.866	(237,853.74)
Tallahassee	Schd. Jc (ACT)	3,464.0	0.0	0.0	3,464.0	6.984	6.984	241,916.12
Energy Auth.	Schd. Ja (EST)	(4,553.0)	0.0	(2,306.9)	(2,246.1)	12.506	12.506	(280,897.22)
Energy Auth.	Schd. Ja (ACT)	4,553.0	0.0	2,408.2	2,144.8	12.165	12.165	260,912.75
Energy Auth.	Schd. Jc (EST)	(3,770.0)	0.0	0.0	(3,770.0)	9.191	9.191	(346,487.32)
Energy Auth.	Schd. Jc (ACT)	3,770.0	0.0	0.0	3,770.0	9.129	9.129	344,151.88
Sub-Total for July 2000		0.0	0.0	199.8	(199.8)	(196.534)	(196.534)	392,624.15
Grand Total for Adjustments		**(4.0)**	**0.0**	**21.0**	**(25.0)**	**(1,780.369)**	**(1,780.369)**	**445,751.02**

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: AUGUST 2000

SCHEDULE A8

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
URCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	36,671.0	0.0	0.0	36,671.0	2.619	2.619	960,500.00
TOTAL	-	36,671.0	0.0	0.0	36,671.0	2.619	2.619	960,500.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	4,557.0	0.0	0.0	4,557.0	2.463	2.463	112,221.95
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	370.0	0.0	0.0	370.0	4.621	4.621	17,099.10
HILLSBOROUGH COUNTY	COGEN.	18,317.0	0.0	0.0	18,317.0	2.447	2.447	448,261.98
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	1,283.0	0.0	0.0	1,283.0	4.452	4.452	57,120.28
FARMLAND HYDRO LP	COGEN.	890.0	0.0	0.0	890.0	3.965	3.965	35,286.89
IMC-AGRICO-S. PIERCE	COGEN.	508.0	0.0	0.0	508.0	3.964	3.964	20,135.81
AUBURNDALE POWER PARTNERS	COGEN.	2,401.0	0.0	0.0	2,401.0	5.275	5.275	126,654.73
ORANGE COGENERATION L.P.	COGEN.	7,843.0	0.0	0.0	7,843.0	2.328	2.328	182,587.30
CUTRALE CITRUS	COGEN.	10.0	0.0	0.0	10.0	4.529	4.529	452.89
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR AUGUST 2000	-	36,179.0	0.0	0.0	36,179.0	2.764	2.764	999,820.93
ADJ. FOR JUNE 2000								
IMC-AGRICO-NICHOLS	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
McKAY BAY REFUSE	COGEN.	(4,593.0)	0.0	0.0	(4,593.0)	2.183	2.183	(100,265.49)
		4,593.0	0.0	0.0	4,593.0	2.213	2.213	101,659.15
MULBERRY PHOSPHATES INC.	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
CARGILL RIDGEWOOD	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
IMC-AGRICO-NEW WALES	COGEN.	(1,260.0)	0.0	0.0	(1,260.0)	3.414	3.414	(43,014.01)
		1,260.0	0.0	0.0	1,260.0	3.414	3.414	43,013.99
HILLSBOROUGH COUNTY	COGEN.	(16,290.0)	0.0	0.0	(16,290.0)	2.176	2.176	(354,541.61)
		16,290.0	0.0	0.0	16,290.0	2.205	2.205	359,119.80
CARGILL MILLPOINT	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
CF INDUSTRIES INC.	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
FARMLAND HYDRO LP	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
IMC-AGRICO-S. PIERCE	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
AUBURNDALE POWER PARTNERS	COGEN.	(3,957.0)	0.0	0.0	(3,957.0)	3.683	3.683	(145,751.58)
		3,957.0	0.0	0.0	3,957.0	3.683	3.683	145,751.35
ORANGE COGENERATION L.P.	COGEN.	(5,543.0)	0.0	0.0	(5,543.0)	2.166	2.166	(120,070.88)
		5,543.0	0.0	0.0	5,543.0	2.205	2.205	122,211.17
CUTRALE CITRUS	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
AS AVAILABLE ASSIGNMENT	* COGEN.		0.0	(1,874.2)	1,874.2	5.598	5.598	104,914.95
			0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR Jun-00 ADJ.	-	0.0	0.0	(1,874.2)	1,874.2	6.030	6.030	113,006.84
GRAND TOTAL		36,179.0	0.0	(1,874.2)	38,053.2	2.924	2.924	1,112,827.77
CURRENT MONTH:								
DIFFERENCE	-	(492.0)	0.0	(1,874.2)	1,382.2	0.305	0.305	152,327.77
DIFFERENCE %	-	(1.3)	0.0	0.0	3.8	11.6	11.6	15.9
PERIOD TO DATE:								
ACTUAL		258,379.0	0.0	728.6	257,650.4	2.356	2.356	6,069,763.10
ESTIMATED		272,292.0	0.0	0.0	272,292.0	2.236	2.236	6,088,300.00
DIFFERENCE	-	(13,913.0)	0.0	728.6	(14,641.6)	0.120	0.120	(18,536.90)
DIFFERENCE %	-	(5.1)	0.0	0.0	(5.4)	5.4	5.4	(0.3)

* Adjustment is for May, June and July 2000.

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: AUGUST 2000

SCHEDULE A9
REVISED WITH NOV. FILING

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	COST IF GENERATED (A) cents/KWH	(B) $	FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	4,553.0	6.148	279,900.00	6.807	309,900.00	30,000.00
TOTAL	-	4,553.0	6.148	279,900.00	6.807	309,900.00	30,000.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL	-	0.0	0.000	0.00	0.000	0.00	0.00
CURRENT MONTH:							
DIFFERENCE	-	(4,553.0)	(6.148)	(279,900.00)	(6.807)	(309,900.00)	(30,000.00)
DIFFERENCE %	-	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)
PERIOD TO DATE:							
ACTUAL		0.0	0.000	(10,512.45)	0.000	0.00	10,512.45
ESTIMATED		133,154.0	4.574	6,090,800.00	5.736	7,637,200.00	1,546,400.00
DIFFERENCE	-	(133,154.0)	(4.574)	(6,101,312.45)	(5.736)	(7,637,200.00)	(1,535,887.55)
DIFFERENCE %	-	(100.0)	(100.0)	(100.2)	(100.0)	(100.0)	(99.3)

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

SEPTEMBER 2000

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER , 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	35,924,374	33,285,760	2,638,614	7.9	1,479,818	1,579,949	(100,131)	(6.3)	2.42762	2.10676	0.32086	15.2
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(4,263)	(4,000)	(263)	7.1	1,479,818 a)	1,579,949 a)	(100,131)	(6.3)	(0.00029)	(0.00025)	(0.00004)	16.0
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,479,818 a)	1,579,949 a)	(100,131)	(6.3)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,479,818 a)	1,579,949 a)	(100,131)	(6.3)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	35,920,091	33,281,760	2,638,331	7.9	1,479,818	1,579,949	(100,131)	(6.3)	2.42733	2.10651	0.32082	15.2
6. Fuel Cost of Purchased Power - Firm (A7)	18,641,829	5,569,000	13,072,829	234.7	340,138	125,025	215,113	172.1	5.48087	4.45431	1.02638	23.0
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	3,019,900	(3,019,900)	(100.0)	0	66,183	(66,183)	(100.0)	0.00000	4.56295	(4.56295)	(100.0)
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 a)	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	858,654	888,400	(29,746)	(3.3)	30,557	35,488	(4,931)	(13.9)	2.81001	2.50338	0.30663	12.2
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	19,500,483	9,477,300	10,023,183	105.8	370,695	226,696	143,999	63.5	5.26052	4.18062	1.07990	25.8
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,850,513	1,806,645	43,868	2.4				
14. Fuel Cost of Economy Sales (A6)	0	87,400	(87,400)	(100.0)	0	3,388	(3,388)	(100.0)	0.00000	2.57969	(2.57969)	(100.0)
15. Gain on Economy Sales - 80% (A6)	0	23,000	(23,000)	(100.0)	0 a)	3,388 a)	(3,388)	(100.0)	0.00000	0.67887	(0.67887)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	170,938	138,400	32,538	23.5	4,881	5,824	(943)	(16.2)	3.50211	2.37637	1.12574	47.4
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	1,452,684	507,300	945,384	186.4	54,090	21,567	32,523	150.8	2.68568	2.35220	0.33348	14.2
21. Fuel Cost of Other Power Sales (A6)	1,775,648	1,943,944	(168,296)	(8.7)	92,143	108,000	(15,857)	(14.7)	1.92706	1.79995	0.12711	7.1
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	3,399,270	2,700,044	699,226	25.9	151,114	138,779	12,335	8.9	2.24947	1.94557	0.30390	15.6
23. Net Inadvertant Interchange					(1,617)	0	(1,617)	0.0				
24. Wheeling Rec'd. less Wheeling Del'vd.					580	0	580	0.0				
25. Interchange and Wheeling Losses					1,610	2,100	(490)	(23.3)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	52,021,304	40,059,016	11,962,288	29.9	1,696,752	1,665,766	30,986	1.9	3.06593	2.40484	0.66109	27.5
27. Net Unbilled	(1,683,790) (a)	(1,522,192) (a)	(161,598)	10.6	(69,908)	(62,026)	(7,882)	12.7	(0.10218)	(0.09183)	(0.01035)	11.3
28. Company Use	108,434 (a)	98,165 (a)	10,269	10.5	4,502	4,000	502	12.6	0.00658	0.00592	0.00066	11.1
29. T & D Losses	2,754,332 (a)	1,624,431 (a)	1,129,901	69.6	114,355	66,192	48,163	72.8	0.16715	0.09800	0.06915	70.6
30. System KWH Sales	52,021,304	40,059,016	11,962,288	29.9	1,647,803	1,657,600	(9,797)	(0.6)	3.15701	2.41669	0.74032	30.6
31. Wholesale KWH Sales	(2,747,356)	(972,184)	(1,775,172)	182.6	(87,024)	(40,228)	(46,796)	116.3	3.15701	2.41668	0.74033	30.6
32. Jurisdictional KWH Sales	49,273,948	39,086,832	10,187,116	26.1	1,560,779	1,617,372	(56,593)	(3.5)	3.15701	2.41669	0.74032	30.6
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	49,307,454	39,113,411	10,194,043	26.1	1,560,779	1,617,372	(56,593)	(3.5)	3.15916	2.41833	0.74083	30.6
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	336,932	347,085	(10,153)	(2.9)	1,560,779	1,617,372	(56,593)	(3.5)	0.02159	0.02146	0.00013	0.6
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	1,560,779	1,617,372	(56,593)	(3.5)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	1,560,779	1,617,372	(56,593)	(3.5)	0.00000	0.00000	0.00000	0.0
36. True-up *	2,684,371	305,574	2,378,797	778.5	1,560,779	1,617,372	(56,593)	(3.5)	0.17199	0.01889	0.15310	810.5
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	52,328,757	39,766,070	12,562,687	31.6	1,560,779	1,617,372	(56,593)	(3.5)	3.35273	2.45888	0.89405	36.4
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.35514	2.46045	0.89469	36.4
40. GPIF * (Already Adjusted for Taxes)	(23,059)	(23,059)	0	0.0	1,560,779	1,617,372	(56,593)	(3.5)	(0.00148)	(0.00143)	(0.00005)	3.5
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	52,305,698	39,743,011	12,562,687	31.6	1,560,779	1,617,372	(56,593)	(3.5)	3.35368	2.45902	0.89464	36.4
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									3.354	2.459	0.895	36.4

* Based on Jurisdictional Sales (a) Included for Informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: SEPTEMBER, 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUN	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	276,623,331	263,884,075	(7,260,744)	(2.6)	13,191,928	13,574,446	(382,519)	(2.8)	2.09691	2.09131	0.00560	0.3
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses	(36,120)	(36,000)	(2,120)	5.9	13,191,928	a) 13,574,446 a)	(382,519)	(2.8)	(0.00029)	(0.00027)	(0.00002)	7.4
4b. Adjustments to Fuel Cost	0	0	0	0.0	13,191,928	a) 13,574,446 a)	(382,519)	(2.8)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	(79)	0	(79)	0.0	13,191,928	a) 13,574,446 a)	(382,519)	(2.8)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	276,585,132	263,848,075	(7,262,943)	(2.6)	13,191,928	13,574,446	(382,519)	(2.8)	2.09662	2.09105	0.00557	0.3
6. Fuel Cost of Purchased Power - Firm (A7)	88,813,337	51,624,500	37,188,837	72.0	1,712,049	1,088,442	623,607	57.3	5.18755	4.74297	0.44458	9.4
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	(10,512)	9,110,700	(9,121,212)	(100.1)	0	199,337	(199,337)	(100.0)	#DIV/0!	4.57050	#DIV/0!	#DIV/0!
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	6,928,417	6,976,700	(48,283)	(0.7)	288,207	307,780	(19,573)	(6.4)	2.40397	2.26678	0.13719	6.1
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	95,731,242	67,711,900	28,019,342	41.4	2,000,256	1,595,559	404,697	25.4	4.78595	4.24377	0.54218	12.8
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					15,192,184	15,170,005	22,179	0.1				
14. Fuel Cost of Economy Sales (A6)	(1,687)	6,607,600	(6,609,287)	(100.0)	0	196,019	(196,019)	(100.0)	#DIV/0!	3.37090	#DIV/0!	#DIV/0!
15. Gain on Economy Sales - 80% (A6)	0	3,356,920	(3,356,920)	(100.0)	0	196,019 a)	(196,019)	(100.0)	0.00000	1.71255	(1.71255)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	127,483	295,300	(167,817)	(56.8)	12,186	19,153	(6,967)	(36.4)	1.04614	1.54180	(0.49566)	(32.1)
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	1,154,174	1,134,100	20,074	1.8	49,477	52,219	(2,742)	(5.3)	2.33275	2.17181	0.16094	7.4
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	108,608	0	108,608	0.0	2,630	0	2,630	0.0	4.12958	0.00000	4.12958	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	2,701	0	2,701	0.0	55	0	55	0.0	4.91091	0.00000	4.91091	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	8,245,616	5,128,400	3,117,416	60.8	342,020	222,991	119,029	53.4	2.41092	2.29982	0.11110	4.8
21. Fuel Cost of Other Power Sales (A6)	20,049,792	17,778,976	2,270,816	12.8	964,496	986,400	(21,904)	(2.2)	2.07878	1.80241	0.27637	15.3
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	29,686,889	34,301,296	(4,614,407)	(13.5)	1,370,864	1,476,782	(105,918)	(7.2)	2.16556	2.32271	(0.15715)	(6.8)
23. Net Inadvertant Interchange					487	0	487	0.0				
24. Wheeling Rec'd. less Wheeling Del'd.					5,166	0	5,166	0.0				
25. Interchange and Wheeling Losses					18,112	22,300	(4,188)	(18.8)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	342,629,485	317,258,679	25,370,806	8.0	13,808,861	13,670,923	137,938	1.0	2.48123	2.32068	0.16055	6.9
27. Net Unbilled	3,968,828 (a)	3,543,261 (a)	425,567	12.0	179,663	160,193	19,470	12.2	0.03068	0.02746	0.00322	11.7
28. Company Use	838,949 (a)	796,273 (a)	42,676	5.4	37,978	36,000	1,978	5.5	0.00648	0.00617	0.00031	5.0
29. T & D Losses	14,444,117 (a)	12,672,179 (a)	1,771,938	14.0	653,864	572,917	80,947	14.1	0.11165	0.09822	0.01343	13.7
30. System KWH Sales	342,629,485	317,258,679	25,370,806	8.0	12,937,356	12,901,813	35,543	0.3	2.64837	2.45902	0.18935	7.7
31. Wholesale KWH Sales	(14,704,751)	(7,787,062)	(6,917,689)	88.8	(531,460)	(301,333)	(230,147)	76.4	2.76876	2.58420	0.18256	7.1
32. Jurisdictional KWH Sales	327,924,734	309,471,617	18,453,117	6.0	12,405,876	12,600,480	(194,605)	(1.5)	2.64330	2.45603	0.18727	7.6
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	328,147,722	309,682,057	18,465,665	6.0	12,405,876	12,600,480	(194,605)	(1.5)	2.64510	2.45770	0.18740	7.6
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	3,162,539	3,221,081	(58,542)	(1.8)	12,405,876	12,600,480	(194,605)	(1.5)	0.02549	0.02556	(0.00007)	(0.3)
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	12,405,876	12,600,480	(194,605)	(1.5)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	12,405,876	12,600,480	(194,605)	(1.5)	0.00000	0.00000	0.00000	0.0
36. True-up *	12,265,354	2,750,166	9,515,188	346.0	12,405,876	12,600,480	(194,605)	(1.5)	0.09887	0.02183	0.07704	352.9
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	343,575,615	315,653,304	27,922,311	8.8	12,405,876	12,600,480	(194,605)	(1.5)	2.76946	2.50509	0.26437	10.6
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.77145	2.50669	0.26456	10.6
40. GPIF * (Already Adjusted for Taxes)	(207,531)	(207,531)	0	0.0	12,405,876	12,600,480	(194,605)	(1.5)	(0.00167)	(0.00165)	(0.00002)	1.2
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	343,368,084	315,445,773	27,922,311	8.9	12,405,876	12,600,480	(194,605)	(1.5)	2.76978	2.50524	0.26454	10.6
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.770	2.505	0.265	10.6

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2000

SCHEDULE A2
PAGE 1 OF 3

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	35,924,374	33,285,760	2,638,614	7.9	276,623,331	283,884,075	(7,260,744)	(2.6)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	3,399,270	2,700,044	699,226	25.9	29,686,889	34,301,296	(4,614,407)	(13.5)
3. FUEL COST OF PURCHASED POWER	18,641,829	5,569,000	13,072,829	234.7	88,813,337	51,624,500	37,188,837	72.0
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	858,654	888,400	(29,746)	(3.3)	6,928,417	6,976,700	(48,283)	(0.7)
4. ENERGY COST OF ECONOMY PURCHASES	0	3,019,900	(3,019,900)	0.0	(10,512)	9,110,700	(9,121,212)	(100.1)
5. TOTAL FUEL & NET POWER TRANSACTION	52,025,587	40,063,016	11,962,571	29.9	342,667,684	317,294,679	25,373,005	8.0
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(4,283)	(4,000)	(283)	7.1	(38,120)	(36,000)	(2,120)	5.9
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST	0	0	0	0.0	(79)	0	(79)	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	52,021,304	40,059,016	11,962,288	29.9	342,629,485	317,258,679	25,370,806	8.0
* INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,560,779	1,617,372	(56,593)	(3.5)	12,405,876	12,600,480	(194,604)	(1.5)
2. NONJURISDICTIONAL SALES	87,024	40,228	46,796	116.3	531,480	301,333	230,147	76.4
3. TOTAL SALES	1,647,803	1,657,600	(9,797)	(0.6)	12,937,356	12,901,813	35,543	0.3
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9471879	0.9757312	(0.0285433)	(2.9)	0.9589190	0.9766441	(0.0177251)	(1.8)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	38,529,308	37,261,172	1,268,136	3.4	293,723,548	290,011,193	3,712,355	1.3
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	(2,684,371)	(305,574)	(2,378,797)	778.5	(12,265,354)	(2,750,166)	(9,515,188)	346.0
b. INCENTIVE PROVISION	23,059	23,059	0	0.0	207,531	207,531	0	0.0
c. TRANSITION ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
d. OTHER ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	35,867,996	36,978,657	(1,110,661)	(3.0)	281,665,725	287,468,558	(5,802,833)	(2.0)
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	52,021,304	40,059,016	11,962,288	29.9	342,629,485	317,258,679	25,370,806	8.0
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B-4)	0.9471879	0.9757312	(0.0285433)	(2.9)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	49,273,948	39,086,832	10,187,116	26.1	327,924,734	309,471,617	18,453,117	6.0
6A.JURISDIC. LOSS MULTIPLIER	1.00068	1.00068	0.0000	0.0	NA	NA	-	-
6B. (LINE 6 x LINE 6A)	49,307,454	39,113,411	10,194,043	26.1	328,147,722	309,682,057	18,465,665	6.0
6C.PEABODY COAL CONTR. BUY-OUT AMORT.	355,718	355,718	0	0.0	3,292,578	3,292,578	0	0.0
6D.(LINE 6C x LINE 5) PB. JURISD.	336,932	347,085	(10,153)	(2.9)	3,162,539	3,221,081	(58,542)	(1.8)
6E.OTHER (SPARE INPUT #1)	0	0	0	0.0	0	0	0	0.0
6F. OIL BELOW THE DISCHARGE VALVE	0	0	0	0.0	0	0	0	0.0
6G. OTHER (SPARE INPUT #2)	0	0	0	0.0	0	0	0	0.0
6H. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. 6B+6D+6E+6F+6G)	49,644,386	39,460,496	10,183,890	25.8	331,310,261	312,903,138	18,407,123	5.9
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6H)	(13,776,390)	(2,481,839)	(11,294,551)	455.1	(49,644,536)	(25,434,580)	(24,209,956)	95.2
8. INTEREST PROVISION FOR THE MONTH	(242,580)	(172,498)	(70,082)	40.6	(919,101)	(635,593)	(283,508)	44.6
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(41,674,900)	(44,455,217)	2,780,317	(6.3)	NOT APPLICABLE			
9a.DEFERRED TRUE-UP BEGINNING OF PERIO	2,361,673	7,879,936	(5,498,263)	(69.8)	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	2,684,371	305,574	2,378,797	778.5	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	(50,627,826)	(38,924,044)	(11,703,782)	30.1	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	(39,293,227)	(36,575,281)	(2,717,946)	7.4	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	(50,385,246)	(38,751,546)	(11,633,700)	30.0	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(89,678,473)	(75,326,827)	(14,351,646)	19.1	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	(44,839,236)	(37,663,414)	(7,175,823)	19.1	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	6.480	5.500	0.980	17.8	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	6.500	5.500	1.000	18.2	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	12.980	11.000	1.980	18.0	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	6.490	5.500	0.990	18.0	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.541	0.458	0.083	18.1	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	(242,580)	(172,498)	(70,082)	40.6	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: SEPTEMBER 2000

SCHEDULE A3
PAGE 1 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
FUEL COST OF SYSTEM NET GENERATION ($)								
1 HEAVY OIL	2,195,772	364,080	1,831,692	503.1	11,631,459	11,566,481	64,978	0.6
2 LIGHT OIL	3,843,707	2,346,718	1,496,989	63.8	12,362,199	15,043,481	(2,681,282)	(17.8)
3 COAL	26,401,406	30,539,440	(4,138,034)	(13.5)	247,360,938	257,238,591	(9,877,653)	(3.8)
4 NATURAL GAS	3,483,489	35,522	3,447,967	9,706.6	5,268,735	35,522	5,233,213	14,732.3
5 NUCLEAR	0	0	0	0.0	0	0	0	0.0
6 OTHER	0	0	0	0.0	0	0	0	0.0
7 TOTAL ($)	35,924,374	33,285,760	2,638,614	7.9	276,623,331	283,884,075	(7,260,744)	(2.6)
SYSTEM NET GENERATION (MWH)								
8 HEAVY OIL	37,077	7,528	29,549	392.5	196,469	253,395	(56,926)	(22.5)
9 LIGHT OIL	47,461	20,239	27,222	134.5	164,059	138,663	25,396	18.3
10 COAL	1,341,617	1,550,950	(209,333)	(13.5)	12,745,807	13,181,156	(435,350)	(3.3)
11 NATURAL GAS	53,663	1,232	52,431	4,255.8	85,593	1,232	84,361	6,847.5
12 NUCLEAR	0	0	0	0.0	0	0	0	0.0
13 OTHER	0	0	0	0.0	0	0	0	0.0
14 TOTAL (MWH)	1,479,818	1,579,949	(100,131)	(6.3)	13,191,928	13,574,446	(382,519)	(2.8)
UNITS OF FUEL BURNED								
15 HEAVY OIL (BBL)	81,891	15,640	66,251	423.6	453,371	635,280	(181,909)	(28.6)
16 LIGHT OIL (BBL)	93,777	60,642	33,135	54.6	345,969	421,294	(75,325)	(17.9)
17 COAL (TON)	606,859	698,974	(92,115)	(13.2)	5,811,688	5,952,449	(140,761)	(2.4)
18 NATURAL GAS (MCF)	653,569	10,700	642,869	6,008.1	1,030,983	10,700	1,020,283	9,535.4
19 NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20 OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
BTUS BURNED (MMBTU)								
21 HEAVY OIL	519,251	98,856	420,395	425.3	2,876,380	4,015,607	(1,139,227)	(28.4)
22 LIGHT OIL	539,876	237,762	302,114	127.1	1,990,511	1,749,201	241,310	13.8
23 COAL	14,119,737	16,251,020	(2,131,283)	(13.1)	133,130,071	137,849,724	(4,719,653)	(3.4)
24 NATURAL GAS	635,458	10,981	624,477	5,686.9	1,002,413	10,981	991,432	9,028.6
25 NUCLEAR	0	0	0	0.0	0	0	0	0.0
26 OTHER	0	0	0	0.0	0	0	0	0.0
27 TOTAL (MMBTU)	15,814,322	16,598,619	(784,297)	(4.7)	138,999,375	143,625,513	(4,626,138)	(3.2)
GENERATION MIX (% MWH)								
28 HEAVY OIL	2.51	0.48	2.03	-	1.49	1.87	(0.38)	-
29 LIGHT OIL	3.21	1.28	1.93	-	1.24	1.02	0.22	-
30 COAL	90.66	98.16	(7.50)	-	96.62	97.10	(0.48)	-
31 NATURAL GAS	3.63	0.08	3.55	-	0.65	0.01	0.64	-
32 NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33 OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34 TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
FUEL COST PER UNIT								
35 HEAVY OIL ($/BBL)	26.81	23.28	3.53	15.2	25.66	18.21	7.45	40.9
36 LIGHT OIL ($/BBL)	40.99	38.70	2.29	5.9	35.73	35.71	0.02	0.1
37 COAL ($/TON)	43.51	43.69	(0.18)	(0.4)	42.56	43.22	(0.66)	(1.5)
38 NATURAL GAS ($/MCF)	5.33	3.32	2.01	60.5	5.11	3.32	1.79	53.9
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40 OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
FUEL COST PER MMBTU ($/MMBTU)								
41 HEAVY OIL	4.23	3.68	0.55	14.9	4.04	2.88	1.16	40.3
42 LIGHT OIL	7.12	9.87	(2.75)	(27.9)	6.21	8.60	(2.39)	(27.8)
43 COAL	1.87	1.88	(0.01)	(0.5)	1.86	1.87	(0.01)	(0.5)
44 NATURAL GAS	5.48	3.23	2.25	69.7	5.26	3.23	2.03	62.8
45 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47 TOTAL ($/MMBTU)	2.27	2.01	0.26	12.9	1.99	1.98	0.01	0.5

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: SEPTEMBER 2000

SCHEDULE A3
PAGE 2 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
BTU BURNED PER KWH (BTU/KWH)								
48 HEAVY OIL	14,005	13,132	873	6.6	14,640	15,847	(1,207)	(7.6)
49 LIGHT OIL	11,375	11,748	(373)	(3.2)	12,133	12,615	(482)	(3.8)
50 COAL	10,524	10,478	46	0.4	10,445	10,458	(13)	(0.1)
51 NATURAL GAS	11,842	8,913	2,929	32.9	11,711	8,913	2,798	31.4
52 NUCLEAR	0	0	0	0.0	0	0	0	0.0
53 OTHER	0	0	0	0.0	0	0	0	0.0
54 TOTAL (BTU/KWH)	10,687	10,506	181	1.7	10,537	10,581	(44)	(0.4)
GENERATED FUEL COST PER KWH (cents/KWH)								
55 HEAVY OIL	5.92	4.84	1.08	22.3	5.92	4.56	1.36	29.8
56 LIGHT OIL	8.10	11.60	(3.50)	(30.2)	7.54	10.85	(3.31)	(30.5)
57 COAL	1.97	1.97	0.00	0.0	1.94	1.95	(0.01)	(0.5)
58 NATURAL GAS	6.49	2.88	3.61	125.3	6.16	2.88	3.28	113.9
59 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61 TOTAL (cents/KWH)	2.43	2.11	0.32	15.2	2.10	2.09	0.01	0.5

SYSTEM NET GENERATION AND FUEL COST — SCHEDULE A4

TAMPA ELECTRIC COMPANY

ACTUAL FOR THE PERIOD/MONTH OF: SEPTEMBER 2000

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPC. FACTO (%)	EQUIV. AVAIL. FACTO (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COS PER KWH (cents /KWH)	COST OF FUEL ($/UNIT)
H.P.#1	30	829	3.8	65.5	44.3	-	HVY.OIL	-	-	-	-	-	-
H.P.#2	30	4,675	21.6	96.2	55.3	-	HVY.OIL	-	-	-	-	-	-
H.P.#3	30	4,339	20.1	92.3	43.4	-	HVY.OIL	-	-	-	-	-	-
H.P.#4	39	4,982	17.7	73.0	48.1	-	HVY.OIL	-	-	-	-	-	-
H.P.#5	67	10,230	21.2	85.0	60.0	-	HVY.OIL	-	-	-	-	-	-
H.P. STATION	196	25,055	17.8	82.5	52.0	16,308	HVY.OIL	64,253	6,359,244	408,600.5	1,663,881	6.64	25.90
GAN.#1	114	57,176	69.7	88.1	73.4	11,695	COAL	28,451	23,502,661	668,674.2	1,191,110	2.08	41.87
GAN.#2	98	44,720	63.4	75.9	79.5	12,271	COAL	23,379	23,472,578	548,765.4	978,769	2.19	41.87
GAN.#3	145	82,938	79.4	93.2	80.0	12,035	COAL	49,579	20,133,101	998,179.0	2,075,639	2.50	41.87
GAN.#4	159	69,608	60.8	73.6	78.3	11,892	COAL	40,960	20,209,500	827,781.1	1,714,802	2.46	41.87
GAN.#5	232	70,563	42.2	49.5	63.1	11,014	COAL	32,987	23,560,721	777,197.5	1,381,010	1.96	41.87
GAN.#6	372	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GANNON STA.	1120	325,005	40.3	48.4	49.0	11,756	COAL	175,356	21,787,662	3,820,597.2	7,341,330	2.26	41.87
B.B.#1	416	155,545	51.9	60.9	75.0	10,522	COAL	65,965	24,811,080	1,636,662.9	2,719,551	1.75	41.23
B.B.#2	416	238,322	79.6	89.8	79.6	10,072	COAL	97,444	24,633,300	2,400,367.3	4,017,341	1.69	41.23
B.B.#3	433	241,247	77.4	88.0	79.9	9,717	COAL	97,892	23,945,640	2,344,086.6	4,035,811	1.67	41.23
B.B. 1 - 3	1265	635,115	69.7	79.7	78.2	10,047	COAL	261,301	24,420,560	6,381,116.8	10,772,703	1.70	41.23
B.B.#4	442	241,406	75.9	84.0	86.7	9,933	COAL	107,905	22,221,759	2,397,837.1	5,676,065	2.35	52.60
B.B. STA.	1707	876,520	71.3	80.8	80.4	10,016	COAL	369,206	23,777,934	8,778,953.9	16,448,768	1.88	44.55
SEB-PHIL. #1(HVY OIL)	17	5,647	46.1	99.9	85.2	9,797	HVY.OIL	8,819	6,273,387	55,325.0	265,945	4.71	30.16
SEB-PHIL. #2(HVY OIL)	17	6,375	52.1	99.9	96.1	8,678	HVY.OIL	8,819	6,273,387	55,325.0	265,946	4.17	30.16
SEB-PHILLIPS TOTAL	34	12,022	49.1	99.9	90.7	9,204	HVY.OIL	17,638	6,273,387	110,650.0	531,891	4.42	30.16
POLK #1 GASIFIER	250	140,092	77.8	83.3	93.3	10,851	COAL	62,297	24,402,200	1,520,186.3	2,611,308	1.86	41.92
POLK #1 CT (OIL)	225	19,334	11.9	99.0	77.2	8,698	LGT.OIL	29,859	5,632,281	168,175.4	1,260,240	6.52	42.21
POLK #1 TOTAL	250	159,426	88.6	97.3	91.0	10,590	-	-	-	1,688,361.7	3,871,548	2.43	-
POLK #2 CT (GAS)	155	53,663	48.1	99.1	86.0	11,842	GAS	653,569	972,289	635,458.0	3,483,489	6.49	5.33
POLK #2 CT (OIL)	155	8,556	7.7	97.9	98.7	8,569	LGT.OIL	12,625	5,807,005	73,313.5	532,853	6.23	42.21
POLK #2 TOTAL	155	62,219	55.8	98.5	87.5	11,392	-	-	-	708,771.5	4,016,342	6.46	-
POLK STATION TOTAL	405	221,645	76.0	97.8	89.7	10,815	-	-	-	2,397,133.2	7,887,890	3.56	-
GAN.C.T.#1	12	499	5.8	62.6	73.9	20,170	LGT.OIL	1,730	5,817,688	10,064.6	69,150	13.86	39.97
B.B.C.T.#1	12	1,160	13.4	100.0	93.4	17,910	LGT.OIL	3,570	5,816,704	20,775.1	142,741	12.31	39.98
B.B.C.T.#2	66	7,845	16.5	89.9	76.8	15,605	LGT.OIL	21,045	5,817,237	122,421.6	841,344	10.72	39.98
B.B.C.T.#3	66	10,067	21.2	100.0	81.4	14,416	LGT.OIL	24,948	5,817,236	145,125.9	997,379	9.91	39.98
C.T. TOTAL	156	19,571	17.4	92.9	79.8	15,246	LGT.OIL	51,293	5,817,354	298,387.2	2,050,614	10.48	39.98
TOT. COAL (GN,BB,POLK)	3077	1,341,617	60.6	69.2	70.0	10,524	COAL	606,859	23,266,915	14,119,737.4	26,401,406	1.97	43.51
SYSTEM	3,618	1,479,818	56.8	73.4	70.2	10,687	-	-	-	15,814,322.0	35,924,374	2.43	-

LEGEND:
H.P. = HOOKERS POINT
B.B. = BIG BEND
GAN. = GANNON
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS
NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2000

		CURRENT MONTH				PERIOD TO DATE			
	HEAVY OIL (1)	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	PURCHASES:								
2	UNITS (BBL)	19,467	15,640	3,827	24.5	441,795	589,192	(147,397)	(25.0)
3	UNIT COST ($/BBL)	11.45	22.88	(11.43)	(50.0)	27.04	18.20	8.84	48.6
4	AMOUNT ($)	222,994	357,860	(134,866)	(37.7)	11,947,824	10,723,326	1,224,498	11.4
5	BURNED:								
6	UNITS (BBL)	81,891	15,640	66,251	423.6	453,371	635,280	(181,909)	(28.6)
7	UNIT COST ($/BBL)	26.81	23.28	3.53	15.2	25.66	18.21	7.45	40.9
8	AMOUNT ($)	2,195,772	364,080	1,831,692	503.1	11,631,459	11,566,481	64,978	0.6
9	ENDING INVENTORY:								
10	UNITS (BBL)	78,683	81,135	(2,452)	(3.0)	78,683	81,135	(2,452)	(3.0)
11	UNIT COST ($/BBL)	26.80	20.44	6.36	31.1	26.80	20.44	6.36	31.1
12	AMOUNT ($)	2,108,553	1,658,340	450,213	27.1	2,108,553	1,658,340	450,213	27.1
13									
14	DAYS SUPPLY:	2,538	174	2,364	1,358.6	-	-	-	-
	LIGHT OIL (2)								
15	PURCHASES:								
16	UNITS (BBL)	101,885	79,684	22,201	27.9	460,359	520,044	(59,685)	(11.5)
17	UNIT COST ($/BBL)	46.59	38.78	7.81	20.1	37.65	36.00	1.65	4.6
18	AMOUNT ($)	4,746,652	3,090,429	1,656,223	53.6	17,333,433	18,722,008	(1,388,575)	(7.4)
19	BURNED:								
20	UNITS (BBL)	93,777	60,642	33,135	54.6	345,969	421,294	(75,325)	(17.9)
21	UNIT COST ($/BBL)	40.99	38.70	2.29	5.9	35.73	35.71	0.02	0.1
22	AMOUNT ($)	3,843,707	2,346,718	1,496,989	63.8	12,362,199	15,043,481	(2,681,282)	(17.8)
23	ENDING INVENTORY:								
24	UNITS (BBL)	98,304	97,057	1,247	1.3	98,304	97,057	1,247	1.3
25	UNIT COST ($/BBL)	40.94	38.50	2.44	6.3	40.94	38.50	2.44	6.3
26	AMOUNT ($)	4,024,658	3,736,313	288,345	7.7	4,024,658	3,736,313	288,345	7.7
27									
28	DAYS SUPPLY: NORMAL	64	61	3	4.9	-	-	-	-
29	DAYS SUPPLY: EMERGENCY	14	14	0	0.0	-	-	-	-
	COAL (3)								
30	PURCHASES:								
31	UNITS (TONS)	417,775	767,000	(349,225)	(45.5)	5,867,007	5,864,200	2,807	0.0
32	UNIT COST ($/TON)	43.09	42.94	0.15	0.3	42.43	42.63	(0.20)	(0.5)
33	AMOUNT ($)	18,003,925	32,931,836	(14,927,911)	(45.3)	248,953,949	249,990,674	(1,036,725)	(0.4)
34	BURNED:								
35	UNITS (TONS)	606,859	698,974	(92,115)	(13.2)	5,811,688	5,952,449	(140,761)	(2.4)
36	UNIT COST ($/TON)	43.51	43.69	(0.18)	(0.4)	42.56	43.22	(0.66)	(1.5)
37	AMOUNT ($)	26,401,406	30,539,440	(4,138,034)	(13.5)	247,360,938	257,238,591	(9,877,653)	(3.8)
38	ENDING INVENTORY:								
39	UNITS (TONS)	832,335	1,037,926	(205,591)	(19.8)	832,335	1,037,926	(205,591)	(19.8)
40	UNIT COST ($/TON)	42.22	42.85	(0.63)	(1.5)	42.22	42.85	(0.63)	(1.5)
41	AMOUNT ($)	35,143,330	44,474,429	(9,331,099)	(21.0)	35,143,330	44,474,429	(9,331,099)	(21.0)
42									
43	DAYS SUPPLY:	44	50	(6)	(12.0)	-	-	-	-
	NATURAL GAS								
44	PURCHASES:								
45	UNITS (MCF)	653,569	10,700	642,869	6,008.1	1,030,983	10,700	1,020,283	9,535.4
46	UNIT COST ($/MCF)	5.33	3.32	2.01	60.5	5.29	3.32	1.97	59.3
47	AMOUNT ($)	3,483,489	35,522	3,447,967	9,706.6	5,449,698	35,522	5,414,176	15,241.6
48	BURNED:								
49	UNITS (MCF)	653,569	10,700	642,869	6,008.1	0	10,700	(10,700)	(100.0)
50	UNIT COST ($/MCF)	5.33	3.32	2.01	60.5	0.00	3.32	(3.32)	(100.0)
51	AMOUNT ($)	3,483,489	35,522	3,447,967	9,706.6	0	35,522	(35,522)	(100.0)
52	ENDING INVENTORY:								
53	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
54	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
56									
57	DAYS SUPPLY:	0	0	0	0.0	-	-	-	-
	NUCLEAR								
58	BURNED:								
59	UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
60	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2000

OTHER	CURRENT MONTH ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	PERIOD TO DATE ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
74 DAYS SUPPLY:	0	0	0	0.0	-	-	-	-

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	17,472
LUBE OIL	0
FUEL ANALYSIS	237
TOTAL	17,709

(2)
RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(7,503)	(299,620)
OTHER USAGE	(1,185)	(47,601)
TOTAL	(8,688)	(347,221)

(3)
RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	69,256
IGNITION #2 OIL	282,148
IGNITION PROPANE	4,521
AERIAL SURVEY ADJ.	(194,318)
ADDITIVES	76,219
TOTAL	237,826

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: SEPTEMBER 2000

SCHEDULE A6
PAGE 1 OF 3

(1) SOLD TO		(2) TYPE & SCH.	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENER.	(6) ---cents/KWH--- (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECON. ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	3,388.0	0.0	3,388.0	2.789	3.636	94,500.00	123,200.00	23,000.00
VARIOUS	JURISDICTIONAL	SCH. -D	5,824.0	0.0	5,824.0	2.376	2.376	138,400.00	138,400.00	
VARIOUS	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPARATED	CONTR.	21,567.0	0.0	21,567.0	2.352	3.295	507,300.00	710,800.00	
FMPA		SCH. -D	108,000.0	0.0	108,000.0	1.800	1.800	1,943,944.00	1,943,944.00	
VARIOUS	JURISDICTIONAL	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	138,779.0	0.0	138,779.0	1.934	2.101	2,684,144.00	2,916,144.00	23,000.00
LESS TRANSMISSION COSTS		-						0.00		
LESS VARIABLE O & M COSTS		-						(7,100.00)		
PLUS 80% OF ECON. ENERGY SALES PROFI		-						23,000.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INC		-								
80% OF ECON. ENERGY SALES PROFITS		-	138,779.0	0.0	138,779.0	1.946	2.101	2,700,044.00	2,916,144.00	23,000.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENRGY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
OGLETHORPE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENN. VALLEY AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEP. CONTRACT		54,090.0	0.0	54,090.0	2.535	3.353	1,371,181.50	1,813,637.70	
SEM. ELEC CO-OP PRECO-1	JURISD.	SCH. -D	5,977.0	1,773.6	4,203.4	3.685	3.685	154,909.59	154,909.59	
SEM. ELEC CO-OP HARDEE	JURISD.	SCH. -D	678.0	0.0	678.0	2.346	2.346	15,905.77	15,905.77	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: SEPTEMBER 2000

SCHEDULE A6
PAGE 2 OF 3

(1) SOLD TO		(2) TYPE & SCH.	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENER.	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECON. ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA		SCH. -D	91,210.0	0.0	91,210.0	1.906	1.906	1,738,253.01	1,738,253.01	
HARDEE POWER PART. TO FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR.& LT.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO JACKSONVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KISSIMMEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ORLANDO		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO SEMINOLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FT. PIERCE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LK. WORTH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ENERGY AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO REEDY CREEK		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PART. TO FLA. PWR.& LT.		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: SEPTEMBER 2000

SCHEDULE A6
PAGE 3 OF 3

(1) SOLD TO		(2) TYPE & SCH.	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENER.	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECON. ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -MA	775.0	0.0	775.0	3.216	3.216	24,924.85	24,924.85	
CITY OF LAKELAND	JURISD.	SCH. -MA	50.0	0.0	50.0	4.847	4.847	2,423.85	2,423.85	
CARGILL	JURISD.	SCH. -MA	108.0	0.0	108.0	8.514	8.514	9,194.78	9,194.78	
THE ENERGY AUTHORITY	JURISD.	SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KOCH	JURISD.	SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SONAT	JURISD.	SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ADJUSTMENTS TO PREVIOUS MO	MON/YR	TYP	SCHED.							
HARDEE POWER PARTNERS	8/00	SEPA	CONTR.	(56,995.0)	0.0	(56,995.0)	2.392	3.220	(1,363,320.40)	(1,835,239.00)	
HARDEE POWER PARTNERS	8/00	SEPA	CONTR.	56,995.0	0.0	56,995.0	2.535	3.353	1,444,823.25	1,911,042.35	
SEMINOLE ELECTRIC COOP PRE	7/00	JURIS	SCH. -D	(3,543.0)	(279.5)	(3,263.5)	2.316	2.316	(75,583.83)	(75,583.83)	
SEMINOLE ELECTRIC COOP PRE	7/00	JURIS	SCH. -D	3,543.0	279.5	3,263.5	2.320	2.320	75,706.49	75,706.49	
CARGILL-ALLIANT	7/00	JURIS	SCH. -MA	(204.0)	0.0	(204.0)	6.958	6.958	(14,194.66)	(14,194.66)	
CARGILL-ALLIANT	7/00	JURIS	SCH. -MA	204.0	0.0	204.0	7.376	7.376	15,046.06	15,046.06	
SUB-TOTAL ECONOMY POWER SALES				0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.0
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.				0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.				6,655.0	1,773.6	4,881.4	3.502	3.502	170,938.02	170,938.02	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.				0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.				54,090.0	0.0	54,090.0	2.686	3.493	1,452,684.35	1,889,441.05	
SUB-TOTAL OTHER D POWER SALES				91,210.0	0.0	91,210.0	1.906	1.906	1,738,253.01	1,738,253.01	
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.				0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.				933.0	0.0	933.0	4.008	4.008	37,394.68	37,394.68	
TOTAL INCLUDING VARIABLE O & M COSTS				152,888.0	1,773.6	151,114.4	2.249	2.538	3,399,270.06	3,836,026.76	0.00
LESS VARIABLE O & M COSTS									0.00		
LESS VARIABLE O & M COSTS - HARDEE									0.00		
LESS TRANSMISSION COSTS SCH. D (SEP.)									0.00		
PLUS 80% OF ECON. ENERGY SALES PROFITS									0.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-		152,888.0	1,773.6	151,114.4	2.249	2.538	3,399,270.06	3,836,026.76	0.00
CURRENT MONTH:											
DIFFERENCE		-		14,109.0	1,773.6	12,335.4	0.303	0.437	699,226.06	919,882.76	(23,000.00)
DIFFERENCE %		-		10.2	0.0	8.9	15.6	20.8	25.9	31.5	(100.0)
PERIOD TO DATE:											
ACTUAL		-		1,378,755.0	7,890.4	1,370,864.6	2.166	2.376	29,686,887.17	32,566,495.13	0.00
ESTIMATED		-		1,476,782.0	0.0	1,476,782.0	2.323	2.554	34,301,296.00	37,709,676.00	3,356,920.00
DIFFERENCE		-		(98,027.0)	7,890.4	(105,917.4)	(0.157)	(0.178)	(4,614,408.83)	(5,143,180.87)	(3,356,920.00)
DIFFERENCE %		-		(6.6)	0.0	(7.2)	(6.8)	(7.0)	(13.5)	(13.6)	(100.0)

* THERE WERE NO SALES TO HARDEE POWER PARTNER FOR OTHERS IN SEPTEMBER.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH SEPTEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	24,651.0	0.0	13,249.0	11,402.0	16.059	16.059	1,831,100.00
HARDEE POWER PARTNERS	IPP	89,851.0	0.0	0.0	89,851.0	3.430	3.430	3,082,300.00
VARIOUS	OTHER	23,772.0	0.0	0.0	23,772.0	2.758	2.758	655,600.00
TOTAL	-	138,274.0	0.0	13,249.0	125,025.0	4.454	4.454	5,569,000.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	122,729.0	0.0	0.0	122,729.0	6.021	6.021	7,389,582.72
HARDEE PWR. PART.-OTHERS	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.	SCH.-Ja	19,230.0	0.0	8,082.7	10,147.3	7.843	7.843	795,849.07
FLA. POWER CORP.	SCH.-Jc	68,222.0	0.0	0.0	68,222.0	3.840	3.840	2,619,432.00
FLA. POWER & LIGHT	SCH.-Ja	8,492.0	0.0	4,485.7	4,006.3	7.285	7.285	291,853.62
FLA. POWER & LIGHT	SCH.-Jc	21,686.0	0.0	0.0	21,686.0	5.929	5.929	1,285,760.35
CITY OF LAKELAND	SCH.-Ja	21,602.0	0.0	14,781.3	6,820.7	9.244	9.244	630,496.94
CITY OF LAKELAND	SCH.-Jc	6,576.0	0.0	0.0	6,576.0	6.936	6.936	456,108.00
ORLANDO	SCH.-Ja	26,462.0	0.0	12,178.6	14,283.4	8.032	8.032	1,147,228.14
ORLANDO	SCH.-Jc	13,738.0	0.0	0.0	13,738.0	8.133	8.133	1,117,282.00
ENTERGY MARKETING	SCH.-Ja	333.0	0.0	277.4	55.6	15.810	15.810	8,790.55
ENTERGY MARKETING	SCH.-Jc	60.0	0.0	0.0	60.0	26.574	26.574	15,944.58
THE ENERGY AUTH.	SCH.-Ja	8,923.0	0.0	3,420.8	5,502.2	8.098	8.098	445,550.12
THE ENERGY AUTH.	SCH.-Jc	11,518.0	0.0	0.0	11,518.0	5.162	5.162	594,503.47
REEDY CREEK	SCH.-Ja	479.0	0.0	30.0	449.0	5.775	5.775	25,930.00
REEDY CREEK	SCH.-Jc	2,101.0	0.0	0.0	2,101.0	5.234	5.234	109,975.00
OKEELANTA	SCH.-Ja	790.0	0.0	673.9	116.1	7.398	7.398	8,590.86
OKEELANTA	SCH.-Jc	1,561.0	0.0	0.0	1,561.0	5.913	5.913	92,308.10
TALLAHASSEE	SCH.-Ja	2,499.0	0.0	557.4	1,941.6	7.244	7.244	140,641.16
TALLAHASSEE	SCH.-Jc	7,713.0	0.0	0.0	7,713.0	4.983	4.983	384,340.75
AQUILA	SCH.-Ja	480.0	0.0	69.0	411.0	8.451	8.451	34,731.60
AQUILA	SCH.-Jc	166.0	0.0	0.0	166.0	6.866	6.866	11,397.86
MORGAN STANLEY	SCH.-Ja	244.0	0.0	117.2	126.8	11.568	11.568	14,670.41
MORGAN STANLEY	SCH.-Jc	1,104.0	0.0	0.0	1,104.0	3.406	3.406	37,603.37
CARGILL ALLIANT	SCH.-Ja	367.0	0.0	92.9	274.1	7.248	7.248	19,863.54
CARGILL ALLIANT	SCH.-Jc	498.0	0.0	0.0	498.0	5.928	5.928	29,520.00
ENRON	SCH.-Ja	272.0	0.0	0.0	272.0	7.317	7.317	19,903.58
ENRON	SCH.-Jc	2,993.0	0.0	0.0	2,993.0	3.959	3.959	118,495.32
KOCH	SCH.-Ja	7,897.0	0.0	1,647.9	6,249.1	7.795	7.795	487,099.32
KOCH	SCH.-Jc	8,834.0	0.0	0.0	8,834.0	6.934	6.934	612,509.15
FARMLAND	SCH.-Jc	296.0	0.0	0.0	296.0	3.504	3.504	10,371.62
RINGHAVER	SCH.-Jc	6,289.0	0.0	0.0	6,289.0	1.691	1.691	106,370.59
OKEELANTA	SCH.-D	9,657.0	0.0	0.0	9,657.0	3.059	3.059	295,392.20
AUBURNDALE POWER	SCH.-D	4,012.0	0.0	0.0	4,012.0	2.334	2.334	93,633.31
ADJUSTMENTS TO PRIOR MONTHS:								
SEE PAGE 2 FOR DETAILS		(270.0)	0.0	0.0	(270.0)	300.0	300.0	(809,900.27)
TOTAL		387,553.0	0.0	47,414.7	340,138.3	5.481	5.481	18,641,829.03
CURRENT MONTH:								
DIFFERENCE	-	249,279.0	0.0	34,165.7	215,113.3	6.077	6.077	13,072,829.03
DIFFERENCE %	-	180.3	0.0	257.9	172.1	136.4	136.4	234.7
PERIOD TO DATE:								
ACTUAL	-	1,928,815.00	0.00	216,765.85	1,712,049.1	5.188	5.188	88,813,337.98
ESTIMATED	-	1,225,042.0	0.0	136,600.0	1,088,442.0	4.743	4.743	51,624,500.00
DIFFERENCE	-	703,773.0	0.0	80,165.9	623,607.1	0.445	0.445	37,188,837.98
DIFFERENCE %	-	57.4	0.0	58.7	57.3	9.4	9.4	72.0

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH SEPTEMBER 2000

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) ----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ADJUSTMENTS:									
HARDEE PWR. PART.-NATIVE	8/00	IPP	(125,833.0)	0.0	0.0	(125,833.0)	5.693	5.693	(7,164,087.55)
HARDEE PWR. PART.-NATIVE	8/00	IPP	125,563.0	0.0	0.0	125,563.0	5.067	5.067	6,362,355.78
FLORIDA POWER & LIGHT	8/00	SCH.-Ja	(14,744.0)	0.0	(6,838.9)	(7,905.1)	9.027	9.027	(713,602.01)
FLORIDA POWER & LIGHT	8/00	SCH.-Ja	14,744.0	0.0	6,838.9	7,905.1	9.024	9.024	713,383.01
ENERGY AUTHORITY	8/00	SCH.-Ja	(6,164.0)	0.0	(4,176.8)	(1,987.2)	8.986	8.986	(178,561.31)
ENERGY AUTHORITY	8/00	SCH.-Ja	6,164.0	0.0	4,176.8	1,987.2	8.900	8.900	176,856.59
ENERGY AUTHORITY	8/00	SCH.-Jc	(6,878.0)	0.0	0.0	(6,878.0)	6.380	6.380	(438,829.94)
ENERGY AUTHORITY	8/00	SCH.-Jc	6,878.0	0.0	0.0	6,878.0	6.407	6.407	440,642.79
TALLAHASSEE	8/00	SCH.-Jc	(2,111.0)	0.0	0.0	(2,111.0)	5.791	5.791	(122,255.38)
TALLAHASSEE	8/00	SCH.-Jc	2,111.0	0.0	0.0	2,111.0	5.591	5.591	118,030.00
AQUILA	8/00	SCH.-Jc	(3,651.0)	0.0	0.0	(3,651.0)	7.994	7.994	(291,874.15)
AQUILA	8/00	SCH.-Jc	3,651.0	0.0	0.0	3,651.0	7.996	7.996	291,928.15
MORGAN STANLEY	8/00	SCH.-Ja	(2,106.0)	0.0	(1,007.2)	(1,098.8)	9.143	9.143	(100,466.67)
MORGAN STANLEY	8/00	SCH.-Ja	2,106.0	0.0	1,007.2	1,098.8	9.143	9.143	100,466.66
MORGAN STANLEY	8/00	SCH.-Jc	(2,871.0)	0.0	0.0	(2,871.0)	7.014	7.014	(201,382.04)
MORGAN STANLEY	8/00	SCH.-Jc	2,871.0	0.0	0.0	2,871.0	6.906	6.906	198,267.48
CARGILL-ALLIANT	8/00	SCH.-Ja	(1,213.0)	0.0	(755.5)	(457.5)	11.329	11.329	(51,831.30)
CARGILL-ALLIANT	8/00	SCH.-Ja	1,213.0	0.0	755.5	457.5	11.114	11.114	50,845.77
CARGILL-ALLIANT	8/00	SCH.-Jc	(489.0)	0.0	0.0	(489.0)	10.470	10.470	(51,196.58)
CARGILL-ALLIANT	8/00	SCH.-Jc	489.0	0.0	0.0	489.0	10.513	10.513	51,410.43
SUB-TOTAL (ADJUSTMENTS)			(270.0)	0.0	0.0	(270.0)	299.963	299.963	(809,900.27)

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: SEPTEMBER 2000

SCHEDULE A8

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	---CENTS/KWH--- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	35,488.0	0.0	0.0	35,488.0	2.503	2.503	888,400.00
TOTAL	-	35,488.0	0.0	0.0	35,488.0	2.503	2.503	888,400.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	10,263.0	0.0	0.0	10,263.0	2.549	2.549	261,585.67
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	190.0	0.0	0.0	190.0	6.022	6.022	11,442.61
HILLSBOROUGH COUNTY	COGEN.	11,172.0	0.0	0.0	11,172.0	2.550	2.550	284,879.13
CARGILL MILLPOINT	COGEN.	37.0	0.0	0.0	37.0	8.012	8.012	2,964.34
CF INDUSTRIES INC.	COGEN.	492.0	0.0	0.0	492.0	5.477	5.477	26,946.12
FARMLAND HYDRO LP	COGEN.	640.0	0.0	0.0	640.0	4.394	4.394	28,122.54
IMC-AGRICO-S. PIERCE	COGEN.	372.0	0.0	0.0	372.0	4.264	4.264	15,863.44
AUBURNDALE POWER PARTNERS	COGEN.	1,556.0	0.0	0.0	1,556.0	5.581	5.581	86,843.19
ORANGE COGENERATION L.P.	COGEN.	5,819.0	0.0	0.0	5,819.0	2.411	2.411	140,320.44
CUTRALE CITRUS	COGEN.	16.0	0.0	0.0	16.0	4.285	4.285	685.63
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR SEPTEMBER 2000	-	30,557.0	0.0	0.0	30,557.0	2.813	2.813	859,653.11
ADJ. FOR JULY 2000								
IMC-AGRICO-NICHOLS	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
McKAY BAY REFUSE	COGEN.	(4,505.0)	0.0	0.0	(4,505.0)	2.325	2.325	(104,746.89)
		4,505.0	0.0	0.0	4,505.0	2.322	2.322	104,619.01
MULBERRY PHOSPHATES INC.	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
CARGILL RIDGEWOOD	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
IMC-AGRICO-NEW WALES	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
HILLSBOROUGH COUNTY	COGEN.	(18,223.0)	0.0	0.0	(18,223.0)	2.330	2.330	(424,549.57)
		18,223.0	0.0	0.0	18,223.0	2.327	2.327	424,029.46
CARGILL MILLPOINT	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
CF INDUSTRIES INC.	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
FARMLAND HYDRO LP	COGEN.	(736.0)	0.0		(736.0)	3.819	3.819	(28,111.02)
		736.0	0.0		736.0	3.819	3.819	28,110.74
IMC-AGRICO-S. PIERCE	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
AUBURNDALE POWER PARTNERS	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
ORANGE COGENERATION L.P.	COGEN.	(7,820.0)	0.0	0.0	(7,820.0)	2.289	2.289	(178,986.92)
		7,820.0	0.0	0.0	7,820.0	2.284	2.284	178,635.81
CUTRALE CITRUS	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
AS AVAILABLE ASSIGNMENT	COGEN.		0.0	0.0	0.0	0.000	0.000	
			0.0	0.0	0.0	0.000	0.000	
SUB-TOTAL FOR Jul-00 ADJ.	-	0.0	0.0	0.0	0.0	0.000	0.000	(999.58)
GRAND TOTAL		30,557.0	0.0	0.0	30,557.0	2.810	2.810	858,653.53
CURRENT MONTH:								
DIFFERENCE	-	(4,931.0)	0.0	0.0	(4,931.0)	0.307	0.307	(29,746.47)
DIFFERENCE %	-	(13.9)	0.0	0.0	(13.9)	12.3	12.3	(3.3)
PERIOD TO DATE:								
ACTUAL		288,936.0	0.0	728.6	288,207.4	2.404	2.404	6,928,416.63
ESTIMATED		1,817,232.0	0.0	0.0	1,817,232.0	0.384	0.384	6,976,700.00
DIFFERENCE	-	(1,528,296.0)	0.0	728.6	(1,529,024.6)	2.020	2.020	(48,283.37)
DIFFERENCE %	-	(84.1)	0.0	0.0	(84.1)	526.0	526.0	(0.7)

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: SEPTEMBER 2000

SCHEDULE A9

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	COST IF GENERATED (A) cents/KWH	COST IF GENERATED (B) $	FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	66,183.0	4.563	3,019,900.00	6.005	3,974,300.00	954,400.00
TOTAL	-	66,183.0	4.563	3,019,900.00	6.005	3,974,300.00	954,400.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL	-	0.0	0.000	0.00	0.000	0.00	0.00
CURRENT MONTH:							
DIFFERENCE	-	(66,183.0)	(4.563)	(3,019,900.00)	(6.005)	(3,974,300.00)	(954,400.00)
DIFFERENCE %	-	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)
PERIOD TO DATE:							
ACTUAL		0.0	0.000	(10,512.45)	0.000	0.00	10,512.45
ESTIMATED		199,337.0	4.571	9,110,700.00	5.825	11,611,500.00	2,500,800.00
DIFFERENCE	-	(199,337.0)	(4.571)	(9,121,212.45)	(5.825)	(11,611,500.00)	(2,490,287.55)
DIFFERENCE %	-	(100.0)	(100.0)	(100.1)	(100.0)	(100.0)	(99.6)

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

OCTOBER 2000

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
1. Fuel Cost of System Net Generation (A3)	29,192,288	30,964,123	(1,771,835)	(5.7)	1,376,720	1,490,395	(113,675)	(7.6)	2.12042	2.07758	0.04284	2.1
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(3,480)	(4,000)	520	(13.0)	1,376,720 a)	1,490,395 a)	(113,675)	(7.6)	(0.00025)	(0.00027)	0.00002	(7.4)
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,376,720 a)	1,490,395 a)	(113,675)	(7.6)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,376,720 a)	1,490,395 a)	(113,675)	(7.6)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	29,188,808	30,960,123	(1,771,315)	(5.7)	1,376,720	1,490,395	(113,675)	(7.6)	2.12017	2.07731	0.04286	2.1
6. Fuel Cost of Purchased Power - Firm (A7)	13,821,491	1,500,500	12,320,991	821.1	222,069	35,077	186,992	533.1	6.22396	4.27773	1.94623	45.5
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	2,929,500	(2,929,500)	(100.0)	0	68,792	(68,792)	(100.0)	0.00000	4.25849	(4.25849)	(100.0)
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 a)	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	1,012,426	854,500	157,926	18.5	38,738	35,819	2,919	8.1	2.61352	2.38561	0.22791	9.6
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	14,833,917	5,284,500	9,549,417	180.7	260,807	139,688	121,119	86.7	5.68770	3.78307	1.90463	50.3
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,637,527	1,630,083	7,444	0.5				
14. Fuel Cost of Economy Sales (A6)	0	3,400	(3,400)	(100.0)	0	162	(162)	(100.0)	0.00000	2.09877	(2.09877)	(100.0)
15. Gain on Economy Sales - 80% (A6)	0	700	(700)	(100.0)	0 a)	162 a)	(162)	(100.0)	0.00000	0.43210	(0.43210)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	(1)	0	(1)	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	185,044	122,800	62,244	50.7	6,159	5,854	305	5.2	3.00445	2.09771	0.90674	43.2
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	1,660,033	450,100	1,209,933	268.8	73,165	19,456	53,709	276.1	2.26889	2.31343	(0.04454)	(1.9)
21. Fuel Cost of Other Power Sales (A6)	1,777,419	2,014,564	(237,145)	(11.8)	90,461	111,600	(21,139)	(18.9)	1.96485	1.80516	0.15969	8.8
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	3,822,495	2,591,564	1,030,931	39.8	169,785	137,072	32,713	23.9	2.13358	1.89066	0.24292	12.8
23. Net Inadvertant Interchange					1,285	0	1,285	0.0				
24. Wheeling Rec'd. less Wheeling Del'd.					(47)	0	(47)	0.0				
25. Interchange and Wheeling Losses					1,475	2,100	(625)	(29.8)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	40,400,230	33,653,059	6,747,171	20.0	1,467,485	1,490,911	(23,426)	(1.6)	2.75303	2.25721	0.49582	22.0
27. Net Unbilled	(2,921,776) (a)	(1,550,120) (a)	(1,371,656)	88.5	(121,307)	(63,164)	(58,143)	92.1	(0.19026)	(0.10488)	(0.08538)	81.4
28. Company Use	99,233 (a)	98,165 (a)	1,068	1.1	4,120	4,000	120	3.0	0.00646	0.00664	(0.00018)	(2.7)
29. T & D Losses	1,180,655 (a)	1,769,273 (a)	(588,418)	(33.3)	49,027	72,094	(23,067)	(32.0)	0.07690	0.11971	(0.04281)	(35.8)
30. System KWH Sales	40,400,230	33,653,059	6,747,171	20.0	1,535,645	1,477,981	57,664	3.9	2.63083	2.27696	0.35387	15.5
31. Wholesale KWH Sales	(1,985,280)	(705,812)	(1,279,468)	181.3	(75,462)	(30,998)	(44,464)	143.4	2.63083	2.27696	0.35387	15.5
32. Jurisdictional KWH Sales	38,414,950	32,947,247	5,467,703	16.6	1,460,183	1,446,983	13,200	0.9	2.63083	2.27696	0.35387	15.5
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	38,441,072	32,969,651	5,471,421	16.6	1,460,183	1,446,983	13,200	0.9	2.63262	2.27851	0.35411	15.5
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	335,831	345,780	(9,949)	(2.9)	1,460,183	1,446,983	13,200	0.9	0.02300	0.02390	(0.00090)	(3.8)
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	1,460,183	1,446,983	13,200	0.9	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	1,460,183	1,446,983	13,200	0.9	0.00000	0.00000	0.00000	0.0
36. True-up *	2,684,371	305,574	2,378,797	778.5	1,460,183	1,446,983	13,200	0.9	0.18384	0.02112	0.16272	770.5
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	41,461,274	33,621,005	7,840,269	23.3	1,460,183	1,446,983	13,200	0.9	2.83946	2.32352	0.51594	22.2
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.84150	2.32519	0.51631	22.2
40. GPIF * (Already Adjusted for Taxes)	(23,059)	(23,059)	0	0.0	1,460,183	1,446,983	13,200	0.9	(0.00158)	(0.00159)	0.00001	(0.6)
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	41,438,215	33,597,946	7,840,269	23.3	1,460,183	1,446,983	13,200	0.9	2.83992	2.32360	0.51632	22.2
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.840	2.324	0.516	22.2

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: OCTOBER 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUN	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	305,815,619	314,848,198	(9,032,579)	(2.9)	14,568,648	15,064,841	(496,194)	(3.3)	2.09914	2.08995	0.00919	0.4
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses	(41,600)	(40,000)	(1,600)	4.0	14,568,648 a)	15,064,841 a)	(496,194)	(3.3)	(0.00029)	(0.00027)	(0.00002)	7.4
4b. Adjustments to Fuel Cost	0	0	0	0.0	14,568,648 a)	15,064,841 a)	(496,194)	(3.3)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	(79)	0	(79)	0.0	14,568,648 a)	15,064,841 a)	(496,194)	(3.3)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	305,773,940	314,808,198	(9,034,258)	(2.9)	14,568,648	15,064,841	(496,194)	(3.3)	2.09885	2.08969	0.00916	0.4
6. Fuel Cost of Purchased Power - Firm (A7)	102,634,828	53,125,000	49,509,828	93.2	1,934,118	1,123,519	810,599	72.1	5.30654	4.72845	0.57809	12.2
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	(10,512)	12,040,200	(12,050,712)	(100.1)	0	268,129	(268,129)	(100.0)	#DIV/0!	4.49045	#DIV/0!	#DIV/0!
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	7,940,843	7,831,200	109,643	1.4	326,945	343,599	(16,654)	(4.8)	2.42880	2.27917	0.14963	6.6
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	110,565,159	72,996,400	37,568,759	51.5	2,261,063	1,735,247	525,816	30.3	4.88996	4.20669	0.68327	16.2
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					16,829,711	16,800,088	29,623	0.2				
14. Fuel Cost of Economy Sales (A6)	(1,687)	6,611,000	(6,612,687)	(100.0)	0	196,181	(196,181)	(100.0)	#DIV/0!	3.36985	#DIV/0!	#DIV/0!
15. Gain on Economy Sales - 80% (A6)	0	3,357,620	(3,357,620)	(100.0)	0	196,181 a)	(196,181)	(100.0)	0.00000	1.71149	(1.71149)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	127,482	295,300	(167,818)	(56.8)	12,186	19,153	(6,967)	(36.4)	1.04613	1.54180	(0.49567)	(32.1)
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	1,339,218	1,256,900	82,318	6.5	55,636	58,073	(2,437)	(4.2)	2.40711	2.16434	0.24277	11.2
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	108,608	0	108,608	0.0	2,630	0	2,630	0.0	4.12958	0.00000	4.12958	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	2,701	0	2,701	0.0	55	0	55	0.0	4.91091	0.00000	4.91091	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	9,905,851	5,578,500	4,327,351	77.6	415,185	242,447	172,738	71.2	2.38589	2.30092	0.08497	3.7
21. Fuel Cost of Other Power Sales (A6)	21,827,211	19,793,540	2,033,671	10.3	1,054,957	1,098,000	(43,043)	(3.9)	2.06901	1.80269	0.26632	14.8
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	33,309,384	36,892,860	(3,583,476)	(9.7)	1,540,649	1,613,854	(73,205)	(4.5)	2.16204	2.28601	(0.12397)	(5.4)
23. Net Inadvertant Interchange					1,752	0	1,752	0.0				
24. Wheeling Rec'd. less Wheeling Del'd.					5,119	0	5,119	0.0				
25. Interchange and Wheeling Losses					19,587	24,400	(4,813)	(19.7)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	383,029,715	350,911,738	32,117,977	9.2	15,276,346	15,161,834	114,512	0.8	2.50734	2.31444	0.19290	8.3
27. Net Unbilled	1,289,107 (a)	2,146,155 (a)	(857,048)	(39.9)	58,356	97,029	(38,673)	(39.9)	0.00891	0.01492	(0.00601)	(40.3)
28. Company Use	929,962 (a)	884,748 (a)	45,214	5.1	42,098	40,000	2,098	5.2	0.00643	0.00615	0.00028	4.6
29. T & D Losses	15,527,143 (a)	14,266,805 (a)	1,260,338	8.8	702,891	645,011	57,880	9.0	0.10728	0.09921	0.00807	8.1
30. System KWH Sales	383,029,715	350,911,738	32,117,977	9.2	14,473,001	14,379,794	93,207	0.6	2.64651	2.44031	0.20620	8.4
31. Wholesale KWH Sales	(16,690,031)	(8,492,874)	(8,197,157)	96.5	(606,942)	(332,331)	(274,611)	82.6	2.74986	2.55555	0.19431	7.6
32. Jurisdictional KWH Sales	366,339,684	342,418,864	23,920,820	7.0	13,866,059	14,047,463	(181,405)	(1.3)	2.64199	2.43759	0.20440	8.4
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	366,586,794	342,651,708	23,937,086	7.0	13,866,059	14,047,463	(181,405)	(1.3)	2.64379	2.43924	0.20455	8.4
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	3,498,370	3,566,861	(68,491)	(1.9)	13,866,059	14,047,463	(181,405)	(1.3)	0.02523	0.02539	(0.00016)	(0.6)
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	13,866,059	14,047,463	(181,405)	(1.3)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	13,866,059	14,047,463	(181,405)	(1.3)	0.00000	0.00000	0.00000	0.0
36. True-up *	14,949,725	3,055,740	11,893,985	389.2	13,866,059	14,047,463	(181,405)	(1.3)	0.10782	0.02175	0.08607	395.7
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	385,036,889	349,274,309	35,762,580	10.2	13,866,059	14,047,463	(181,405)	(1.3)	2.77683	2.48639	0.29044	11.7
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.77883	2.48818	0.29065	11.7
40. GPIF * (Already Adjusted for Taxes)	(230,590)	(230,590)	0	0.0	13,866,059	14,047,463	(181,405)	(1.3)	(0.00166)	(0.00164)	(0.00002)	1.2
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	384,806,299	349,043,719	35,762,580	10.2	13,866,059	14,047,463	(181,405)	(1.3)	2.77717	2.48654	0.29063	11.7
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.777	2.487	0.290	11.7

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	29,192,288	30,964,123	(1,771,835)	(5.7)	305,815,619	314,848,198	(9,032,579)	(2.9)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	3,622,495	2,591,564	1,030,931	39.8	33,309,384	36,892,860	(3,583,476)	(9.7)
3. FUEL COST OF PURCHASED POWER	13,821,491	1,500,500	12,320,991	821.1	102,634,828	53,125,000	49,509,828	93.2
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	1,012,426	854,500	157,926	18.5	7,940,843	7,831,200	109,643	1.4
4. ENERGY COST OF ECONOMY PURCHASES	0	2,929,500	(2,929,500)	0.0	(10,512)	12,040,200	(12,050,712)	(100.1)
5. TOTAL FUEL & NET POWER TRANSACTION	40,403,710	33,657,059	6,746,651	20.0	383,071,394	350,951,738	32,119,656	9.2
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(3,480)	(4,000)	520	(13.0)	(41,600)	(40,000)	(1,600)	4.0
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST	0	0	0	0.0	(79)	0	(79)	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	40,400,230	33,653,059	6,747,171	20.0	383,029,715	350,911,738	32,117,977	9.2
* INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,460,183	1,446,983	13,200	0.9	13,866,059	14,047,463	(181,404)	(1.3)
2. NONJURISDICTIONAL SALES	75,462	30,998	44,464	143.4	606,942	332,331	274,611	82.6
3. TOTAL SALES	1,535,645	1,477,981	57,664	3.9	14,473,001	14,379,794	93,207	0.
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9508597	0.9790268	(0.0281671)	(2.9)	0.9580638	0.9768890	(0.0188252)	(1.9)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	36,127,737	33,315,013	2,812,724	8.4	329,851,285	323,326,206	6,525,079	2.0
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	(2,684,371)	(305,574)	(2,378,797)	778.5	(14,949,725)	(3,055,740)	(11,893,985)	389.2
b. INCENTIVE PROVISION	23,059	23,059	0	0.0	230,590	230,590	0	0.0
c. TRANSITION ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
d. OTHER ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	33,466,425	33,032,498	433,927	1.3	315,132,150	320,501,056	(5,368,906)	(1.7)
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	40,400,230	33,653,059	6,747,171	20.0	383,029,715	350,911,738	32,117,977	9.2
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B-4)	0.9508597	0.9790268	(0.0281671)	(2.9)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	38,414,950	32,947,247	5,467,703	16.6	366,339,684	342,418,864	23,920,820	7.0
6A.JURISDIC. LOSS MULTIPLIER	1.00068	1.00068	0.0000	0.0	NA	NA	-	-
6B. (LINE 6 x LINE 6A)	38,441,072	32,969,651	5,471,421	16.6	366,588,794	342,651,708	23,937,086	7.0
6C.PEABODY COAL CONTR. BUY-OUT AMORT.	353,187	353,187	0	0.0	3,645,765	3,645,765	0	0.0
6D.(LINE 6C x LINE 5) PB. JURISD.	335,831	345,780	(9,949)	(2.9)	3,498,370	3,566,861	(68,491)	(1.9)
6E.OTHER (SPARE INPUT #1)	0	0	0	0.0	0	0	0	0.0
6F. OIL BELOW THE DISCHARGE VALVE	0	0	0	0.0	0	0	0	0.0
6G. OTHER (SPARE INPUT #2)	0	0	0	0.0	0	0	0	0.0
6H. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. 6B+6D+6E+6F+6G)	38,776,903	33,315,431	5,461,472	16.4	370,087,164	346,218,569	23,868,595	6.9
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6H)	(5,310,478)	(282,933)	(5,027,545)	1,776.9	(54,955,014)	(25,717,513)	(29,237,501)	113.7
8. INTEREST PROVISION FOR THE MONTH	(281,000)	(178,220)	(102,780)	57.7	(1,200,101)	(813,813)	(386,288)	47.5
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(53,009,499)	(46,803,980)	(6,205,519)	13.3	NOT APPLICABLE			
9a.DEFERRED TRUE-UP BEGINNING OF PERIOD	2,381,673	7,879,936	(5,498,263)	(69.8)	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	2,684,371	305,574	2,378,797	778.5	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	(53,534,933)	(39,079,623)	(14,455,310)	37.0	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	(50,627,826)	(38,924,044)	(11,703,782)	30.1	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	(53,253,933)	(38,901,403)	(14,352,530)	36.9	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(103,881,759)	(77,825,447)	(26,056,312)	33.5	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	(51,940,879)	(38,912,724)	(13,028,156)	33.5	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	6.500	5.500	1.000	18.2	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	6.490	5.500	0.990	18.0	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	12.990	11.000	1.990	18.1	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	6.495	5.500	0.995	18.1	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.541	0.458	0.083	18.1	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	(281,000)	(178,220)	(102,780)	57.7	NOT APPLICABLE			

GENERA[illegible] SYSTEM COMPARATIVE DATA BY FUEL T[illegible]E — SCHEDULE A3
TAMPA ELECTRIC COMPANY — PAGE 1 OF 2
FOR THE MONTH OF: OCTOBER 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
FUEL COST OF SYSTEM NET GENERATION ($)								
1 HEAVY OIL	668,113	111,118	556,995	501.3	12,299,572	11,677,599	621,973	5.3
2 LIGHT OIL	1,038,221	2,246,371	(1,208,150)	(53.8)	13,400,420	17,289,852	(3,889,432)	(22.5)
3 COAL	25,772,677	28,595,035	(2,822,358)	(9.9)	273,133,615	285,833,626	(12,700,011)	(4.4)
4 NATURAL GAS	1,713,277	11,599	1,701,678	14,670.9	6,982,012	47,121	6,934,891	14,717.2
5 NUCLEAR	0	0	0	0.0	0	0	0	0.0
6 OTHER	0	0	0	0.0	0	0	0	0.0
7 TOTAL ($)	29,192,288	30,964,123	(1,771,835)	(5.7)	305,815,619	314,848,198	(9,032,579)	(2.9)
SYSTEM NET GENERATION (MWH)								
8 HEAVY OIL	11,483	2,217	9,266	418.0	207,952	255,612	(47,660)	(18.6)
9 LIGHT OIL	14,514	20,944	(6,430)	(30.7)	178,573	159,607	18,966	11.9
10 COAL	1,324,303	1,466,832	(142,529)	(9.7)	14,070,110	14,647,988	(577,879)	(3.9)
11 NATURAL GAS	26,420	402	26,018	6,472.1	112,013	1,634	110,379	6,755.1
12 NUCLEAR	0	0	0	0.0	0	0	0	0.0
13 OTHER	0	0	0	0.0	0	0	0	0.0
14 TOTAL (MWH)	1,376,720	1,490,395	(113,675)	(7.6)	14,568,648	15,064,841	(496,194)	(3.3)
UNITS OF FUEL BURNED								
15 HEAVY OIL (BBL)	22,479	4,332	18,147	418.9	475,850	639,612	(163,762)	(25.6)
16 LIGHT OIL (BBL)	25,940	61,127	(35,187)	(57.6)	371,909	482,421	(110,512)	(22.9)
17 COAL (TON)	591,564	659,436	(67,872)	(10.3)	6,403,252	6,611,885	(208,633)	(3.2)
18 NATURAL GAS (MCF)	293,175	3,500	289,675	8,276.4	1,324,158	14,200	1,309,958	9,225.1
19 NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20 OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
BTUS BURNED (MMBTU)								
21 HEAVY OIL	141,795	27,381	114,414	417.9	3,018,175	4,042,988	(1,024,813)	(25.3)
22 LIGHT OIL	150,279	237,344	(87,065)	(36.7)	2,140,790	1,986,545	154,245	7.8
23 COAL	13,871,242	15,318,580	(1,447,338)	(9.4)	147,001,313	153,168,304	(6,166,991)	(4.0)
24 NATURAL GAS	283,400	3,584	279,816	7,807.4	1,285,813	14,565	1,271,248	8,728.1
25 NUCLEAR	0	0	0	0.0	0	0	0	0.0
26 OTHER	0	0	0	0.0	0	0	0	0.0
27 TOTAL (MMBTU)	14,446,716	15,586,889	(1,140,173)	(7.3)	153,446,091	159,212,402	(5,766,311)	(3.6)
GENERATION MIX (% MWH)								
28 HEAVY OIL	0.83	0.15	0.68	-	1.43	1.70	(0.27)	-
29 LIGHT OIL	1.05	1.41	(0.36)	-	1.23	1.06	0.17	-
30 COAL	96.19	98.42	(2.23)	-	96.58	97.23	(0.65)	-
31 NATURAL GAS	1.92	0.03	1.89	-	0.77	0.01	0.76	-
32 NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33 OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34 TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
FUEL COST PER UNIT								
35 HEAVY OIL ($/BBL)	29.72	25.65	4.07	15.9	25.85	18.26	7.59	41.6
36 LIGHT OIL ($/BBL)	40.02	36.75	3.27	8.9	36.03	35.84	0.19	0.5
37 COAL ($/TON)	43.57	43.36	0.21	0.5	42.66	43.23	(0.57)	(1.3)
38 NATURAL GAS ($/MCF)	5.84	3.31	2.53	76.4	5.27	3.32	1.95	58.7
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40 OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
FUEL COST PER MMBTU ($/MMBTU)								
41 HEAVY OIL	4.71	4.06	0.65	16.0	4.08	2.89	1.19	41.2
42 LIGHT OIL	6.91	9.46	(2.55)	(27.0)	6.26	8.70	(2.44)	(28.0)
43 COAL	1.86	1.87	(0.01)	(0.5)	1.86	1.87	(0.01)	(0.5)
44 NATURAL GAS	6.05	3.24	2.81	86.7	5.43	3.24	2.19	67.6
45 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47 TOTAL ($/MMBTU)	2.02	1.99	0.03	1.5	1.99	1.98	0.01	0.5

GENERA...G SYSTEM COMPARATIVE DATA BY FUEL ..PE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: OCTOBER 2000

SC...DULE A3
PAGE 2 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
BTU BURNED PER KWH (BTU/KWH)								
48 HEAVY OIL	12,348	12,350	(2)	0.0	14,514	15,817	(1,303)	(8.2)
49 LIGHT OIL	10,354	11,332	(978)	(8.6)	11,988	12,446	(458)	(3.7)
50 COAL	10,474	10,443	31	0.3	10,448	10,457	(9)	(0.1)
51 NATURAL GAS	10,727	8,915	1,812	20.3	11,479	8,914	2,565	28.8
52 NUCLEAR	0	0	0	0.0	0	0	0	0.0
53 OTHER	0	0	0	0.0	0	0	0	0.0
54 TOTAL (BTU/KWH)	10,494	10,458	36	0.3	10,533	10,568	(35)	(0.3)
GENERATED FUEL COST PER KWH (cents/KWH)								
55 HEAVY OIL	5.82	5.01	0.81	16.2	5.91	4.57	1.34	29.3
56 LIGHT OIL	7.15	10.73	(3.58)	(33.4)	7.50	10.83	(3.33)	(30.7)
57 COAL	1.95	1.95	0.00	0.0	1.94	1.95	(0.01)	(0.5)
58 NATURAL GAS	6.48	2.89	3.59	124.2	6.23	2.88	3.35	116.3
59 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61 TOTAL (cents/KWH)	2.12	2.08	0.04	1.9	2.10	2.09	0.01	0.5

SYSTEM NET GENERATION AND FUEL COST

TAMPA ELECTRIC COMPANY

SCHEDULE A4

ACTUAL FOR THE PERIOD/MONTH OF: OCTOBER 2000

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPAB-ILITY (MW)	NET GENERATION (MWH)	NET CAPC. FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents /KWH)	COST OF FUEL ($/UNIT)
H.P.#1	32	622	2.6	99.0	35.3	-	HVY.OIL	2,342	-	-	60,793	9.77	25.95
H.P.#2	32	726	3.0	94.8	37.7	-	HVY.OIL	2,734	-	-	70,952	9.77	25.95
H.P.#3	32	692	2.9	94.4	34.6	-	HVY.OIL	2,605	-	-	67,614	9.77	25.95
H.P.#4	41	0	0.0	0.0	0.0	-	HVY.OIL	0	-	-	0	0.00	0.00
H.P.#5	52	367	0.9	87.2	51.7	-	HVY.OIL	1,384	-	-	35,916	9.79	25.95
H.P. STATION	189	2,407	1.7	72.8	32.4	23,950	HVY.OIL	9,065	6,359,266	57,648.4	235,275	9.77	25.95
GAN.#1	114	47,627	56.2	81.8	64.6	11,231	COAL	22,970	23,287,562	534,915.3	975,327	2.05	42.46
GAN.#2	88	27,166	41.5	47.7	86.2	11,945	COAL	13,629	23,810,140	324,508.4	578,699	2.13	42.46
GAN.#3	155	64,197	55.7	76.4	66.5	12,052	COAL	39,020	19,828,560	773,710.4	1,656,824	2.58	42.46
GAN.#4	169	73,981	58.8	80.3	61.6	12,088	COAL	45,094	19,831,940	894,301.5	1,914,731	2.59	42.46
GAN.#5	242	93,570	52.0	62.5	63.7	10,622	COAL	41,997	23,667,081	993,946.4	1,783,230	1.91	42.46
GAN.#6	392	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GANNON STA.	1,160	306,541	35.5	46.6	44.0	11,487	COAL	182,710	21,642,075	3,521,382.0	6,908,811	2.25	42.4(
B.B.#1	426	171,208	54.0	64.3	71.0	10,648	COAL	74,604	24,435,739	1,823,003.9	3,100,733	1.81	41.56
B.B.#2	426	197,267	62.2	76.8	72.2	10,160	COAL	81,952	24,455,160	2,004,149.3	3,406,134	1.73	41.56
B.B.#3	443	244,124	74.1	86.4	74.0	10,110	COAL	101,448	24,328,040	2,468,031.0	4,216,438	1.73	41.56
B.B. 1 - 3	1,295	612,599	63.6	76.0	72.4	10,276	COAL	258,004	24,399,560	6,295,184.2	10,723,305	1.75	41.56
B.B.#4	447	235,197	70.7	78.4	73.5	10,117	COAL	103,607	22,966,150	2,379,462.9	5,194,793	2.21	50.14
B.B. STA.	1,742	847,796	65.4	76.6	72.7	10,232	COAL	361,611	23,988,866	8,674,647.1	15,918,098	1.88	44.02
SEB-PHIL. #1(HVY OIL)	17	4,182	33.1	99.8	84.0	10,061	HVY.OIL	6,707	6,273,073	42,073.5	216,419	5.18	32.27
SEB-PHIL. #2(HVY OIL)	17	4,894	38.7	100.0	97.5	8,597	HVY.OIL	6,707	6,273,073	42,073.5	216,419	4.42	32.27
SEB-PHILLIPS TOTAL	34	9,076	35.9	99.9	90.8	9,271	HVY.OIL	13,414	6,273,073	84,147.0	432,838	4.77	32.27
POLK #1 GASIFIER	250	169,966	91.4	92.4	98.8	9,856	COAL	67,243	24,912,841	1,675,212.9	2,945,768	1.73	43.81
POLK #1 CT (OIL)	245	9,758	5.4	99.1	77.1	7,817	LGT.OIL	13,237	5,762,056	76,274.3	550,865	5.65	41.61
POLK #1 TOTAL	250	179,724	96.6	99.0	96.6	9,745	-	-	-	1,751,487.2	3,496,633	1.95	-
POLK #2 CT (GAS)	160	26,420	22.2	61.5	91.6	10,727	GAS	293,175	966,658	283,400.0	1,713,277	6.48	5.84
POLK #2 CT (OIL)	160	978	0.8	61.5	65.0	13,631	LGT.OIL	2,301	5,794,646	13,330.7	66,963	6.85	29.1
POLK #2 TOTAL	160	27,398	23.0	61.5	90.3	10,830	-	-	-	296,730.7	1,780,240	6.50	-
POLK STATION TOTAL	410	207,122	67.9	84.3	94.1	9,889	-	-	-	2,048,217.9	5,276,873	2.55	-
GAN.C.T.#1	17	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	-	0.00	0.00
B.B.C.T.#1	17	137	1.1	100.0	49.5	20,582	LGT.OIL	484	5,828,442	2,819.8	19,553	14.27	40.42
B.B.C.T.#2	80	1,774	3.0	100.0	55.8	16,116	LGT.OIL	4,901	5,833,247	28,589.5	198,082	11.17	40.42
B.B.C.T.#3	80	1,867	3.1	99.7	56.3	15,675	LGT.OIL	5,017	5,833,234	29,264.4	202,758	10.86	40.42
C.T. TOTAL	194	3,778	2.6	91.1	50.6	16,060	LGT.OIL	10,402	5,833,017	60,673.7	420,393	11.13	40.42
TOT. COAL (GN,BB,POLK)	3,152	1,324,303	56.5	66.8	64.2	10,474	COAL	591,564	23,448,408	13,871,242.0	25,772,677	1.95	43.57
SYSTEM	3,729	1,376,720	49.6	68.9	63.1	10,494	-	-	-	14,446,716.1	29,192,288	2.12	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS
NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2000

SCHEDULE A5
PAGE 1 OF 2

		CURRENT MONTH				PERIOD TO DATE			
	HEAVY OIL (1)	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	PURCHASES:								
2	UNITS (BBL)	11,916	4,332	7,584	175.1	453,711	593,524	(139,813)	(23.6)
3	UNIT COST ($/BBL)	33.51	23.22	10.29	44.3	27.21	18.24	8.97	49.2
4	AMOUNT ($)	399,337	100,609	298,728	296.9	12,347,161	10,823,935	1,523,226	14.1
5	BURNED:								
6	UNITS (BBL)	22,479	4,332	18,147	418.9	475,850	639,612	(163,762)	(25.6)
7	UNIT COST ($/BBL)	29.72	25.65	4.07	15.9	25.85	18.26	7.59	41.6
8	AMOUNT ($)	668,113	111,118	556,995	501.3	12,299,572	11,677,599	621,973	5.3
9	ENDING INVENTORY:								
10	UNITS (BBL)	68,120	81,135	(13,015)	(16.0)	68,120	81,135	(13,015)	(16.0)
11	UNIT COST ($/BBL)	27.29	20.49	6.80	33.2	27.29	20.49	6.80	33.2
12	AMOUNT ($)	1,858,703	1,662,163	196,540	11.8	1,858,703	1,662,163	196,540	11.8
13									
14	DAYS SUPPLY:	6,193	321	5,872	1,829.2	-	-	-	-
	LIGHT OIL (2)								
15	PURCHASES:								
16	UNITS (BBL)	33,985	79,938	(45,953)	(57.5)	494,344	599,982	(105,638)	(17.6)
17	UNIT COST ($/BBL)	40.84	36.21	4.63	12.8	37.87	36.03	1.84	5.1
18	AMOUNT ($)	1,387,858	2,894,652	(1,506,794)	(52.1)	18,721,291	21,616,660	(2,895,369)	(13.4)
19	BURNED:								
20	UNITS (BBL)	25,940	61,127	(35,187)	(57.6)	371,909	482,421	(110,512)	(22.9)
21	UNIT COST ($/BBL)	40.02	36.75	3.27	8.9	36.03	35.84	0.19	0.5
22	AMOUNT ($)	1,038,221	2,246,371	(1,208,150)	(53.8)	13,400,420	17,289,852	(3,889,432)	(22.5)
23	ENDING INVENTORY:								
24	UNITS (BBL)	96,715	97,057	(342)	(0.4)	96,715	97,057	(342)	(0.4)
25	UNIT COST ($/BBL)	40.87	37.83	3.04	8.0	40.87	37.83	3.04	8.0
26	AMOUNT ($)	3,952,411	3,671,726	280,685	7.6	3,952,411	3,671,726	280,685	7.6
27									
28	DAYS SUPPLY: NORMAL	85	67	18	26.4	-	-	-	-
29	DAYS SUPPLY: EMERGENCY	14	14	(0)	(1.3)	-	-	-	-
	COAL (3)								
30	PURCHASES:								
31	UNITS (TONS)	559,062	638,000	(78,938)	(12.4)	6,426,069	6,502,200	(76,131)	(1.2)
32	UNIT COST ($/TON)	43.65	40.60	3.05	7.5	42.54	42.43	0.11	0.3
33	AMOUNT ($)	24,401,818	25,902,624	(1,500,806)	(5.8)	273,355,767	275,893,298	(2,537,531)	(0.9)
34	BURNED:								
35	UNITS (TONS)	591,564	659,436	(67,872)	(10.3)	6,403,252	6,611,885	(208,633)	(3.2)
36	UNIT COST ($/TON)	43.57	43.36	0.21	0.5	42.66	43.23	(0.57)	(1.3)
37	AMOUNT ($)	25,772,677	28,595,035	(2,822,358)	(9.9)	273,133,615	285,833,626	(12,700,011)	(4.4)
38	ENDING INVENTORY:								
39	UNITS (TONS)	799,833	1,016,490	(216,657)	(21.3)	799,833	1,016,490	(216,657)	(21.3)
40	UNIT COST ($/TON)	42.55	41.97	0.58	1.4	42.55	41.97	0.58	1.4
41	AMOUNT ($)	34,031,229	42,665,338	(8,634,109)	(20.2)	34,031,229	42,665,338	(8,634,109)	(20.2)
42									
43	DAYS SUPPLY:	41	50	(9)	(17.1)	-	-	-	-
	NATURAL GAS (4)								
44	PURCHASES:								
45	UNITS (MCF)	293,175	3,500	289,675	8,276.4	1,324,158	14,200	1,309,958	9,225.1
46	UNIT COST ($/MCF)	5.80	3.31	2.49	75.2	5.40	3.32	2.08	62.7
47	AMOUNT ($)	1,701,249	11,599	1,689,650	14,567.2	7,150,947	47,121	7,103,826	15,075.7
48	BURNED:								
49	UNITS (MCF)	293,175	3,500	289,675	8,276.4	0	14,200	(14,200)	(100.0)
50	UNIT COST ($/MCF)	5.84	3.31	2.53	76.4	0.00	3.32	(3.32)	(100.0)
51	AMOUNT ($)	1,713,277	11,599	1,701,678	14,670.9	0	47,121	(47,121)	(100.0)
52	ENDING INVENTORY:								
53	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
54	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
56									
57	DAYS SUPPLY:	0	0	0	0.0	-	-	-	-
	NUCLEAR								
58	BURNED:								
59	UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
60	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2000

OTHER	CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH %	PERIOD TO DATE ACTUAL	PERIOD TO DATE ESTIMATED	PERIOD TO DATE DIFFERENCE AMOUNT	PERIOD TO DATE %
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
74 DAYS SUPPLY:	0	0	0	0.0	-	-	-	-

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	18,926
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	18,926

(2)
RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	(28,772)
IGNITION	(8,822)	(359,162)
OTHER USAG	(812)	(33,950)
TOTAL	(9,634)	(421,884)

(3)
RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	70
IGNITION #2 OIL	340,236
IGNITION PROPANE	3,482
AERIAL SURVEY ADJ.	(102,386)
ADDITIVES	18,911
GREEN FUEL	(1,555)
TOTAL	258,758

(4)

RECONCILIATION - GAS	DOLLARS
START-UP FUEL (PRIOR PERIOD ADJ.)	12,028

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: OCTOBER 2000

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN ENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN N ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	162.0	0.0	162.0	2.284	2.840	3,700.00	4,600.00	700.00
VARIOUS	JURISD.	SCH. -D	5,854.0	0.0	5,854.0	2.098	2.098	122,800.00	122,800.00	
VARIOUS	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPAR.	CONTRACT	19,456.0	0.0	19,456.0	2.313	3.256	450,100.00	633,400.00	
FMPA		SCH. -D	111,600.0	0.0	111,600.0	1.805	1.805	2,014,564.00	2,014,564.00	
VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	137,072.0	0.0	137,072.0	1.890	2.025	2,591,164.00	2,775,364.00	700.00
LESS TRANSMISSION COSTS		-						0.00		
LESS VARIABLE O & M COSTS		-						(300.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS		-						700.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-	137,072.0	0.0	137,072.0	1.891	2.025	2,591,564.00	2,775,364.00	700.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENRGY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
OGLETHORPE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENN, VALLEY AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEP. CONTRACT		73,165.0	0.0	73,165.0	2.382	3.194	1,742,790.30	2,336,890.10	
SEMINOLE ELECTRIC CO-OP PRECO-1	JURISD.	SCH. -D	5,502.0	278.1	5,223.9	3.136	3.136	163,803.67	163,803.67	
SEMINOLE ELECTRIC CO-OP HARDEE	JURISD.	SCH. -D	935.0	0.0	935.0	2.272	2.272	21,239.98	21,239.98	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: OCTOBER 2000

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN ENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN N ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA		SCH. -D	84,915.0	0.0	84,915.0	1.878	1.878	1,594,669.85	1,594,669.85	
HARDEE POWER PART. TO FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR.& LT.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO JACKSONVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KISSIMMEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ORLANDO		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO SEMINOLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FT. PIERCE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LK. WORTH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ENERGY AUTHORITY		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR.& LT.		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: OCTOBER 2000

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN ENERATION	(6) —cents/KWH— (A) FUEL COST	(6) (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN N ECONOMY ENERGY SALES
FLORIDA POWER & LIGHT		SCH. -MA	5,265.0	0.0	5,265.0	3.370	3.370	177,443.01	177,443.01	
FLORIDA POWER CORP.		SCH. -MA	50.0	0.0	50.0	4.597	4.597	2,298.65	2,298.65	
HOMESTEAD		SCH. -MA	10.0	0.0	10.0	3.750	3.750	375.03	375.03	
CARGILL ALLIANT		SCH. -MA	171.0	0.0	171.0	0.748	0.748	1,278.99	1,278.99	
ORLANDO		SCH. -MA	50.0	0.0	50.0	3.147	3.147	1,573.65	1,573.65	
ADJUSTMENTS TO PREVIOUS MONTHS	MO/YR TYP	SCHED.								
HARDEE POWER PART. EST.	9/00 SEPAR.	CONTRACT	(54,090.0)	0.0	(54,090.0)	2.535	3.353	(1,371,181.50)	(1,813,637.70)	
HARDEE POWER PART. ACT.	9/00 SEPAR.	CONTRACT	54,090.0	0.0	54,090.0	2.382	3.194	1,288,423.80	1,727,634.60	
CARGILL ALLIANT EST.	9/00	SCH. -MA	(108.0)	0.0	(108.0)	8.514	8.514	(9,194.78)	(9,194.78)	
CARGILL ALLIANT ACT.	9/00	SCH. -MA	108.0	0.0	108.0	8.310	8.310	8,974.76	8,974.76	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			6,437.0	278.1	6,158.9	3.004	3.004	185,043.65	185,043.65	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.			73,165.0	0.0	73,165.0	2.269	3.076	1,660,032.60	2,250,887.00	
SUB-TOTAL OTHER D POWER SALES			84,915.0	0.0	84,915.0	1.878	1.878	1,594,669.85	1,594,669.85	
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			5,546.0	0.0	5,546.0	3.295	3.295	182,749.31	182,749.31	
TOTAL INCLUDING VARIABLE O & M COSTS			170,063.0	278.1	169,784.9	2.134	2.482	3,622,495.41	4,213,349.81	0.00
LESS VARIABLE O & M COSTS								0.00		
LESS VARIABLE O & M COSTS - HARDEE								0.00		
LESS TRANSMISSION COSTS SCH. D (SEP.)								0.00		
PLUS 80% OF ECON. ENERGY SALES PROFITS								0.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS			170,063.0	278.1	169,784.9	2.134	2.482	3,622,495.41	4,213,349.81	0.00
CURRENT MONTH:										
DIFFERENCE			32,991.0	278.1	32,712.9	0.243	0.457	1,030,931.41	1,437,985.81	(700.00)
DIFFERENCE %			24.1	0.0	23.9	12.9	22.6	39.8	51.8	(100.0)
PERIOD TO DATE:										
ACTUAL			1,548,818.0	8,168.5	1,540,649.5	2.162	2.387	33,309,382.58	36,779,844.94	0.00
ESTIMATED			1,613,854.0	0.0	1,613,854.0	2.286	2.509	36,892,860.00	40,485,040.00	3,357,620.00
DIFFERENCE			(65,036.0)	8,168.5	(73,204.5)	(0.124)	(0.122)	(3,583,477.42)	(3,705,195.06)	(3,357,620.00)
DIFFERENCE %			(4.0)	0.0	(4.5)	(5.4)	(4.9)	(9.7)	(9.2)	(100.0)

* THERE WERE NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN OCTOBER.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONT OCTOBER 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	24,166.0	0.0	13,693.0	10,473.0	6.395	6.395	669,700.00
HARDEE POWER PARTNERS	IPP	10,700.0	0.0	0.0	10,700.0	4.400	4.400	470,800.00
VARIOUS	OTHER	13,904.0	0.0	0.0	13,904.0	2.589	2.589	360,000.00
TOTAL	-	48,770.0	0.0	13,693.0	35,077.0	4.278	4.278	1,500,500.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	50,448.0	0.0	0.0	50,448.0	7.131	7.131	3,597,588.06
HARDEE PWR. PART.-OTHERS	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.	SCH.-Ja	2,930.0	0.0	1,403.1	1,526.9	8.138	8.138	124,253.54
FLA. POWER CORP.	SCH.-Jc	34,890.0	0.0	0.0	34,890.0	4.679	4.679	1,632,393.75
FLA. POWER & LIGHT	SCH.-Ja	1,951.0	0.0	1,024.1	926.9	6.424	6.424	59,546.99
FLA. POWER & LIGHT	SCH.-Jc	19,879.0	0.0	0.0	19,879.0	6.301	6.301	1,252,582.50
CITY OF LAKELAND	SCH.-Ja	6,431.0	0.0	2,579.8	3,851.2	15.888	15.888	611,876.59
CITY OF LAKELAND	SCH.-Jc	21,385.0	0.0	0.0	21,385.0	6.247	6.247	1,335,958.40
ORLANDO	SCH.-Ja	3,153.0	0.0	1,708.3	1,444.7	8.470	8.470	122,373.12
ORLANDO	SCH.-Jc	2,247.0	0.0	0.0	2,247.0	7.233	7.233	162,518.00
ENTERGY MARKETING	SCH.-Ja	670.0	0.0	208.7	461.3	9.496	9.496	43,807.26
ENTERGY MARKETING	SCH.-Jc	860.0	0.0	0.0	860.0	5.172	5.172	44,481.25
THE ENERGY AUTH.	SCH.-Ja	418.0	0.0	387.2	30.8	7.415	7.415	2,283.93
THE ENERGY AUTH.	SCH.-Jc	3,969.0	0.0	0.0	3,969.0	6.058	6.058	240,450.89
REEDY CREEK	SCH.-Jc	175.0	0.0	0.0	175.0	5.017	5.017	8,780.00
OKEELANTA	SCH.-Jc	616.0	0.0	0.0	616.0	7.000	7.000	43,121.48
TALLAHASSEE	SCH.-Ja	727.0	0.0	389.0	338.0	7.429	7.429	25,110.32
TALLAHASSEE	SCH.-Jc	8,587.0	0.0	0.0	8,587.0	5.879	5.879	504,848.68
AQUILA	SCH.-Ja	46.0	0.0	0.0	46.0	8.583	8.583	3,948.00
OGLETHORPE	SCH.-Jc	98.0	0.0	0.0	98.0	3.210	3.210	3,146.00
MORGAN STANLEY	SCH.-Ja	2,914.0	0.0	442.9	2,471.1	8.935	8.935	220,781.34
MORGAN STANLEY	SCH.-Jc	53,650.0	0.0	0.0	53,650.0	5.324	5.324	2,856,091.21
CARGILL ALLIANT	SCH.-Jc	649.0	0.0	0.0	649.0	5.183	5.183	33,640.00
ENRON	SCH.-Jc	637.0	0.0	0.0	637.0	5.104	5.104	32,513.25
KOCH	SCH.-Jc	99.0	0.0	0.0	99.0	6.121	6.121	6,060.00
RELIANT	SCH.-Ja	344.0	0.0	100.0	244.0	5.707	5.707	13,926.00
RELIANT	SCH.-Jc	1,969.0	0.0	0.0	1,969.0	5.659	5.659	111,426.00
SOUTHERN COMPANY	SCH.-Jc	1,131.0	0.0	0.0	1,131.0	2.637	2.637	29,821.00
OKEELANTA	SCH.-D	7,937.0	0.0	0.0	7,937.0	3.380	3.380	268,291.22
AUBURNDALE	SCH.-D	1,918.0	0.0	0.0	1,918.0	2.334	2.334	44,763.32
ADJUSTMENTS TO PRIOR MONTHS:								
SEE PAGE 2 FOR DETAILS		(416.0)	0.0	0.0	(416.0)	(92.574)	(92.574)	385,109.27
TOTAL		230,312.0	0.0	8,243.1	222,068.9	6.224	6.224	13,821,491.37
CURRENT MONTH:								
DIFFERENCE	-	181,542.0	0.0	(5,449.9)	186,991.9	6.589	54.887	12,320,991.37
DIFFERENCE %	-	372.2	0.0	(39.8)	533.1	154.0	1,283.0	821.1
PERIOD TO DATE:								
ACTUAL	-	2,159,127.00	0.00	225,008.95	1,934,118.0	5.307	5.307	102,634,829.35
ESTIMATED	-	1,273,812.0	0.0	150,293.0	1,123,519.0	4.728	4.728	53,125,000.00
DIFFERENCE	-	885,315.0	0.0	74,716.0	810,599.0	0.579	0.579	49,509,829.35
DIFFERENCE %	-	69.5	0.0	49.7	72.1	12.2	12.2	93.2

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONT OCTOBER 2000

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) ——CENTS/KWH—— (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ADJUSTMENTS (SEP. 2000):									
HARDEE PWR. PART.-NATI	(EST)	IPP	(122,729.0)	0.0	0.0	(122,729.0)	6.021	6.021	(7,389,582.72)
HARDEE PWR. PART.-NATI	(ACT)	IPP	122,729.0	0.0	0.0	122,729.0	6.327	6.327	7,765,254.23
OKEELANTA	(EST)	SCH.-D	(9,657.0)	0.0	0.0	(9,657.0)	3.059	3.059	(295,392.20)
OKEELANTA	(ACT)	SCH.-D	9,247.0	0.0	0.0	9,247.0	3.194	3.194	295,392.20
RINGHAVER	(EST)	SCH.-Jc	(6,289.0)	0.0	0.0	(6,289.0)	1.691	1.691	(106,370.59)
RINGHAVER	(ACT)	SCH.-Jc	6,289.0	0.0	0.0	6,289.0	2.094	2.094	131,687.90
ENERGY AUTHORITY	(EST)	SCH.-Ja	(8,923.0)	0.0	(3,420.8)	(5,502.2)	8.098	8.098	(445,550.12)
ENERGY AUTHORITY	(ACT)	SCH.-Ja	8,923.0	0.0	3,420.8	5,502.2	8.105	8.105	445,928.04
ENERGY AUTHORITY	(EST)	SCH.-Jc	(11,518.0)	0.0	0.0	(11,518.0)	5.162	5.162	(594,503.47)
ENERGY AUTHORITY	(ACT)	SCH.-Jc	11,512.0	0.0	0.0	11,512.0	5.017	5.017	577,566.22
ENRON	(EST)	SCH.-Ja	(272.0)	0.0	0.0	(272.0)	7.317	7.317	(19,903.58)
ENRON	(ACT)	SCH.-Ja	272.0	0.0	0.0	272.0	7.438	7.438	20,230.00
ENRON	(EST)	SCH.-Jc	(2,993.0)	0.0	0.0	(2,993.0)	3.959	3.959	(118,495.32)
ENRON	(ACT)	SCH.-Jc	2,993.0	0.0	0.0	2,993.0	4.017	4.017	120,235.70
AQUILA	(EST)	SCH.-Ja	(480.0)	0.0	(69.0)	(411.0)	8.451	8.451	(34,731.60)
AQUILA	(ACT)	SCH.-Ja	480.0	0.0	69.0	411.0	8.425	8.425	34,624.90
AQUILA	(EST)	SCH.-Jc	(166.0)	0.0	0.0	(166.0)	6.866	6.866	(11,397.86)
AQUILA	(ACT)	SCH.-Jc	166.0	0.0	0.0	166.0	6.418	6.418	10,654.70
TALLAHASSEE	(EST)	SCH.-Ja	(2,499.0)	0.0	(557.4)	(1,941.6)	7.244	7.244	(140,641.16)
TALLAHASSEE	(ACT)	SCH.-Ja	2,489.0	0.0	557.4	1,931.6	7.418	7.418	143,290.80
TALLAHASSEE	(EST)	SCH.-Jc	(7,713.0)	0.0	0.0	(7,713.0)	4.983	4.983	(384,340.75)
TALLAHASSEE	(ACT)	SCH.-Jc	7,723.0	0.0	0.0	7,723.0	5.020	5.020	387,674.42
ENTERGY	(EST)	SCH.-Ja	(333.0)	0.0	(277.4)	(55.6)	15.810	15.810	(8,790.55)
ENTERGY	(ACT)	SCH.-Ja	333.0	0.0	277.4	55.6	9.395	9.395	5,223.68
ENTERGY	(EST)	SCH.-Jc	(60.0)	0.0	0.0	(60.0)	26.574	26.574	(15,944.58)
ENTERGY	(ACT)	SCH.-Jc	60.0	0.0	0.0	60.0	8.804	8.804	5,282.60
MORGAN STANLEY	(EST)	SCH.-Ja	(244.0)	0.0	(117.2)	(126.8)	11.570	11.570	(14,670.41)
MORGAN STANLEY	(ACT)	SCH.-Ja	244.0	0.0	117.2	126.8	8.771	8.771	11,122.02
MORGAN STANLEY	(EST)	SCH.-Jc	(1,104.0)	0.0	0.0	(1,104.0)	3.406	3.406	(37,603.37)
MORGAN STANLEY	(ACT)	SCH.-Jc	1,104.0	0.0	0.0	1,104.0	3.157	3.157	34,852.50
KOCH	(EST)	SCH.-Ja	(7,897.0)	0.0	(1,647.9)	(6,249.1)	7.795	7.795	(487,099.32)
KOCH	(ACT)	SCH.-Ja	7,894.0	0.0	1,647.9	6,246.1	7.841	7.841	489,771.59
KOCH	(EST)	SCH.-Jc	(8,834.0)	0.0	0.0	(8,834.0)	6.934	6.934	(612,509.15)
KOCH	(ACT)	SCH.-Jc	8,837.0	0.0	0.0	8,837.0	7.059	7.059	623,844.52
SUB-TOTAL (ADJUSTMENTS)			(416.0)	0.0	0.0	(416.0)	(92.574)	(92.574)	385,109.27

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: OCTOBER 2000

SCHEDULE A8

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDUL	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP TIBLE	MWH FOR FIRM	----CENTS/KWH--- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	35,819.0	0.0	0.0	35,819.0	2.386	2.386	854,500.00
TOTAL	-	35,819.0	0.0	0.0	35,819.0	2.386	2.386	854,500.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	10,355.0	0.0	0.0	10,355.0	2.105	2.105	217,923.57
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	93.0	0.0	0.0	93.0	5.797	5.797	5,391.46
HILLSBOROUGH COUNTY	COGEN.	18,199.0	0.0	0.0	18,199.0	2.129	2.129	387,493.69
CARGILL MILLPOINT	COGEN.	234.0	0.0	0.0	234.0	2.324	2.324	5,439.13
CF INDUSTRIES INC.	COGEN.	934.0	0.0	0.0	934.0	4.705	4.705	43,944.88
FARMLAND HYDRO LP	COGEN.	760.0	0.0	0.0	760.0	4.381	4.381	33,298.84
IMC-AGRICO-S. PIERCE	COGEN.	1,009.0	0.0	0.0	1,009.0	13.032	13.032	131,497.39
AUBURNDALE POWER PARTNERS	COGEN.	1,052.0	0.0	0.0	1,052.0	2.995	2.995	31,507.62
ORANGE COGENERATION L.P.	COGEN.	6,072.0	0.0	0.0	6,072.0	2.047	2.047	124,292.17
CUTRALE CITRUS	COGEN.	30.0	0.0	0.0	30.0	2.714	2.714	814.06
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR OCTOBER 2000	-	38,738.0	0.0	0.0	38,738.0	2.534	2.534	981,602.81
ADJ. FOR AUGUST 2000								
IMC-AGRICO-NICHOLS	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
McKAY BAY REFUSE	COGEN.	(4,557.0)	0.0	0.0	(4,557.0)	2.463	2.463	(112,221.95)
		4,557.0	0.0	0.0	4,557.0	2.561	2.561	116,713.57
MULBERRY PHOSPHATES INC.	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
CARGILL RIDGEWOOD	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
IMC-AGRICO-NEW WALES	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
HILLSBOROUGH COUNTY	COGEN.	(18,317.0)	0.0	0.0	(18,317.0)	2.447	2.447	(448,261.98)
		18,317.0	0.0	0.0	18,317.0	2.542	2.542	465,568.59
CARGILL MILLPOINT	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
CF INDUSTRIES INC.	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
FARMLAND HYDRO LP	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
IMC-AGRICO-S. PIERCE	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
AUBURNDALE POWER PARTNERS	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
ORANGE COGENERATION L.P.	COGEN.	(7,843.0)	0.0	0.0	(7,843.0)	2.328	2.328	(182,587.30)
		7,843.0	0.0	0.0	7,843.0	2.443	2.443	191,612.28
CUTRALE CITRUS	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
AS AVAILABLE ASSIGNMENT	COGEN.		0.0		0.0	0.000	0.000	
			0.0		0.0	0.000	0.000	
SUB-TOTAL FOR Aug-00 ADJ.	-	0.0	0.0	0.0	0.0	0.000	0.000	30,823.21
GRAND TOTAL		38,738.0	0.0	0.0	38,738.0	2.614	2.614	1,012,426.02
CURRENT MONTH:								
DIFFERENCE	-	2,919.0	0.0	0.0	2,919.0	0.228	0.228	157,926.02
DIFFERENCE %	-	8.1	0.0	0.0	8.1	9.6	9.6	18.5
PERIOD TO DATE:								
ACTUAL		327,674.0	0.0	728.6	326,945.4	2.429	2.429	7,940,842.65
ESTIMATED		343,599.0	0.0	0.0	343,599.0	2.279	2.279	7,831,200.00
DIFFERENCE	-	(15,925.0)	0.0	728.6	(16,653.6)	0.150	0.150	109,642.65
DIFFERENCE %	-	(4.6)	0.0	0.0	(4.8)	6.6	6.6	1.4

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: OCTOBER 2000

SCHEDULE A9

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDUL	TOTAL MWH URCHASE	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	COST IF GENERATED (A) ents/KW	(B) $	FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	68,792.0	4.258	2,929,500.00	5.959	4,099,300.00	1,169,800.00
TOTAL	-	68,792.0	4.258	2,929,500.00	5.959	4,099,300.00	1,169,800.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL	-	0.0	0.000	0.00	0.000	0.00	0.00
CURRENT MONTH:							
DIFFERENCE	-	(68,792.0)	(4.258)	(2,929,500.00)	(5.959)	(4,099,300.00)	(1,169,800.00)
DIFFERENCE %	-	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)
PERIOD TO DATE:							
ACTUAL		0.0	0.000	(10,512.45)	0.000	0.00	10,512.45
ESTIMATED		268,129.0	4.490	12,040,200.00	5.859	15,710,800.00	3,670,600.00
DIFFERENCE	-	(268,129.0)	(4.490)	(12,050,712.45)	(5.859)	(15,710,800.00)	(3,660,087.55)
DIFFERENCE %	-	(100.0)	(100.0)	(100.1)	(100.0)	(100.0)	(99.7)

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

NOVEMBER 2000

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	26,633,611	26,537,142	96,469	0.4	1,278,827	1,318,681	(39,854)	(3.0)	2.08266	2.01240	0.07026	3.5
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (FLMeade/Wauch. Wheeling Losses)	(3,168)	(4,000)	832	(20.8)	1,278,827 a)	1,318,681 a)	(39,854)	(3.0)	(0.00025)	(0.00030)	0.00005	(16.7)
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,278,827 a)	1,318,681 a)	(39,854)	(3.0)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,278,827 a)	1,318,681 a)	(39,854)	(3.0)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	26,630,443	26,533,142	97,301	0.4	1,278,827	1,318,681	(39,854)	(3.0)	2.08241	2.01210	0.07031	3.5
6. Fuel Cost of Purchased Power - Firm (A7)	11,766,765	1,193,500	10,573,265	885.9	179,871	30,522	149,349	489.3	6.54178	3.91029	2.63149	67.3
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	1,785,300	(1,785,300)	(100.0)	0	40,587	(40,587)	(100.0)	0.00000	4.39870	(4.39870)	(100.0)
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 a)	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	602,485	734,800	(132,115)	(18.0)	31,530	33,595	(2,065)	(6.1)	1.91083	2.18663	(0.27580)	(12.6)
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	12,369,250	3,713,400	8,655,850	233.1	211,401	104,704	106,697	101.9	5.85108	3.54657	2.30451	65.0
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,490,228	1,423,385	66,843	4.7				
14. Fuel Cost of Economy Sales (A6)	0	33,400	(33,400)	(100.0)	0	1,629	(1,629)	(100.0)	0.00000	2.05034	(2.05034)	(100.0)
15. Gain on Economy Sales - 80% (A6)	0	11,600	(11,600)	(100.0)	0 a)	1,629 a)	(1,629)	(100.0)	0.00000	0.71209	(0.71209)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	152,056	118,100	33,956	28.8	5,137	5,784	(647)	(11.2)	2.96002	2.04184	0.91818	45.0
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A8)	1,055,340	240,900	814,440	338.1	51,975	10,609	41,366	389.9	2.03048	2.27071	(0.24023)	(10.6)
21. Fuel Cost of Other Power Sales (A6)	1,588,761	1,943,944	(355,183)	(18.3)	85,115	108,000	(22,885)	(21.2)	1.86661	1.79995	0.06666	3.7
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	2,796,157	2,347,944	448,213	19.1	142,227	128,022	16,205	12.9	1.96598	1.86312	0.10286	5.5
23. Net Inadvertant Interchange					123	0	123	0.0				
24. Wheeling Rec'd. less Wheeling Del'd.					(1,992)	0	(1,992)	0.0				
25. Interchange and Wheeling Losses					1,414	1,900	(486)	(25.6)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	36,203,536	27,896,598	8,304,938	29.8	1,344,718	1,295,463	49,255	3.8	2.69228	2.15356	0.53872	25.0
27. Net Unbilled	(868,028) (a)	(2,162,153) (a)	1,294,125	(59.9)	(36,039)	(88,103)	52,064	(59.1)	(0.06640)	(0.16775)	0.10135	(60.4)
28. Company Use	92,345 (a)	98,165 (a)	(5,820)	(5.9)	3,834	4,000	(166)	(4.2)	0.00706	0.00762	(0.00056)	(7.3)
29. T & D Losses	1,678,925 (a)	2,224,095 (a)	(545,170)	(24.5)	69,706	90,627	(20,921)	(23.1)	0.12844	0.17255	(0.04411)	(25.6)
30. System KWH Sales	36,203,536	27,896,598	8,304,938	29.8	1,307,217	1,288,939	18,278	1.4	2.76951	2.16446	0.60505	28.0
31. Wholesale KWH Sales	(1,885,760)	(380,339)	(1,505,421)	395.8	(68,090)	(17,572)	(50,518)	287.5	2.76951	2.16446	0.60505	28.0
32. Jurisdictional KWH Sales	34,317,776	27,518,259	6,799,517	24.7	1,239,127	1,271,367	(32,240)	(2.5)	2.76951	2.16446	0.60505	28.0
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	34,341,112	27,536,971	6,804,141	24.7	1,239,127	1,271,367	(32,240)	(2.5)	2.77140	2.16593	0.60547	28.0
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	332,391	345,876	(13,485)	(3.9)	1,239,127	1,271,367	(32,240)	(2.5)	0.02682	0.02721	(0.00039)	(1.4)
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	1,239,127	1,271,367	(32,240)	(2.5)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	1,239,127	1,271,367	(32,240)	(2.5)	0.00000	0.00000	0.00000	0.0
36. True-up *	2,684,371	305,574	2,378,797	778.5	1,239,127	1,271,367	(32,240)	(2.5)	0.21663	0.02404	0.19259	801.1
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	37,357,874	28,188,421	9,169,453	32.5	1,239,127	1,271,367	(32,240)	(2.5)	3.01485	2.21717	0.79768	36.0
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.01702	2.21877	0.79825	36.0
40. GPIF * (Already Adjusted for Taxes)	(23,059)	(23,059)	0	0.0	1,239,127	1,271,367	(32,240)	(2.5)	(0.00186)	(0.00181)	(0.00005)	2.8
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	37,334,815	28,165,362	9,169,453	32.6	1,239,127	1,271,367	(32,240)	(2.5)	3.01516	2.21696	0.79820	36.0
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									3.015	2.217	0.798	36.0

* Based on Jurisdictional Sales (a) Included for Informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: NOVEMBER 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	332,449,230	341,385,340	(8,936,110)	(2.6)	15,847,475	16,383,522	(536,048)	(3.3)	2.09781	2.08371	0.01410	0.7
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses	(44,768)	(44,000)	(768)	1.7	15,847,475 a)	16,383,522 a)	(536,048)	(3.3)	(0.00026)	(0.00027)	(0.00001)	3.7
4b. Adjustments to Fuel Cost	0	0	0	0.0	15,847,475 a)	16,383,522 a)	(536,048)	(3.3)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	(79)	0	(79)	0.0	15,847,475 a)	16,383,522 a)	(536,048)	(3.3)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	332,404,383	341,341,340	(8,936,957)	(2.6)	15,847,475	16,383,522	(536,046)	(3.3)	2.09752	2.08344	0.01408	0.7
6. Fuel Cost of Purchased Power - Firm (A7)	114,401,593	54,318,500	60,083,093	110.6	2,113,989	1,154,041	959,948	83.2	5.41165	4.70681	0.70484	15.0
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	(10,512)	13,825,500	(13,836,012)	(100.1)	0	308,716	(308,716)	(100.0)	#DIV/0!	4.47839	#DIV/0!	#DIV/0!
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	8,543,328	8,565,800	(22,472)	(0.3)	358,475	377,194	(18,719)	(5.0)	2.38324	2.27093	0.11231	4.9
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	122,934,409	76,709,800	46,224,609	60.3	2,472,464	1,839,951	632,513	34.4	4.97214	4.16912	0.80302	19.3
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					18,319,939	18,223,473	96,466	0.5				
14. Fuel Cost of Economy Sales (A6)	(1,687)	6,644,400	(6,646,087)	(100.0)	0	197,810	(197,810)	(100.0)	#DIV/0!	3.35898	#DIV/0!	#DIV/0!
15. Gain on Economy Sales - 80% (A6)	0	3,369,220	(3,369,220)	(100.0)	0	197,810 a)	(197,810)	(100.0)	0.00000	1.70326	(1.70326)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	127,462	295,300	(167,838)	(56.8)	12,186	19,153	(6,967)	(36.4)	1.04613	1.54180	(0.49567)	(32.1)
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	1,491,274	1,375,000	116,274	8.5	60,773	63,857	(3,084)	(4.8)	2.45384	2.15325	0.30059	14.0
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	108,608	0	108,608	0.0	2,630	0	2,630	0.0	4.12958	0.00000	4.12958	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	2,701	0	2,701	0.0	55	0	55	0.0	4.91091	0.00000	4.91091	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	10,961,191	5,819,400	5,141,791	88.4	467,160	253,056	214,104	84.6	2.34635	2.29965	0.04670	2.0
21. Fuel Cost of Other Power Sales (A6)	23,415,972	21,737,484	1,678,488	7.7	1,140,072	1,206,000	(65,928)	(5.5)	2.05390	1.80244	0.25146	14.0
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	36,105,541	39,240,804	(3,135,263)	(8.0)	1,682,876	1,739,876	(57,000)	(3.3)	2.14547	2.25538	(0.10991)	(4.9)
23. Net Inadvertant Interchange					1,875	0	1,875	0.0				
24. Wheeling Rec'd. less Wheeling Del'd.					3,127	0	3,127	0.0				
25. Interchange and Wheeling Losses					21,001	26,300	(5,299)	(20.1)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	419,233,251	378,810,336	40,422,915	10.7	16,621,064	16,457,297	163,767	1.0	2.52230	2.30178	0.22052	9.6
27. Net Unbilled	492,991 (a)	197,432 (a)	295,559	149.7	22,317	8,926	13,391	150.0	0.00312	0.00126	0.00186	147.6
28. Company Use	1,014,856 (a)	973,223 (a)	41,433	4.3	45,932	44,000	1,932	4.4	0.00643	0.00621	0.00022	3.5
29. T & D Losses	17,066,977 (a)	16,271,356 (a)	795,621	4.9	772,597	735,638	36,959	5.0	0.10815	0.10385	0.00430	4.1
30. System KWH Sales	419,233,251	378,810,336	40,422,915	10.7	15,780,218	15,668,733	111,485	0.7	2.65670	2.41762	0.23908	9.9
31. Wholesale KWH Sales	(18,575,791)	(8,873,213)	(9,702,578)	109.3	(675,032)	(349,903)	(325,129)	92.9	2.75184	2.53591	0.21593	8.5
32. Jurisdictional KWH Sales	400,657,460	369,937,123	30,720,337	8.3	15,105,186	15,318,830	(213,645)	(1.4)	2.65245	2.41492	0.23753	9.8
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	400,929,906	370,168,679	30,741,227	8.3	15,105,186	15,318,830	(213,645)	(1.4)	2.65425	2.41656	0.23769	9.8
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	3,830,761	3,912,737	(81,976)	(2.1)	15,105,186	15,318,830	(213,645)	(1.4)	0.02536	0.02554	(0.00018)	(0.7)
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	15,105,186	15,318,830	(213,645)	(1.4)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	15,105,186	15,318,830	(213,645)	(1.4)	0.00000	0.00000	0.00000	0.0
36. True-up *	17,634,096	3,361,314	14,272,782	424.6	15,105,186	15,318,830	(213,645)	(1.4)	0.11674	0.02194	0.09480	432.1
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	422,394,763	377,462,730	44,932,033	11.9	15,105,186	15,318,830	(213,645)	(1.4)	2.79636	2.46404	0.33232	13.5
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.79837	2.46581	0.33256	13.5
40. GPIF * (Already Adjusted for Taxes)	(253,649)	(253,649)	0	0.0	15,105,186	15,318,830	(213,645)	(1.4)	(0.00168)	(0.00166)	(0.00002)	1.2
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	422,141,114	377,209,081	44,932,033	11.9	15,105,186	15,318,830	(213,645)	(1.4)	2.79689	2.46415	0.33254	13.5
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.797	2.464	0.333	13.5

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2000

SCHEDULE A2
PAGE 1 OF 3

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	26,633,611	26,537,142	96,469	0.4	332,449,230	341,385,340	(8,936,110)	(2.6)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	2,796,157	2,347,944	448,213	19.1	36,105,541	39,240,804	(3,135,263)	(8.0)
3. FUEL COST OF PURCHASED POWER	11,766,765	1,193,500	10,573,265	885.9	114,401,593	54,318,500	60,083,093	110.6
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	602,485	734,600	(132,115)	(18.0)	8,543,328	8,565,800	(22,472)	(0.3)
4. ENERGY COST OF ECONOMY PURCHASES	0	1,785,300	(1,785,300)	0.0	(10,512)	13,825,500	(13,836,012)	(100.1)
5. TOTAL FUEL & NET POWER TRANSACTION	36,206,704	27,902,598	8,304,106	29.8	419,278,098	378,854,336	40,423,762	10.7
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(3,168)	(4,000)	832	(20.8)	(44,768)	(44,000)	(768)	1.7
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST	0	0	0	0.0	(79)	0	(79)	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	36,203,536	27,898,598	8,304,938	29.8	419,233,251	378,810,336	40,422,915	10.7
*INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,239,127	1,271,367	(32,240)	(2.5)	15,105,186	15,318,830	(213,644)	(1.4)
2. NONJURISDICTIONAL SALES	68,090	17,572	50,518	287.5	675,032	349,903	325,129	92.9
3. TOTAL SALES	1,307,217	1,288,939	18,278	1.4	15,780,218	15,668,733	111,485	0.7
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9479122	0.9863671	(0.0384549)	(3.9)	0.9572229	0.9776687	(0.0204458)	(2.1)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	30,551,155	29,240,947	1,310,208	4.5	360,402,440	352,567,153	7,835,287	2.2
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	(2,684,371)	(305,574)	(2,378,797)	778.5	(17,634,096)	(3,361,314)	(14,272,782)	424.6
b. INCENTIVE PROVISION	23,059	23,059	0	0.0	253,649	253,649	0	0.0
c. TRANSITION ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
d. OTHER ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	27,889,843	28,958,432	(1,068,589)	(3.7)	343,021,993	349,459,488	(6,437,495)	(1.8)
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	36,203,536	27,898,598	8,304,938	29.8	419,233,251	378,810,336	40,422,915	10.7
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B-4)	0.9479122	0.9863671	(0.0384549)	(3.9)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	34,317,776	27,518,259	6,799,517	24.7	400,657,460	369,937,123	30,720,337	8.3
6A.JURISDIC. LOSS MULTIPLIER	1.00068	1.00068	0.0000	0.0	NA	NA	-	-
6B. (LINE 6 x LINE 6A)	34,341,112	27,536,971	6,804,141	24.7	400,929,906	370,188,679	30,741,227	8.3
6C.PEABODY COAL CONTR. BUY-OUT AMORT.	350,656	350,656	0	0.0	3,996,421	3,996,421	0	0.0
6D.(LINE 6C x LINE 5) PB. JURISD.	332,391	345,876	(13,485)	(3.9)	3,830,761	3,912,737	(81,976)	(2.1)
6E.OTHER (SPARE INPUT #1)	0	0	0	0.0	0	0	0	0.0
6F. OIL BELOW THE DISCHARGE VALVE	0	0	0	0.0	0	0	0	0.0
6G. OTHER (SPARE INPUT #2)	0	0	0	0.0	0	0	0	0.0
6H. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. 6B+6D+6E+6F+6G)	34,673,503	27,882,847	6,790,656	24.4	404,760,667	374,101,416	30,659,251	8.2
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6H)	(6,783,660)	1,075,585	(7,859,245)	(730.7)	(61,738,674)	(24,641,928)	(37,096,746)	150.5
8. INTEREST PROVISION FOR THE MONTH	(304,603)	(175,822)	(128,781)	73.2	(1,504,704)	(989,635)	(515,069)	52.0
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(55,916,606)	(46,959,559)	(8,957,047)	19.1	NOT APPLICABLE			
9a.DEFERRED TRUE-UP BEGINNING OF PERIOD	2,381,673	7,879,936	(5,498,263)	(69.8)	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	2,684,371	305,574	2,378,797	778.5	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	(57,938,825)	(37,874,286)	(20,064,539)	53.0	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	(53,534,933)	(39,079,623)	(14,455,310)	37.0	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	(57,634,222)	(37,698,464)	(19,935,758)	52.9	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(111,169,155)	(76,778,087)	(34,391,068)	44.8	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	(55,584,578)	(38,389,044)	(17,195,535)	44.8	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	6.490	5.500	0.990	18.0	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	6.650	5.500	1.150	20.9	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	13.140	11.000	2.140	19.5	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	6.570	5.500	1.070	19.5	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.548	0.458	0.090	19.7	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	(304,603)	(175,822)	(128,781)	73.2	NOT APPLICABLE			

GENERA 3 SYSTEM COMPARATIVE DATA BY FUEL 'E — S DULE A3
TAMPA ELECTRIC COMPANY — PAGE 1 OF 2
FOR THE MONTH OF: NOVEMBER 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
FUEL COST OF SYSTEM NET GENERATION ($)								
1 HEAVY OIL	445,965	77,885	368,080	472.6	12,745,537	11,755,484	990,053	8.4
2 LIGHT OIL	872,613	1,325,643	(453,030)	(34.2)	14,273,033	18,615,495	(4,342,462)	(23.3)
3 COAL	24,133,476	25,131,226	(997,750)	(4.0)	297,267,091	310,964,852	(13,697,761)	(4.4)
4 NATURAL GAS	1,181,557	2,388	1,179,169	49,378.9	8,163,569	49,509	8,114,060	16,389.1
5 NUCLEAR	0	0	0	0.0	0	0	0	0.0
6 OTHER	0	0	0	0.0	0	0	0	0.0
7 TOTAL ($)	26,633,611	26,537,142	96,469	0.4	332,449,230	341,385,340	(8,936,110)	(2.6)
SYSTEM NET GENERATION (MWH)								
8 HEAVY OIL	8,626	1,587	7,039	443.5	216,578	257,199	(40,621)	(15.8)
9 LIGHT OIL	8,307	11,772	(3,465)	(29.4)	186,880	171,379	15,501	9.0
10 COAL	1,243,257	1,305,245	(61,988)	(4.7)	15,313,367	15,953,233	(639,867)	(4.0)
11 NATURAL GAS	18,637	77	18,560	24,103.9	130,650	1,711	128,939	7,535.9
12 NUCLEAR	0	0	0	0.0	0	0	0	0.0
13 OTHER	0	0	0	0.0	0	0	0	0.0
14 TOTAL (MWH)	1,278,827	1,318,681	(39,854)	(3.0)	15,847,475	16,383,522	(536,048)	(3.3)
UNITS OF FUEL BURNED								
15 HEAVY OIL (BBL)	14,375	3,693	10,682	289.2	490,225	643,305	(153,080)	(23.8)
16 LIGHT OIL (BBL)	21,262	37,652	(16,390)	(43.5)	393,171	520,073	(126,902)	(24.4)
17 COAL (TON)	548,230	583,206	(34,976)	(6.0)	6,951,482	7,195,091	(243,609)	(3.4)
18 NATURAL GAS (MCF)	218,447	700	217,747	31,106.7	1,542,605	14,900	1,527,705	10,253.1
19 NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20 OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
BTUS BURNED (MMBTU)								
21 HEAVY OIL	90,325	23,354	66,971	286.8	3,108,500	4,066,342	(957,842)	(23.6)
22 LIGHT OIL	123,921	135,670	(11,749)	(8.7)	2,264,711	2,122,215	142,496	6.7
23 COAL	12,962,073	13,524,690	(562,617)	(4.2)	159,963,386	166,692,994	(6,729,608)	(4.0)
24 NATURAL GAS	218,022	683	217,339	31,821.2	1,503,835	15,248	1,488,587	9,762.5
25 NUCLEAR	0	0	0	0.0	0	0	0	0.0
26 OTHER	0	0	0	0.0	0	0	0	0.0
27 TOTAL (MMBTU)	13,394,341	13,684,397	(290,056)	(2.1)	166,840,432	172,896,799	(6,056,367)	(3.5)
GENERATION MIX (% MWH)								
28 HEAVY OIL	0.67	0.12	0.55	-	1.37	1.57	(0.20)	-
29 LIGHT OIL	0.65	0.89	(0.24)	-	1.18	1.05	0.13	-
30 COAL	97.22	98.98	(1.76)	-	96.63	97.37	(0.74)	-
31 NATURAL GAS	1.46	0.01	1.45	-	0.82	0.01	0.81	-
32 NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33 OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34 TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
FUEL COST PER UNIT								
35 HEAVY OIL ($/BBL)	31.02	21.09	9.93	47.1	26.00	18.27	7.73	42.3
36 LIGHT OIL ($/BBL)	41.04	35.21	5.83	16.6	36.30	35.79	0.51	1.4
37 COAL ($/TON)	44.02	43.09	0.93	2.2	42.76	43.22	(0.46)	(1.1)
38 NATURAL GAS ($/MCF)	5.41	3.41	2.00	58.7	5.29	3.32	1.97	59.3
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40 OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
FUEL COST PER MMBTU ($/MMBTU)								
41 HEAVY OIL	4.94	3.33	1.61	48.3	4.10	2.89	1.21	41.9
42 LIGHT OIL	7.04	9.77	(2.73)	(27.9)	6.30	8.77	(2.47)	(28.2)
43 COAL	1.86	1.86	0.00	0.0	1.86	1.87	(0.01)	(0.5)
44 NATURAL GAS	5.42	3.50	1.92	54.9	5.43	3.25	2.18	67.1
45 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47 TOTAL ($/MMBTU)	1.99	1.94	0.05	2.6	1.99	1.97	0.02	1.0

GENER. ..G SYSTEM COMPARATIVE DATA BY FUE. .PE ... EDULE A3

TAMPA ELECTRIC COMPANY PAGE 2 OF 2

FOR THE MONTH OF: NOVEMBER 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
BTU BURNED PER KWH (BTU/KWH)								
48 HEAVY OIL	10,471	14,716	(4,245)	(28.8)	14,353	15,810	(1,457)	(9.2)
49 LIGHT OIL	14,918	11,525	3,393	29.4	12,119	12,383	(264)	(2.1)
50 COAL	10,426	10,362	64	0.6	10,446	10,449	(3)	0.0
51 NATURAL GAS	11,698	8,870	2,828	31.9	11,510	8,912	2,598	29.2
52 NUCLEAR	0	0	0	0.0	0	0	0	0.0
53 OTHER	0	0	0	0.0	0	0	0	0.0
54 TOTAL (BTU/KWH)	10,474	10,377	97	0.9	10,528	10,553	(25)	(0.2)
GENERATED FUEL COST PER KWH (cents/KWH)								
55 HEAVY OIL	5.17	4.91	0.26	5.3	5.88	4.57	1.31	28.7
56 LIGHT OIL	10.50	11.26	(0.76)	(6.7)	7.64	10.86	(3.22)	(29.7)
57 COAL	1.94	1.93	0.01	0.5	1.94	1.95	(0.01)	(0.5)
58 NATURAL GAS	6.34	3.10	3.24	104.5	6.25	2.89	3.36	116.3
59 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61 TOTAL (cents/KWH)	2.08	2.01	0.07	3.5	2.10	2.08	0.02	1.0

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD/MONTH OF: NOVEMBER 2000

SCHEDULE A4

(A) PLANT/UNIT	(B) NET CAPAB-ILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPC. FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents /KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	32	(1)	0.0	100.0	0.0	0	HVY.OIL	656	6,359,186	4,169.4	17,348	0.00	26.46
H.P.#2	32	(1)	0.0	100.0	0.0	0	HVY.OIL	771	6,359,272	4,900.9	20,392	0.00	26.46
H.P.#3	32	0	0.0	100.0	0.0	0	HVY.OIL	199	6,359,296	1,265.5	5,265	0.00	26.46
H.P.#4	41	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	52	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	189	(2)	0.0	50.8	62.7	0	HVY.OIL	1,625	6,359,240	10,335.8	43,005	0.00	26.46
GAN.#1	114	30,558	37.2	56.9	37.6	11,888	COAL	15,279	23,775,843	363,271.1	651,603	2.13	42.65
GAN.#2	88	32,403	51.1	61.9	516.4	11,590	COAL	16,348	22,972,559	375,555.4	697,192	2.15	42.65
GAN.#3	155	71,488	64.1	86.2	113.3	12,369	COAL	45,773	19,317,821	884,234.6	1,952,079	2.73	42.65
GAN.#4	169	7,634	6.3	9.6	0.0	12,626	COAL	4,781	20,160,991	96,389.7	203,895	2.67	42.65
GAN.#5	242	56,895	32.7	39.0	0.0	10,800	COAL	26,398	23,277,998	614,492.6	1,125,794	1.98	42.65
GAN.#6	392	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GANNON STA.	1160	198,978	23.8	31.3	78.6	11,730	COAL	108,579	21,495,348	2,333,943.4	4,630,563	2.33	42.65
B.B.#1	426	241,000	78.6	89.3	89.6	10,522	COAL	102,660	24,700,080	2,535,710.2	4,390,937	1.82	42.77
B.B.#2	426	210,103	68.5	82.6	0.0	10,138	COAL	86,232	24,700,520	2,129,975.2	3,688,284	1.76	42.77
B.B.#3	443	214,117	67.1	81.7	0.0	10,195	COAL	89,425	24,411,739	2,183,019.8	3,824,854	1.79	42.77
B.B. 1 - 3	1295	665,220	71.3	84.5	75.8	10,295	COAL	278,317	24,607,571	6,848,705.2	11,904,075	1.79	42.77
B.B.#4	447	214,494	66.6	72.4	0.0	10,249	COAL	98,666	22,280,301	2,198,313.7	4,762,021	2.22	48.26
B.B. STA.	1742	879,714	70.1	81.4	84.4	10,284	COAL	376,983	23,998,464	9,047,018.9	16,666,096	1.89	44.21
SEB-PHIL. #1(HVY OIL)	17	4,005	32.7	100.0	0.0	9,986	HVY.OIL	6,375	6,273,631	39,994.4	201,480	5.03	31.60
SEB-PHIL. #2(HVY OIL)	17	4,623	37.8	100.0	0.0	8,651	HVY.OIL	6,375	6,273,631	39,994.4	201,480	4.36	31.60
SEB-PHILLIPS TOTAL	34	8,628	35.2	100.0	99.3	9,271	HVY.OIL	12,750	6,273,631	79,988.8	402,960	4.67	31.60
POLK #1 GASIFIER	250	164,565	91.4	87.1	0.0	9,608	COAL	62,668	25,230,000	1,581,111.1	2,836,817	1.72	45.27
POLK #1 CT (OIL)	245	1,602	0.9	100.0	0.0	14,931	LGT.OIL	4,123	5,801,572	23,919.3	170,804	10.66	41.43
POLK #1 TOTAL	250	166,167	92.3	94.8	83.7	9,659	-	-	-	1,605,030.4	3,007,621	1.81	-
POLK #2 CT (GAS)	150	18,637	17.3	66.9	0.0	11,698	GAS	218,447	998,054	218,022.0	1,181,557	6.34	5.41
POLK #2 CT (OIL)	170	3,083	2.5	88.5	0.0	12,958	LGT.OIL	6,886	5,801,578	39,949.9	285,275	9.25	41.43
POLK #2 TOTAL	150	21,720	20.1	78.4	91.7	11,877	-	-	-	257,971.9	1,466,832	6.75	-
POLK STATION TOTAL	400	187,887	65.2	88.7	0.0	9,916	-	-	-	1,863,002.3	4,474,453	2.38	-
GAN.C.T.#1	17	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	17	10	0.1	98.4	1.4	311,790	LGT.OIL	532	5,856,641	3,117.9	21,628	216.28	40.63
B.B.C.T.#2	80	1,693	2.9	98.5	0.0	16,129	LGT.OIL	4,662	5,856,960	27,306.2	189,403	11.19	40.63
B.B.C.T.#3	80	1,919	3.3	97.8	0.0	15,439	LGT.OIL	5,058	5,856,957	29,627.3	205,503	10.71	40.63
C.T. TOTAL	194	3,622	2.6	89.6	66.0	16,580	LGT.OIL	10,253	5,856,942	60,051.4	416,534	11.50	40.63
TOT. COAL (GN,BB,POLK)	3152	1,243,257	54.8	63.4	62.0	10,426	COAL	548,230	23,643,489	12,962,073.4	24,133,476	1.94	44.02
SYSTEM	3,719	1,278,827	47.8	65.6	0.0	10,474	-	-	-	13,394,340.6	26,633,611	2.08	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS
NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2000

	CURRENT MONTH				PERIOD TO DATE			
HEAVY OIL (1)	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1 PURCHASES:								
2 UNITS (BBL)	10,657	3,693	6,964	188.6	464,368	597,217	(132,849)	(22.2)
3 UNIT COST ($/BBL)	31.08	21.90	9.18	41.9	27.30	18.26	9.04	49.5
4 AMOUNT ($)	331,206	80,864	250,342	309.6	12,678,367	10,904,799	1,773,568	16.3
5 BURNED:								
6 UNITS (BBL)	14,375	3,693	10,682	289.2	490,225	643,305	(153,080)	(23.8)
7 UNIT COST ($/BBL)	31.02	21.09	9.93	47.1	26.00	18.27	7.73	42.3
8 AMOUNT ($)	445,965	77,885	368,080	472.6	12,745,537	11,755,484	990,053	8.4
9 ENDING INVENTORY:								
10 UNITS (BBL)	64,402	81,135	(16,733)	(20.6)	64,402	81,135	(16,733)	(20.6)
11 UNIT COST ($/BBL)	27.30	20.56	6.74	32.8	27.30	20.56	6.74	32.8
12 AMOUNT ($)	1,758,473	1,668,471	90,002	5.4	1,758,473	1,668,471	90,002	5.4
13								
14 DAYS SUPPLY:	6,440	441	5,999	1,360.3	-	-	-	-
LIGHT OIL (2)								
15 PURCHASES:								
16 UNITS (BBL)	21,134	55,086	(33,952)	(61.6)	515,478	655,068	(139,590)	(21.3)
17 UNIT COST ($/BBL)	41.54	34.04	7.50	22.0	38.02	35.86	2.16	6.0
18 AMOUNT ($)	877,997	1,875,201	(997,204)	(53.2)	19,599,288	23,491,861	(3,892,573)	(16.6)
19 BURNED:								
20 UNITS (BBL)	21,262	37,652	(16,390)	(43.5)	393,171	520,073	(126,902)	(24.4)
21 UNIT COST ($/BBL)	41.04	35.21	5.83	16.6	36.30	35.79	0.51	1.4
22 AMOUNT ($)	872,613	1,325,643	(453,030)	(34.2)	14,273,033	18,615,495	(4,342,462)	(23.3)
23 ENDING INVENTORY:								
24 UNITS (BBL)	93,576	97,057	(3,481)	(3.6)	93,576	97,057	(3,481)	(3.6)
25 UNIT COST ($/BBL)	41.00	36.86	4.14	11.2	41.00	36.86	4.14	11.2
26 AMOUNT ($)	3,836,648	3,577,898	258,750	7.2	3,836,648	3,577,898	258,750	7.2
27								
28 DAYS SUPPLY: NORMAL	85	69	16	23.2	-	-	-	-
29 DAYS SUPPLY: EMERGEN	13	14	(1)	(7.1)	-	-	-	-
COAL (3)								
30 PURCHASES:								
31 UNITS (TONS)	484,994	681,000	(196,006)	(28.8)	6,911,063	7,183,200	(272,137)	(3.8)
32 UNIT COST ($/TON)	43.46	41.28	2.18	5.3	42.60	42.32	0.28	0.7
33 AMOUNT ($)	21,080,062	28,114,711	(7,034,649)	(25.0)	294,435,829	304,008,009	(9,572,180)	(3.1)
34 BURNED:								
35 UNITS (TONS)	548,230	583,206	(34,976)	(6.0)	6,951,482	7,195,091	(243,609)	(3.4)
36 UNIT COST ($/TON)	44.02	43.09	0.93	2.2	42.76	43.22	(0.46)	(1.1)
37 AMOUNT ($)	24,133,476	25,131,226	(997,750)	(4.0)	297,267,091	310,964,852	(13,697,761)	(4.4)
38 ENDING INVENTORY:								
39 UNITS (TONS)	736,597	1,114,284	(377,687)	(33.9)	736,597	1,114,284	(377,687)	(33.9)
40 UNIT COST ($/TON)	42.63	41.67	0.96	2.3	42.63	41.67	0.96	2.3
41 AMOUNT ($)	31,398,487	46,436,833	(15,038,346)	(32.4)	31,398,487	46,436,833	(15,038,346)	(32.4)
42								
43 DAYS SUPPLY:	38	54	(16)	(29.6)	-	-	-	-
NATURAL GAS (4)								
44 PURCHASES:								
45 UNITS (MCF)	218,447	700	217,747	31,106.7	1,542,605	14,900	1,527,705	10,253.1
46 UNIT COST ($/MCF)	5.41	3.41	2.00	58.7	5.40	3.32	2.08	62.7
47 AMOUNT ($)	1,181,557	2,388	1,179,169	49,378.9	8,332,504	49,509	8,282,995	16,730.3
48 BURNED:								
49 UNITS (MCF)	218,447	700	217,747	31,106.7	1,542,605	14,900	1,527,705	10,253.1
50 UNIT COST ($/MCF)	5.41	3.41	2.00	58.7	5.29	3.32	1.97	59.3
51 AMOUNT ($)	1,181,557	2,388	1,179,169	49,378.9	8,163,569	49,509	8,114,060	16,389.1
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
56								
57 DAYS SUPPLY:	0	0	0	0.0	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2000

OTHER	CURRENT MONTH ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	PERIOD TO DATE ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
74 DAYS SUPPLY:	0	0	0	0.0	-	-	-	-

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	14,529
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	14,529

(2)
RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(4,377)	(178,157)
OTHER USAGE	1,366	57,010
TOTAL	(3,011)	(121,147)

(3)
RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	35,016
IGNITION #2 OIL	163,629
IGNITION PROPANE	0
AERIAL SURVEY ADJ.	164,914
ADDITIVES	57,043
GREEN FUEL ADJ.	70
TOTAL	420,672

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: NOVEMBER 2000

SCHEDULE A6
PAGE 1 OF 3

(1) SOLD TO		(2) TYPE & SCHEDUL	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	1,629.0	0.0	1,629.0	2.259	3.149	36,800.00	51,300.00	11,600.00
VARIOUS	JURISDICTIONAL	SCH. -D	5,784.0	0.0	5,784.0	2.042	2.042	118,100.00	118,100.00	
VARIOUS	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPARATED	CONTRACT	10,609.0	0.0	10,609.0	2.271	3.212	240,900.00	340,800.00	
FMPA		SCH. -D	108,000.0	0.0	108,000.0	1.800	1.800	1,943,944.00	1,943,944.00	
VARIOUS	JURISDICTIONAL	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	126,022.0	0.0	126,022.0	1.857	1.947	2,339,744.00	2,454,144.00	11,600.00
LESS TRANSMISSION COSTS		-						0.00		
LESS VARIABLE O & M COSTS		-						(3,400.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS		-						11,600.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-	126,022.0	0.0	126,022.0	1.863	1.947	2,347,944.00	2,454,144.00	11,600.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENRGY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
OGLETHORPE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENN, VALLEY AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEP. CONTRACT		51,975.0	0.0	51,975.0	2.236	3.055	1,162,161.00	1,587,836.25	
SEMINOLE ELECTRIC CO-OP PRECO-	JURISD.	SCH. -D	4,363.0	80.8	4,282.2	3.187	3.187	136,484.96	136,484.96	
SEMINOLE ELECTRIC CO-OP HARDEE	JURISD.	SCH. -D	855.0	0.0	855.0	1.821	1.821	15,571.14	15,571.14	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: NOVEMBER 2000

(1) SOLD TO		(2) TYPE & SCHEDUL	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA		SCH. -D	82,565.0	0.0	82,565.0	1.841	1.841	1,520,188.08	1,520,188.08	
HARDEE POWER PART. TO FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR.& LT.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO JACKSONVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KISSIMMEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ORLANDO		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO SEMINOLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FT. PIERCE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LK. WORTH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ENERGY AUTHORITY		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: NOVEMBER 2000

(1) SOLD TO		(2) TYPE & SCHEDUL	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(5)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -MA	50.0	0.0	50.0	3.847	3.847	1,923.65	1,923.65	
FLA. PWR. & LIGHT	JURISD.	SCH. -MA	1,765.0	0.0	1,765.0	2.866	2.866	50,586.87	50,586.87	
HARDEE POWER PART. TO LAKELAN	JURISD.	SCH. -MA	60.0	0.0	60.0	4.295	4.295	2,576.71	2,576.71	
ORLANDO UTIL. COMM.	JURISD.	SCH. -MA	138.0	0.0	138.0	2.085	2.085	2,877.46	2,877.46	
LAKELAND	JURISD.	SCH. -MA	120.0	0.0	120.0	3.439	3.439	4,126.36	4,126.36	
REEDY CREEK	JURISD.	SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
THE ENERGY AUTHORITY	JURISD.	SCH. -MA	51.0	0.0	51.0	2.847	2.847	1,452.16	1,452.16	
SONAT	JURISD.	SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
RELIANT ENERGY	JURISD.	SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CARGILL ALLIANT	JURISD.	SCH. -MA	234.0	0.0	234.0	1.064	1.064	2,490.24	2,490.24	
ADJUSTMENTS TO PREVIOUS MONTH	MON/YR TYPE	SCHED.								
HARDEE POWER PARTNERS EST.	10/00 SEPAR.	CONTRACT	(73,165.0)	0.0	(73,165.0)	2.382	3.194	(1,742,790.30)	(2,336,890.10)	
HARDEE POWER PARTNERS ACT.	10/00 SEPAR.	CONTRACT	73,165.0	0.0	73,165.0	2.236	3.055	1,635,969.40	2,235,190.75	
CARGILL ALLIANT	10/00 JURISD.	SCH. -MA	(171.0)	0.0	(171.0)	0.748	0.748	(1,278.99)	(1,278.99)	
CARGILL ALLIANT	10/00 JURISD.	SCH. -MA	303.0	0.0	303.0	1.260	1.260	3,818.02	3,818.02	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			5,218.0	80.8	5,137.2	2.960	2.960	152,056.10	152,056.10	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.			51,975.0	0.0	51,975.0	2.030	2.659	1,055,340.10	1,486,136.90	
SUB-TOTAL OTHER D POWER SALES			82,565.0	0.0	82,565.0	1.841	1.841	1,520,188.08	1,520,188.08	
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			2,550.0	0.0	2,550.0	2.689	2.689	68,572.48	68,572.48	
TOTAL INCLUDING VARIABLE O & M COSTS			142,308.0	80.8	142,227.2	1.966	2.269	2,796,156.76	3,226,953.56	0.00
LESS VARIABLE O & M COSTS								0.00		
LESS VARIABLE O & M COSTS - HARDEE								0.00		
LESS TRANSMISSION COSTS SCH. D (SEP.)								0.00		
PLUS 80% OF ECON. ENERGY SALES PROFITS -								0.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS -			142,308.0	80.8	142,227.2	1.966	2.269	2,796,156.76	3,226,953.56	0.00
CURRENT MONTH:										
DIFFERENCE		-	16,286.0	80.8	16,205.2	0.103	0.322	448,212.76	772,809.56	(11,600.00)
DIFFERENCE %		-	12.9	0.0	12.9	5.5	16.5	19.1	31.5	(100.0)
PERIOD TO DATE:										
ACTUAL		-	1,691,126.0	8,249.3	1,682,876.7	2.145	2.377	36,105,539.34	40,006,798.50	0.00
ESTIMATED		-	1,739,876.0	0.0	1,739,876.0	2.255	2.468	39,240,804.00	42,939,184.00	3,369,220.00
DIFFERENCE		-	(48,750.0)	8,249.3	(56,999.3)	(0.110)	(0.091)	(3,135,264.66)	(2,932,385.50)	(3,369,220.00)
DIFFERENCE %		-	(2.8)	0.0	(3.3)	(4.9)	(3.7)	(8.0)	(6.8)	(100.0)

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. SEC 60% OR $243.47 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH O NOVEMBER 2000

SCHEDULE A7

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) ----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	12,004.0	0.0	6,520.0	5,484.0	6.395	6.395	350,700.00
HARDEE POWER PARTNERS	IPP	11,838.0	0.0	0.0	11,838.0	4.217	4.217	499,200.00
VARIOUS	OTHER	13,200.0	0.0	0.0	13,200.0	2.603	2.603	343,600.00
TOTAL	-	37,042.0	0.0	6,520.0	30,522.0	3.910	3.910	1,193,500.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	49,806.0	0.0	0.0	49,806.0	9.232	9.232	4,598,164.46
HARDEE PWR. PART.-OTHERS	IPP	60.0	0.0	0.0	60.0	4.024	4.024	2,414.40
FLA. POWER CORP.	SCH.-Ja	6,479.0	0.0	629.2	5,849.8	8.254	8.254	482,834.43
FLA. POWER CORP.	SCH.-Jc	26,299.0	0.0	0.0	26,299.0	5.020	5.020	1,320,156.00
FLA. POWER & LIGHT	SCH.-Ja	2,604.0	0.0	506.7	2,097.3	7.143	7.143	149,799.49
FLA. POWER & LIGHT	SCH.-Jc	28,591.0	0.0	0.0	28,591.0	5.896	5.896	1,685,834.00
LAKELAND	SCH.-Ja	1,241.0	0.0	100.0	1,141.0	8.366	8.366	95,457.00
LAKELAND	SCH.-Jc	10,024.0	0.0	0.0	10,024.0	6.199	6.199	621,427.50
ORLANDO	SCH.-Ja	5,964.0	0.0	726.8	5,237.2	8.310	8.310	435,208.42
ORLANDO	SCH.-Jc	436.0	0.0	0.0	436.0	7.615	7.615	33,200.00
ENTERGY MARKETING	SCH.-Jc	564.0	0.0	0.0	564.0	5.745	5.745	32,404.00
THE ENERGY AUTHORITY	SCH.-Ja	530.0	0.0	157.0	373.0	6.988	6.988	26,067.00
THE ENERGY AUTHORITY	SCH.-Jc	4,728.0	0.0	0.0	4,728.0	6.976	6.976	329,813.74
CORAL POWER	SCH.-Ja	14.0	0.0	0.0	14.0	8.386	8.386	1,174.04
CORAL POWER	SCH.-Jc	3,038.0	0.0	0.0	3,038.0	3.889	3.889	118,138.78
OKEELANTA	SCH.-Jc	846.0	0.0	0.0	846.0	6.134	6.134	51,894
TALLAHASSEE	SCH.-Jc	5,030.0	0.0	0.0	5,030.0	6.201	6.201	311,891.90
AQUILA	SCH.-Ja	122.0	0.0	0.0	122.0	9.197	9.197	11,220.64
AQUILA	SCH.-Jc	1,055.0	0.0	0.0	1,055.0	7.034	7.034	74,211.90
MORGAN STANLEY	SCH.-Ja	145.0	0.0	98.0	47.0	5.491	5.491	2,580.80
MORGAN STANLEY	SCH.-Jc	7,811.0	0.0	0.0	7,811.0	5.758	5.758	449,771.14
OGLETHORPE	SCH.-Jc	39.0	0.0	0.0	39.0	9.157	9.157	3,571.31
ENRON	SCH.-Jc	7,326.0	0.0	0.0	7,326.0	3.658	3.658	267,957.24
KOCH	SCH.-Ja	686.0	0.0	27.6	658.4	6.468	6.468	42,584.29
KOCH	SCH.-Jc	5,898.0	0.0	0.0	5,898.0	6.328	6.328	373,216.06
SOUTHERN COMPANY	SCH.-Ja	393.0	0.0	0.0	393.0	15.396	15.396	60,508.03
SOUTHERN COMPANY	SCH.-Jc	390.0	0.0	0.0	390.0	18.413	18.413	71,810.01
RELIANT	SCH.-Jc	2,600.0	0.0	0.0	2,600.0	5.335	5.335	138,698.50
DUKE ENERGY	SCH.-Jc	124.0	0.0	0.0	124.0	6.741	6.741	8,358.70
OKEELANTA	SCH.-D	6,714.0	0.0	0.0	6,714.0	3.484	3.484	233,895.00
AUBURNDALE	SCH.-D	2,559.0	0.0	0.0	2,559.0	2.334	2.334	59,726.59
ADJUSTMENTS TO PRIOR MONTHS:								
HARDEE PWR. PART.-NATIVE	IPP	(50,448.0)	0.0	0.0	(50,448.0)	7.131	7.131	(3,597,588.06)
HARDEE PWR. PART.-NATIVE	IPP	50,448.0	0.0	0.0	50,448.0	6.788	6.788	3,424,547.02
FLA. POWER & LIGHT	SCH.-Tx *	0.0	0.0	0.0	0.0	0.000	0.000	(161,045.35)
ENTERGY	SCH.-Jc	(860.0)	0.0	0.0	(860.0)	5.172	5.172	(44,481.25)
ENTERGY	SCH.-Jc	860.0	0.0	0.0	860.0	5.216	5.216	44,855.03
THE ENERGY AUTH.	SCH.-Jc	(3,969.0)	0.0	0.0	(3,969.0)	6.058	6.058	(240,450.89)
THE ENERGY AUTH.	SCH.-Jc	3,969.0	0.0	0.0	3,969.0	6.093	6.093	241,832.86
ENRON	SCH.-Jc	(637.0)	0.0	0.0	(637.0)	5.104	5.104	(32,513.25)
ENRON	SCH.-Jc	637.0	0.0	0.0	637.0	5.115	5.115	32,583.42
TALLAHASSEE	SCH.-Jc	(8,587.0)	0.0	0.0	(8,587.0)	5.879	5.879	(504,848.68)
TALLAHASSEE	SCH.-Jc	8,587.0	0.0	0.0	8,587.0	5.931	5.931	509,294.85
SOUTHERN COMPANY	SCH.-Jc	(1,131.0)	0.0	0.0	(1,131.0)	2.637	2.637	(29,821.00)
SOUTHERN COMPANY	SCH.-Jc	1,131.0	0.0	0.0	1,131.0	2.645	2.645	29,916.47
MORGAN STANLEY	SCH.-Jc	(53,650.0)	0.0	0.0	(53,650.0)	5.324	5.324	(2,856,091.21)
MORGAN STANLEY	SCH.-Jc	53,650.0	0.0	0.0	53,650.0	5.325	5.325	2,856,785.86
TOTAL		182,116.0	0.0	2,245.4	179,870.6	6.542	6.542	11,756,765.27
CURRENT MONTH:								
DIFFERENCE	-	145,074.0	0.0	(4,274.6)	149,348.6	7.080	7.080	10,573,265.27
DIFFERENCE %	-	391.6	0.0	(65.6)	489.3	181.1	181.1	885.9
PERIOD TO DATE:								
ACTUAL	-	2,341,243.0	0.00	227,254.3	2,113,988.7	5.412	5.412	114,401,594.62
ESTIMATED	-	1,310,854.0	0.0	156,813.0	1,154,041.0	4.707	4.707	54,318,500.00
DIFFERENCE	-	1,030,389.0	0.0	70,441.3	959,947.7	0.705	0.705	60,083,094.62
DIFFERENCE %	-	78.6	0.0	44.9	83.2	15.0	15.0	110.6

* Adjustment to transmission charges for January - May 2000

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: NOVEMBER 2000

SCHEDULE A8

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
URCHASED FROM	TYPE & SCHEDUL	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP TIBLE	MWH FOR FIRM	—CENTS/KWH— (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (5)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	33,595.0	0.0	0.0	33,595.0	2.187	2.187	734,600.00
TOTAL	-	33,595.0	0.0	0.0	33,595.0	2.187	2.187	734,600.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	6,638.0	0.0	0.0	6,638.0	1.929	1.929	128,032.25
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	332.0	0.0	0.0	332.0	4.178	4.178	13,872.14
HILLSBOROUGH COUNTY	COGEN.	18,043.0	0.0	0.0	18,043.0	1.934	1.934	348,916.23
CARGILL MILLPOINT	COGEN.	214.0	0.0	0.0	214.0	2.825	2.825	6,046.21
CF INDUSTRIES INC.	COGEN.	589.0	0.0	0.0	589.0	3.782	3.782	22,273.94
FARMLAND HYDRO LP	COGEN.	16.0	0.0	0.0	16.0	5.106	5.106	817.02
IMC-AGRICO-S. PIERCE	COGEN.	483.0	0.0	0.0	483.0	3.088	3.088	14,914.75
AUBURNDALE POWER PARTNERS	COGEN.	488.0	0.0	0.0	488.0	2.110	2.110	10,294.89
ORANGE COGENERATION L.P.	COGEN.	4,713.0	0.0	0.0	4,713.0	1.850	1.850	87,199.18
CUTRALE CITRUS	COGEN.	14.0	0.0	0.0	14.0	2.023	2.023	283.20
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR NOVEMBER 2000	-	31,530.0	0.0	0.0	31,530.0	2.007	2.007	632,649.81
ADJ. FOR SEPTEMBE 2000								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	(10,263.0)	0.0	0.0	(10,263.0)	2.549	2.549	(261,585.67)
		10,263.0	0.0	0.0	10,263.0	2.440	2.440	250,430.10
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	(190.0)	0.0	0.0	(190.0)	6.022	6.022	(11,442.61)
		190.0	0.0	0.0	190.0	6.021	6.021	11,440.57
HILLSBOROUGH COUNTY	COGEN.	(11,172.0)	0.0	0.0	(11,172.0)	2.550	2.550	(284,879.13)
		11,172.0	0.0	0.0	11,172.0	2.443	2.443	272,893.15
CARGILL MILLPOINT	COGEN.	(37.0)	0.0	0.0	(37.0)	8.012	8.012	(2,964.34)
		37.0	0.0	0.0	37.0	7.789	7.789	2,881.77
CF INDUSTRIES INC.	COGEN.	(492.0)	0.0	0.0	(492.0)	5.477	5.477	(26,946.12)
		492.0	0.0	0.0	492.0	5.530	5.530	27,205.21
FARMLAND HYDRO LP	COGEN.	(640.0)	0.0	0.0	(640.0)	4.394	4.394	(28,122.54)
		640.0	0.0	0.0	640.0	4.396	4.396	28,136.05
IMC-AGRICO-S. PIERCE	COGEN.	(372.0)	0.0	0.0	(372.0)	4.264	4.264	(15,863.44)
		372.0	0.0	0.0	372.0	4.267	4.267	15,873.56
AUBURNDALE POWER PARTNERS	COGEN.	(1,556.0)	0.0	0.0	(1,556.0)	5.581	5.581	(86,843.19)
		1,556.0	0.0	0.0	1,556.0	5.568	5.568	86,632.51
ORANGE COGENERATION L.P.	COGEN.	(5,819.0)	0.0	0.0	(5,819.0)	2.411	2.411	(140,320.44)
		5,819.0	0.0	0.0	5,819.0	2.291	2.291	133,310.16
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR Sep-99 ADJ.	-	0.0	0.0	0.0	0.0	0.000	0.000	(30,164.40)
GRAND TOTAL		31,530.0	0.0	0.0	31,530.0	1.911	1.911	602,485.41
CURRENT MONTH:								
DIFFERENCE	-	(2,065.0)	0.0	0.0	(2,065.0)	(0.276)	(0.276)	(132,114.59)
DIFFERENCE %	-	(6.1)	0.0	0.0	(6.1)	(12.6)	(12.6)	(18.0)
PERIOD TO DATE:								
ACTUAL		359,204.0	0.0	728.6	358,475.4	2.383	2.383	8,543,328.06
ESTIMATED		377,194.0	0.0	0.0	377,194.0	2.271	2.271	8,565,800.00
DIFFERENCE	-	(17,990.0)	0.0	728.6	(18,718.6)	0.112	0.112	(22,471.94)
DIFFERENCE %	-	(4.8)	0.0	0.0	(5.0)	4.9	4.9	(0.3)

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: NOVEMBER 2000

SCHEDULE A9

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	COST IF GENERATED (A) cents/KWH	(B) $	FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	40,587.0	4.399	1,785,300.00	6.007	2,438,200.00	652,900.00
TOTAL	-	40,587.0	4.399	1,785,300.00	6.007	2,438,200.00	652,900.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL	-	0.0	0.000	0.00	0.000	0.00	0.00
CURRENT MONTH:							
DIFFERENCE	-	(40,587.0)	(4.399)	(1,785,300.00)	(6.007)	(2,438,200.00)	(652,900.00)
DIFFERENCE %	-	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)
PERIOD TO DATE:							
ACTUAL		0.0	0.000	(10,512.45)	0.000	0.00	10,512.45
ESTIMATED		308,716.0	4.478	13,825,500.00	5.879	18,149,000.00	4,323,500.00
DIFFERENCE	-	(308,716.0)	(4.478)	(13,836,012.45)	(5.879)	(18,149,000.00)	(4,312,987.55)
DIFFERENCE %	-	(100.0)	(100.0)	(100.1)	(100.0)	(100.0)	(99.8)

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

DECEMBER 2000

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER , 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	32,318,513	27,870,163	4,448,350	16.0	1,435,566	1,408,374	27,192	1.9	2.25127	1.97889	0.27238	13.8
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (FLMeade/Wauch. Wheeling Losses)	(3,748)	(4,000)	252	(6.3)	1,435,566 a)	1,408,374 a)	27,192	1.9	(0.00026)	(0.00028)	0.00002	(7.1)
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,435,566 a)	1,408,374 a)	27,192	1.9	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,435,566 a)	1,408,374 a)	27,192	1.9	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	32,314,765	27,866,163	4,448,602	16.0	1,435,566	1,408,374	27,192	1.9	2.25101	1.97861	0.27240	13.8
6. Fuel Cost of Purchased Power - Firm (A7)	11,706,495	1,958,300	9,750,195	497.9	184,329	42,598	141,731	332.7	6.35195	4.59716	1.75479	38.2
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	721,200	(721,200)	(100.0)	0	18,000	(18,000)	(100.0)	0.00000	4.00667	(4.00667)	(100.0)
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 a)	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	762,489	659,500	102,989	15.6	34,865	34,715	150	0.4	2.18698	1.89976	0.28722	15.1
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	12,470,984	3,339,000	9,131,984	273.5	219,194	95,313	123,881	130.0	5.68947	3.50319	2.18628	62.4
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,654,760	1,503,687	151,073	10.0				
14. Fuel Cost of Economy Sales (A6)	0	9,000	(9,000)	(100.0)	0	256	(256)	(100.0)	0.00000	3.51563	(3.51563)	(100.0)
15. Gain on Economy Sales - 80% (A6)	0	1,200	(1,200)	(100.0)	0 a)	256 a)	(256)	(100.0)	0.00000	0.46875	(0.46875)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	72,246	119,800	(47,554)	(39.7)	2,960	5,758	(2,798)	(48.6)	2.44074	2.08058	0.36016	17.3
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	54,273	284,400	(230,127)	(80.9)	2,185	12,690	(10,505)	(82.8)	2.48389	2.24113	0.24276	10.8
21. Fuel Cost of Other Power Sales (A6)	2,903,508	2,014,564	888,944	44.1	118,005	111,600	6,405	5.7	2.46050	1.80516	0.65534	36.3
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	3,030,027	2,428,964	601,063	24.7	123,150	130,304	(7,154)	(5.5)	2.46044	1.86407	0.59637	32.0
23. Net Inadvertant Interchange					(282)	0	(282)	0.0				
24. Wheeling Rec'd. less Wheeling Delv'd.					989	0	989	0.0				
25. Interchange and Wheeling Losses					1,818	2,000	(184)	(9.2)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	41,755,722	28,776,199	12,979,523	45.1	1,530,501	1,371,383	159,118	11.6	2.72824	2.09833	0.62991	30.0
27. Net Unbilled	1,495,728 (a)	(207,201) (a)	1,702,929	(821.9)	62,100	(6,443)	70,543	(835.5)	0.10791	(0.01610)	0.12401	(770.2)
28. Company Use	91,743 (a)	98,165 (a)	(6,422)	(6.5)	3,809	4,000	(191)	(4.8)	0.00662	0.00763	(0.00101)	(13.2)
29. T & D Losses	1,892,301 (a)	2,186,621 (a)	(294,320)	(13.5)	78,565	89,100	(10,535)	(11.8)	0.13653	0.16994	(0.03341)	(19.7)
30. System KWH Sales	41,755,722	28,776,199	12,979,523	45.1	1,386,027	1,286,726	99,301	7.7	3.01262	2.23639	0.77623	34.7
31. Wholesale KWH Sales	(2,246,570)	(325,439)	(1,921,131)	590.3	(74,572)	(14,552)	(60,020)	412.5	3.01262	2.23639	0.77623	34.7
32. Jurisdictional KWH Sales	39,509,152	28,450,760	11,058,392	38.9	1,311,455	1,272,174	39,281	3.1	3.01262	2.23639	0.77623	34.7
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	39,536,018	28,470,107	11,065,911	38.9	1,311,455	1,272,174	39,281	3.1	3.01467	2.23791	0.77676	34.7
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	329,395	344,188	(14,793)	(4.3)	1,311,455	1,272,174	39,281	3.1	0.02512	0.02706	(0.00194)	(7.2)
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	1,311,455	1,272,174	39,281	3.1	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	1,311,455	1,272,174	39,281	3.1	0.00000	0.00000	0.00000	0.0
36. True-up *	2,684,371	305,569	2,378,802	778.5	1,311,455	1,272,174	39,281	3.1	0.20469	0.02402	0.18067	752.2
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	42,549,784	29,119,864	13,429,920	46.1	1,311,455	1,272,174	39,281	3.1	3.24447	2.28898	0.95549	41.7
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.24681	2.29063	0.95618	41.7
40. GPIF * (Already Adjusted for Taxes)	(23,053)	(23,053)	0	0.0	1,311,455	1,272,174	39,281	3.1	(0.00176)	(0.00181)	0.00005	(2.8)
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	42,526,731	29,096,811	13,429,920	46.2	1,311,455	1,272,174	39,281	3.1	3.24505	2.28882	0.95623	41.8
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									3.245	2.289	0.956	41.8

* Based on Jurisdictional Sales (a) Included for Informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: DECEMBER, 2000

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	364,767,743	369,255,503	(4,487,760)	(1.2)	17,283,041	17,791,896	(508,856)	(2.9)	2.11055	2.07541	0.03514	1.7
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (FLMeade/Wauch. Wheeling Losses	(48,516)	(48,000)	(516)	1.1	17,283,041 a)	17,791,896 a)	(508,856)	(2.9)	(0.00028)	(0.00027)	(0.00001)	3.7
4b. Adjustments to Fuel Cost	0	0	0	0.0	17,283,041 a)	17,791,896 a)	(508,856)	(2.9)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	(79)	0	(79)	0.0	17,283,041 a)	17,791,896 a)	(508,856)	(2.9)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	364,719,148	369,207,503	(4,488,355)	(1.2)	17,283,041	17,791,896	(508,856)	(2.9)	2.11027	2.07514	0.03513	1.7
6. Fuel Cost of Purchased Power - Firm (A7)	126,110,088	56,276,800	69,833,288	124.1	2,298,318	1,196,639	1,101,679	92.1	5.48706	4.70291	0.78415	16.7
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	(10,512)	14,546,700	(14,557,212)	(100.1)	0	326,716	(326,716)	(100.0)	0.00000	4.45240	(4.45240)	(100.0)
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0	0 a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	9,305,817	9,225,300	80,517	0.9	393,340	411,909	(18,569)	(4.5)	2.36585	2.23965	0.12620	5.6
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	135,405,393	80,048,800	55,356,593	69.2	2,691,658	1,935,264	756,394	39.1	5.03056	4.13632	0.89424	21.6
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					19,974,699	19,727,160	247,539	1.3				
14. Fuel Cost of Economy Sales (A6)	(1,687)	6,653,400	(6,655,087)	(100.0)	0	198,066	(198,066)	(100.0)	0.00000	3.35918	(3.35918)	(100.0)
15. Gain on Economy Sales - 80% (A6)	0	3,370,420	(3,370,420)	(100.0)	0	198,066 a)	(198,066)	(100.0)	0.00000	1.70167	(1.70167)	(100.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	127,482	295,300	(167,818)	(56.8)	12,186	19,153	(6,967)	(36.4)	1.04613	1.54160	(0.49567)	(32.1)
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	1,563,520	1,494,800	68,720	4.6	63,733	69,615	(5,882)	(8.4)	2.45323	2.14724	0.30599	14.3
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	108,608	0	108,608	0.0	2,630	0	2,630	0.0	4.12958	0.00000	4.12958	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	2,701	0	2,701	0.0	55	0	55	0.0	4.91091	0.00000	4.91091	0.0
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	11,015,464	6,103,800	4,911,664	80.5	469,345	265,746	203,599	76.6	2.34699	2.29685	0.05014	2.2
21. Fuel Cost of Other Power Sales (A6)	26,319,480	23,752,048	2,567,432	10.8	1,258,077	1,317,600	(59,523)	(4.5)	2.09204	1.80268	0.28936	16.1
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	39,135,568	41,669,768	(2,534,200)	(6.1)	1,806,026	1,870,180	(64,154)	(3.4)	2.16694	2.22812	(0.06118)	(2.7)
23. Net Inadvertant Interchange					1,593	0	1,593	0.0				
24. Wheeling Rec'd. less Wheeling Del'd.					4,116	0	4,116	0.0				
25. Interchange and Wheeling Losses					22,817	28,300	(5,483)	(19.4)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	460,988,973	407,586,535	53,402,438	13.1	18,151,565	17,828,680	322,885	1.8	2.53967	2.28613	0.25354	11.1
27. Net Unbilled	1,864,805 (a)	10,683 (a)	1,854,122	17,355.8	84,417	483	83,934	17,377.6	0.01086	0.00006	0.01080	18,000.0
28. Company Use	1,098,799 (a)	1,061,698 (a)	37,101	3.5	49,741	48,000	1,741	3.6	0.00640	0.00626	0.00014	2.2
29. T & D Losses	18,802,509 (a)	18,242,132 (a)	560,377	3.1	851,162	824,738	26,424	3.2	0.10953	0.10759	0.00194	1.8
30. System KWH Sales	460,988,973	407,586,535	53,402,438	13.1	17,166,245	16,955,459	210,786	1.2	2.68544	2.40387	0.28157	11.7
31. Wholesale KWH Sales	(20,822,361)	(9,198,652)	(11,623,709)	126.4	(749,604)	(364,455)	(385,149)	105.7	2.77778	2.52395	0.25383	10.1
32. Jurisdictional KWH Sales	440,166,612	398,387,883	41,778,729	10.5	16,416,641	16,591,004	(174,364)	(1.1)	2.68122	2.40123	0.27999	11.7
33. Jurisdictional Loss Multiplier - 1.00068												
34. Jurisdictional KWH Sales Adjusted for Line Losses	440,465,924	398,658,786	41,807,138	10.5	16,416,641	16,591,004	(174,364)	(1.1)	2.68305	2.40286	0.28019	11.7
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	4,160,156	4,256,925	(96,769)	(2.3)	16,416,641	16,591,004	(174,364)	(1.1)	0.02534	0.02566	(0.00032)	(1.2)
35a. Fuel Credit Differential - FMPA Sale	0	0	0	0.0	16,416,641	16,591,004	(174,364)	(1.1)	0.00000	0.00000	0.00000	0.0
35b. Oil Below the Discharge Valve	0	0	0	0.0	16,416,641	16,591,004	(174,364)	(1.1)	0.00000	0.00000	0.00000	0.0
36. True-up *	20,318,467	3,666,883	16,651,584	454.1	16,416,641	16,591,004	(174,364)	(1.1)	0.12377	0.02210	0.10167	460.0
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	484,944,547	406,582,594	58,361,953	14.4	16,416,641	16,591,004	(174,364)	(1.1)	2.83215	2.45062	0.38153	15.6
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.83419	2.45238	0.38181	15.6
40. GPIF * (Already Adjusted for Taxes)	(276,702)	(276,702)	0	0.0	16,416,641	16,591,004	(174,364)	(1.1)	(0.00169)	(0.00167)	(0.00002)	1.2
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	484,667,845	406,305,892	58,361,953	14.4	16,416,641	16,591,004	(174,364)	(1.1)	2.83250	2.45071	0.38179	15.6
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.833	2.451	0.382	15.6

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CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	32,318,513	27,870,163	4,448,350	16.0	364,767,743	369,255,503	(4,487,760)	(1.2)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	3,030,027	2,428,964	601,063	24.7	39,135,568	41,669,768	(2,534,200)	(6.1)
3. FUEL COST OF PURCHASED POWER	11,708,495	1,958,300	9,750,195	497.9	126,110,088	56,276,800	69,833,288	124.1
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	762,489	659,500	102,989	15.6	9,305,817	9,225,300	80,517	0.9
4. ENERGY COST OF ECONOMY PURCHASES	0	721,200	(721,200)	0.0	(10,512)	14,546,700	(14,557,212)	(100.1)
5. TOTAL FUEL & NET POWER TRANSACTION	41,759,470	28,780,199	12,979,271	45.1	461,037,568	407,634,535	53,403,033	13.1
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(3,748)	(4,000)	252	(6.3)	(48,516)	(48,000)	(516)	1.1
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST	0	0	0	0.0	(79)	0	(79)	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	41,755,722	28,776,199	12,979,523	45.1	460,988,973	407,586,535	53,402,438	13.
* INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,311,455	1,272,174	39,281	3.1	16,416,641	16,591,004	(174,363)	(1.1)
2. NONJURISDICTIONAL SALES	74,572	14,552	60,020	412.5	749,604	364,455	385,149	105.7
3. TOTAL SALES	1,386,027	1,286,726	99,301	7.7	17,166,245	16,955,459	210,786	1
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9461973	0.9886907	(0.0424934)	(4.3)	0.9563327	0.9785052	(0.0221725)	(2.3)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	32,268,645	29,259,933	3,008,712	10.3	392,671,085	381,827,086	10,843,999	2.8
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	(2,684,371)	(305,569)	(2,378,802)	778.5	(20,318,467)	(3,666,883)	(16,651,584)	454.1
b. INCENTIVE PROVISION	23,053	23,053	0	0.0	276,702	276,702	0	0.0
c. TRANSITION ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
d. OTHER ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	29,607,327	28,977,417	629,910	2.2	372,629,320	378,436,905	(5,807,585)	(1.5)
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	41,755,722	28,776,199	12,979,523	45.1	460,988,973	407,586,535	53,402,438	13.1
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B-4)	0.9461973	0.9886907	(0.0424934)	(4.3)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	39,509,152	28,450,760	11,058,392	38.9	440,166,612	398,387,883	41,778,729	10.5
6A.JURISDIC. LOSS MULTIPLIER	1.00068	1.00068	0.0000	0.0	NA	NA	-	-
6B. (LINE 6 x LINE 6A)	39,536,018	28,470,107	11,065,911	38.9	440,465,924	398,658,786	41,807,138	10.5
6C.PEABODY COAL CONTR. BUY-OUT AMORT.	348,125	348,125	0	0.0	4,344,546	4,344,546	0	0.0
6D.(LINE 6C x LINE 5) PB. JURISD.	329,395	344,188	(14,793)	(4.3)	4,160,156	4,256,925	(96,769)	(2.3)
6E.OTHER (SPARE INPUT #1)	0	0	0	0.0	0	0	0	0.0
6F. OIL BELOW THE DISCHARGE VALVE	0	0	0	0.0	0	0	0	0.0
6G. OTHER (SPARE INPUT #2)	0	0	0	0.0	0	0	0	0.0
6H. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. 6B+6D+6E+6F+6G)	39,865,413	28,814,295	11,051,118	38.4	444,626,080	402,915,711	41,710,369	10.4
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6H)	(10,258,086)	163,122	(10,421,208)	(6,388.6)	(71,996,760)	(24,478,806)	(47,517,954)	194.1
8. INTEREST PROVISION FOR THE MONTH	(338,257)	(172,391)	(165,866)	96.2	(1,842,961)	(1,162,026)	(680,935)	58.6
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(60,320,498)	(45,754,222)	(14,566,276)	31.8	NOT APPLICABLE			
9a.DEFERRED TRUE-UP BEGINNING OF PERIOD	2,381,673	7,879,936	(5,498,263)	(69.8)	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	2,684,371	305,569	2,378,802	778.5	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	(65,850,797)	(37,577,986)	(28,272,811)	75.2	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2000

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	(57,938,825)	(37,874,286)	(20,064,539)	53.0	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	(65,512,540)	(37,405,595)	(28,106,945)	75.1	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(123,451,365)	(75,279,881)	(48,171,484)	64.0	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	(61,725,683)	(37,639,941)	(24,085,743)	64.0	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	6.650	5.500	1.150	20.9	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	6.500	5.500	1.000	18.2	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	13.150	11.000	2.150	19.5	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	6.575	5.500	1.075	19.5	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.548	0.458	0.090	19.7	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	(338,257)	(172,391)	(165,866)	96.2	NOT APPLICABLE			

GENER G SYSTEM COMPARATIVE DATA BY FUEL PE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: DECEMBER 2000

SCHEDULE A3
PAGE 1 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
FUEL COST OF SYSTEM NET GENERATION ($)								
1 HEAVY OIL	432,246	54,838	377,408	688.2	13,177,783	11,810,322	1,367,461	11.6
2 LIGHT OIL	4,458,562	1,141,887	3,316,675	290.5	18,731,595	19,757,382	(1,025,787)	(5.2)
3 COAL	27,061,865	26,670,586	391,279	1.5	324,328,956	337,635,438	(13,306,482)	(3.9)
4 NATURAL GAS	365,840	2,852	362,988	12,727.5	8,529,409	52,361	8,477,048	16,189.6
5 NUCLEAR	0	0	0	0.0	0	0	0	0.0
6 OTHER	0	0	0	0.0	0	0	0	0.0
7 TOTAL ($)	32,318,513	27,870,163	4,448,350	16.0	364,767,743	369,255,503	(4,487,760)	(1.2)
SYSTEM NET GENERATION (MWH)								
8 HEAVY OIL	8,341	1,122	7,219	643.4	224,919	258,321	(33,402)	(12.9)
9 LIGHT OIL	56,511	6,741	49,770	738.3	243,391	178,120	65,271	36.6
10 COAL	1,365,909	1,400,416	(34,507)	(2.5)	16,679,276	17,353,649	(674,374)	(3.9)
11 NATURAL GAS	4,805	95	4,710	4,957.9	135,455	1,806	133,649	7,400.3
12 NUCLEAR	0	0	0	0.0	0	0	0	0.0
13 OTHER	0	0	0	0.0	0	0	0	0.0
14 TOTAL (MWH)	1,435,566	1,408,374	27,192	1.9	17,283,041	17,791,896	(508,856)	(2.9)
UNITS OF FUEL BURNED								
15 HEAVY OIL (BBL)	14,063	2,505	11,558	461.4	504,288	645,810	(141,522)	(21.9)
16 LIGHT OIL (BBL)	109,148	33,058	76,090	230.2	502,319	553,131	(50,812)	(9.2)
17 COAL (TON)	598,921	627,758	(28,837)	(4.6)	7,550,403	7,822,849	(272,446)	(3.5)
18 NATURAL GAS (MCF)	49,746	800	48,946	6,118.3	1,592,351	15,700	1,576,651	10,042.4
19 NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20 OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
BTUS BURNED (MMBTU)								
21 HEAVY OIL	88,342	15,841	72,501	457.7	3,196,842	4,082,183	(885,341)	(21.7)
22 LIGHT OIL	634,771	77,509	557,262	719.0	2,899,482	2,199,724	699,758	31.8
23 COAL	14,023,154	14,618,770	(595,616)	(4.1)	173,986,540	181,311,764	(7,325,224)	(4.0)
24 NATURAL GAS	48,368	849	47,519	5,597.1	1,552,203	16,097	1,536,106	9,542.8
25 NUCLEAR	0	0	0	0.0	0	0	0	0.0
26 OTHER	0	0	0	0.0	0	0	0	0.0
27 TOTAL (MMBTU)	14,794,635	14,712,969	81,666	0.6	181,635,067	187,609,768	(5,974,701)	(3.2)
GENERATION MIX (% MWH)								
28 HEAVY OIL	0.58	0.08	0.50	-	1.30	1.45	(0.15)	-
29 LIGHT OIL	3.94	0.48	3.46	-	1.41	1.00	0.41	-
30 COAL	95.15	99.43	(4.28)	-	96.51	97.54	(1.03)	-
31 NATURAL GAS	0.33	0.01	0.32	-	0.78	0.01	0.77	-
32 NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33 OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34 TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
FUEL COST PER UNIT								
35 HEAVY OIL ($/BBL)	30.74	21.89	8.85	40.4	26.13	18.29	7.84	42.9
36 LIGHT OIL ($/BBL)	40.85	34.54	6.31	18.3	37.29	35.72	1.57	4.4
37 COAL ($/TON)	45.18	42.49	2.69	6.3	42.96	43.16	(0.20)	(0.5)
38 NATURAL GAS ($/MCF)	7.35	3.57	3.78	105.9	5.36	3.34	2.02	60.5
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40 OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
FUEL COST PER MMBTU ($/MMBTU)								
41 HEAVY OIL	4.89	3.46	1.43	41.3	4.12	2.89	1.23	42.6
42 LIGHT OIL	7.02	14.73	(7.71)	(52.3)	6.46	8.98	(2.52)	(28.1)
43 COAL	1.93	1.82	0.11	6.0	1.86	1.86	0.00	0.0
44 NATURAL GAS	7.56	3.36	4.20	125.0	5.50	3.25	2.25	69.2
45 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47 TOTAL ($/MMBTU)	2.18	1.89	0.29	15.3	2.01	1.97	0.04	2.0

GENER. .G SYSTEM COMPARATIVE DATA BY FUE. .PE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: DECEMBER 2000

. EDULE A3
PAGE 2 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
BTU BURNED PER KWH (BTU/KWH)								
48 HEAVY OIL	10,591	14,119	(3,528)	(25.0)	14,213	15,803	(1,590)	(10.1)
49 LIGHT OIL	11,233	11,498	(265)	(2.3)	11,913	12,350	(437)	(3.5)
50 COAL	10,267	10,439	(172)	(1.6)	10,431	10,448	(17)	(0.2)
51 NATURAL GAS	10,066	8,937	1,129	12.6	11,459	8,913	2,546	28.6
52 NUCLEAR	0	0	0	0.0	0	0	0	0.0
53 OTHER	0	0	0	0.0	0	0	0	0.0
54 TOTAL (BTU/KWH)	10,306	10,447	(141)	(1.3)	10,509	10,545	(36)	(0.3)
GENERATED FUEL COST PER KWH (cents/KWH)								
55 HEAVY OIL	5.18	4.89	0.29	5.9	5.86	4.57	1.29	28.2
56 LIGHT OIL	7.89	16.94	(9.05)	(53.4)	7.70	11.09	(3.39)	(30.6)
57 COAL	1.98	1.90	0.08	4.2	1.94	1.95	(0.01)	(0.5)
58 NATURAL GAS	7.61	3.00	4.61	153.7	6.30	2.90	3.40	117.2
59 NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60 OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61 TOTAL (cents/KWH)	2.25	1.98	0.27	13.6	2.11	2.08	0.03	1.4

SCHEDULE A4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD/MONTH OF: DECEMBER 2000

(A) PLANT/UNIT	(B) NET CAPAB-ILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPC. FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents /KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	32	(23)	(0.1)	100.0	0.0	0	HVY.OIL	244	6,359,237	1,550.7	6,688	0.00	27.43
H.P.#2	32	(5)	0.0	100.0	0.0	0	HVY.OIL	49	6,358,393	308.7	1,331	0.00	27.42
H.P.#3	32	0	0.0	46.1	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	41	(108)	0.0	99.9	0.0	0	HVY.OIL	1,128	6,359,285	7,174.1	30,939	0.00	27.43
H.P.#5	52	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	189	(136)	0.0	63.3	0.0	0	HVY.OIL	1,421	6,359,246	9,033.5	38,958	0.00	27.42
GAN.#1	114	55,293	65.2	94.2	65.2	11,881	COAL	27,584	23,816,600	656,957.1	1,233,013	2.23	44.70
GAN.#2	88	44,785	68.4	78.5	86.8	11,603	COAL	22,795	22,795,819	519,630.7	1,018,943	2.28	44.70
GAN.#3	155	37,262	32.3	38.4	58.8	12,167	COAL	23,464	19,321,659	453,363.4	1,048,847	2.81	44.70
GAN.#4	169	59,548	47.4	66.2	73.6	11,542	COAL	35,765	19,216,580	687,281.0	1,598,705	2.68	44.70
GAN.#5	242	27,772	15.4	18.1	53.9	10,384	COAL	12,034	23,965,024	288,395.1	537,923	1.94	44.70
GAN.#6	392	63,447	21.8	36.6	60.3	9,695	COAL	27,396	22,452,741	615,115.3	1,224,609	1.93	44.70
GANNON STA.	1160	288,107	33.4	46.1	63.2	11,179	COAL	149,038	21,610,211	3,220,742.6	6,662,040	2.31	44.70
B.B.#1	426	190,621	60.1	62.0	82.4	10,219	COAL	80,064	24,329,600	1,947,925.1	3,461,444	1.82	43.23
B.B.#2	426	259,270	81.8	94.9	81.8	9,932	COAL	105,840	24,328,780	2,574,958.1	4,575,829	1.76	43.23
B.B.#3	443	250,252	75.9	89.5	78.1	9,954	COAL	103,455	24,078,380	2,491,028.8	4,472,717	1.79	43.23
B.B. 1 - 3	1295	700,143	72.7	82.2	80.7	10,018	COAL	289,359	24,239,481	7,013,912.0	12,509,990	1.79	43.23
B.B.#4	447	234,332	70.5	76.3	83.7	10,038	COAL	105,655	22,262,527	2,352,136.2	5,291,440	2.26	50.08
B.B. STA.	1742	934,475	72.1	80.7	81.5	10,023	COAL	395,014	23,710,704	9,366,048.2	17,801,430	1.90	45.07
SEB-PHIL. #1(HVY OIL)	17	4,014	31.7	99.4	81.4	9,879	HVY.OIL	6,321	6,273,406	39,654.2	196,644	4.90	31.11
SEB-PHIL. #2(HVY OIL)	17	4,463	35.3	96.4	89.0	8,885	HVY.OIL	6,321	6,273,406	39,654.2	196,644	4.41	31.11
SEB-PHILLIPS TOTAL	34	8,477	33.5	97.9	85.3	9,356	HVY.OIL	12,642	6,273,406	79,308.4	393,288	4.64	31.11
POLK #1 GASIFIER	250	143,327	77.1	80.7	93.6	10,022	COAL	54,869	26,177,999	1,436,363.0	2,598,395	1.81	47.36
POLK #1 CT (OIL)	245	22,504	12.3	99.4	72.6	8,095	LGT.OIL	31,481	5,786,669	182,169.2	1,265,622	5.62	40.20
POLK #1 TOTAL	250	165,831	89.2	97.4	90.1	9,760	-	-	-	1,618,532.2	3,864,017	2.33	-
POLK #2 CT (GAS)	150	4,805	4.3	13.8	82.6	10,066	GAS	49,746	972,299	48,368.0	365,840	7.61	7.35
POLK #2 CT (OIL)	170	19,421	15.4	70.5	73.7	12,153	LGT.OIL	40,567	5,817,946	236,016.6	1,630,910	8.40	40.20
POLK #2 TOTAL	150	24,226	21.7	43.9	75.3	11,739	-	-	-	284,384.6	1,996,750	8.24	-
POLK STATION TOTAL	400	190,057	63.9	77.4	84.6	10,012	-	-	-	1,902,916.8	5,860,767	3.08	-
GAN.C.T.#1	17	0	0.0	0.0	0.0	0	LGT.OIL	-	0	0.0	-	0.00	0.00
B.B.C.T.#1	17	680	5.4	98.8	77.8	15,660	LGT.OIL	1,830	5,818,852	10,648.5	77,049	11.33	42.10
B.B.C.T.#2	80	6,986	11.7	94.9	61.7	15,119	LGT.OIL	18,090	5,838,745	105,622.9	761,647	10.90	42.10
B.B.C.T.#3	80	6,920	11.6	90.4	64.8	14,496	LGT.OIL	17,180	5,838,981	100,313.7	723,334	10.45	42.10
C.T. TOTAL	194	14,586	10.1	85.1	59.0	14,849	LGT.OIL	37,100	5,837,873	216,585.1	1,562,030	10.71	42.10
TOT. COAL (GN,BB,POLK)	3152	1,365,909	58.2	68.0	75.7	10,267	COAL	598,921	23,414,045	14,023,153.8	27,061,865	1.98	45.18
SYSTEM	3,719	1,435,566	51.9	69.1	70.8	10,306	-	-	-	14,794,634.6	32,318,513	2.25	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS
NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2000

SCHEDULE A5
PAGE 1 OF 2
REVISED P-T-D
LINES 49 & 51

		CURRENT MONTH				PERIOD TO DATE			
	HEAVY OIL (1)	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	PURCHASES:								
2	UNITS (BBL)	11,261	2,505	8,756	349.5	475,629	599,722	(124,093)	(20.7)
3	UNIT COST ($/BBL)	29.90	20.38	9.52	46.7	27.36	18.27	9.09	49.8
4	AMOUNT ($)	336,648	51,062	285,586	559.3	13,015,015	10,955,861	2,059,154	18.8
5	BURNED:								
6	UNITS (BBL)	14,063	2,505	11,558	461.4	504,288	645,810	(141,522)	(21.9)
7	UNIT COST ($/BBL)	30.74	21.89	8.85	40.4	26.13	18.29	7.84	42.9
8	AMOUNT ($)	432,246	54,838	377,408	688.2	13,177,783	11,810,322	1,367,461	11.6
9	ENDING INVENTORY:								
10	UNITS (BBL)	61,600	81,135	(19,535)	(24.1)	61,600	81,135	(19,535)	(24.1)
11	UNIT COST ($/BBL)	27.32	20.56	6.76	32.9	27.32	20.56	6.76	32.9
12	AMOUNT ($)	1,682,786	1,667,932	14,854	0.9	1,682,786	1,667,932	14,854	0.9
13									
14	DAYS SUPPLY:	5,600	252	5,348	2,122.2	-	-	-	-
	LIGHT OIL (2)								
15	PURCHASES:								
16	UNITS (BBL)	84,403	50,857	33,546	66.0	599,881	705,925	(106,044)	(15.0)
17	UNIT COST ($/BBL)	41.09	32.74	8.35	25.5	38.45	35.64	2.81	7.9
18	AMOUNT ($)	3,467,939	1,665,180	1,802,759	108.3	23,067,227	25,157,041	(2,089,814)	(8.3)
19	BURNED:								
20	UNITS (BBL)	109,148	33,058	76,090	230.2	502,319	553,131	(50,812)	(9.2)
21	UNIT COST ($/BBL)	40.85	34.54	6.31	18.3	37.29	35.72	1.57	4.4
22	AMOUNT ($)	4,458,562	1,141,887	3,316,675	290.5	18,731,595	19,757,382	(1,025,787)	(5.2)
23	ENDING INVENTORY:								
24	UNITS (BBL)	51,532	97,057	(45,525)	(46.9)	51,532	97,057	(45,525)	(46.9)
25	UNIT COST ($/BBL)	41.14	35.69	5.45	15.3	41.14	35.69	5.45	15.3
26	AMOUNT ($)	2,120,000	3,463,744	(1,343,744)	(38.8)	2,120,000	3,463,744	(1,343,744)	(38.8)
27									
28	DAYS SUPPLY: NORMAL	51	65	(14)	(21.5)	-	-	-	-
29	DAYS SUPPLY: EMERGENCY	7	14	(7)	(50.0)	-	-	-	-
	COAL (3)								
30	PURCHASES:								
31	UNITS (TONS)	477,414	755,000	(277,586)	(36.8)	7,388,477	7,938,200	(549,723)	(6.9)
32	UNIT COST ($/TON)	44.74	41.52	3.22	7.8	42.74	42.25	0.49	1.2
33	AMOUNT ($)	21,360,854	31,346,218	(9,985,364)	(31.9)	315,796,683	335,354,227	(19,557,544)	(5.8)
34	BURNED:								
35	UNITS (TONS)	598,921	627,758	(28,837)	(4.6)	7,550,403	7,822,849	(272,446)	(3.5)
36	UNIT COST ($/TON)	45.18	42.49	2.69	6.3	42.96	43.16	(0.20)	(0.5)
37	AMOUNT ($)	27,061,865	26,670,586	391,279	1.5	324,328,956	337,635,438	(13,306,482)	(3.9)
38	ENDING INVENTORY:								
39	UNITS (TONS)	615,090	1,241,526	(626,436)	(50.5)	615,090	1,241,526	(626,436)	(50.5)
40	UNIT COST ($/TON)	43.23	41.79	1.44	3.4	43.23	41.79	1.44	3.4
41	AMOUNT ($)	26,593,053	51,886,326	(25,293,273)	(48.7)	26,593,053	51,886,326	(25,293,273)	(48.7)
42									
43	DAYS SUPPLY:	31	62	(31)	(50.0)	-	-	-	-
	NATURAL GAS (4)								
44	PURCHASES:								
45	UNITS (MCF)	49,746	800	48,946	6,118.3	1,592,351	15,700	1,576,651	10,042.4
46	UNIT COST ($/MCF)	7.35	3.57	3.78	105.9	5.46	3.34	2.12	63.5
47	AMOUNT ($)	365,840	2,852	362,988	12,727.5	8,698,344	52,361	8,645,983	16,512.3
48	BURNED:								
49	UNITS (MCF)	49,746	800	48,946	6,118.3	1,592,351	15,700	1,576,651	10,042.4
50	UNIT COST ($/MCF)	7.35	3.57	3.78	105.9	5.36	3.34	2.02	60.5
51	AMOUNT ($)	365,840	2,852	362,988	12,727.5	8,529,409	52,361	8,477,048	16,189.6
52	ENDING INVENTORY:								
53	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
54	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
56									
57	DAYS SUPPLY:	0	0	0	0.0	-	-	-	-
	NUCLEAR								
58	BURNED:								
59	UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
60	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2000

OTHER	CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH %	PERIOD TO DATE ACTUAL	PERIOD TO DATE ESTIMATED	PERIOD TO DATE DIFFERENCE AMOUNT	PERIOD TO DATE %
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73 AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
74 DAYS SUPPLY:	0	0	0	0.0	-	-	-	-

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	19,911
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	19,911

(2)
RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(16,571)	(695,561)
OTHER USAGE	(728)	(30,464)
TOTAL	(17,299)	(726,025)

(3)
RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	28,841
IGNITION #2 OIL	675,650
IGNITION PROPANE	26,172
AERIAL SURVEY ADJ.	164,914
ADDITIVES	0
TOTAL	895,577

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: DECEMBER 2000

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) ---cents/KWH--- (A) FUEL COST	(6) (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:									
VARIOUS	ECON.	256.0	0.0	256.0	3.711	4.297	9,500.00	11,000.00	1,200.00
VARIOUS JURISDICTIONAL	SCH. -D	5,758.0	0.0	5,758.0	2.081	2.081	119,800.00	119,800.00	
VARIOUS SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS SEPARATED	CONTRACT	12,690.0	0.0	12,690.0	2.241	3.184	284,400.00	404,000.00	
FMPA	SCH. -D	111,600.0	0.0	111,600.0	1.805	1.805	2,014,564.00	2,014,564.00	
VARIOUS JURISDICTIONAL	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS	-	130,304.0	0.0	130,304.0	1.864	1.956	2,428,264.00	2,549,364.00	1,200.00
LESS TRANSMISSION COSTS	-						0.00		
LESS VARIABLE O & M COSTS	-						(500.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS	-						1,200.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS	-	130,304.0	0.0	130,304.0	1.864	1.956	2,428,964.00	2,549,364.00	1,200.00
ACTUAL:									
FLA. PWR. CORP.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF ST. CLOUD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SONAT	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY, INC.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENRGY, INC.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENN, VALLEY AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL. SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH. SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS SEP. CONTRACT		2,185.0	0.0	2,185.0	2.246	3.049	49,075.10	66,620.65	
SEMINOLE ELECTRIC CO-OP PRECO-1 JURISD.	SCH. -D	2,122.0	28.3	2,095.7	2.601	2.601	54,519.41	54,519.41	
SEMINOLE ELECTRIC CO-OP HARDEE JURISD.	SCH. -D	864.0	0.0	864.0	2.052	2.052	17,726.89	17,726.89	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: DECEMBER 2000

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(6) (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
THE ENERGY AUTHORITY	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA		SCH. -D	101,595.0	0.0	101,595.0	1.934	1.934	1,965,354.93	1,965,354.93	
HARDEE POWER PART. TO FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR.& LT.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO JACKSONVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KISSIMMEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ORLANDO		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO SEMINOLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FT. PIERCE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LK. WORTH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ENERGY AUTHORITY		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: DECEMBER 2000

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) —cents/KWH— (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -MA	3,440.0	0.0	3,440.0	12.358	12.358	425,120.32	425,120.32	
FLA. PWR. & LIGHT	JURISD.	SCH. -MA	4,450.0	0.0	4,450.0	3.038	3.038	135,203.35	135,203.35	
LAKELAND	JURISD.	SCH. -MA	1,685.0	0.0	1,685.0	3.990	3.990	67,227.56	67,227.56	
TALLAHASSEE	JURISD.	SCH. -MA	50.0	0.0	50.0	2.650	2.650	1,325.15	1,325.15	
REEDY CREEK	JURISD.	SCH. -MA	665.0	0.0	665.0	0.088	0.088	585.03	585.03	
ENRON	JURISD.	SCH. -MA	10.0	0.0	10.0	277.040	277.040	27,704.00	27,704.00	
THE ENERGY AUTHORITY	JURISD.	SCH. -MA	4,940.0	0.0	4,940.0	4.090	4.090	202,065.32	202,065.32	
OGLETHORPE	JURISD.	SCH. -MA	200.0	0.0	200.0	12.850	12.850	25,700.60	25,700.60	
CORAL ENERGY	JURISD.	SCH. -MA	134.0	0.0	134.0	2.950	2.950	3,953.40	3,953.40	
DUKE ENERGY	JURISD.	SCH. -MA	352.0	0.0	352.0	4.663	4.663	16,413.06	16,413.06	
MORGAN STANLEY	JURISD.	SCH. -MA	320.0	0.0	320.0	7.686	7.686	24,595.96	24,595.96	
CARGILL ALLIANT	JURISD.	SCH. -MA	91.0	0.0	91.0	2.616	2.616	2,380.72	2,380.72	
HARDEE POWER PART. TO ENERGY AUTH	JURISD.	SCH. -MA	73.0	0.0	73.0	7.608	7.608	5,553.75	5,553.75	
ADJUSTMENTS TO PREVIOUS MONTHS	MON/YR TY	SCHED.								
HARDEE POWER PARTNERS	11/00 SEPAR	CONTRACT	(51,975.0)	0.0	(51,975.0)	2.236	3.055	(1,162,161.00)	(1,587,836.25)	
HARDEE POWER PARTNERS	11/00 SEPAR	CONTRACT	51,975.0	0.0	51,975.0	2.246	3.049	1,167,358.50	1,584,717.75	
FMPA	01/00 SEPAR	SCH. - D	(110,850.0)	0.0	(110,850.0)	1.942	1.942	(2,152,687.45)	(2,152,687.45)	
FMPA	01/00 SEPAR	SCH. - D	110,850.0	0.0	110,850.0	1.942	1.942	2,153,012.45	2,153,012.45	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			2,986.0	26.3	2,959.7	2.441	2.441	72,246.30	72,246.30	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.			2,185.0	0.0	2,185.0	2.494	2.906	54,272.60	63,502.15	
SUB-TOTAL OTHER D POWER SALES			101,595.0	0.0	101,595.0	1.935	1.935	1,965,679.93	1,965,679.93	
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			16,410.0	0.0	16,410.0	5.715	5.715	937,828.22	937,828.22	
TOTAL INCLUDING VARIABLE O & M COSTS			123,176.0	26.3	123,149.7	2.460	2.468	3,030,027.05	3,039,256.60	0.00
LESS VARIABLE O & M COSTS								0.00		
LESS VARIABLE O & M COSTS - HARDEE								0.00		
LESS TRANSMISSION COSTS SCH. D (SEP.)								0.00		
PLUS 80% OF ECON. ENERGY SALES PROFITS	-							0.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS	-		123,176.0	26.3	123,149.7	2.460	2.468	3,030,027.05	3,039,256.60	0.00
CURRENT MONTH:										
DIFFERENCE		-	(7,128.0)	26.3	(7,154.3)	0.596	0.512	601,063.05	489,892.60	(1,200.00)
DIFFERENCE %		-	(5.5)	0.0	(5.5)	32.0	26.2	24.7	19.2	(100.0)
PERIOD TO DATE:										
ACTUAL		-	1,814,302.0	8,275.6	1,806,026.4	2.167	2.383	39,135,586.39	43,046,055.10	0.00
ESTIMATED		-	1,870,180.0	0.0	1,870,180.0	2.228	2.432	41,669,768.00	45,488,548.00	3,370,420.00
DIFFERENCE		-	(55,878.0)	8,275.6	(64,153.6)	(0.061)	(0.049)	(2,534,201.61)	(2,442,492.90)	(3,370,420.00)
DIFFERENCE %		-	(3.0)	0.0	(3.4)	(2.7)	(2.0)	(6.1)	(5.4)	(100.0)

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. SEC 60% OR $889.97 HAVE BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF : DECEMBER 2000

SCHEDULE A7

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) ----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	2,655.0	0.0	1,506.0	1,149.0	7.372	7.372	84,700.00
HARDEE POWER PARTNERS	IPP	27,177.0	0.0	0.0	27,177.0	5.530	5.530	1,503,000.00
VARIOUS	OTHER	14,272.0	0.0	0.0	14,272.0	2.597	2.597	370,600.00
TOTAL	-	44,104.0	0.0	1,506.0	42,598.0	4.597	4.597	1,958,300.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	68,648.0	0.0	0.0	68,648.0	7.894	7.894	5,419,039.82
HARDEE PWR. PART.-OTHERS	*IPP*	*73.0*	*0.0*	*0.0*	*73.0*	*6.795*	*6.795*	*4,960.43*
FLA. POWER CORP.	SCH.-Ja	1,547.0	0.0	144.2	1,402.8	11.046	11.046	154,953.45
FLA. POWER CORP.	SCH.-Jc	33,344.0	0.0	0.0	33,344.0	4.943	4.943	1,648,269.00
FLA. POWER & LIGHT	SCH.-Ja	2,656.0	0.0	472.4	2,183.6	7.433	7.433	162,305.86
FLA. POWER & LIGHT	SCH.-Jc	38,049.0	0.0	0.0	38,049.0	7.148	7.148	2,719,900.00
LAKELAND	SCH.-Ja	775.0	0.0	177.0	598.0	56.204	56.204	336,100.00
LAKELAND	SCH.-Jc	4,066.0	0.0	0.0	4,066.0	11.622	11.622	472,551.50
ORLANDO	SCH.-Ja	747.0	0.0	100.0	647.0	8.618	8.618	55,760.00
ORLANDO	SCH.-Jc	953.0	0.0	0.0	953.0	9.154	9.154	87,240.00
TALLAHASSEE	SCH.-Ja	613.0	0.0	0.0	613.0	27.438	27.438	168,197.31
TALLAHASSEE	SCH.-Jc	1,663.0	0.0	0.0	1,663.0	12.324	12.324	204,947.81
THE ENERGY AUTHORITY	SCH.-Ja	708.0	0.0	0.0	708.0	11.929	11.929	84,456.88
THE ENERGY AUTHORITY	SCH.-Jc	7,388.0	0.0	0.0	7,388.0	6.757	6.757	499,228.03
AQUILA	SCH.-Ja	83.0	0.0	83.0	0.0	0.000	0.000	235.00
AQUILA	SCH.-Jc	1,468.0	0.0	0.0	1,468.0	7.739	7.739	113,612.60
OKEELANTA	SCH.-Ja	139.0	0.0	0.0	139.0	5.940	5.940	8,256.11
OKEELANTA	SCH.-Jc	3,082.0	0.0	0.0	3,082.0	5.858	5.858	180,539.89
DUKE ENERGY TRADING	SCH.-Ja	98.0	0.0	44.1	53.9	21.265	21.265	11,467.36
DUKE ENERGY TRADING	SCH.-Jc	2,621.0	0.0	0.0	2,621.0	9.288	9.288	243,446.94
REEDY CREEK	*SCH.-Jc*	*1,805.0*	*0.0*	*0.0*	*1,805.0*	4.393	4.393	79,295.00
LAKE WORTH	SCH.-Jc	24.0	0.0	0.0	24.0	11.663	11.663	2,799.07
ENRON	SCH.-Jc	384.0	0.0	0.0	384.0	6.465	6.465	24,824.00
SOUTHERN COMPANY	SCH.-Ja	887.0	0.0	489.0	398.0	14.671	14.671	58,391.46
SOUTHERN COMPANY	SCH.-Jc	4,008.0	0.0	0.0	4,008.0	4.849	4.849	194,347.65
KOCH	SCH.-Ja	86.0	0.0	0.0	86.0	30.698	30.698	26,400.00
KOCH	SCH.-Jc	282.0	0.0	0.0	282.0	9.151	9.151	25,806.00
ENTERGY MARKETING	SCH.-Jc	141.0	0.0	0.0	141.0	9.787	9.787	13,800.00
OKEELANTA	SCH.-D	5,917.0	0.0	0.0	5,917.0	3.581	3.581	211,863.00
AUBURNDALE	SCH.-D	3,582.0	0.0	0.0	3,582.0	2.334	2.334	83,612.75
ADJUSTMENTS TO PRIOR MONTHS:								
HARDEE PWR. PART.-NATIV 11/00	IPP	(49,806.0)	0.0	0.0	(49,806.0)	9.232	9.232	(4,598,164.46)
HARDEE PWR. PART.-NATIV 11/00	IPP	49,806.0	0.0	0.0	49,806.0	6.033	6.033	3,004,750.76
ENERGY AUTHORITY 11/00	SCH.-Ja	(530.0)	0.0	(157.0)	(373.0)	6.988	6.988	(26,067.00)
ENERGY AUTHORITY 11/00	SCH.-Ja	531.0	0.0	157.0	374.0	6.970	6.970	26,067.00
ENERGY AUTHORITY 11/00	SCH.-Jc	(4,728.0)	0.0	0.0	(4,728.0)	6.976	6.976	(329,813.74)
ENERGY AUTHORITY 11/00	SCH.-Jc	4,728.0	0.0	0.0	4,728.0	7.005	7.005	331,195.71
TALLAHASSEE 11/00	SCH.-Jc	(5,030.0)	0.0	0.0	(5,030.0)	6.201	6.201	(311,891.90)
TALLAHASSEE 11/00	SCH.-Jc	5,030.0	0.0	0.0	5,030.0	6.269	6.269	315,328.02
ENRON 11/00	SCH.-Jc	(7,326.0)	0.0	0.0	(7,326.0)	3.658	3.658	(267,957.24)
ENRON 11/00	SCH.-Jc	7,326.0	0.0	0.0	7,326.0	3.662	3.662	268,259.18
KOCH 11/00	SCH.-Ja	(686.0)	0.0	(27.6)	(658.4)	6.468	6.468	(42,584.29)
KOCH 11/00	SCH.-Ja	688.0	0.0	27.6	660.4	6.448	6.448	42,584.29
KOCH 11/00	SCH.-Jc	(5,896.0)	0.0	0.0	(5,896.0)	6.328	6.328	(373,216.06)
KOCH 11/00	SCH.-Jc	5,897.0	0.0	0.0	5,897.0	6.329	6.329	373,216.06
MORGAN STANLEY 11/00	SCH.-Jc	(7,901.0)	0.0	0.0	(7,901.0)	5.693	5.693	(449,771.14)
MORGAN STANLEY 11/00	*SCH.-Jc*	7,901.0	0.0	0.0	7,901.0	5.695	5.695	449,935.77
CORAL POWER LLC 11/00	SCH.-Jc	(3,038.0)	0.0	0.0	(3,038.0)	3.889	3.889	(118,138.78)
CORAL POWER LLC 11/00	SCH.-Jc	3,038.0	0.0	0.0	3,038.0	3.889	3.889	118,155.86
TOTAL		185,839.0	0.0	1,509.6	184,329.4	6.352	6.352	11,708,494.96
CURRENT MONTH:								
DIFFERENCE	-	141,735.0	0.0	3.6	141,731.4	6.879	6.879	9,750,194.96
DIFFERENCE %	-	321.4	0.0	0.2	332.7	149.6	149.6	497.9
PERIOD TO DATE:								
ACTUAL	-	2,527,082.0	0.0	228,763.9	2,298,318.1	5.487	5.487	126,110,089.58
ESTIMATED	-	1,354,958.0	0.0	158,319.0	1,196,639.0	4.703	4.703	56,276,800.00
DIFFERENCE	-	1,172,124.0	0.0	70,444.9	1,101,679.1	0.784	0.784	69,833,289.58
DIFFERENCE %	-	86.5	0.0	44.5	92.1	16.7	16.7	124.1

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
SCHEDULE A8

FOR THE MONTH OF: DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	34,715.0	0.0	0.0	34,715.0	1.900	1.900	659,500.00
TOTAL	-	34,715.0	0.0	0.0	34,715.0	1.900	1.900	659,500.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	6,971.0	0.0	0.0	6,971.0	2.017	2.017	140,613.57
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	21.0	0.0	0.0	21.0	2.305	2.305	484.01
HILLSBOROUGH COUNTY	COGEN.	19,077.0	0.0	0.0	19,077.0	2.013	2.013	384,024.54
CARGILL MILLPOINT	COGEN.	307.0	0.0	0.0	307.0	3.512	3.512	10,780.56
CF INDUSTRIES INC.	COGEN.	464.0	0.0	0.0	464.0	6.125	6.125	28,418.40
FARMLAND HYDRO LP	COGEN.	1,501.0	0.0	0.0	1,501.0	3.869	3.869	58,072.14
IMC-AGRICO-S. PIERCE	COGEN.	730.0	0.0	0.0	730.0	5.713	5.713	41,707.30
AUBURNDALE POWER PARTNERS	COGEN.	212.0	0.0	0.0	212.0	2.109	2.109	4,471.49
ORANGE COGENERATION L.P.	COGEN.	5,580.0	0.0	0.0	5,580.0	1.974	1.974	110,133.69
CUTRALE CITRUS	COGEN.	2.0	0.0	0.0	2.0	4.746	4.746	94.92
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR DECEMBER 2000	-	34,865.0	0.0	0.0	34,865.0	2.234	2.234	778,800.62
ADJ. FOR OCTOBER 2000								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0		0.0	0.000	0.000	0.00
		0.0	0.0		0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	(10,355.0)	0.0		(10,355.0)	2.105	2.105	(217,923.57)
		10,355.0	0.0		10,355.0	2.061	2.061	213,463.77
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0		0.0	0.000	0.000	0.00
		0.0	0.0		0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0		0.0	0.000	0.000	0.00
		0.0	0.0		0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	0.0	0.0		0.0	0.000	0.000	0.00
		0.0	0.0		0.0	0.000	0.000	0.00
HILLSBOROUGH COUNTY	COGEN.	(18,199.0)	0.0		(18,199.0)	2.129	2.129	(387,493.69)
		18,199.0	0.0		18,199.0	2.081	2.081	378,738.23
CARGILL MILLPOINT	COGEN.	0.0	0.0		0.0	0.000	0.000	0.00
		0.0	0.0		0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	0.0	0.0		0.0	0.000	0.000	0.00
		0.0	0.0		0.0	0.000	0.000	0.00
FARMLAND HYDRO LP	COGEN.	0.0	0.0		0.0	0.000	0.000	0.00
		0.0	0.0		0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE	COGEN.	0.0	0.0		0.0	0.000	0.000	0.00
		0.0	0.0		0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS	COGEN.	0.0	0.0		0.0	0.000	0.000	0.00
		0.0	0.0		0.0	0.000	0.000	0.00
ORANGE COGENERATION L.P.	COGEN.	(6,072.0)	0.0		(6,072.0)	2.047	2.047	(124,292.17)
		6,072.0	0.0		6,072.0	1.996	1.996	121,196.23
CUTRALE CITRUS	COGEN.	0.0	0.0		0.0	0.000	0.000	0.00
		0.0	0.0		0.0	0.000	0.000	0.00
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0		0.0	0.000	0.000	0.00
		0.0	0.0		0.0	0.000	0.000	0.00
SUB-TOTAL FOR Oct-00 ADJ.	-	0.0	0.0	0.0	0.0	0.000	0.000	(16,311.20)
GRAND TOTAL		34,865.0	0.0	0.0	34,865.0	2.187	2.187	762,489.42
CURRENT MONTH:								
DIFFERENCE	-	150.0	0.0	0.0	150.0	0.287	0.287	102,989.42
DIFFERENCE %	-	0.4	0.0	0.0	0.4	15.1	15.1	15.6
PERIOD TO DATE:								
ACTUAL		394,069.0	0.0	728.6	393,340.4	2.366	2.366	9,305,617.48
ESTIMATED		411,909.0	0.0	0.0	411,909.0	2.240	2.240	9,225,300.00
DIFFERENCE	-	(17,840.0)	0.0	728.6	(18,568.6)	0.126	0.126	80,517.48
DIFFERENCE %	-	(4.3)	0.0	0.0	(4.5)	5.6	5.6	0.9

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: DECEMBER 2000

SCHEDULE A9

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	COST IF GENERATED (A) cents/KWH	(B) $	FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	18,000.0	4.007	721,200.00	5.257	946,300.00	225,100.00
TOTAL	-	18,000.0	4.007	721,200.00	5.257	946,300.00	225,100.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL	-	0.0	0.000	0.00	0.000	0.00	0.00
CURRENT MONTH:							
DIFFERENCE	-	(18,000.0)	(4.007)	(721,200.00)	(5.257)	(946,300.00)	(225,100.00)
DIFFERENCE %	-	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)
PERIOD TO DATE:							
ACTUAL		0.0	0.000	(10,512.45)	0.000	0.00	10,512.45
ESTIMATED		326,716.0	4.452	14,546,700.00	5.845	19,095,300.00	4,548,600.00
DIFFERENCE	-	(326,716.0)	(4.452)	(14,557,212.45)	(5.845)	(19,095,300.00)	(4,538,087.55)
DIFFERENCE %	-	(100.0)	(100.0)	(100.1)	(100.0)	(100.0)	(99.8)

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A6

JANUARY 2000 - DECEMBER 2000

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

SCHEDULE A6
PAGE 1 OF 1

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	198,066.0	0.0	198,066.0	3.569	5.696	7,069,300.00	11,282,400.00	3,370,420.00
VARIOUS	JURISDICTIONAL	SCH. -D	69,615.0	0.0	69,615.0	2.147	2.147	1,494,800.00	1,494,800.00	
VARIOUS	SEPARATED	SCH. -D	19,153.0	0.0	19,153.0	1.731	1.905	331,500.00	364,900.00	
HARDEE POWER PARTNERS	SEPARATED	CONTRACT	265,746.0	0.0	265,746.0	2.297	3.234	6,103,800.00	8,594,400.00	
FMPA		SCH. -D	1,317,600.0	0.0	1,317,600.0	1.803	1.803	23,752,048.00	23,752,048.00	
VARIOUS	JURISDICTIONAL	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	1,870,180.0	0.0	1,870,180.0	2.072	2.432	38,751,448.00	45,488,548.00	3,370,420.00
LESS TRANSMISSION COSTS		-						(36,200.00)		
LESS VARIABLE O & M COSTS		-						(415,900.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS		-						3,370,420.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-	1,870,180.0	0.0	1,870,180.0	2.228	2.432	41,669,768.00	45,488,548.00	3,370,420.00
ACTUAL:										
KOCH		ECON.-C	0.0	0.0	0.0	0.000	0.000	(1,686.72)	(1,686.72)	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	12,186.0	0.0	12,186.0	1.872	2.013	228,122.13	245,291.55	
HARDEE POWER PARTNERS	SEPAR.	CONTRAC	469,345.0	0.0	469,345.0	2.347	3.169	11,015,463.18	14,871,427.67	
SEMINOLE ELEC CO-OP PRECO-1	JURISD.	SCH. -D	61,483.0	8,275.6	53,207.4	2.561	2.561	1,362,720.59	1,362,720.59	
SEMINOLE ELEC CO-OP HARDEE	JURISD.	SCH. -D	10,526.0	0.0	10,526.0	1.908	1.908	200,799.04	200,799.04	
FLORIDA POWER & LIGHT		STEAM-A	50.0	0.0	50.0	20.000	20.000	10,000.00	10,000.00	
ORLANDO UTIL. COMM.		STEAM-A	373.0	0.0	373.0	19.714	19.714	73,532.80	73,532.80	
FMPA	JURISD.	SCH. -D	1,091,250.0	0.0	1,091,250.0	1.911	1.911	20,851,235.04	20,851,235.04	
HARDEE POWER PART. TO FLA. PWR. CORP.	JURISD.	SCH. -J	55.0	0.0	55.0	4.911	4.911	2,701.01	2,701.01	
CARGILL ALLIANT Total	JURISD.	SCH. -M	940.0	0.0	940.0	3.480	3.480	32,709.80	32,709.80	
CITY OF HOMESTEAD Total	JURISD.	SCH. -M	20.0	0.0	20.0	10.550	10.550	2,110.06	2,110.06	
CITY OF LAKELAND Total	JURISD.	SCH. -M	9,377.0	0.0	9,377.0	2.857	2.857	267,921.02	267,921.02	
CITY OF NEW SMYRNA BCH. Total	JURISD.	SCH. -M	92.0	0.0	92.0	9.772	9.772	8,990.28	8,990.28	
CORAL ENERGY Total	JURISD.	SCH. -M	134.0	0.0	134.0	2.950	2.950	3,953.40	3,953.40	
DUKE ENERGY Total	JURISD.	SCH. -M	352.0	0.0	352.0	4.663	4.663	16,413.06	16,413.06	
ENRON Total	JURISD.	SCH. -M	10.0	0.0	10.0	277.040	277.040	27,704.00	27,704.00	
FLA. PWR. & LIGHT Total	JURISD.	SCH. -M	124,422.0	0.0	124,422.0	2.653	2.653	3,300,903.39	3,300,903.39	
FLA. PWR. CORP. Total	JURISD.	SCH. -M	13,062.0	0.0	13,062.0	6.499	6.499	848,920.56	848,920.56	
HARDEE POWER PART. TO AQUILA Total	JURISD.	SCH. -M	440.0	0.0	440.0	4.368	4.368	19,217.09	19,217.09	
HARDEE POWER PART. TO ENERGY AUTHORITY	JURISD.	SCH. -M	433.0	0.0	433.0	4.608	4.608	19,954.62	19,954.62	
HARDEE POWER PART. TO FLA. PWR. CORP. Tota	JURISD.	SCH. -M	671.0	0.0	671.0	5.677	5.677	38,092.75	38,092.75	
HARDEE POWER PART. TO FLA. PWR.& LT. Total	JURISD.	SCH. -M	2,107.0	0.0	2,107.0	3.193	3.193	67,278.47	67,278.47	
HARDEE POWER PART. TO KOCH ENERGY Total	JURISD.	SCH. -M	550.0	0.0	550.0	6.318	6.318	34,748.11	34,748.11	
HARDEE POWER PART. TO LAKELAND Total	JURISD.	SCH. -M	91.0	0.0	91.0	4.360	4.360	3,967.64	3,967.64	
HARDEE POWER PART. TO ORLANDO Total	JURISD.	SCH. -M	108.0	0.0	108.0	3.236	3.236	3,494.41	3,494.41	
HARDEE POWER PART. TO REEDY CREEK Total	JURISD.	SCH. -M	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PART. TO TALLAHASSEE Total	JURISD.	SCH. -M	265.0	0.0	265.0	3.841	3.841	10,178.77	10,178.77	
KOCH ENERGY Total	JURISD.	SCH. -M	1,772.0	0.0	1,772.0	9.452	9.452	167,486.25	167,486.25	
MORGAN STANLEY Total	JURISD.	SCH. -M	320.0	0.0	320.0	7.686	7.686	24,595.96	24,595.96	
OGLETHORPE Total	JURISD.	SCH. -M	200.0	0.0	200.0	12.850	12.850	25,700.60	25,700.60	
ORLANDO UTIL. COMM. Total	JURISD.	SCH. -M	3,415.0	0.0	3,415.0	2.943	2.943	100,511.77	100,511.77	
REEDY CREEK Total	JURISD.	SCH. -M	750.0	0.0	750.0	0.321	0.321	2,409.04	2,409.04	
RELIANT ENERGY Total	JURISD.	SCH. -M	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SONAT Total	JURISD.	SCH. -M	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SOUTHERN COMPANY Total	JURISD.	SCH. -M	1,405.0	0.0	1,405.0	6.083	6.083	85,461.36	85,461.36	
TALLAHASSEE Total	JURISD.	SCH. -M	180.0	0.0	180.0	3.643	3.643	6,557.54	6,557.54	
THE ENERGY AUTHORITY Total	JURISD.	SCH. -M	7,918.0	0.0	7,918.0	3.925	3.925	310,753.97	310,753.97	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	(1,686.72)	(1,686.72)	0.00
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.			12,186.0	0.0	12,186.0	1.872	2.013	228,122.13	245,291.55	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			72,009.0	8,275.6	63,733.4	2.453	2.453	1,563,519.63	1,563,519.63	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.			55.0	0.0	55.0	4.911	4.911	2,701.01	2,701.01	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.			469,345.0	0.0	469,345.0	2.347	3.169	11,015,463.18	14,871,427.67	
SUB-TOTAL OTHER D POWER SALES			1,091,250.0	0.0	1,091,250.0	1.911	1.911	20,851,235.04	20,851,235.04	
SUB-TOTAL SCHEDULE M POWER SALES-JURISD.			169,034.0	0.0	169,034.0	3.212	3.212	5,430,034.12	5,430,034.12	
SUB-TOTAL OTHER POWER SALES			423.0	0.0	423.0	19.748	19.748	83,532.80	83,532.80	
TOTAL INCLUDING VARIABLE O & M COSTS			1,814,302.0	8,275.6	1,806,026.4	2.169	2.383	39,172,921.19	43,046,055.10	0.00
LESS VARIABLE O & M COSTS								0.00		
LESS VARIABLE O & M COSTS - HARDEE								0.00		
LESS TRANSMISSION COSTS SCH. D (SEP.)								(37,354.80)		
PLUS 80% OF ECON. ENERGY SALES PROFITS -								0.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS	-		1,814,302.0	8,275.6	1,806,026.4	2.167	2.383	39,135,566.39	43,046,055.10	0.00
DIFFERENCE			(55,878.0)	8,275.6	(64,153.6)	(0.061)	(0.049)	(2,534,201.61)	(2,442,492.90)	(3,370,420.00)
DIFFERENCE %			(3.0)	0.0	(3.4)	(2.7)	(2.0)	(6.1)	(5.4)	(100.0)

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. SEC 60% OR $47,118.76 HAVE BEEN EXCLUDED.

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A7

JANUARY 2000 - DECEMBER 2000

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD OF : JANUARY 2000 - DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	——CENTS/KWH—— (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	302,510.0	0.0	158,319.0	144,191.0	12.626	12.626	18,205,000.0
HARDEE POWER PARTNERS	IPP	724,762.0	0.0	0.0	724,762.0	3.610	3.610	26,167,000.0
VARIOUS	OTHER	327,686.0	0.0	0.0	327,686.0	3.633	3.633	11,904,800.0
TOTAL	-	**1,354,958.0**	**0.0**	**158,319.0**	**1,196,639.0**	**4.703**	**4.703**	**56,276,800.00**
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP Total	819,579.0	0.0	0.0	819,579.0	5.268	5.268	43,176,829.89
HARDEE PWR. PART.-OTHERS	IPP Total	121,110.0	0.0	0.0	121,110.0	5.478	5.478	6,633,996.66
AQUILA	SCH.-Ja Tota	9,457.0	0.0	6,876.6	2,580.4	9.035	9.035	233,132.27
AQUILA	SCH.-Jc Tota	13,338.0	0.0	0.0	13,338.0	6.998	6.998	933,408.96
AUBURNDALE POWER PARTNERS	SCH.-D Total	57,792.0	0.0	0.0	57,792.0	3.799	3.799	2,195,445.20
AUBURNDALE POWER PARTNERS	SCH.-Jc Tota	4,981.0	0.0	0.0	4,981.0	2.334	2.334	116,259.57
CARGILL ALLIANT	SCH.-Ja Tota	1,600.0	0.0	848.4	751.6	9.648	9.648	72,509.31
CARGILL ALLIANT	SCH.-Jc Tota	6,522.0	0.0	0.0	6,522.0	4.909	4.909	320,139.43
CARGILL FERTILIZER	SCH.-Ja Tota	266.0	0.0	151.0	115.0	13.174	13.174	15,150.00
CARGILL FERTILIZER	SCH.-Jc Tota	4,088.0	0.0	0.0	4,088.0	3.153	3.153	128,911.82
CITY OF LAKELAND	SCH.-Ja Tota	93,898.0	0.0	54,399.9	39,498.1	10.272	10.272	4,057,417.99
CITY OF LAKELAND	SCH.-Jc Tota	84,317.0	0.0	0.0	84,317.0	6.579	6.579	5,546,927.65
CORAL POWER	SCH.-Ja Tota	4,205.0	0.0	1,423.3	2,781.7	9.460	9.460	263,159.86
CORAL POWER	SCH.-Jc Tota	8,275.0	0.0	0.0	8,275.0	6.786	6.786	561,540.57
DUKE ENERGY	SCH.-Ja Tota	98.0	0.0	44.1	53.9	21.265	21.265	11,467.36
DUKE ENERGY	SCH.-Jc Tota	2,745.0	0.0	0.0	2,745.0	9.173	9.173	251,805.64
ENRON	SCH.-Ja Tota	1,472.0	0.0	827.7	644.3	7.815	7.815	50,352.80
ENRON	SCH.-Jc Tota	13,461.0	0.0	0.0	13,461.0	4.604	4.604	619,736.75
ENTERGY	SCH.-Ja Tota	7,874.0	0.0	5,103.2	2,770.8	8.406	8.406	232,915.35
ENTERGY	SCH.-Jc Tota	9,155.0	0.0	0.0	9,155.0	6.478	6.478	593,081.52
FARMLAND HYDRO LP	SCH.-Jc Tota	1,186.0	0.0	0.0	1,186.0	3.502	3.502	41,601.31
FLA. POWER & LIGHT	SCH.-Ja Tota	73,560.0	0.0	44,567.7	28,992.3	7.299	7.299	2,116,255.78
FLA. POWER & LIGHT	SCH.-Jc Tota	212,984.0	0.0	0.0	212,984.0	5.753	5.753	12,252,394.84
FLA. POWER & LIGHT	SCH.-Tx Tota	0.0	0.0	0.0	0.0	0.000	0.000	(161,045.35)
FLA. POWER & LIGHT	STEAM-A Tot	25.0	0.0	0.0	25.0	11.544	11.544	2,886.00
FLA. POWER CORP.	SCH.-Ja Tota	65,449.0	0.0	38,158.8	27,290.2	7.705	7.705	2,102,721.41
FLA. POWER CORP.	SCH.-Jc Tota	285,253.0	0.0	0.0	285,253.0	4.015	4.015	11,451,771.75
KOCH	SCH.-Ja Tota	14,817.0	0.0	5,660.4	9,156.6	7.703	7.703	705,340.69
KOCH	SCH.-Jc Tota	21,429.0	0.0	0.0	21,429.0	6.876	6.876	1,473,412.09
LAKE WORTH	SCH.-Jc Tota	24.0	0.0	0.0	24.0	11.663	11.663	2,799.07
MORGAN STANLEY	SCH.-Ja Tota	7,908.0	0.0	3,141.8	4,766.2	9.127	9.127	435,004.29
MORGAN STANLEY	SCH.-Jc Tota	71,293.0	0.0	0.0	71,293.0	5.665	5.665	4,038,636.18
OGLETHORPE	SCH.-Jc Tota	137.0	0.0	0.0	137.0	4.903	4.903	6,717.31
OKEELANTA	SCH.-D Total	135,530.0	0.0	0.0	135,530.0	4.228	4.228	5,730,411.16
OKEELANTA	SCH.-Ja Tota	3,090.0	0.0	1,772.1	1,317.9	5.194	5.194	68,452.88
OKEELANTA	SCH.-Jc Tota	9,852.0	0.0	0.0	9,852.0	5.699	5.699	561,459.58
ORLANDO UTIL. COMM.	SCH.-Ja Tota	83,057.0	0.0	40,037.6	43,019.4	7.526	7.526	3,237,552.12
ORLANDO UTIL. COMM.	SCH.-Jc Tota	77,020.0	0.0	0.0	77,020.0	7.690	7.690	5,923,216.50
REEDY CREEK	SCH.-Ja Tota	485.0	0.0	30.0	455.0	5.781	5.781	26,302.00
REEDY CREEK	SCH.-Jc Tota	5,107.0	0.0	0.0	5,107.0	4.644	4.644	237,165.50
RELIANT	SCH.-Ja Tota	6,883.0	0.0	2,562.7	4,320.3	5.272	5.272	227,778.28
RELIANT	SCH.-Jc Tota	11,929.0	0.0	0.0	11,929.0	5.406	5.406	644,908.38
RINGHAVER	SCH.-Jc Tota	9,920.0	0.0	0.0	9,920.0	2.030	2.030	201,421.94
SEMPRA	SCH.-Jc Tota	100.0	0.0	0.0	100.0	4.900	4.900	4,900.00
SOUTHERN COMPANY	SCH.-Ja Tota	1,280.0	0.0	489.0	791.0	15.032	15.032	118,899.49
SOUTHERN COMPANY	SCH.-Jc Tota	5,529.0	0.0	0.0	5,529.0	5.355	5.355	296,074.13
TALLAHASSEE	SCH.-Ja Tota	8,377.0	0.0	3,395.7	4,981.3	10.199	10.199	508,029.14
TALLAHASSEE	SCH.-Jc Tota	39,255.0	0.0	0.0	39,255.0	5.739	5.739	2,252,759.42
THE ENERGY AUTH.	SCH.-Ja Tota	40,403.0	0.0	19,273.9	21,129.1	7.461	7.461	1,576,539.92
THE ENERGY AUTH.	SCH.-Jc Tota	70,965.0	0.0	0.0	70,965.0	5.653	5.653	4,011,535.17
TOTAL		**2,527,082.0**	**0.0**	**228,763.9**	**2,298,318.1**	**5.487**	**5.487**	**126,110,089.58**
DIFFERENCE	-	1,172,124.0	0.0	70,444.9	1,101,679.1	0.784	0.784	69,833,289.58
DIFFERENCE %	-	86.5	0.0	44.5	92.1	16.7	16.7	124.1

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A8

JANUARY 2000 - DECEMBER 2000

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2000 - DECEMBER 2000

SCHEDULE A8
PAGE 1 OF 1

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	----CENTS/KWH---- (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	411,909.0	0.0	0.0	411,909.0	2.240	2.240	9,225,300.00
TOTAL	-	**411,909.0**	**0.0**	**0.0**	**411,909.0**	**2.240**	**2.240**	**9,225,300.00**
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	69,712.0	0.0	0.0	69,712.0	2.142	2.142	1,493,109.68
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	213.0	0.0	0.0	213.0	7.600	7.600	16,186.97
IMC-AGRICO-NEW WALES	COGEN.	4,965.0	0.0	0.0	4,965.0	4.271	4.271	212,059.26
HILLSBOROUGH COUNTY	COGEN.	200,117.0	0.0	0.0	200,117.0	2.125	2.125	4,251,932.43
CARGILL MILLPOINT	COGEN.	792.0	0.0	0.0	792.0	3.175	3.175	25,147.67
CF INDUSTRIES INC.	COGEN.	15,248.0	0.0	0.0	15,248.0	3.412	3.412	520,226.37
FARMLAND HYDRO LP	COGEN.	9,416.0	0.0	0.0	9,416.0	3.286	3.286	309,438.53
IMC-AGRICO-S. PIERCE	COGEN.	6,919.0	0.0	0.0	6,919.0	5.943	5.943	411,172.91
AUBURNDALE POWER PARTNERS	COGEN.	13,716.0	0.0	0.0	13,716.0	4.027	4.027	552,346.15
ORANGE COGENERATION L.P.	COGEN.	72,851.0	0.0	0.0	72,851.0	2.109	2.109	1,536,550.78
CUTRALE CITRUS	COGEN.	120.0	0.0	0.0	120.0	3.134	3.134	3,760.55
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	728.6	(728.6)	3.584	3.584	(26,113.82)
TOTAL	-	**394,069.0**	**0.0**	**728.6**	**393,340.4**	**2.366**	**2.366**	**9,305,817.48**
DIFFERENCE PERIOD TO DATE	-	(17,840.0)	0.0	728.6	(18,568.6)	0.126	0.126	80,517.48
DIFFERENCE % PERIOD TO DATE	-	(4.3)	0.0	0.0	(4.5)	5.6	5.6	0.9

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A9

JANUARY 2000 - DECEMBER 2000

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

SCHEDULE A9
PAGE 1 OF 1

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	COST IF GENERATED (A) cents/KWH	COST IF GENERATED (B) $	FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	326,716.0	4.452	14,546,700.00	5.845	19,095,300.00	4,548,600.00
TOTAL	-	**326,716.0**	**4.452**	**14,546,700.00**	**5.845**	**19,095,300.00**	**4,548,600.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	(10,512.45)	0.000	0.00	10,512.45
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**(10,512.45)**	**0.000**	**0.00**	**10,512.45**
DIFFERENCE	-	(326,716.0)	(4.452)	(14,557,212.45)	(5.845)	(19,095,300.00)	(4,538,087.55)
DIFFERENCE %	-	(100.0)	(100.0)	(100.1)	(100.0)	(100.0)	(99.8)

EXHIBIT NO._____
DOCKET NO. 010001-EI
TAMPA ELECTRIC COMPANY
(JDJ-2)
FILED 08/20/01
DOCUMENT NO. 1

TAMPA ELECTRIC COMPANY

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. _____ EXHIBIT NO. 2
COMPANY/ WITNESS: Jordan
DATE: 11-20-01

CALCULATION OF ESTIMATED TRUE-UP
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2001 THROUGH DECEMBER 2001

SCHEDULE E1-B

		ACTUAL						ESTIMATED						
		Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TOTAL
A. 1.	Fuel Cost of System Net Generation	35,049,220	25,906,064	28,330,024	26,941,440	27,442,642	36,399,600	35,041,284	36,391,718	32,849,664	30,297,255	27,298,671	28,711,246	370,658,828
2.	Fuel Cost of Power Sold [1]	4,860,627	2,828,366	2,785,635	1,928,904	201,546	1,140,789	2,033,300	1,463,000	872,800	1,718,300	1,292,700	1,010,700	22,136,667
3.	Fuel Cost of Purchased Power	22,623,589	8,185,643	10,471,838	21,799,335	16,795,332	16,405,170	12,819,500	16,103,700	10,909,200	6,737,100	3,413,100	2,488,300	148,751,807
3a.	Demand and Non-Fuel Cost of Purchased Pwr	0	0	0	0	0	0	0	0	0	0	0	0	0
3b.	Payments to Qualifying Facilities	614,083	477,237	865,771	840,934	823,903	851,322	956,400	950,100	911,000	900,200	733,200	711,900	9,636,050
4.	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
5.	Adjustment to Fuel Cost (Ft. Meade/Wau. Wheeling)	(4,145)	(2,961)	(3,158)	(4,064)	(4,381)	(4,558)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(47,267)
5a.	Adjustment to Fuel Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	**TOTAL FUEL & NET POWER TRANS.**	**53,422,120**	**31,737,617**	**36,878,840**	**47,648,741**	**44,855,950**	**52,510,745**	**46,779,884**	**51,978,518**	**43,793,064**	**36,212,255**	**30,148,271**	**30,896,746**	**506,862,751**
[1]	Includes Gains													
B. 1.	Jurisdictional MWH Sales	1,604,027	1,292,892	1,209,453	1,232,701	1,303,234	1,580,541	1,649,041	1,626,561	1,675,400	1,498,370	1,294,124	1,286,997	17,253,340
2.	Non-Jurisdictional MWH Sales	59,200	43,339	68,623	71,754	76,402	69,941	84,557	84,910	79,709	57,487	43,408	39,316	778,646
3.	**TOTAL SALES (LINE B1+B2)**	**1,663,227**	**1,336,231**	**1,278,076**	**1,304,455**	**1,379,636**	**1,650,482**	**1,733,598**	**1,711,471**	**1,755,109**	**1,555,857**	**1,337,532**	**1,326,313**	**18,031,986**
4.	**Jurisdictional % of Total Sales**	**0.9644065**	**0.9675662**	**0.9463076**	**0.9449931**	**0.9446216**	**0.9576239**	**0.9512246**	**0.9503877**	**0.9545846**	**0.9630512**	**0.9675462**	**0.9703569**	-
1.	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	39,749,385	32,021,651	29,884,053	34,416,247	36,519,851	44,240,442	42,908,569	45,835,998	47,208,010	42,203,613	36,426,773	36,226,917	467,641,509
1a.	Adjustment to Fuel Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
2.	True-up Provision	(3,560,110)	(3,560,110)	(3,560,110)	(3,426,463)	(3,426,463)	(3,426,463)	(3,426,463)	(3,426,463)	(3,426,463)	(3,426,463)	(3,426,463)	(3,426,461)	(41,518,495)
2a.	Incentive Provision	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,870	1,150,407
2b.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	**FUEL REVENUE APPLICABLE TO PERIOD**	**36,285,142**	**28,557,408**	**26,419,810**	**31,085,651**	**33,189,255**	**40,909,846**	**39,577,973**	**42,505,402**	**43,877,414**	**38,873,017**	**33,096,177**	**32,896,326**	**427,273,421**
4.	Total Fuel and Net Power Transactions (Line A6)	53,422,120	31,737,617	36,878,840	47,648,741	44,855,950	52,510,745	46,779,884	51,978,518	43,793,064	36,212,255	30,148,271	30,896,746	506,862,751
5.	Jurisd. Total Fuel and Net Power Transactions (Line A6*Line B4)	51,520,640	30,708,247	34,898,727	45,027,733	42,371,899	50,285,544	44,498,176	49,399,744	41,804,184	34,874,256	29,169,845	29,980,871	484,539,866
5a.	Jurisdictional Loss Multiplier	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	-
5b.	Jurisdictional Sales Adjusted for Line Losses	51,554,644	30,728,514	34,921,760	45,057,451	42,399,864	50,318,732	44,527,545	49,432,348	41,831,775	34,897,273	29,189,097	30,000,658	484,859,661
5c.	Peabody Coal Contract Buyout Amortization	345,594	343,063	340,532	338,002	335,471	332,940	330,409	327,878	325,347	322,816	320,285	317,754	3,980,091
5d.	Peabody Jurisdictionalized (Line 5c*Line B4)	333,293	331,936	322,248	319,410	316,893	318,831	314,293	311,611	310,571	310,888	309,891	308,335	3,808,200
6.	**JURISD. TOTAL FUEL AND NET POWER TRANSACTIONS INCLUDING PEABODY**	**51,887,937**	**31,060,450**	**35,244,008**	**45,376,861**	**42,716,757**	**50,637,563**	**44,841,838**	**49,743,959**	**42,142,346**	**35,208,161**	**29,498,988**	**30,308,993**	**488,667,861**
7.	Over/(Under) Recovery	(15,602,795)	(2,503,042)	(8,824,198)	(14,291,210)	(9,527,502)	(9,727,717)	(5,263,865)	(7,238,557)	1,735,068	3,664,856	3,597,189	2,587,333	(61,394,440)
8.	Interest Provision	(360,990)	(346,828)	(339,307)	(345,611)	(337,165)	(335,871)	(352,268)	(371,519)	(370,509)	(351,342)	(329,010)	(308,399)	(4,148,819)
9.	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD**													**(65,543,259)**

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2001 THROUGH DECEMBER 2001

SCHEDULE E2

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
		ACTUAL						ESTIMATED						TOTAL
		Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	PERIOD
1.	Fuel Cost of System Net Generation	35,049,220	25,906,064	28,330,024	26,941,440	27,442,642	36,399,600	35,041,284	36,391,718	32,849,664	30,297,255	27,298,671	28,711,246	370,658,828
2.	Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Fuel Cost of Power Sold [1]	4,860,627	2,828,366	2,785,635	1,928,904	201,546	1,140,789	2,033,300	1,463,000	872,800	1,718,300	1,292,700	1,010,700	22,136,667
4.	Fuel Cost of Purchased Power	22,623,589	8,185,643	10,471,838	21,799,335	16,795,332	16,405,170	12,819,500	16,103,700	10,909,200	6,737,100	3,413,100	2,488,300	148,751,807
5.	Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	Payments to Qualifying Facilities	614,083	477,237	865,771	840,934	823,903	851,322	956,400	950,100	911,000	900,200	733,200	711,900	9,636,050
7.	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Adjustment to Fuel Cost (Ft. Meade/Wau. Wheeling)	(4,145)	(2,961)	(3,158)	(4,064)	(4,381)	(4,558)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(47,267)
8a.	Adjustment to Fuel Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
9.	**TOTAL FUEL & NET POWER TRANSACTIONS**	**53,422,120**	**31,737,617**	**36,878,840**	**47,648,741**	**44,855,950**	**52,510,745**	**46,779,884**	**51,978,518**	**43,793,064**	**36,212,255**	**30,148,271**	**30,896,746**	**506,862,751**
10.	Jurisdictional kWh Sold	1,604,027	1,292,892	1,209,453	1,232,701	1,303,234	1,580,541	1,649,041	1,626,561	1,675,400	1,498,370	1,294,124	1,286,997	17,253,340
11.	Jurisdictional % of Total Sales	0.9644065	0.9675662	0.9463076	0.9449931	0.9446216	0.9576239	0.9512246	0.9503877	0.9545846	0.9630512	0.9675462	0.9703569	-
12.	Jurisdictional Total Fuel & Net Power Transactions (Line 9 * Line 11)	51,520,640	30,708,247	34,898,727	45,027,733	42,371,899	50,285,544	44,498,176	49,399,744	41,804,184	34,874,256	29,169,845	29,980,871	484,539,866
13.	Jurisdictional Loss Multiplier	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	-
14.	Jurisdictional Sales Adjusted for Line Losses (Line 12 * Line 13)	51,554,644	30,728,514	34,921,760	45,057,451	42,399,864	50,318,732	44,527,545	49,432,348	41,831,775	34,897,273	29,189,097	30,000,658	484,859,661
15.	Peabody Coal Contract Buyout Amortization	345,594	343,063	340,532	338,002	335,471	332,940	330,409	327,878	325,347	322,816	320,285	317,754	3,980,091
16.	Peabody Jurisdictionalized (Line 15 * Line 11)	333,293	331,936	322,248	319,410	316,893	318,831	314,293	311,611	310,571	310,888	309,891	308,335	3,808,200
17.	**JURISD. TOTAL FUEL & NET PWR. TRANS. INCL. PEABODY (LINE 14+16)**	**51,887,937**	**31,060,450**	**35,244,008**	**45,376,861**	**42,716,757**	**50,637,563**	**44,841,838**	**49,743,959**	**42,142,346**	**35,208,161**	**29,498,988**	**30,308,993**	**488,667,861**
18.	Cost Per kWh Sold (Cents/kWh)	3.2349	2.4024	2.9140	3.6811	3.2778	3.2038	2.7193	3.0582	2.5154	2.3498	2.2795	2.3550	2.8323
19.	True-up (Cents/kWh) [2]	0.2219	0.2754	0.2944	0.2780	0.2629	0.2168	0.2078	0.2107	0.2045	0.2287	0.2648	0.2662	0.2443
20.	Total (Cents/kWh) (Line 18+19)	3.4568	2.6778	3.2084	3.9591	3.5407	3.4206	2.9271	3.2689	2.7199	2.5785	2.5443	2.6212	3.0766
21.	Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
22.	Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	3.4593	2.6797	3.2107	3.9620	3.5432	3.4231	2.9292	3.2713	2.7219	2.5804	2.5461	2.6231	3.0789
23.	GPIF Adjusted for Taxes (Cents/kWh) [2]	(0.0060)	(0.0074)	(0.0079)	(0.0078)	(0.0074)	(0.0061)	(0.0058)	(0.0059)	(0.0057)	(0.0064)	(0.0074)	(0.0074)	(0.0068)
24.	**TOTAL RECOVERY FACTOR (LINE 22+23)**	**3.4533**	**2.6723**	**3.2028**	**3.9542**	**3.5358**	**3.4170**	**2.9234**	**3.2654**	**2.7162**	**2.5740**	**2.5387**	**2.6157**	**3.0721**
25.	**RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH**	**3.453**	**2.672**	**3.203**	**3.954**	**3.536**	**3.417**	**2.923**	**3.265**	**2.716**	**2.574**	**2.539**	**2.616**	**3.072**

[1] Includes Gains
[2] Based on Jurisdictional Sales Only

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2001 THROUGH JUNE 2001

	ACTUAL					
	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	420,184	36,350	400,450	510,597	472,083	468,206
2. LIGHT OIL	1,782,769	514,784	853,929	2,319,198	1,193,892	2,483,834
3. COAL	31,099,641	24,761,074	25,754,995	21,423,434	23,829,168	29,756,671
4. NATURAL GAS	1,746,626	593,856	1,320,650	2,688,211	1,947,499	3,690,889
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**35,049,220**	**25,906,064**	**28,330,024**	**26,941,440**	**27,442,642**	**36,399,600**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	9,216	-184	9,099	12,473	10,686	10,429
9. LIGHT OIL	21,595	7,304	10,957	29,557	17,519	35,146
10. COAL	1,539,561	1,212,024	1,217,008	1,016,102	1,208,522	1,318,054
11. NATURAL GAS	16,577	6,687	33,394	44,598	31,541	44,864
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,586,949**	**1,225,831**	**1,270,458**	**1,102,730**	**1,268,268**	**1,408,493**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	15,844	1,339	13,885	19,042	16,439	16,147
16. LIGHT OIL (BBL)	47,071	13,099	22,924	65,075	33,668	70,234
17. COAL (TON)	694,773	544,405	564,068	473,994	545,406	624,704
18. NATURAL GAS (MCF)	171,562	110,135	244,674	512,883	356,960	536,955
19. NUCLEAR (MMBTU)	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	99,634	8,516	87,106	119,460	103,131	101,299
22. LIGHT OIL	271,148	76,191	129,847	375,223	194,479	407,937
23. COAL	15,874,032	12,782,894	12,976,358	10,823,474	12,853,528	14,436,193
24. NATURAL GAS	166,808	107,083	237,894	498,671	347,068	522,076
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**16,411,623**	**12,974,684**	**13,431,205**	**11,816,828**	**13,498,207**	**15,467,505**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.58	-0.02	0.72	1.13	0.84	0.74
29. LIGHT OIL	1.36	0.60	0.86	2.68	1.38	2.50
30. COAL	97.02	98.87	95.79	92.15	95.29	93.57
31. NATURAL GAS	1.04	0.55	2.63	4.04	2.49	3.19
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT						
35. HEAVY OIL ($/BBL)	26.52	27.15	28.84	26.81	28.72	29.00
36. LIGHT OIL ($/BBL)	37.87	39.30	37.25	35.64	35.46	35.37
37. COAL ($/TON)	44.76	45.48	45.66	45.20	43.69	47.63
38. NATURAL GAS ($/MCF)	10.18	5.39	5.40	5.24	5.46	6.87
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)						
41. HEAVY OIL	4.22	4.27	4.60	4.27	4.58	4.62
42. LIGHT OIL	6.57	6.76	6.58	6.18	6.14	6.09
43. COAL	1.96	1.94	1.98	1.98	1.85	2.06
44. NATURAL GAS	10.47	5.55	5.55	5.39	5.61	7.07
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**2.14**	**2.00**	**2.11**	**2.28**	**2.03**	**2.35**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	10,811	-46,283	9,573	9,577	9,651	9,713
49. LIGHT OIL	12,556	10,431	11,851	12,695	11,101	11,607
50. COAL	10,311	10,547	10,663	10,652	10,636	10,953
51. NATURAL GAS	10,063	16,014	7,124	11,181	11,004	11,637
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**10,342**	**10,584**	**10,572**	**10,716**	**10,643**	**10,982**
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	4.56	-19.76	4.40	4.09	4.42	4.49
56. LIGHT OIL	8.26	7.05	7.79	7.85	6.81	7.07
57. COAL	2.02	2.04	2.12	2.11	1.97	2.26
58. NATURAL GAS	10.54	8.88	3.95	6.03	6.17	8.23
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**2.21**	**2.11**	**2.23**	**2.44**	**2.16**	**2.58**

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JULY 2001 THROUGH DECEMBER 2001

	ESTIMATED						
	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)							
1. HEAVY OIL	472,222	636,011	431,259	306,440	210,839	211,926	4,576,567
2. LIGHT OIL	1,648,298	1,912,287	713,749	719,785	830,276	714,802	15,687,603
3. COAL	31,690,047	32,253,143	30,346,353	28,112,388	25,601,925	27,096,430	331,725,269
4. NATURAL GAS	1,230,717	1,590,277	1,358,303	1,158,642	655,631	688,088	18,669,389
5. NUCLEAR	0	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0	0
7. TOTAL ($)	**35,041,284**	**36,391,718**	**32,849,664**	**30,297,255**	**27,298,671**	**28,711,246**	**370,658,828**
SYSTEM NET GENERATION (MWH)							
8. HEAVY OIL	11,787	15,893	10,607	7,363	4,913	4,809	107,091
9. LIGHT OIL	22,019	25,040	11,933	12,212	13,279	12,093	218,654
10. COAL	1,464,030	1,515,590	1,469,560	1,413,990	1,313,390	1,388,970	16,076,801
11. NATURAL GAS	30,356	33,310	30,392	26,752	14,282	13,887	326,640
12. NUCLEAR	0	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0	0
14. TOTAL (MWH)	**1,528,192**	**1,589,833**	**1,522,492**	**1,460,317**	**1,345,864**	**1,419,759**	**16,729,186**
UNITS OF FUEL BURNED							
15. HEAVY OIL (BBL)	17,704	23,873	15,905	11,058	7,378	7,200	165,814
16. LIGHT OIL (BBL)	48,244	56,555	20,849	21,039	24,338	20,761	443,857
17. COAL (TON)	656,455	680,985	653,310	616,920	572,564	606,366	7,233,950
18. NATURAL GAS (MCF)	332,281	404,425	332,444	274,554	145,388	143,176	3,565,437
19. NUCLEAR (MMBTU)	0	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0	0
BTUS BURNED (MMBTU)							
21. HEAVY OIL	111,000	150,000	100,000	69,000	46,000	45,000	1,040,146
22. LIGHT OIL	336,000	382,000	171,000	175,000	195,000	176,000	2,889,826
23. COAL	15,495,000	16,027,000	15,428,000	14,694,000	13,611,000	14,406,000	169,407,480
24. NATURAL GAS	342,000	416,000	342,000	282,000	149,000	147,000	3,557,601
25. NUCLEAR	0						0
26. OTHER	0						0
27. TOTAL (MMBTU)	**16,284,000**	**16,975,000**	**16,041,000**	**15,220,000**	**14,001,000**	**14,774,000**	**176,895,052**
GENERATION MIX (% MWH)							
28. HEAVY OIL	0.77	1.00	0.70	0.50	0.37	0.34	0.64
29. LIGHT OIL	1.44	1.58	0.78	0.84	0.99	0.85	1.31
30. COAL	95.80	95.32	96.52	96.83	97.58	97.83	96.10
31. NATURAL GAS	1.99	2.10	2.00	1.83	1.06	0.98	1.95
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT							
35. HEAVY OIL ($/BBL)	26.67	26.64	27.11	27.71	28.58	29.43	27.60
36. LIGHT OIL ($/BBL)	34.17	33.81	34.23	34.21	34.11	34.43	35.34
37. COAL ($/TON)	48.27	47.36	46.45	45.57	44.71	44.69	45.86
38. NATURAL GAS ($/MCF)	3.70	3.93	4.09	4.22	4.51	4.81	5.24
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)							
41. HEAVY OIL	4.25	4.24	4.31	4.44	4.58	4.71	4.40
42. LIGHT OIL	4.91	5.01	4.17	4.11	4.26	4.06	5.43
43. COAL	2.05	2.01	1.97	1.91	1.88	1.88	1.96
44. NATURAL GAS	3.60	3.82	3.97	4.11	4.40	4.68	5.25
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**2.15**	**2.14**	**2.05**	**1.99**	**1.95**	**1.94**	**2.10**
BTU BURNED PER KWH (BTU/KWH)							
48. HEAVY OIL	9,417	9,438	9,428	9,371	9,363	9,357	9,713
49. LIGHT OIL	15,260	15,256	14,330	14,330	14,685	14,554	13,216
50. COAL	10,584	10,575	10,498	10,392	10,363	10,372	10,537
51. NATURAL GAS	11,266	12,489	11,253	10,541	10,433	10,585	10,892
52. NUCLEAR	0	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**10,656**	**10,677**	**10,536**	**10,422**	**10,403**	**10,406**	**10,574**
GENERATED FUEL COST PER KWH (CENTS/KWH)							
55. HEAVY OIL	4.01	4.00	4.07	4.16	4.29	4.41	4.27
56. LIGHT OIL	7.49	7.64	5.98	5.89	6.25	5.91	7.17
57. COAL	2.16	2.13	2.06	1.99	1.95	1.95	2.06
58. NATURAL GAS	4.05	4.77	4.47	4.33	4.59	4.95	5.72
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**2.29**	**2.29**	**2.16**	**2.07**	**2.03**	**2.02**	**2.22**

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2001 THROUGH JUNE 2001

	ACTUAL					
	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	15,146	0	11,101	21,932	17,651	14,395
3. UNIT COST ($/BBL)	20.66	0.00	25.98	24.90	28.73	28.50
4. AMOUNT ($)	312,935	54,931	288,413	546,189	507,054	410,323
5. BURNED:						
6. UNITS (BBL)	15,844	1,339	13,885	19,042	16,439	16,147
7. UNIT COST ($/BBL)	26.52	27.15	28.84	26.81	28.72	29.00
8. AMOUNT ($)	420,184	36,350	400,450	510,597	472,083	468,206
9. ENDING INVENTORY:						
10. UNITS (BBL)	60,902	59,563	56,779	59,669	60,881	59,129
11. UNIT COST ($/BBL)	26.18	27.11	26.80	26.42	26.79	26.93
12. AMOUNT ($)	1,594,510	1,614,861	1,521,445	1,576,269	1,630,894	1,592,517
13. DAYS SUPPLY:	516	347	220	138	97	105
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	88,713	47,414	30,604	58,251	68,782	81,496
16. UNIT COST ($/BBL)	36.08	39.25	31.84	33.10	34.28	35.09
17. AMOUNT ($)	3,200,555	1,861,100	974,437	1,928,037	2,357,663	2,860,004
18. BURNED:						
19. UNITS (BBL)	47,071	13,099	22,924	65,075	33,668	70,234
20. UNIT COST ($/BBL)	37.87	39.30	37.25	35.64	35.46	35.37
21. AMOUNT ($)	1,782,769	514,784	853,929	2,319,198	1,193,892	2,483,834
22. ENDING INVENTORY:						
23. UNITS (BBL)	86,321	110,846	108,650	92,827	114,948	113,608
24. UNIT COST ($/BBL)	38.05	38.46	37.03	35.79	35.11	35.03
25. AMOUNT ($)	3,284,696	4,263,200	4,022,876	3,322,593	4,036,328	3,979,930
26. DAYS SUPPLY: NORMAL	129	138	80	36	30	34
27. DAYS SUPPLY: EMERGENCY	12	16	16	13	16	16
COAL						
28. PURCHASES:						
29. UNITS (TONS)	612,823	575,338	731,531	727,865	697,082	478,741
30. UNIT COST ($/TON)	44.24	43.92	45.12	45.57	44.22	54.51
31. AMOUNT ($)	27,109,855	25,271,158	33,006,099	33,169,862	30,826,000	26,094,697
32. BURNED:						
33. UNITS (TONS)	694,773	544,405	564,068	473,994	545,406	624,704
34. UNIT COST ($/TON)	44.76	45.48	45.66	45.20	43.69	47.63
35. AMOUNT ($)	31,099,641	24,761,074	25,754,995	21,423,434	23,829,168	29,756,671
36. ENDING INVENTORY:						
37. UNITS (TONS)	533,140	564,073	731,536	985,407	1,137,083	991,120
38. UNIT COST ($/TON)	43.73	43.61	44.56	44.93	45.16	48.24
39. AMOUNT ($)	23,314,709	24,596,940	32,596,149	44,277,088	51,355,740	47,810,167
40. DAYS SUPPLY:	28	30	37	44	47	41
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	171,562	110,135	244,674	512,883	356,960	536,955
43. UNIT COST ($/MCF)	10.18	5.39	5.40	5.24	5.46	6.86
44. AMOUNT ($)	1,746,626	593,856	1,320,650	2,688,211	1,947,499	3,685,081
45. BURNED:						
46. UNITS (MCF)	171,562	110,135	244,674	512,883	356,960	536,955
47. UNIT COST ($/MCF)	10.18	5.39	5.40	5.24	5.46	6.87
48. AMOUNT ($)	1,746,626	593,856	1,320,650	2,688,211	1,947,499	3,690,889
49. ENDING INVENTORY:						
50. UNITS (MCF)	0	0	0	0	0	0
51. UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00
52. AMOUNT ($)	0	0	0	0	0	0
53. DAYS SUPPLY:	0	0	0	0	0	0
NUCLEAR						
54. BURNED:						
55. UNITS (MMBTU)	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0
OTHER						
58. PURCHASES:						
59. UNITS (MMBTU)	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0
62. BURNED:						
63. UNITS (MMBTU)	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0
66. ENDING INVENTORY:						
67. UNITS (MMBTU)	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JULY 2001 THROUGH DECEMBER 2001

	ESTIMATED						
	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TOTAL
HEAVY OIL							
1. PURCHASES:							
2. UNITS (BBL)	17,704	23,873	15,905	11,058	7,378	7,200	163,343
3. UNIT COST ($/BBL)	25.95	26.27	26.70	27.35	28.48	29.67	26.67
4. AMOUNT ($)	459,419	627,079	424,609	302,475	210,134	213,589	4,357,150
5. BURNED:							
6. UNITS (BBL)	17,704	23,873	15,905	11,058	7,378	7,200	165,814
7. UNIT COST ($/BBL)	26.67	26.64	27.11	27.71	28.58	29.43	27.60
8. AMOUNT ($)	472,222	636,011	431,259	306,440	210,839	211,926	4,576,567
9. ENDING INVENTORY:							
10. UNITS (BBL)	59,129	59,129	59,129	59,129	59,129	59,129	59,129
11. UNIT COST ($/BBL)	25.87	25.90	25.95	26.03	26.15	26.31	26.31
12. AMOUNT ($)	1,529,752	1,531,235	1,534,518	1,539,387	1,546,437	1,555,915	1,555,915
13. DAYS SUPPLY:	138	340	422	739	924	1,598	-
LIGHT OIL							
14. PURCHASES:							
15. UNITS (BBL)	58,034	65,840	29,582	30,205	33,659	30,279	622,859
16. UNIT COST ($/BBL)	32.82	33.11	33.56	33.94	34.30	34.79	34.51
17. AMOUNT ($)	1,904,646	2,180,010	992,728	1,025,149	1,154,661	1,053,411	21,492,401
18. BURNED:							
19. UNITS (BBL)	48,244	56,555	20,849	21,039	24,338	20,761	443,857
20. UNIT COST ($/BBL)	34.17	33.81	34.23	34.21	34.11	34.43	35.34
21. AMOUNT ($)	1,648,298	1,912,287	713,749	719,785	830,276	714,802	15,687,603
22. ENDING INVENTORY:							
23. UNITS (BBL)	113,465	113,465	113,465	113,465	113,465	113,465	113,465
24. UNIT COST ($/BBL)	34.37	34.01	33.89	33.89	33.98	34.14	34.14
25. AMOUNT ($)	3,899,873	3,858,491	3,845,842	3,845,028	3,855,531	3,873,539	3,873,539
26. DAYS SUPPLY: NORMAL	59	82	86	82	79	65	-
27. DAYS SUPPLY: EMERGENCY	16	16	16	16	16	16	
COAL							
28. PURCHASES:							
29. UNITS (TONS)	520,400	685,400	573,500	629,000	683,000	681,000	7,595,680
30. UNIT COST ($/TON)	46.68	45.43	44.19	43.57	44.09	43.83	45.24
31. AMOUNT ($)	24,290,939	31,135,156	25,343,875	27,408,430	30,111,123	29,849,100	343,616,294
32. BURNED:							
33. UNITS (TONS)	656,455	680,985	653,310	616,920	572,564	606,366	7,233,950
34. UNIT COST ($/TON)	48.27	47.36	46.45	45.57	44.71	44.69	45.86
35. AMOUNT ($)	31,690,047	32,253,143	30,346,353	28,112,388	25,601,925	27,096,430	331,725,269
36. ENDING INVENTORY:							
37. UNITS (TONS)	855,065	859,480	779,670	791,750	902,186	976,820	976,820
38. UNIT COST ($/TON)	47.88	46.87	45.81	44.84	44.84	44.69	44.69
39. AMOUNT ($)	40,937,229	40,282,247	35,713,911	35,503,138	40,453,491	43,653,529	43,653,529
40. DAYS SUPPLY:	40	43	40	40	46	51	-
NATURAL GAS							
41. PURCHASES:							
42. UNITS (MCF)	332,281	404,425	332,444	274,554	145,388	143,176	3,565,437
43. UNIT COST ($/MCF)	3.70	3.93	4.09	4.22	4.51	4.81	5.23
44. AMOUNT ($)	1,230,717	1,590,277	1,358,303	1,158,642	655,631	688,088	18,663,581
45. BURNED:							
46. UNITS (MCF)	332,281	404,425	332,444	274,554	145,388	143,176	3,565,437
47. UNIT COST ($/MCF)	3.70	3.93	4.09	4.22	4.51	4.81	5.24
48. AMOUNT ($)	1,230,717	1,590,277	1,358,303	1,158,642	655,631	688,088	18,669,389
49. ENDING INVENTORY:							
50. UNITS (MCF)	0	0	0	0	0	0	0
51. UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52. AMOUNT ($)	0	0	0	0	0	0	0
53. DAYS SUPPLY:	0	0	0	0	0	0	-
NUCLEAR							
54. BURNED:							
55. UNITS (MMBTU)	0	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0	0
OTHER							
58. PURCHASES:							
59. UNITS (MMBTU)	0	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0	0
62. BURNED:							
63. UNITS (MMBTU)	0	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0	0
66. ENDING INVENTORY:							
67. UNITS (MMBTU)	0	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0	

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

POWER SOLD
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2001 THROUGH JUNE 2001

(1)	(2)		(3)	(4)	(5)	(6)	(7) CENTS/KWH		(8)	(9)
MONTH	SOLD TO		TYPE & SCHEDULE	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)	TOTAL COST (6)X(7B)
ACTUAL Jan-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	3,001.0	59.3	2,941.7	2.719	2.719	79,988.31	79,988.31
	HPP	SEPARATED	CONTRACT	72,685.0	0.0	72,685.0	2.290	2.980	1,664,699.20	2,166,002.75
	FMPA	JURISD.	SCH. -D	108,285.0	0.0	108,285.0	1.927	1.927	2,086,989.95	2,086,989.95
	VARIOUS	JURISD.	MKT. BASE	18,225.0	0.0	18,225.0	5.646	5.646	1,028,949.57	1,028,949.57
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			202,196.0	59.3	202,136.7	2.405	2.653	4,860,627.03	5,361,930.58
ACTUAL Feb-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	3,193.0	0.0	3,193.0	2.199	2.199	70,217.14	70,217.14
	HPP	SEPARATED	CONTRACT	47,065.0	0.0	47,065.0	2.442	2.997	1,149,167.85	1,410,663.30
	FMPA	JURISD.	SCH. -D	72,580.0	0.0	72,580.0	1.930	1.930	1,400,845.45	1,400,845.45
	VARIOUS	JURISD.	MKT. BASE	7,011.0	0.0	7,011.0	2.969	3.221	208,135.44	225,819.69
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			129,849.0	0.0	129,849.0	2.178	2.393	2,828,365.88	3,107,545.58
ACTUAL Mar-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	3,182.0	10.2	3,171.8	2.749	2.749	87,184.89	87,184.89
	HPP	SEPARATED	CONTRACT	67,575.0	0.0	67,575.0	2.446	3.044	1,652,681.55	2,056,972.20
	FMPA	JURISD.	SCH. -D	50,695.0	0.0	50,695.0	1.931	1.931	979,000.85	979,000.85
	VARIOUS	JURISD.	MKT. BASE	4,422.0	0.0	4,422.0	1.510	2.740	66,767.88	121,161.93
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			125,874.0	10.2	125,863.8	2.213	2.578	2,785,635.17	3,244,319.87
ACTUAL Apr-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	3,212.0	417.4	2,794.6	3.780	3.780	105,622.06	105,622.06
	HPP	SEPARATED	CONTRACT	71,440.0	0.0	71,440.0	2.511	3.218	1,793,914.50	2,298,607.55
	FMPA	JURISD.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	MKT. BASE	948.0	0.0	948.0	3.098	3.353	29,367.37	31,784.77
	VARIOUS	JURISD.	SCH. -J	192.0	0.0	192.0	0.000	0.255	0.00	489.60
	TOTAL			75,792.0	417.4	75,374.6	2.559	3.233	1,928,903.93	2,436,503.98
ACTUAL May-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	3,064.0	131.7	2,932.3	2.265	2.265	66,407.04	66,407.04
	HPP	SEPARATED	CONTRACT	1,930.0	0.0	1,930.0	(1.494)	(1.478)	(28,826.80)	(28,523.10)
	FMPA	JURISD.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	MKT. BASE	5,986.0	0.0	5,986.0	2.739	2.979	163,965.41	178,327.01
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			10,980.0	131.7	10,848.3	1.858	1.993	201,545.65	216,210.95
ACTUAL Jun-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	2,745.9	266.9	2,479.0	2.346	2.346	58,149.51	58,149.51
	HPP	SEPARATED	CONTRACT	31,617.0	0.0	31,617.0	3.173	3.499	1,003,208.42	1,106,161.60
	FMPA	JURISD.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	MKT. BASE	2,323.0	0.0	2,323.0	2.867	3.122	66,611.72	72,535.37
	VARIOUS	JURISD.	SCH. -J	276.0	0.0	276.0	4.645	4.645	12,819.11	12,819.11
	TOTAL			36,961.9	266.9	36,695.0	3.109	3.406	1,140,788.76	1,249,665.59

POWER SOLD
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JULY 2001 THROUGH DECEMBER 2001

(1) MONTH	(2) SOLD TO		(3) TYPE & SCHEDULE	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)	(9) TOTAL COST (6)X(7B)
ESTIMATED Jul-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	614.0	0.0	614.0	2.410	2.410	14,800.00	14,800.00
	HPP	SEPARATED	CONTRACT	37,758.0	0.0	37,758.0	2.484	3.639	938,000.00	1,374,000.00
	FMPA	JURISD.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	MKT. BASE	18,776.0	0.0	18,776.0	5.755	6.010	1,080,500.00	1,128,400.00
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			57,148.0	0.0	57,148.0	3.558	4.405	2,033,300.00	2,517,200.00
ESTIMATED Aug-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	6,055.0	0.0	6,055.0	1.706	1.706	103,300.00	103,300.00
	HPP	SEPARATED	CONTRACT	37,758.0	0.0	37,758.0	2.494	3.649	941,800.00	1,377,800.00
	FMPA	JURISD.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	MKT. BASE	8,833.0	0.0	8,833.0	4.731	4.986	417,900.00	440,400.00
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			52,646.0	0.0	52,646.0	2.779	3.650	1,463,000.00	1,921,500.00
ESTIMATED Sep-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	6,030.0	0.0	6,030.0	1.698	1.698	102,400.00	102,400.00
	HPP	SEPARATED	CONTRACT	26,100.0	0.0	26,100.0	2.418	3.573	631,200.00	932,600.00
	FMPA	JURISD.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	MKT. BASE	5,050.0	0.0	5,050.0	2.756	3.012	139,200.00	152,100.00
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			37,180.0	0.0	37,180.0	2.347	3.193	872,800.00	1,187,100.00
ESTIMATED Oct-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	6,055.0	0.0	6,055.0	1.706	1.706	103,300.00	103,300.00
	HPP	SEPARATED	CONTRACT	53,940.0	0.0	53,940.0	2.403	3.558	1,296,300.00	1,919,200.00
	FMPA	JURISD.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	MKT. BASE	11,764.0	0.0	11,764.0	2.709	2.964	318,700.00	348,700.00
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			71,759.0	0.0	71,759.0	2.395	3.304	1,718,300.00	2,371,200.00
ESTIMATED Nov-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	5,972.0	0.0	5,972.0	1.680	1.680	100,300.00	100,300.00
	HPP	SEPARATED	CONTRACT	24,012.0	0.0	24,012.0	2.342	3.496	562,300.00	839,500.00
	FMPA	JURISD.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	MKT. BASE	23,248.0	0.0	23,248.0	2.710	2.965	630,100.00	689,400.00
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			53,232.0	0.0	53,232.0	2.428	3.061	1,292,700.00	1,629,200.00
ESTIMATED Dec-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	5,995.0	0.0	5,995.0	1.688	1.688	101,200.00	101,200.00
	HPP	SEPARATED	CONTRACT	2,157.0	0.0	2,157.0	2.304	3.459	49,700.00	74,600.00
	FMPA	JURISD.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	MKT. BASE	34,605.0	0.0	34,605.0	2.485	2.739	859,800.00	948,000.00
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			42,757.0	0.0	42,757.0	2.364	2.628	1,010,700.00	1,123,800.00
Jan-01 THRU Dec-01	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	49,118.9	885.5	48,233.4	2.058	2.058	992,868.95	992,868.95
	HPP	SEPARATED	CONTRACT	474,037.0	0.0	474,037.0	2.458	3.276	11,654,144.72	15,527,584.30
	FMPA	JURISD.	SCH. -D	231,560.0	0.0	231,560.0	1.929	1.929	4,466,836.25	4,466,836.25
	VARIOUS	JURISD.	MKT. BASE	141,191.0	0.0	141,191.0	3.548	3.800	5,009,997.39	5,365,578.34
	VARIOUS	JURISD.	SCH. -J	468.0	0.0	468.0	2.739	2.844	12,819.11	13,308.71
	TOTAL			896,374.9	885.5	895,489.4	2.472	2.944	22,136,666.42	26,366,176.55

PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2001 THROUGH JUNE 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (7)X(8A)
ACTUAL Jan-01									
	VARIOUS	SCH. J	156,147.0	0.0	4,394.0	151,753.0	8.667	8.667	13,152,110.23
	HPP	IPP	82,250.0	0.0	0.0	82,250.0	11.515	11.515	9,471,478.81
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**238,397.0**	**0.0**	**4,394.0**	**234,003.0**	**9.668**	**9.668**	**22,623,589.04**
ACTUAL Feb-01									
	VARIOUS	SCH. J	80,269.0	0.0	0.0	80,269.0	5.429	5.429	4,358,178.78
	HPP	IPP	58,435.0	0.0	0.0	58,435.0	6.550	6.550	3,827,464.64
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**138,704.0**	**0.0**	**0.0**	**138,704.0**	**5.902**	**5.902**	**8,185,643.42**
ACTUAL Mar-01									
	VARIOUS	SCH. J	118,293.0	0.0	594.2	117,698.8	5.516	5.516	6,492,321.60
	HPP	IPP	73,141.0	0.0	0.0	73,141.0	5.441	5.441	3,979,516.01
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**191,434.0**	**0.0**	**594.2**	**190,839.8**	**5.487**	**5.487**	**10,471,837.61**
ACTUAL Apr-01									
	VARIOUS	SCH. J	274,208.0	0.0	24,996.0	249,212.0	6.536	6.536	16,288,095.35
	HPP	IPP	72,146.0	0.0	0.0	72,146.0	6.235	6.235	4,498,564.75
	VARIOUS	OTHER	17,995.0	0.0	0.0	17,995.0	5.628	5.628	1,012,675.25
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**364,349.0**	**0.0**	**24,996.0**	**339,353.0**	**6.424**	**6.424**	**21,799,335.35**
ACTUAL May-01									
	VARIOUS	SCH. J	222,843.0	0.0	8,533.9	214,309.1	4.969	4.969	10,649,774.54
	HPP	IPP	102,327.0	0.0	0.0	102,327.0	4.899	4.899	5,013,263.48
	VARIOUS	OTHER	20,851.0	0.0	0.0	20,851.0	5.430	5.430	1,132,294.00
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**346,021.0**	**0.0**	**8,533.9**	**337,487.1**	**4.977**	**4.977**	**16,795,332.02**
ACTUAL Jun-01									
	VARIOUS	SCH. J	216,266.0	0.0	21,804.2	194,461.8	6.078	6.078	11,820,049.81
	HPP	IPP	95,024.0	0.0	0.0	95,024.0	2.483	2.483	2,359,447.00
	VARIOUS	OTHER	28,079.0	0.0	0.0	28,079.0	7.926	7.926	2,225,673.00
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**339,369.0**	**0.0**	**21,804.2**	**317,564.8**	**5.166**	**5.166**	**16,405,169.81**

PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JULY 2001 THROUGH DECEMBER 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (7)X(8A)
ESTIMATED Jul-01									
	VARIOUS	SCH. J	14,757.0	0.0	8,609.0	6,148.0	9.504	9.504	584,300.00
	HPP	IPP	97,535.0	0.0	0.0	97,535.0	4.457	4.457	4,347,100.00
	VARIOUS	OTHER	48,303.0	0.0	0.0	48,303.0	9.033	9.033	4,363,300.00
	VARIOUS	MKT BASED	54,924.0	0.0	0.0	54,924.0	6.418	6.418	3,524,800.00
	TOTAL		**215,519.0**	**0.0**	**8,609.0**	**206,910.0**	**6.196**	**6.196**	**12,819,500.00**
ESTIMATED Aug-01									
	VARIOUS	SCH. J	35,747.0	0.0	18,711.0	17,036.0	9.049	9.049	1,541,600.00
	HPP	IPP	124,336.0	0.0	0.0	124,336.0	4.458	4.458	5,542,900.00
	VARIOUS	OTHER	44,451.0	0.0	0.0	44,451.0	9.309	9.309	4,137,800.00
	VARIOUS	MKT BASED	66,194.0	0.0	0.0	66,194.0	7.374	7.374	4,881,400.00
	TOTAL		**270,728.0**	**0.0**	**18,711.0**	**252,017.0**	**6.390**	**6.390**	**16,103,700.00**
ESTIMATED Sep-01									
	VARIOUS	SCH. J	12,257.0	0.0	7,664.0	4,593.0	7.640	7.640	350,900.00
	HPP	IPP	83,469.0	0.0	0.0	83,469.0	4.532	4.532	3,783,200.00
	VARIOUS	OTHER	63,991.0	0.0	0.0	63,991.0	6.744	6.744	4,315,800.00
	VARIOUS	MKT BASED	38,537.0	0.0	0.0	38,537.0	6.382	6.382	2,459,300.00
	TOTAL		**198,254.0**	**0.0**	**7,664.0**	**190,590.0**	**5.724**	**5.724**	**10,909,200.00**
ESTIMATED Oct-01									
	VARIOUS	SCH. J	11,612.0	0.0	7,308.0	4,304.0	7.642	7.642	328,900.00
	HPP	IPP	53,482.0	0.0	0.0	53,482.0	4.809	4.809	2,572,000.00
	VARIOUS	OTHER	33,214.0	0.0	0.0	33,214.0	4.866	4.866	1,616,100.00
	VARIOUS	MKT BASED	34,481.0	0.0	0.0	34,481.0	6.439	6.439	2,220,100.00
	TOTAL		**132,789.0**	**0.0**	**7,308.0**	**125,481.0**	**5.369**	**5.369**	**6,737,100.00**
ESTIMATED Nov-01									
	VARIOUS	SCH. J	2,892.0	0.0	1,928.0	964.0	7.645	7.645	73,700.00
	HPP	IPP	28,764.0	0.0	0.0	28,764.0	5.219	5.219	1,501,200.00
	VARIOUS	OTHER	8,310.0	0.0	0.0	8,310.0	5.201	5.201	432,200.00
	VARIOUS	MKT BASED	26,418.0	0.0	0.0	26,418.0	5.322	5.322	1,406,000.00
	TOTAL		**66,384.0**	**0.0**	**1,928.0**	**64,456.0**	**5.295**	**5.295**	**3,413,100.00**
ESTIMATED Dec-01									
	VARIOUS	SCH. J	1,901.0	0.0	1,416.0	485.0	7.649	7.649	37,100.00
	HPP	IPP	30,293.0	0.0	0.0	30,293.0	5.303	5.303	1,606,500.00
	VARIOUS	OTHER	4,494.0	0.0	0.0	4,494.0	5.401	5.401	242,700.00
	VARIOUS	MKT BASED	7,924.0	0.0	0.0	7,924.0	7.597	7.597	602,000.00
	TOTAL		**44,612.0**	**0.0**	**1,416.0**	**43,196.0**	**5.760**	**5.760**	**2,488,300.00**
Jan-01 THRU Dec-01	VARIOUS	SCH. J	1,147,192.0	0.0	105,958.3	1,041,233.7	6.308	6.308	65,677,030.31
	HPP	IPP	901,202.0	0.0	0.0	901,202.0	5.382	5.382	48,502,634.69
	VARIOUS	OTHER	269,688.0	0.0	0.0	269,688.0	7.223	7.223	19,478,542.25
	VARIOUS	MKT BASED	228,478.0	0.0	0.0	228,478.0	6.606	6.606	15,093,600.00
	TOTAL		**2,546,560.0**	**0.0**	**105,958.3**	**2,440,601.7**	**6.095**	**6.095**	**148,751,807.25**

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2001 THROUGH DECEMBER 2001

SCHEDULE E8

(1) MONTH		(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUPTIBLE	(7) MWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJUSTMENT (7)*(8A)
ACTUAL	Jan-01	VARIOUS	CO-GEN.	27,546.0	0.0	0.0	27,546.0	2.229	2.229	614,083.33
ACTUAL	Feb-01	VARIOUS	CO-GEN.	23,925.0	0.0	0.0	23,925.0	1.995	1.995	477,236.80
ACTUAL	Mar-01	VARIOUS	CO-GEN.	34,669.0	0.0	0.0	34,669.0	2.497	2.497	865,771.24
ACTUAL	Apr-01	VARIOUS	CO-GEN.	35,151.0	0.0	0.0	35,151.0	2.392	2.392	840,934.31
ACTUAL	May-01	VARIOUS	CO-GEN.	36,042.0	0.0	0.0	36,042.0	2.286	2.286	823,902.59
ACTUAL	Jun-01	VARIOUS	CO-GEN.	37,342.0	0.0	0.0	37,342.0	2.280	2.280	851,322.45
ESTIMATED	Jul-01	VARIOUS	CO-GEN.	36,435.0	0.0	0.0	36,435.0	2.625	2.625	956,400.00
ESTIMATED	Aug-01	VARIOUS	CO-GEN.	36,435.0	0.0	0.0	36,435.0	2.608	2.608	950,100.00
ESTIMATED	Sep-01	VARIOUS	CO-GEN.	35,259.0	0.0	0.0	35,259.0	2.584	2.584	911,000.00
ESTIMATED	Oct-01	VARIOUS	CO-GEN.	36,435.0	0.0	0.0	36,435.0	2.471	2.471	900,200.00
ESTIMATED	Nov-01	VARIOUS	CO-GEN.	33,223.0	0.0	0.0	33,223.0	2.207	2.207	733,200.00
ESTIMATED	Dec-01	VARIOUS	CO-GEN.	34,479.0	0.0	0.0	34,479.0	2.065	2.065	711,900.00
	TOTAL			**406,941.0**	**0.0**	**0.0**	**406,941.0**	**2.368**	**2.368**	**9,636,050.72**

SCHEDULE E9

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2001 THROUGH DECEMBER 2001

(1)		(2)	(3)	(4)	(5)	(6)	(7)		(8)
MONTH		PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT. COST CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT (4)X(5)	COST IF GENERATED (A) CENTS PER KWH	(B) ($000)	FUEL SAVINGS (7B)-(6)
ACTUAL	Jan-01	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	Feb-01	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	Mar-01	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	Apr-01	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	May-01	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	Jun-01	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED	Jul-01	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED	Aug-01	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED	Sep-01	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED	Oct-01	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED	Nov-01	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED	Dec-01	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
	TOTAL			**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**

EXHIBIT NO.
DOCKET NO. 010001-EI
TAMPA ELECTRIC COMPANY
(JDJ-2)
FILED 08/20/01
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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY
ACTUAL / ESTIMATED
JANUARY 2001 THROUGH DECEMBER 2001

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY
CALCULATION OF THE CURRENT (ACTUAL/ESTIMATED) PERIOD TRUE-UP
JANUARY 2001 THROUGH DECEMBER 2001

1.	FINAL OVER/(UNDER) RECOVERY FOR JANUARY 2000 THROUGH DECEMBER 2000	($589,079)
2.	ACTUAL/ESTIMATED OVER/(UNDER) RECOVERY FOR THE CURRENT PERIOD JANUARY 2001 THROUGH DECEMBER 2001	($4,971,024)
3.	CURRENT PERIOD TRUE-UP AMOUNT TO BE REFUNDED/(RECOVERED) IN THE PROJECTION PERIOD JANUARY 2002 THROUGH DECEMBER 2002	($5,560,103)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT

	Actual Jan-01	Actual Feb-01	Actual Mar-01	Actual Apr-01	Actual May-01	Actual Jun-01	Estimated Jul-01	Estimated Aug-01	Estimated Sep-01	Estimated Oct-01	Estimated Nov-01	Estimated Dec-01	Total
1 UNIT POWER CAPACITY CHARGES	2,975,224	2,231,992	1,898,354	2,067,439	3,590,159	3,842,845	3,553,400	3,553,400	4,793,700	1,872,900	2,022,200	2,022,200	34,423,813
2 CAPACITY PAYMENTS TO COGENERATORS	975,430	975,430	975,430	999,350	999,350	999,350	999,300	999,300	999,300	999,300	999,300	999,300	11,920,140
3 (UNIT POWER CAPACITY REVENUES)	(898,312)	(919,805)	(468,537)	(76,547)	(109,790)	(73,429)	(36,000)	(138,600)	(133,000)	(143,000)	(160,200)	(177,200)	(3,334,420)
4 TOTAL CAPACITY DOLLARS	3,052,342	2,287,617	2,405,247	2,990,242	4,479,719	4,768,766	4,516,700	4,414,100	5,660,000	2,729,200	2,861,300	2,844,300	43,009,533
5 SEPARATION FACTOR	0.9593944	0.9593944	0.9593944	0.9593944	0.9593944	0.9593944	0.9593944	0.9593944	0.9593944	0.9593944	0.9593944	0.9593944	
6 JURISDICTIONAL CAPACITY DOLLARS	2,928,400	2,194,727	2,307,581	2,868,821	4,297,817	4,575,127	4,333,297	4,234,863	5,430,172	2,618,379	2,745,115	2,728,805	41,263,104
7 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	3,266,251	2,540,650	2,289,147	2,402,763	2,539,924	3,198,505	3,366,576	3,343,593	3,422,536	2,999,840	2,499,201	2,497,202	34,366,188
8 PRIOR PERIOD TRUE-UP PROVISION	164,770	164,770	164,770	164,770	164,770	164,770	164,770	164,770	164,770	164,770	164,770	164,769	1,977,239
9 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	3,431,021	2,705,420	2,453,917	2,567,533	2,704,694	3,363,275	3,531,346	3,508,363	3,587,306	3,164,610	2,663,971	2,661,971	36,343,427
10 TRUE-UP PROVISION FOR MONTH OVER/(UNDER) RECOVERY (Line 9 - Line 6)	502,621	510,693	146,336	(301,288)	(1,593,123)	(1,211,852)	(801,951)	(726,500)	(1,842,866)	546,231	(81,144)	(66,834)	(4,919,677)
11 INTEREST PROVISION FOR MONTH	7,817	8,504	8,794	7,198	2,563	(2,661)	(6,494)	(9,769)	(14,628)	(17,385)	(17,217)	(18,069)	(51,347)
12 TRUE-UP AND INT. PROVISION BEGINNING OF MONTH - OVER/(UNDER) RECOVERY	1,388,160	1,733,828	2,088,255	2,078,615	1,619,755	(135,575)	(1,514,858)	(2,488,073)	(3,389,112)	(5,411,376)	(5,047,300)	(5,310,431)	1,388,160
13 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS MONTH	(164,770)	(164,770)	(164,770)	(164,770)	(164,770)	(164,770)	(164,770)	(164,770)	(164,770)	(164,770)	(164,770)	(164,769)	(1,977,239)
14 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 10 - 13)	1,733,828	2,088,255	2,078,615	1,619,755	(135,575)	(1,514,858)	(2,488,073)	(3,389,112)	(5,411,376)	(5,047,300)	(5,310,431)	(5,560,103)	**(5,560,103)**

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EXHIBIT NO. ____
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TAMPA ELECTRIC COMPANY
(JDJ-2)
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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT

	Actual Jan-01	Actual Feb-01	Actual Mar-01	Actual Apr-01	Actual May-01	Actual Jun-01	Estimated Jul-01	Estimated Aug-01	Estimated Sep-01	Estimated Oct-01	Estimated Nov-01	Estimated Dec-01	Total
1 BEGINNING TRUE-UP AMOUNT	1,388,160	1,733,828	2,088,255	2,078,615	1,619,755	(135,575)	(1,514,858)	(2,488,073)	(3,389,112)	(5,411,376)	(5,047,300)	(5,310,431)	1,388,160
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	1,726,011	2,079,751	2,069,821	1,612,557	(138,138)	(1,512,197)	(2,481,579)	(3,379,343)	(5,396,748)	(5,029,915)	(5,293,214)	(5,542,034)	(5,508,756)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT. (LINE 1 + LINE 2)	3,114,171	3,813,579	4,158,076	3,691,172	1,481,617	(1,647,772)	(3,996,437)	(5,867,416)	(8,785,860)	(10,441,291)	(10,340,514)	(10,852,465)	(4,120,596)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	1,557,086	1,906,790	2,079,038	1,845,586	740,809	(823,886)	(1,998,219)	(2,933,708)	(4,392,930)	(5,220,646)	(5,170,257)	(5,426,233)	(2,060,298)
5 INTEREST RATE % - 1ST DAY OF MONTH	6.500	5.550	5.150	5.000	4.370	3.940	3.800	4.000	4.000	4.000	4.000	4.000	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	5.550	5.150	5.000	4.370	3.940	3.800	4.000	4.000	4.000	4.000	4.000	4.000	NA
7 TOTAL (LINE 5 + LINE 6)	12.050	10.700	10.150	9.370	8.310	7.740	7.800	8.000	8.000	8.000	8.000	8.000	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	6.025	5.350	5.075	4.685	4.155	3.870	3.900	4.000	4.000	4.000	4.000	4.000	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.502	0.446	0.423	0.390	0.346	0.323	0.325	0.333	0.333	0.333	0.333	0.333	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	7,817	8,504	8,794	7,198	2,563	(2,661)	(6,494)	(9,769)	(14,628)	(17,385)	(17,217)	(18,069)	(51,347)

EXHIBIT NO. ____
DOCKET NO. 010001-EI
TAMPA ELECTRIC COMPANY
(JDJ-2)
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TAMPA ELECTRIC COMPANY
DOCKET NO. 010001-EI
FILED: 9/20/01

EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 1

PROJECTED CAPACITY COST RECOVERY

JANUARY 2002 - DECEMBER 2002

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 3
COMPANY/ WITNESS: Jordan
DATE: 11-30-01

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2002 THROUGH DECEMBER 2002
PROJECTED

RATE CLASS	(1) AVG 12 CP LOAD FACTOR AT METER %	(2) PROJECTED SALES AT METER MWH	(3) PROJECTED AVG 12 CP AT METER MWH	(4) DEMAND LOSS EXPANSION FACTOR	(5) ENERGY LOSS EXPANSION FACTOR	(6) PROJECTED SALES AT GENERATION MWH	(7) PROJECTED AVG 12 CP AT GENERATION MWH	(8) PERCENTAG OF SALES AT GENERATION %	(9) PERCENTAGE OF DEMAND AT GENERATION %
RS	54.76%	7,980,408	1,664	1.05830	1.03546	8,263,358	1,761	45.09%	58.56%
GS, TS	59.53%	1,016,567	195	1.05830	1.03546	1,052,610	206	5.75%	6.85%
GSD, EV-X	79.01%	4,909,794	709	1.05780	1.03495	5,081,414	750	27.73%	24.94%
GSLD, SBF	87.10%	2,095,190	275	1.04580	1.02730	2,152,386	288	11.75%	9.58%
IS-1&3, SBI-1&3	NA	1,560,773	NA	NA	1.01035	1,576,928	NA	8.61%	NA
SL/OL	1290.46%	188,794	2	1.05830	1.03546	195,488	2	1.07%	0.07%
TOTAL		17,751,526	2,845			18,322,184	3,007	100.00%	100.00%

(1) AVG 12 CP load factor based on actual 1999 calendar data.
(2) Projected MWH sales for the period Jan. 2002 thru Dec. 2002.
(3) Calculated: Col (2) / (8760*Col (1)).
(4) Based on 1999 demand losses.
(5) Based on 1999 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).

NOTE: Interruptible rates not included in demand allocation of capacity payments.

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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2002 THROUGH DECEMBER 2002
PROJECTED

	Projected JANUARY	Projected FEBRUARY	Projected MARCH	Projected APRIL	Projected MAY	Projected JUNE	Projected JULY	Projected AUGUST	Projected SEPTEMBER	Projected OCTOBER	Projected NOVEMBER	Projected DECEMBER	Total
1 UNIT POWER CAPACITY CHARGES	3,672,200	3,672,200	3,485,400	3,285,400	1,635,400	2,572,400	2,572,400	2,572,400	2,572,400	3,835,400	3,835,400	1,635,400	35,346,400
2 CAPACITY PAYMENTS TO COGENERATORS	1,275,700	1,275,700	1,275,700	1,532,400	1,532,400	1,532,400	1,532,400	1,532,400	1,532,400	1,537,100	1,537,100	1,537,100	17,632,800
3 (UNIT POWER CAPACITY REVENUES)	(147,900)	(149,900)	(163,000)	(141,700)	(160,200)	(163,700)	(159,300)	(167,800)	(145,200)	(136,200)	(145,500)	(149,000)	(1,829,400)
4 TOTAL CAPACITY DOLLARS	$4,800,000	$4,798,000	$4,598,100	$4,676,100	$3,007,600	$3,941,100	$3,945,500	$3,937,000	$3,959,600	$5,236,300	$5,227,000	$3,023,500	$51,149,800
5 SEPARATION FACTOR	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
6 JURISDICTIONAL CAPACITY DOLLARS	$4,410,811	$4,408,973	$4,225,281	$4,296,957	$2,763,740	$3,621,551	$3,625,595	$3,617,784	$3,638,551	$4,811,735	$4,803,189	$2,778,351	$47,002,518
7 ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2001 - DEC. 2001 OVER/(UNDER) RECOVERY													5,560,103
8 TOTAL													$52,562,621
9 REVENUE TAX FACTOR													1.00072
10 TOTAL RECOVERABLE CAPACITY DOLLARS													$52,600,466

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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2002 THROUGH DECEMBER 2002
PROJECTED

RATE CLASS	(1) PERCENTAGE OF SALES AT GENERATION %	(2) PERCENTAGE OF DEMAND AT GENERATION %	(3) ENERGY RELATED COSTS ($)	(4) DEMAND RELATED COSTS ($)	(5) TOTAL CAPACITY COSTS ($)	(6) PROJECTED SALES AT METER MWH	(7) CAPACITY RECOVERY FACTOR $/MWH
RS	45.09%	58.56%	1,823,880	28,434,095	30,257,975	7,980,408	3.79
GS, TS	5.75%	6.85%	232,586	3,326,051	3,558,637	1,016,567	3.50
GSD, EV-X	27.73%	24.94%	1,121,672	12,109,739	13,231,411	4,909,794	2.69
GSLD, SBF	11.75%	9.58%	475,285	4,651,616	5,126,901	2,095,190	2.45
IS-1&3, SBI-1&3	8.61%	NA	348,272	0	348,272	1,560,773	0.22
SL/OL	1.07%	0.07%	43,281	33,989	77,270	188,794	0.41
TOTAL	100.00%	100.00%	4,044,976	48,555,490	52,600,466	17,751,526	2.96
			7.69%	92.31%			

NOTE: Using the 12 CP and 1/13th allocation method requires 1/13th or 7.69% of capacity costs to be allocated on the basis of energy, and 12/13th or 92.31% to be allocated on the basis of demand.

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EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY
JANUARY 2002 - DECEMBER 2002

SCHEDULES E1 THROUGH E10
SCHEDULE H-1

EXHIBIT NO._____
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TAMPA ELECTRIC COMPANY

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26	Schedule E-1C GPIF & True-Up Adj. Factors	(")
27	Schedule E-1D Fuel Adjustment Factor for TOD	(")
28	Schedule E-1E Fuel Recovery Factor-with Line Losses	(")
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FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

SCHEDULE E1

		DOLLARS	MWH	CENTS/KWH
1.	*Fuel Cost of System Net Generation (E3)*	392,688,455	16,979,301	2.31275
2.	Nuclear Fuel Disposal Cost	0	0	0.00000
3.	Coal Car Investment	0	0	0.00000
4.	Adjustments to Fuel Cost (Ft. Meade / Wauchula Wheeling)	(48,000)	16,979,301 [1]	(0.00028)
4a.	Adjustments to Fuel Cost	0	0	0.00000
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4a)**	**392,640,455**	**16,979,301**	**2.31247**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	143,368,600	2,724,226	5.26273
7.	Energy Cost of Economy Purchases (E9)	0	0	0.00000
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	*0.00000*
9.	Energy Payments to Qualifying Facilities (E8)	10,762,700	473,104	2.27491
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)**	**154,131,300**	**3,197,330**	**4.82063**
11.	**TOTAL AVAILABLE KWH (LINE 5 + LINE 10)**		20,176,631	
12.	Fuel Cost of Economy Sales (E6)	0	0	0.00000
13.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	1,069,200	72,804	1.46860
15.	Fuel Cost of Schedule D HPP Sales - Separated (E6)	12,453,700	486,051	2.56222
17.	Fuel Cost of Market Based Sales - Jurisd. (E6)	5,111,200	216,898	2.35650
18.	Gains (E6)	3,150,500	0	0.00000
20.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**21,784,600**	**775,753**	**2.80819**
21.	Net Inadvertant Interchange		0	
22.	Wheeling Received Less Wheeling Delivered		0	
23.	Interchange and Wheeling Losses		11,400	
24.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-20+21+22-23)**	**524,987,155**	**19,389,478**	**2.70759**
25.	Net Unbilled	NA [1][a]	NA [a]	NA
26.	Company Use	1,332,134 [1]	49,200	0.00704
27.	T & D Losses	11,088,777 [1]	409,544	0.05858
28.	System MWH Sales	524,987,155	18,930,734	2.77320
29.	Wholesale MWH Sales	(32,845,501)	(1,179,208)	2.78539
30.	Jurisdictional MWH Sales	492,141,654	17,751,526	2.77239
31.	Jurisdictional Loss Multiplier			1.00066
32.	Jurisdictional MWH Sales Adjusted for Line Loss	492,466,467	17,751,526	2.77422
33.	True-up [2]	88,672,735	17,751,526	0.49952
34.	Peabody Coal Contract Buy-Out Amort. (Jurisdictionalized)	3,390,659	17,751,526	0.01910
36.	Total Jurisdictional Fuel Cost (Excl. GPIF)	584,529,861	17,751,526	3.29284
37.	Revenue Tax Factor			1.00072
38.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	584,950,722	17,751,526	3.29521
39.	GPIF Adjusted for Taxes [2]	1,095,745	17,751,526	0.00617
40.	**Fuel Factor Adjusted for Taxes Including GPIF**	586,046,467	17,751,526	3.30138
41.	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**3.301**

[a] *Data not available at this time.*
[1] Included For Informational Purposes Only
[2] Calculation Based on Jurisdictional KWH Sales

CALCULATION OF PROJECTED PERIOD TOTAL TRUE-UP
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JANUARY 2002 THRU DECEMBER 2002

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E-1B) January 2001 - December 2001 (6 months actual, 6 months estimated)	($65,543,259)
2.	FINAL TRUE-UP (January 2000 - December 2000) (Per True-Up filed April 2, 2001)	($23,129,476)
3.	TOTAL OVER/(UNDER) RECOVERY (Lines 1 + 2) To be included in the 12 month projected period January 2002 thru December 2002 (Schedule E1, line 33)	($88,672,735)
4.	JURISDICTIONAL MWH SALES (Projected January 2002 thru December 2002)	17,751,526
5.	TRUE-UP FACTOR - cents/kwh (Lines 3/4) * (100 cents/1000 KWH)	**0.4995**

SCHEDULE E1-C

INCENTIVE FACTOR AND TRUE-UP FACTOR
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY) (January 2002 Through December 2002)	$1,095,745	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2001 Through December 2001)	($88,672,735)	
2.	TOTAL SALES (January 2002 Through December 2002)	17,751,526	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR	**0.0062**	Cents/kWh
	B. TRUE-UP FACTOR	**0.4995**	Cents/kWh

SCHEDULE E1-D

FUEL ADJUSTMENT FACTOR FOR
OPTIONAL TIME-OF-DAY RATES
TAMPA ELECTRIC COMPANY

ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

1. COST RATIO
   ON-PEAK COST / OFF-PEAK COST = $\frac{5.437}{3.349}$ = 1.6235

2. SALES/GENERATION

   29.84 % ON-PEAK

   70.16 % OFF-PEAK

3. FORMULA
   FUEL ADJUSTMENT FACTOR ADJUSTED FOR TAX AND GPIF = (% ON-PEAK GENERATION * COST RATIO * OFF-PEAK FACTOR) + (% OFF-PEAK GENERATION * OFF-PEAK FACTOR)

3.3014	=	0.2984	*	1.6235	Y +	0.7016	Y
3.3014	=	1.1861	*	Y			
2.7834	=	Y					

where Y = OFF-PEAK FACTOR and

X	=	1.6235	Y
X	=	1.6235	* 2.7834
X	=	4.5188	

where X = ON-PEAK FACTOR

	ON-PEAK	OFF-PEAK
4. **FUEL COST (CENTS/KWH)**	**4.5188**	**2.7834**
5. **FUEL FACTOR (CENTS/KWH, NEAREST 0.001)**	**4.519**	**2.783**

SCHEDULE E1-E

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

GROUP	RATE SCHEDULE	AVERAGE FACTOR	FUEL RECOVERY LOSS MULTIPLIER	FUEL RECOVERY FACTOR
A	RS,GS,TS	3.301	1.0035	**3.313**
A1*	SL-2, OL-1&3	3.301	N/A	**3.054**
B	GSD,GSLD,SBF	3.301	1.0009	**3.304**
C	IS-1&3,SBI-1&3	3.301	0.9792	**3.232**
A	RST,GST			
	ON-PEAK	4.519	1.0035	**4.535**
	OFF-PEAK	2.783	1.0035	**2.793**
A1	SL-2, OL-1&3			
	ON-PEAK	N/A	N/A	**N/A**
	OFF-PEAK	N/A	N/A	**N/A**
B	GSDT, EV-X, GSLDT, SBFT			
	ON-PEAK	4.519	1.0009	**4.523**
	OFF-PEAK	2.783	1.0009	**2.786**
C	IST-1&3, SBIT-1&3			
	ON-PEAK	4.519	0.9792	**4.425**
	OFF-PEAK	2.783	0.9792	**2.725**

*** GROUP A1 IS BASED ON GROUP A, 15% ON-PEAK AND 85% OFF-PEAK**

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

SCHEDULE E2

	(a) Jan-02	(b) Feb-02	(c) Mar-02	(d) Apr-02	(e) May-02	(f) Jun-02	(g) Jul-02	(h) Aug-02	(i) Sep-02	(j) Oct-02	(k) Nov-02	(l) Dec-02	(m) TOTAL PERIOD
						ESTIMATED							
1. Fuel Cost of System Net Generation	31,558,471	27,148,168	27,978,239	27,602,299	33,060,389	38,316,729	40,333,515	40,084,800	38,934,550	31,860,939	27,054,266	28,756,090	392,688,455
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold (1)	1,842,600	1,803,900	2,943,300	2,079,100	1,826,100	2,103,800	2,231,900	2,363,200	1,183,800	1,699,400	1,101,400	606,100	21,784,600
4. Fuel Cost of Purchased Power	8,118,500	9,145,800	11,220,700	14,887,000	6,535,500	12,912,400	15,706,300	14,582,600	15,459,900	17,790,700	14,296,000	4,713,200	143,368,600
5. Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
6. Payments to Qualifying Facilities	649,700	701,900	805,100	851,500	940,200	977,900	1,027,800	1,025,700	986,000	1,001,500	812,100	783,300	10,762,700
7. Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
8. Adjustment to Fuel Cost (Ft. Meade/Wau. Wheeling)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(48,000)
8a. Adjustment to Fuel Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
9. TOTAL FUEL & NET POWER TRANSACTIONS	**36,680,071**	**35,187,968**	**37,056,739**	**41,257,699**	**38,705,989**	**50,099,229**	**54,831,715**	**53,325,900**	**54,192,650**	**48,949,739**	**41,056,966**	**33,642,490**	**524,987,155**
10. Jurisdictional kWh Sold	1,440,732	1,302,603	1,277,398	1,307,785	1,435,041	1,637,201	1,709,442	1,697,561	1,724,872	1,537,244	1,340,950	1,340,695	17,751,526
11. Jurisdictional % of Total Sales	0.9385650	0.9425403	0.9124917	0.9225971	0.9339413	0.9325125	0.9331723	0.9325547	0.9421489	0.9373170	0.9550089	0.9737083	
12. Jurisdictional Total Fuel & Net Power Transactions (Line 9 * Line 11)	34,426,631	33,166,078	33,813,967	38,064,233	36,149,122	46,718,157	51,167,438	49,729,319	51,057,546	45,881,423	39,209,768	32,757,972	492,141,654
13. Jurisdictional Loss Multiplier	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	
14. Jurisdictional Sales Adjusted for Line Losses (Line 12 * Line 13)	34,449,353	33,187,968	33,836,284	38,089,355	36,172,980	46,748,991	51,201,209	49,762,140	51,091,244	45,911,705	39,235,646	32,779,592	492,466,467
15. Peabody Coal Contract Buyout Amortization	315,223	312,692	310,161	307,630	305,099	302,568	300,037	297,506	294,975	292,444	289,913	287,383	3,615,631
16. Peabody Jurisdictionalized (Line 15 * Line 11)	295,857	294,725	283,019	283,819	284,945	282,148	279,986	277,441	277,910	274,113	276,869	279,827	3,390,659
17. JURISD. TOTAL FUEL & NET PWR. TRANS. INCL. PEABODY AND FUEL CREDIT (LINE 14+16)	**34,745,210**	**33,482,693**	**34,119,303**	**38,373,174**	**36,457,925**	**47,031,139**	**51,481,195**	**50,039,581**	**51,369,154**	**46,185,818**	**39,512,515**	**33,059,419**	**495,857,126**
18. Cost Per kWh Sold (Cents/kWh)	2.4116	2.5704	2.6710	2.9342	2.5405	2.8727	3.0116	2.9477	2.9781	3.0045	2.9466	2.4658	2.7933
19. True-up (Cents/kWh) (2)	0.4995	0.4995	0.4995	0.4995	0.4995	0.4995	0.4995	0.4995	0.4995	0.4995	0.4995	0.4995	0.4995
20. Total (Cents/kWh) (Line 18+19)	2.9111	3.0699	3.1705	3.4337	3.0400	3.3722	3.5111	3.4472	3.4776	3.5040	3.4461	2.9653	3.2928
21. Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
22. Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	2.9132	3.0721	3.1728	3.4362	3.0422	3.3746	3.5136	3.4497	3.4801	3.5065	3.4486	2.9674	3.2952
23. GPIF Adjusted for Taxes (Cents/kWh) (2)	0.0062	0.0062	0.0062	0.0062	0.0062	0.0062	0.0062	0.0062	0.0062	0.0062	0.0062	0.0062	0.0062
24. TOTAL RECOVERY FACTOR (LINE 22+23)	**2.9194**	**3.0783**	**3.1790**	**3.4424**	**3.0484**	**3.3808**	**3.5198**	**3.4559**	**3.4863**	**3.5127**	**3.4548**	**2.9736**	**3.3014**
25. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	**2.919**	**3.078**	**3.179**	**3.442**	**3.048**	**3.381**	**3.520**	**3.456**	**3.486**	**3.513**	**3.455**	**2.974**	**3.301**

(1) Includes Gains
(2) Based on Jurisdictional Sales Only

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

SCHEDULE E3
PAGE 1 OF 2

	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	267,340	293,929	423,881	216,472	256,278	527,624
2. LIGHT OIL	999,295	1,013,913	1,441,938	1,406,581	702,939	1,827,418
3. COAL	29,484,272	25,370,267	24,835,472	23,547,417	29,073,710	31,017,189
4. NATURAL GAS	807,564	470,059	1,276,948	2,431,829	3,027,462	4,944,498
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**31,558,471**	**27,148,168**	**27,978,239**	**27,602,299**	**33,060,389**	**38,316,729**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	5,837	6,278	9,235	4,768	5,679	12,491
9. LIGHT OIL	16,255	15,647	22,340	18,434	12,023	25,010
10. COAL	1,449,147	1,237,658	1,185,003	1,117,966	1,399,464	1,481,058
11. NATURAL GAS	16,227	11,051	29,776	45,735	54,336	89,093
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,487,466**	**1,270,634**	**1,246,354**	**1,186,903**	**1,471,502**	**1,607,652**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	8,696	9,353	13,760	7,097	8,436	18,613
16. LIGHT OIL (BBL)	28,598	29,183	42,088	41,776	21,042	57,069
17. COAL (TON)	643,239	547,442	529,065	498,208	617,782	661,694
18. NATURAL GAS (MCF)	165,088	110,200	299,642	461,959	557,896	911,496
19. NUCLEAR (MMBTU)	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	54,600	58,728	86,394	44,562	52,969	116,867
22. LIGHT OIL	160,876	164,510	238,704	238,271	116,797	325,999
23. COAL	15,012,355	12,839,818	12,387,401	11,630,052	14,543,621	15,557,662
24. NATURAL GAS	169,726	113,314	308,076	474,940	573,495	937,026
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**15,397,557**	**13,176,370**	**13,020,575**	**12,387,825**	**15,286,882**	**16,937,554**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.39	0.49	0.74	0.40	0.39	0.78
29. LIGHT OIL	1.09	1.23	1.79	1.55	0.82	1.56
30. COAL	97.43	97.41	95.08	94.20	95.10	92.12
31. NATURAL GAS	1.09	0.87	2.39	3.85	3.69	5.54
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT						
35. HEAVY OIL ($/BBL)	30.74	31.43	30.81	30.50	30.38	28.35
36. LIGHT OIL ($/BBL)	34.94	34.74	34.26	33.67	33.41	32.02
37. COAL ($/TON)	45.84	46.34	46.94	47.26	47.06	46.88
38. NATURAL GAS ($/MCF)	4.89	4.27	4.26	5.26	5.43	5.42
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)						
41. HEAVY OIL	4.90	5.00	4.91	4.86	4.84	4.51
42. LIGHT OIL	6.21	6.16	6.04	5.90	6.02	5.61
43. COAL	1.96	1.98	2.00	2.02	2.00	1.99
44. NATURAL GAS	4.76	4.15	4.14	5.12	5.28	5.28
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**2.05**	**2.06**	**2.15**	**2.23**	**2.16**	**2.26**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	9,354	9,355	9,355	9,346	9,327	9,356
49. LIGHT OIL	9,897	10,514	10,685	12,926	9,714	13,035
50. COAL	10,359	10,374	10,453	10,403	10,392	10,504
51. NATURAL GAS	10,459	10,254	10,346	10,385	10,555	10,517
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**10,352**	**10,370**	**10,447**	**10,437**	**10,389**	**10,536**
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	4.58	4.68	4.59	4.54	4.51	4.22
56. LIGHT OIL	6.15	6.48	6.45	7.63	5.85	7.31
57. COAL	2.03	2.05	2.10	2.11	2.08	2.09
58. NATURAL GAS	4.98	4.25	4.29	5.32	5.57	5.55
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**2.12**	**2.14**	**2.24**	**2.33**	**2.25**	**2.38**

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)							
1. HEAVY OIL	573,919	552,745	646,831	555,932	526,204	427,635	5,268,790
2. LIGHT OIL	2,229,445	1,948,408	1,271,047	1,198,203	1,268,822	840,485	16,148,494
3. COAL	32,403,497	32,468,563	30,451,240	24,868,198	21,163,653	25,108,360	329,791,838
4. NATURAL GAS	5,126,654	5,115,084	6,565,432	5,238,606	4,095,587	2,379,610	41,479,333
5. NUCLEAR	0	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0	0
7. TOTAL ($)	**40,333,515**	**40,084,800**	**38,934,550**	**31,860,939**	**27,054,266**	**28,756,090**	**392,688,455**
SYSTEM NET GENERATION (MWH)							
8. HEAVY OIL	14,661	14,978	17,799	15,060	13,853	11,199	131,838
9. LIGHT OIL	30,411	27,437	19,454	19,095	20,152	14,882	241,140
10. COAL	1,533,022	1,540,456	1,460,904	1,180,633	1,004,780	1,257,922	15,848,013
11. NATURAL GAS	91,934	91,198	117,040	96,461	74,071	41,388	758,310
12. NUCLEAR	0	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0	0
14. TOTAL (MWH)	**1,670,028**	**1,674,069**	**1,615,197**	**1,311,249**	**1,112,856**	**1,325,391**	**16,979,301**
UNITS OF FUEL BURNED							
15. HEAVY OIL (BBL)	21,819	22,293	26,509	22,427	20,632	16,635	196,270
16. LIGHT OIL (BBL)	71,673	63,660	41,680	39,487	42,836	28,385	507,477
17. COAL (TON)	687,447	690,810	653,677	524,300	443,555	553,670	7,050,889
18. NATURAL GAS (MCF)	940,096	933,059	1,197,386	979,057	747,035	424,524	7,727,438
19. NUCLEAR (MMBTU)	0	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0	0
BTUS BURNED (MMBTU)							
21. HEAVY OIL	137,001	139,982	166,450	140,821	129,550	104,454	1,232,378
22. LIGHT OIL	410,290	363,896	236,496	224,093	243,128	159,231	2,882,291
23. COAL	16,159,698	16,237,239	15,342,312	12,260,238	10,386,128	13,085,564	165,442,088
24. NATURAL GAS	966,455	959,241	1,230,929	1,006,512	767,971	436,388	7,944,073
25. NUCLEAR	0	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0	0
27. TOTAL (MMBTU)	**17,673,444**	**17,700,358**	**16,976,187**	**13,631,664**	**11,526,777**	**13,785,637**	**177,500,830**
GENERATION MIX (% MWH)							
28. HEAVY OIL	0.88	0.89	1.10	1.15	1.24	0.84	0.78
29. LIGHT OIL	1.82	1.64	1.20	1.46	1.81	1.12	1.42
30. COAL	91.80	92.02	90.45	90.03	90.29	94.92	93.33
31. NATURAL GAS	5.50	5.45	7.25	7.36	6.66	3.12	4.47
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT							
35. HEAVY OIL ($/BBL)	26.30	24.79	24.40	24.79	25.50	25.71	26.84
36. LIGHT OIL ($/BBL)	31.11	30.61	30.50	30.34	29.62	29.61	31.82
37. COAL ($/TON)	47.14	47.00	46.58	47.43	47.71	45.35	46.77
38. NATURAL GAS ($/MCF)	5.45	5.48	5.48	5.35	5.48	5.61	5.37
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)							
41. HEAVY OIL	4.19	3.95	3.89	3.95	4.06	4.09	4.28
42. LIGHT OIL	5.43	5.35	5.37	5.35	5.22	5.28	5.60
43. COAL	2.01	2.00	1.98	2.03	2.04	1.92	1.99
44. NATURAL GAS	5.30	5.33	5.33	5.20	5.33	5.45	5.22
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**2.28**	**2.26**	**2.29**	**2.34**	**2.35**	**2.09**	**2.21**
BTU BURNED PER KWH (BTU/KWH)							
48. HEAVY OIL	9,345	9,346	9,352	9,351	9,352	9,327	9,348
49. LIGHT OIL	13,491	13,263	12,157	11,736	12,065	10,700	11,953
50. COAL	10,541	10,541	10,502	10,384	10,337	10,403	10,439
51. NATURAL GAS	10,512	10,518	10,517	10,434	10,368	10,544	10,476
52. NUCLEAR	0	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**10,583**	**10,573**	**10,510**	**10,396**	**10,358**	**10,401**	**10,454**
GENERATED FUEL COST PER KWH (CENTS/KWH)							
55. HEAVY OIL	3.91	3.69	3.63	3.69	3.80	3.82	4.00
56. LIGHT OIL	7.33	7.10	6.53	6.27	6.30	5.65	6.70
57. COAL	2.11	2.11	2.08	2.11	2.11	2.00	2.08
58. NATURAL GAS	5.58	5.61	5.61	5.43	5.53	5.75	5.47
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**2.42**	**2.39**	**2.41**	**2.43**	**2.43**	**2.17**	**2.31**

SCHEDULE E4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

ESTIMATED FOR THE PERIOD: JANUARY 2002

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. H.P.#1	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
2. H.P.#2	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
3. H.P.#3	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
4. H.P.#4	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
5. H.P.#5	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
6. H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
7. GAN.#1	114	43,403	51.2	75.0	83.7	11,452	COAL	20,710	24,000,435	497,049.0	912,030	2.10	44.04
8. GAN.#2	98	16,657	22.8	41.3	85.4	11,965	COAL	8,304	24,000,843	199,303.0	365,693	2.20	44.04
9. GAN.#3	145	57,783	53.6	71.0	84.3	12,052	COAL	35,347	19,702,238	696,415.0	1,556,617	2.69	44.04
10. GAN.#4	169	61,946	49.3	65.1	80.2	12,037	COAL	37,846	19,702,373	745,656.0	1,666,668	2.69	44.04
11. GAN.#5	227	82,068	48.6	66.9	67.2	10,473	COAL	35,843	23,980,512	859,533.5	1,578,460	1.92	44.04
12. GAN.#6	392	167,645	57.5	78.0	75.7	10,565	COAL	71,027	24,935,892	1,771,121.6	3,127,899	1.87	44.04
13. GANNON STA.	**1,145**	**429,502**	**50.4**	**69.5**	**14.0**	**11,104**	**COAL**	**209,077**	**22,810,152**	**4,769,078.1**	**9,207,367**	**2.14**	**44.04**
14. B.B.#1	426	219,162	69.1	80.2	78.8	10,134	COAL	92,506	24,008,866	2,220,964.2	4,160,373	1.90	44.97
15. B.B.#2	426	246,809	77.9	82.5	85.0	9,919	COAL	102,735	23,830,424	2,448,218.6	4,620,413	1.87	44.97
16. B.B.#3	433	175,015	54.3	79.7	71.9	10,013	COAL	74,146	23,635,003	1,752,440.9	3,334,649	1.91	44.97
17. B.B. 1 - 3	1,285	640,986	67.0	80.8	26.3	10,018	COAL	269,387	23,837,912	6,421,623.7	12,115,435	1.89	44.97
18. B.B.#4	447	247,723	74.5	87.8	80.2	10,015	COAL	111,375	22,276,581	2,481,054.2	5,870,229	2.37	52.71
19. B.B. STA.	**1,732**	**888,709**	**69.0**	**82.6**	**19.8**	**10,018**	**COAL**	**380,762**	**23,381,214**	**8,902,677.9**	**17,985,664**	**2.02**	**47.24**
20. PHILLIPS #1 (HVY OIL)	17	2,948	23.3	91.0	97.4	9,354	HVY OIL	4,391	6,280,096	27,575.9	134,992	4.58	30.74
21. PHILLIPS #2 (HVY OIL)	17	2,889	22.8	91.0	97.7	9,354	HVY OIL	4,305	6,277,375	27,024.1	132,348	4.58	30.74
22. SEB-PHILLIPS TOTAL	**34**	**5,837**	**23.1**	**91.0**	**48.8**	**9,354**	**HVY OIL**	**8,696**	**6,278,749**	**54,600.0**	**267,340**	**4.58**	**30.74**
23. POLK #1 GASIFIER	250	130,936	70.4	-	-	10,239	COAL	53,400	25,104,850	1,340,599.0	2,291,241	1.75	42.91
24. POLK #1 CT OIL	250	9,855	5.3	-	-	8,127	LGT OIL	14,700	5,448,626	80,094.8	512,838	5.20	34.89
25. POLK #1 TOTAL	**250**	**140,791**	**75.7**	**84.5**	**97.8**	**10,091**		**-**	**-**	**1,420,693.8**	**2,804,079**	**1.99**	**-**
26. POLK #2 CT GAS	180	15,307	11.4	-	-	10,511	GAS	156,500	1,028,102	160,898.0	758,446	4.95	4.85
27. POLK #2 CT OIL	180	3,827	2.9	-	-	10,511	LGT OIL	6,900	5,829,565	40,224.0	247,259	6.46	35.83
28. POLK #2 TOTAL	**180**	**19,134**	**14.3**	**83.5**	**78.7**	**10,511**		**-**	**-**	**201,122.0**	**1,005,705**	**5.26**	**-**
29. POLK #3 GAS	**180**	**0**	**0.0**	**0.0**	**0.0**	**0**	GAS	**0**	0	**0.0**	**0**	**0.00**	**0.00**
30. CITY OF TAMPA GAS	**6**	**920**	**20.6**	**100.0**	**95.8**	**9,596**	GAS	**8,588**	1,027,946	**8,828.0**	**49,118**	**5.34**	**5.72**
31. GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#1	17	203	1.6	64.9	99.5	18,005	LGT OIL	631	5,792,393	3,655.0	21,568	10.62	34.18
33. B.B.C.T.#2	80	1,269	2.1	69.1	88.1	15,574	LGT OIL	3,410	5,795,601	19,763.0	116,557	9.18	34.18
34. B.B.C.T.#3	80	1,101	1.8	69.1	91.8	15,567	LGT OIL	2,957	5,796,077	17,139.0	101,073	9.18	34.18
35. C.T. TOTAL (OIL)	**177**	**2,573**	**2.0**	**68.7**	**32.3**	**15,763**	**LGT OIL**	**6,998**	**5,795,513**	**40,557.0**	**239,198**	**9.30**	**34.18**
36. TOT COAL (GN,BB,POLK)	**3,127**	**1,449,147**	**62.3**	**71.2**	**8.8**	**10,359**	**COAL**	**643,239**	**23,338,689**	**15,012,355.0**	**29,484,272**	**2.03**	**45.84**
37. SYSTEM	**3,704**	**1,487,466**	**64.0**	**74.2**	**6.9**	**10,352**	**-**	**-**	**-**	**15,397,556.8**	**31,558,471**	**2.12**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: FEBRUARY 2002

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. H.P.#1	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
2. H.P.#2	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
3. H.P.#3	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
4. H.P.#4	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
5. H.P.#5	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
6. H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
7. GAN.#1	114	47,196	61.6	75.0	89.2	11,386	COAL	22,392	23,999,464	537,396.0	972,832	2.06	43.45
8. GAN.#2	98	14,126	21.4	32.9	92.4	11,868	COAL	6,986	23,998,569	167,654.0	303,510	2.15	43.45
9. GAN.#3	145	56,639	58.1	71.0	88.4	12,004	COAL	34,509	19,702,425	679,911.0	1,499,262	2.65	43.45
10. GAN.#4	169	60,575	53.3	64.9	85.1	11,974	COAL	36,814	19,702,369	725,323.0	1,599,404	2.64	43.45
11. GAN.#5	227	41,414	27.1	35.9	69.9	10,463	COAL	18,069	23,980,707	433,307.4	785,017	1.90	43.45
12. GAN.#6	392	155,198	58.9	78.0	77.5	10,584	COAL	65,874	24,936,072	1,642,638.8	2,861,931	1.84	43.45
13. GANNON STA.	**1,145**	**375,148**	**48.8**	**62.7**	**14.6**	**11,159**	**COAL**	**184,644**	**22,671,899**	**4,186,230.2**	**8,021,956**	**2.14**	**43.45**
14. B.B.#1	426	110,206	38.5	43.0	82.1	10,137	COAL	45,924	24,326,132	1,117,153.3	2,094,875	1.90	45.62
15. B.B.#2	426	229,392	80.1	82.6	87.4	9,916	COAL	94,212	24,144,953	2,274,744.3	4,297,586	1.87	45.62
16. B.B.#3	433	201,224	69.2	79.8	78.5	9,991	COAL	82,823	24,272,924	2,010,356.4	3,778,064	1.88	45.62
17. B.B. 1 - 3	1,285	540,822	62.6	68.5	27.6	9,989	COAL	222,959	24,229,809	5,402,254.0	10,170,525	1.88	45.62
18. B.B.#4	447	202,839	67.5	87.6	79.6	10,031	COAL	91,339	22,276,659	2,034,727.8	5,009,906	2.47	54.85
19. B.B. STA.	**1,732**	**743,661**	**63.9**	**73.5**	**20.5**	**10,000**	**COAL**	**314,298**	**23,662,199**	**7,436,981.8**	**15,180,431**	**2.04**	**48.30**
20. PHILLIPS #1 (HVY OIL)	17	3,162	27.7	90.9	97.9	9,355	HVY OIL	4,711	6,278,752	29,579.2	148,049	4.68	31.43
21. PHILLIPS #2 (HVY OIL)	17	3,116	27.3	90.9	98.5	9,355	HVY OIL	4,642	6,279,362	29,148.8	145,880	4.68	31.43
22. SEB-PHILLIPS TOTAL	**34**	**6,278**	**27.5**	**90.9**	**49.1**	**9,355**	**HVY OIL**	**9,353**	**6,279,055**	**58,728.0**	**293,929**	**4.68**	**31.43**
23. POLK #1 GASIFIER	250	118,849	70.7	-	-	10,237	COAL	48,500	25,084,662	1,216,606.1	2,167,880	1.82	44.70
24. POLK #1 CT OIL	250	8,946	5.3	-	-	8,124	LGT OIL	13,300	5,464,301	72,675.2	464,882	5.20	34.95
25. POLK #1 TOTAL	**250**	**127,795**	**76.1**	**84.4**	**98.3**	**10,089**		**-**	**-**	**1,289,281.3**	**2,632,762**	**2.06**	**-**
26. POLK #2 CT GAS	180	10,023	8.3	-	-	10,321	GAS	100,600	1,028,280	103,445.0	416,595	4.16	4.14
27. POLK #2 CT OIL	180	2,506	2.1	-	-	10,320	LGT OIL	4,500	5,746,889	25,861.0	158,325	6.32	35.18
28. POLK #2 TOTAL	**180**	**12,529**	**10.4**	**41.7**	**88.1**	**10,321**		**-**	**-**	**129,306.0**	**574,920**	**4.59**	**-**
29. POLK #3 GAS	**180**	**0**	**0.0**	**0.0**	**0.0**	**0**	GAS	**0**	0	**0.0**	**0**	**0.00**	**0.00**
30. CITY OF TAMPA GAS	**6**	**1028**	**25.5**	**100.0**	**96.3**	**9,600**	GAS	**9,600**	1,028,021	**9,869.0**	**53,464**	**5.20**	**5.57**
31. GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#1	17	269	2.4	51.0	98.9	18,022	LGT OIL	836	5,799,043	4,848.0	28,695	10.67	34.32
33. B.B.C.T.#2	80	2,102	3.9	69.0	90.6	15,567	LGT OIL	5,646	5,795,430	32,721.0	193,791	9.22	34.32
34. B.B.C.T.#3	80	1,824	3.4	69.0	91.2	15,573	LGT OIL	4,901	5,795,756	28,405.0	168,220	9.22	34.32
35. C.T. TOTAL (OIL)	**177**	**4,195**	**3.5**	**67.3**	**33.9**	**15,727**	**LGT OIL**	**11,383**	**5,795,836**	**65,974.0**	**390,706**	**9.31**	**34.32**
36. TOT COAL (GN,BB,POLK)	**3,127**	**1,237,658**	**58.9**	**63.6**	**9.1**	**10,374**	**COAL**	**547,442**	**23,454,207**	**12,839,818.1**	**25,370,267**	**2.05**	**46.34**
37. SYSTEM	**3,704**	**1,270,634**	**51.0**	**65.6**	**6.9**	**10,370**	**-**	**-**	**-**	**13,176,370.3**	**27,148,168**	**2.14**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: MARCH 2002

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. H.P.#1	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
2. H.P.#2	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
3. H.P.#3	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
4. H.P.#4	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
5. H.P.#5	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
6. H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
7. GAN.#1	114	42,173	49.7	70.2	89.1	11,436	COAL	20,096	24,000,100	482,306.0	869,560	2.06	43.27
8. GAN.#2	98	33,334	45.7	71.0	91.9	12,067	COAL	16,761	23,999,523	402,256.0	725,254	2.18	43.27
9. GAN.#3	145	54,755	50.8	71.0	87.6	12,045	COAL	33,473	19,702,626	659,506.0	1,448,387	2.65	43.27
10. GAN.#4	169	59,766	47.5	65.1	84.4	12,038	COAL	36,515	19,702,615	719,441.0	1,580,015	2.64	43.27
11. GAN.#5	227	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
12. GAN.#6	392	170,436	58.4	78.0	77.0	10,657	COAL	72,843	24,935,980	1,816,411.6	3,151,939	1.85	43.27
13. GANNON STA.	**1,145**	**360,464**	**42.3**	**58.3**	**14.3**	**11,319**	**COAL**	**179,688**	**22,705,582**	**4,079,920.6**	**7,775,155**	**2.16**	**43.27**
14. B.B.#1	426	211,098	66.6	77.7	80.7	10,201	COAL	88,527	24,325,985	2,153,506.5	4,112,720	1.95	46.46
15. B.B.#2	426	242,333	76.5	82.5	83.4	9,897	COAL	99,333	24,144,984	2,398,393.7	4,614,737	1.90	46.46
16. B.B.#3	433	7,910	2.5	2.6	83.0	9,995	COAL	3,257	24,273,687	79,059.4	151,311	1.91	46.46
17. B.B. 1 - 3	1,285	461,341	48.3	54.0	27.2	10,038	COAL	191,117	24,231,019	4,630,959.6	8,878,768	1.92	46.46
18. B.B.#4	447	231,577	69.6	87.8	80.2	10,058	COAL	104,560	22,276,513	2,329,232.2	5,793,853	2.50	55.41
19. B.B. STA.	**1,732**	**692,918**	**53.8**	**62.7**	**20.4**	**10,045**	**COAL**	**295,677**	**23,539,849**	**6,960,191.8**	**14,672,621**	**2.12**	**49.62**
20. PHILLIPS #1 (HVY OIL)	17	4,623	36.6	85.1	98.5	9,355	HVY OIL	6,888	6,278,818	43,248.5	212,187	4.59	30.81
21. PHILLIPS #2 (HVY OIL)	17	4,612	36.5	91.0	98.7	9,355	HVY OIL	6,872	6,278,449	43,145.5	211,694	4.59	30.81
22. SEB-PHILLIPS TOTAL	**34**	**9,235**	**36.5**	**88.0**	**49.3**	**9,355**	**HVY OIL**	**13,760**	**6,278,634**	**86,394.0**	**423,881**	**4.59**	**30.81**
23. POLK #1 GASIFIER	250	131,621	70.8	-	-	10,236	COAL	53,700	25,089,181	1,347,289.0	2,387,696	1.81	44.46
24. POLK #1 CT OIL	250	9,907	5.3	-	-	8,125	LGT OIL	14,800	5,438,845	80,494.9	513,534	5.18	34.70
25. POLK #1 TOTAL	**250**	**141,528**	**76.1**	**84.5**	**98.3**	**10,088**		**-**	**-**	**1,427,783.9**	**2,901,230**	**2.05**	**-**
26. POLK #2 CT GAS	180	28,133	21.0	-	-	10,390	GAS	284,300	1,028,153	292,304.0	1,195,510	4.25	4.21
27. POLK #2 CT OIL	180	7,033	5.3	-	-	10,390	LGT OIL	12,600	5,799,683	73,076.0	427,224	6.07	33.91
28. POLK #2 TOTAL	**180**	**35,166**	**26.3**	**83.5**	**84.6**	**10,390**		**-**	**-**	**365,380.0**	**1,622,734**	**4.61**	**-**
29. POLK #3 GAS	**180**	**0**	**0.0**	**0.0**	**0.0**	**0**	GAS	**0**	0	**0.0**	**0**	**0.00**	**0.00**
30. CITY OF TAMPA GAS	**6**	**1643**	**36.8**	**100.0**	**96.4**	**9,600**	GAS	**15,342**	1,028,028	**15,772.0**	**81,438**	**4.96**	**5.31**
31. GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#1	17	535	4.2	62.9	98.3	18,004	LGT OIL	1,662	5,795,427	9,632.0	56,710	10.60	34.12
33. B.B.C.T.#2	80	2,553	4.3	53.5	93.9	15,518	LGT OIL	6,835	5,796,342	39,618.0	233,222	9.14	34.12
34. B.B.C.T.#3	80	2,312	3.9	53.5	93.2	15,520	LGT OIL	6,191	5,795,994	35,883.0	211,248	9.14	34.12
35. C.T. TOTAL (OIL)	**177**	**5,400**	**4.1**	**54.4**	**31.5**	**15,765**	**LGT OIL**	**14,688**	**5,796,092**	**85,133.0**	**501,180**	**9.28**	**34.12**
36. TOT COAL (GN,BB,POLK)	**3,127**	**1,185,003**	**50.9**	**56.1**	**9.1**	**10,453**	**COAL**	**529,065**	**23,413,761**	**12,387,401.4**	**24,835,472**	**2.10**	**46.94**
37. SYSTEM	**3,704**	**1,246,354**	**45.2**	**60.7**	**6.6**	**10,447**	**-**	**-**	**-**	**13,020,575.3**	**27,978,239**	**2.24**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: APRIL 2002

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. H.P.#1	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
2. H.P.#2	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
3. H.P.#3	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
4. H.P.#4	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
5. H.P.#5	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
6. H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
7. GAN.#1	114	5,856	7.1	9.9	93.4	11,429	COAL	2,789	23,996,773	66,927.0	119,103	2.03	42.70
8. GAN.#2	98	28,717	40.7	54.4	96.1	12,102	COAL	14,480	24,000,760	347,531.0	618,361	2.15	42.70
9. GAN.#3	145	41,356	39.6	54.4	89.1	12,074	COAL	25,899	19,279,663	499,324.0	1,106,004	2.67	42.70
10. GAN.#4	159	56,538	49.4	65.1	87.2	12,088	COAL	35,448	19,280,157	683,443.0	1,513,789	2.68	42.70
11. GAN.#5	208	47,252	31.6	40.2	73.0	10,717	COAL	21,116	23,981,199	506,387.0	901,748	1.91	42.70
12. GAN.#6	372	139,572	52.1	67.6	79.0	10,696	COAL	59,865	24,936,009	1,492,794.2	2,556,505	1.83	42.70
13. GANNON STA.	**1,096**	**319,291**	**40.5**	**53.1**	**16.5**	**11,264**	**COAL**	**159,597**	**22,534,297**	**3,596,406.2**	**6,816,510**	**2.13**	**42.70**
14. B.B.#1	416	212,847	71.1	80.3	82.1	10,189	COAL	89,149	24,325,887	2,168,628.5	4,181,042	1.96	46.90
15. B.B.#2	416	233,660	78.0	82.5	85.1	9,884	COAL	95,649	24,144,958	2,309,441.1	4,485,889	1.92	46.90
16. B.B.#3	433	21,612	6.9	10.4	63.2	10,122	COAL	9,012	24,273,546	218,753.2	422,658	1.96	46.90
17. B.B. 1 - 3	1,265	468,119	51.4	57.1	27.2	10,033	COAL	193,810	24,234,161	4,696,822.8	9,089,589	1.94	46.90
18. B.B.#4	442	233,507	73.4	87.6	81.9	10,036	COAL	105,201	22,276,562	2,343,516.6	5,873,398	2.52	55.83
19. B.B. STA.	**1,707**	**701,626**	**57.1**	**65.0**	**20.5**	**10,034**	**COAL**	**299,011**	**23,545,419**	**7,040,339.4**	**14,962,987**	**2.13**	**50.04**
20. PHILLIPS #1 (HVY OIL)	17	2,719	22.2	54.5	96.4	9,346	HVY OIL	4,047	6,279,194	25,411.9	123,441	4.54	30.50
21. PHILLIPS #2 (HVY OIL)	17	2,049	16.7	36.4	96.4	9,346	HVY OIL	3,050	6,278,721	19,150.1	93,031	4.54	30.50
22. SEB-PHILLIPS TOTAL	**34**	**4,768**	**19.5**	**45.5**	**48.2**	**9,346**	**HVY OIL**	**7,097**	**6,278,991**	**44,562.0**	**216,472**	**4.54**	**30.50**
23. POLK #1 GASIFIER	250	97,049	53.9	-	-	10,235	COAL	39,600	25,083,490	993,306.2	1,768,920	1.82	44.67
24. POLK #1 CT OIL	250	7,305	4.1	-	-	8,120	LGT OIL	10,900	5,441,633	59,313.8	374,016	5.12	34.31
25. POLK #1 TOTAL	**250**	**104,354**	**58.0**	**53.4**	**97.8**	**10,087**		**-**	**-**	**1,052,620.0**	**2,142,936**	**2.05**	**-**
26. POLK #2 CT GAS	150	44,208	40.9	-	-	10,412	GAS	447,700	1,028,104	460,282.0	2,360,498	5.34	5.27
27. POLK #2 CT OIL	150	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
28. POLK #2 TOTAL	**150**	**44,208**	**40.9**	**83.4**	**102.0**	**10,412**		**-**	**-**	**460,282.0**	**2,360,498**	**5.34**	**-**
29. POLK #3 GAS	**150**	**0**	**0.0**	**0.0**	**0.0**	**0**	GAS	**0**	0	**0.0**	**0**	**0.00**	**0.00**
30. CITY OF TAMPA GAS	**6**	**1527**	**35.3**	**100.0**	**96.4**	**9,599**	GAS	**14,259**	1,027,982	**14,658.0**	**71,331**	**4.67**	**5.00**
31. GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#1	12	831	9.6	65.0	98.9	19,668	LGT OIL	2,820	5,795,745	16,344.0	94,307	11.35	33.44
33. B.B.C.T.#2	66	5,279	11.1	69.1	96.4	15,784	LGT OIL	14,376	5,796,119	83,325.0	480,767	9.11	33.44
34. B.B.C.T.#3	66	5,019	10.6	69.1	95.1	15,798	LGT OIL	13,680	5,795,906	79,288.0	457,491	9.12	33.44
35. C.T. TOTAL (OIL)	**144**	**11,129**	**10.7**	**68.8**	**33.2**	**16,080**	**LGT OIL**	**30,876**	**5,795,990**	**178,957.0**	**1,032,565**	**9.28**	**33.44**
36. TOT COAL (GN,BB,POLK)	**3,053**	**1,117,966**	**50.9**	**55.4**	**9.4**	**10,403**	**COAL**	**498,208**	**23,343,768**	**11,630,051.8**	**23,547,417**	**2.11**	**47.26**
37. SYSTEM	**3,537**	**1,186,903**	**46.6**	**58.5**	**7.2**	**10,437**	**-**	**-**	**-**	**12,387,824.6**	**27,602,299**	**2.33**	**-**

LEGEND:
H.P. = HOOKERS POINT
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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: MAY 2002

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. H.P.#1	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
2. H.P.#2	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
3. H.P.#3	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
4. H.P.#4	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
5. H.P.#5	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
6. H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY OIL**	**0**	**0**	**0.0**	**500**	**0.00**	**0.00**
7. GAN.#1	114	43,119	50.8	75.0	87.6	11,554	COAL	20,758	23,999,711	498,186.0	885,018	2.05	42.64
8. GAN.#2	98	27,559	37.8	71.0	89.8	12,421	COAL	14,263	23,999,860	342,310.0	608,104	2.21	42.64
9. GAN.#3	145	46,016	42.7	71.0	83.1	12,210	COAL	29,142	19,279,871	561,854.0	1,242,470	2.70	42.64
10. GAN.#4	159	58,233	49.2	65.1	84.0	10,837	COAL	32,731	19,279,765	631,046.0	1,395,487	2.40	42.64
11. GAN.#5	208	77,777	50.3	66.9	69.5	10,891	COAL	35,322	23,980,706	847,046.5	1,505,955	1.94	42.64
12. GAN.#6	372	127,028	45.9	62.9	74.9	10,809	COAL	55,061	24,935,744	1,372,987.0	2,347,528	1.85	42.64
13. GANNON STA.	**1,096**	**379,732**	**46.6**	**67.0**	**13.5**	**11,201**	**COAL**	**187,277**	**22,711,969**	**4,253,429.5**	**7,984,562**	**2.10**	**42.64**
14. B.B.#1	416	222,883	72.0	80.2	82.0	10,261	COAL	94,017	24,325,919	2,287,049.9	4,443,181	1.99	47.26
15. B.B.#2	416	247,631	80.0	82.5	87.3	9,907	COAL	101,608	24,144,954	2,453,320.5	4,801,926	1.94	47.26
16. B.B.#3	433	208,430	64.7	79.7	73.2	10,031	COAL	86,139	24,272,699	2,090,826.0	4,070,872	1.95	47.26
17. B.B. 1 - 3	1,265	678,944	72.1	80.8	26.9	10,062	COAL	281,764	24,244,390	6,831,196.4	13,315,979	1.96	47.26
18. B.B.#4	442	212,788	64.7	87.8	79.8	10,096	COAL	96,441	22,276,493	2,148,367.3	5,445,134	2.56	56.46
19. B.B. STA.	**1,707**	**891,732**	**70.2**	**82.6**	**20.1**	**10,070**	**COAL**	**378,205**	**23,742,583**	**8,979,563.7**	**18,761,113**	**2.10**	**49.61**
20. PHILLIPS #1 (HVY OIL)	17	3,975	31.4	91.0	92.8	9,327	HVY OIL	5,904	6,279,726	37,075.5	179,008	4.50	30.32
21. PHILLIPS #2 (HVY OIL)	17	1,704	13.5	41.1	92.8	9,327	HVY OIL	2,532	6,277,054	15,893.5	76,770	4.51	30.32
22. SEB-PHILLIPS TOTAL	**34**	**5,679**	**22.5**	**66.1**	**46.4**	**9,327**	**HVY OIL**	**8,436**	**6,278,924**	**52,969.0**	**255,778**	**4.50**	**30.32**
23. POLK #1 GASIFIER	250	128,000	68.8	-	-	10,239	COAL	52,300	25,059,809	1,310,628.0	2,328,035	1.82	44.51
24. POLK #1 CT OIL	250	9,634	5.2	-	-	8,128	LGT OIL	14,400	5,437,611	78,301.6	484,056	5.02	33.62
25. POLK #1 TOTAL	**250**	**137,634**	**74.0**	**38.2**	**95.6**	**10,091**		**-**	**-**	**1,388,929.6**	**2,812,091**	**2.04**	**-**
26. POLK #2 CT GAS	150	31,075	27.8	-	-	10,566	GAS	319,400	1,027,977	328,336.0	1,736,067	5.59	5.44
27. POLK #2 CT OIL	150	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
28. POLK #2 TOTAL	**150**	**31,075**	**27.8**	**83.5**	**93.7**	**10,566**		**-**	**-**	**328,336.0**	**1,736,067**	**5.59**	**-**
29. POLK #3 GAS	**150**	**22266**	**20.0**	**69.9**	**92.2**	**10,581**	GAS	**229,200**	1,027,932	**235,602.0**	**1,245,794**	**5.60**	**5.44**
30. CITY OF TAMPA GAS	**6**	**995**	**22.3**	**100.0**	**95.9**	**9,605**	GAS	**9,296**	1,028,077	**9,557.0**	**45,601**	**4.58**	**4.91**
31. GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#1	12	172	1.9	64.9	95.6	19,715	LGT OIL	585	5,796,581	3,391.0	19,278	11.21	32.95
33. B.B.C.T.#2	66	1,155	2.4	69.1	92.1	15,825	LGT OIL	3,154	5,795,181	18,278.0	103,938	9.00	32.95
34. B.B.C.T.#3	66	1,062	2.2	69.1	94.7	15,844	LGT OIL	2,903	5,796,073	16,826.0	95,667	9.01	32.95
35. C.T. TOTAL (OIL)	**144**	**2,389**	**2.2**	**68.7**	**32.5**	**16,113**	**LGT OIL**	**6,642**	**5,795,694**	**38,495.0**	**218,883**	**9.16**	**32.95**
36. TOT COAL (GN,BB,POLK)	**3,053**	**1,399,464**	**61.6**	**70.3**	**8.9**	**10,392**	**COAL**	**617,782**	**23,541,672**	**14,543,621.2**	**29,073,710**	**2.08**	**47.06**
37. SYSTEM	**3,537**	**1,471,502**	**55.9**	**73.4**	**7.1**	**10,389**	**-**	**-**	**-**	**15,286,881.8**	**33,060,389**	**2.25**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: JUNE 2002

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. H.P.#1	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
2. H.P.#2	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
3. H.P.#3	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
4. H.P.#4	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
5. H.P.#5	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
6. H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
7. GAN.#1	114	50,829	61.9	75.0	91.7	11,573	COAL	24,509	24,000,245	588,222.0	1,037,174	2.04	42.32
8. GAN.#2	98	34,588	49.0	71.1	94.9	12,553	COAL	18,091	24,000,111	434,186.0	765,577	2.21	42.32
9. GAN.#3	145	56,700	54.3	71.1	88.1	12,186	COAL	35,838	19,279,815	690,950.0	1,516,596	2.67	42.32
10. GAN.#4	159	54,660	47.7	65.0	86.4	12,240	COAL	34,702	19,280,157	669,060.0	1,468,523	2.69	42.32
11. GAN.#5	208	81,330	54.3	66.9	75.0	10,959	COAL	37,168	23,981,115	891,330.1	1,572,879	1.93	42.32
12. GAN.#6	372	162,603	60.7	78.1	79.9	10,833	COAL	70,639	24,936,068	1,761,458.9	2,989,308	1.84	42.32
13. GANNON STA.	**1,096**	**440,710**	**55.8**	**72.2**	**14.5**	**11,425**	**COAL**	**220,947**	**22,789,207**	**5,035,207.0**	**9,350,057**	**2.12**	**42.32**
14. B.B.#1	416	219,187	73.2	80.3	84.2	10,278	COAL	92,610	24,325,979	2,252,828.9	4,389,672	2.00	47.40
15. B.B.#2	416	241,084	80.5	82.5	87.8	9,942	COAL	99,274	24,144,920	2,396,962.8	4,705,543	1.95	47.40
16. B.B.#3	433	220,566	70.7	79.7	81.1	10,035	COAL	91,187	24,272,753	2,213,359.5	4,322,223	1.96	47.40
17. B.B. 1 - 3	1,265	680,837	74.8	80.8	28.1	10,080	COAL	283,071	24,245,335	6,863,151.2	13,417,438	1.97	47.40
18. B.B.#4	442	231,752	72.8	87.6	83.9	10,148	COAL	105,576	22,276,552	2,351,869.3	5,965,800	2.57	56.51
19. B.B. STA.	**1,707**	**912,589**	**74.3**	**82.6**	**21.1**	**10,098**	**COAL**	**388,647**	**23,710,515**	**9,215,020.5**	**19,383,238**	**2.12**	**49.87**
20. PHILLIPS #1 (HVY OIL)	17	6,271	51.2	91.0	98.9	9,356	HVY OIL	9,344	6,279,120	58,672.1	264,875	4.22	28.35
21. PHILLIPS #2 (HVY OIL)	17	6,220	50.8	91.0	99.2	9,356	HVY OIL	9,269	6,278,444	58,194.9	262,749	4.22	28.35
22. SEB-PHILLIPS TOTAL	**34**	**12,491**	**51.0**	**91.0**	**49.5**	**9,356**	**HVY OIL**	**18,613**	**6,278,784**	**116,867.0**	**527,624**	**4.22**	**28.35**
23. POLK #1 GASIFIER	250	127,759	71.0	-	-	10,234	COAL	52,100	25,094,712	1,307,434.5	2,283,894	1.79	43.84
24. POLK #1 CT OIL	250	9,616	5.3	-	-	8,123	LGT OIL	14,300	5,462,266	78,110.4	470,490	4.89	32.90
25. POLK #1 TOTAL	**250**	**137,375**	**76.3**	**84.6**	**98.7**	**10,086**		**-**	**-**	**1,385,544.9**	**2,754,384**	**2.01**	**-**
26. POLK #2 CT GAS	150	48,342	44.8	-	-	10,536	GAS	495,400	1,028,088	509,315.0	2,692,202	5.57	5.43
27. POLK #2 CT OIL	150	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
28. POLK #2 TOTAL	**150**	**48,342**	**44.8**	**83.5**	**97.4**	**10,536**		**-**	**-**	**509,315.0**	**2,692,202**	**5.57**	**-**
29. POLK #3 GAS	**150**	**38856**	**36.0**	**70.0**	**96.7**	**10,539**	**GAS**	**398,400**	**1,027,909**	**409,519.0**	**2,165,065**	**5.57**	**5.43**
30. CITY OF TAMPA GAS	**6**	**1895**	**43.9**	**100.0**	**96.3**	**9,600**	**GAS**	**17,696**	**1,028,029**	**18,192.0**	**87,231**	**4.60**	**4.93**
31. GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#1	12	1,120	13.0	65.0	98.2	19,749	LGT OIL	3,816	5,796,384	22,119.0	121,070	10.81	31.73
33. B.B.C.T.#2	66	7,377	15.5	68.9	96.4	15,811	LGT OIL	20,124	5,795,965	116,638.0	638,472	8.65	31.73
34. B.B.C.T.#3	66	6,897	14.5	68.9	95.0	15,823	LGT OIL	18,829	5,795,953	109,132.0	597,386	8.66	31.73
35. C.T. TOTAL (OIL)	**144**	**15,394**	**14.8**	**68.6**	**33.3**	**16,103**	**LGT OIL**	**42,769**	**5,795,997**	**247,889.0**	**1,356,928**	**8.81**	**31.73**
36. TOT COAL (GN,BB,POLK)	**3,063**	**1,481,058**	**67.4**	**72.1**	**9.1**	**10,504**	**COAL**	**661,694**	**23,511,868**	**15,557,662.0**	**31,017,189**	**2.09**	**46.88**
37. SYSTEM	**3,637**	**1,607,652**	**63.1**	**78.6**	**6.5**	**10,536**	**-**	**-**	**-**	**16,937,554.4**	**38,316,729**	**2.38**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SCHEDULE E4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

ESTIMATED FOR THE PERIOD: JULY 2002

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. H.P.#1	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
2. H.P.#2	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
3. H.P.#3	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
4. H.P.#4	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
5. H.P.#5	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
6. H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
7. GAN.#1	114	49,973	58.9	75.0	91.1	11,579	COAL	24,111	23,999,668	578,656.0	1,011,405	2.02	41.95
8. GAN.#2	98	35,703	49.0	71.0	94.1	12,568	COAL	18,697	23,999,786	448,724.0	784,300	2.20	41.95
9. GAN.#3	145	57,971	53.7	71.0	87.5	12,194	COAL	36,665	19,279,831	706,895.0	1,538,019	2.65	41.95
10. GAN.#4	159	55,503	46.9	65.1	85.6	12,256	COAL	35,281	19,280,066	680,220.0	1,479,963	2.67	41.95
11. GAN.#5	208	81,938	52.9	66.9	73.2	10,982	COAL	37,523	23,981,006	899,839.3	1,574,010	1.92	41.95
12. GAN.#6	372	168,152	60.8	78.0	80.0	10,822	COAL	72,978	24,936,123	1,819,788.4	3,061,273	1.82	41.95
13. GANNON STA.	**1,096**	**449,240**	**55.1**	**72.1**	**14.5**	**11,428**	**COAL**	**225,255**	**22,792,492**	**5,134,122.7**	**9,448,970**	**2.10**	**41.95**
14. B.B.#1	416	226,492	73.2	80.2	84.4	10,361	COAL	96,464	24,325,901	2,346,573.7	4,598,388	2.03	47.67
15. B.B.#2	416	249,193	80.5	82.5	87.8	9,988	COAL	103,085	24,144,972	2,488,984.4	4,914,008	1.97	47.67
16. B.B.#3	433	225,390	70.0	79.7	80.2	10,129	COAL	94,057	24,272,780	2,283,024.9	4,483,648	1.99	47.67
17. B.B. 1 - 3	1,265	701,075	74.5	80.8	28.0	10,154	COAL	293,606	24,245,359	7,118,583.0	13,996,044	2.00	47.67
18. B.B.#4	442	250,787	76.3	87.8	84.4	10,196	COAL	114,786	22,276,461	2,557,025.8	6,528,322	2.60	56.87
19. B.B. STA.	**1,707**	**951,862**	**74.9**	**82.6**	**21.1**	**10,165**	**COAL**	**408,392**	**23,691,965**	**9,675,608.8**	**20,524,366**	**2.16**	**50.26**
20. PHILLIPS #1 (HVY OIL)	17	7,358	58.2	91.0	96.6	9,345	HVY OIL	10,950	6,279,224	68,757.5	288,025	3.91	26.30
21. PHILLIPS #2 (HVY OIL)	17	7,303	57.7	91.0	96.8	9,345	HVY OIL	10,869	6,278,728	68,243.5	285,894	3.91	26.30
22. SEB-PHILLIPS TOTAL	**34**	**14,661**	**58.0**	**91.0**	**48.3**	**9,345**	**HVY OIL**	**21,819**	**6,278,977**	**137,001.0**	**573,919**	**3.91**	**26.30**
23. POLK #1 GASIFIER	250	131,920	70.9	-	-	10,233	COAL	53,800	25,092,320	1,349,966.8	2,430,161	1.84	45.17
24. POLK #1 CT OIL	250	9,929	5.3	-	-	8,123	LGT OIL	14,800	5,449,669	80,655.1	477,550	4.81	32.27
25. POLK #1 TOTAL	**250**	**141,849**	**76.3**	**84.5**	**98.5**	**10,086**		**-**	**-**	**1,430,621.9**	**2,907,711**	**2.05**	**-**
26. POLK #2 CT GAS	150	49,721	44.6	-	-	10,532	GAS	509,400	1,028,009	523,668.0	2,783,005	5.60	5.46
27. POLK #2 CT OIL	150	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
28. POLK #2 TOTAL	**150**	**49,721**	**44.6**	**83.5**	**97.5**	**10,532**		**-**	**-**	**523,668.0**	**2,783,005**	**5.60**	**-**
29. POLK #3 GAS	**150**	**40222**	**36.0**	**69.9**	**97.2**	**10,533**	**GAS**	**412,100**	**1,028,078**	**423,671.0**	**2,251,426**	**5.60**	**5.46**
30. CITY OF TAMPA GAS	**6**	**1991**	**44.6**	**100.0**	**96.5**	**9,601**	**GAS**	**18,596**	**1,027,963**	**19,116.0**	**92,223**	**4.63**	**4.96**
31. GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#1	12	1,507	16.9	64.9	98.1	19,731	LGT OIL	5,130	5,796,296	29,735.0	158,023	10.49	30.80
33. B.B.C.T.#2	66	9,767	19.9	69.1	96.1	15,801	LGT OIL	26,627	5,795,997	154,330.0	820,208	8.40	30.80
34. B.B.C.T.#3	66	9,208	18.8	69.1	96.2	15,809	LGT OIL	25,116	5,795,907	145,570.0	773,664	8.40	30.80
35. C.T. TOTAL (OIL)	**144**	**20,482**	**19.1**	**68.7**	**33.3**	**16,094**	**LGT OIL**	**56,873**	**5,795,984**	**329,635.0**	**1,751,895**	**8.55**	**30.80**
36. TOT COAL (GN,BB,POLK)	**3,063**	**1,533,022**	**67.5**	**72.1**	**9.2**	**10,541**	**COAL**	**687,447**	**23,506,828**	**16,159,698.3**	**32,403,497**	**2.11**	**47.14**
37. SYSTEM	**3,537**	**1,670,028**	**63.5**	**78.5**	**6.4**	**10,583**	**-**	**-**	**-**	**17,673,444.4**	**40,333,515**	**2.42**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: AUGUST 2002

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. H.P.#1	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
2. H.P.#2	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
3. H.P.#3	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
4. H.P.#4	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
5. H.P.#5	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
6. H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
7. GAN.#1	114	50,593	59.7	75.0	91.3	11,576	COAL	24,403	23,999,631	585,663.0	1,015,091	2.01	41.60
8. GAN.#2	98	36,332	49.8	71.0	94.3	12,561	COAL	19,016	23,999,527	456,375.0	791,008	2.18	41.60
9. GAN.#3	145	58,139	53.9	71.0	87.7	12,190	COAL	36,759	19,280,067	708,716.0	1,529,063	2.63	41.60
10. GAN.#4	159	55,904	47.3	65.1	86.0	12,248	COAL	35,515	19,280,135	684,734.0	1,477,316	2.64	41.60
11. GAN.#5	208	82,477	53.3	66.9	73.7	10,976	COAL	37,749	23,980,924	905,255.9	1,570,244	1.90	41.60
12. GAN.#6	372	169,458	61.2	78.0	80.6	10,816	COAL	73,501	24,936,093	1,832,827.8	3,057,419	1.80	41.60
13. GANNON STA.	**1,096**	**452,903**	**55.5**	**72.1**	**14.5**	**11,423**	**COAL**	**226,943**	**22,796,789**	**5,173,571.7**	**9,440,141**	**2.08**	**41.60**
14. B.B.#1	416	226,762	73.3	80.2	84.6	10,361	COAL	96,580	24,325,817	2,349,387.4	4,606,084	2.03	47.69
15. B.B.#2	416	249,205	80.5	82.5	87.8	9,989	COAL	103,094	24,145,066	2,489,211.4	4,916,749	1.97	47.69
16. B.B.#3	433	227,683	70.7	79.7	81.0	10,126	COAL	94,984	24,272,880	2,305,535.2	4,529,968	1.99	47.69
17. B.B. 1 - 3	1,265	703,650	74.8	80.8	28.2	10,153	COAL	294,658	24,245,512	7,144,134.0	14,052,801	2.00	47.69
18. B.B.#4	442	251,891	76.6	87.8	84.9	10,198	COAL	115,309	22,276,468	2,568,677.2	6,566,200	2.61	56.94
19. B.B. STA.	**1,707**	**955,541**	**75.2**	**82.6**	**21.2**	**10,165**	**COAL**	**409,967**	**23,691,690**	**9,712,811.2**	**20,619,001**	**2.16**	**50.29**
20. PHILLIPS #1 (HVY OIL)	17	7,519	59.4	91.0	97.2	9,346	HVY OIL	11,191	6,279,278	70,271.4	277,476	3.69	24.79
21. PHILLIPS #2 (HVY OIL)	17	7,459	59.0	91.0	97.3	9,346	HVY OIL	11,102	6,279,103	69,710.6	275,269	3.69	24.79
22. SEB-PHILLIPS TOTAL	**34**	**14,978**	**59.2**	**91.0**	**48.6**	**9,346**	**HVY OIL**	**22,293**	**6,279,191**	**139,982.0**	**552,745**	**3.69**	**24.79**
23. POLK #1 GASIFIER	250	132,012	71.0	-	-	10,233	COAL	53,900	25,062,258	1,350,855.7	2,409,421	1.83	44.70
24. POLK #1 CT OIL	250	9,936	5.3	-	-	8,123	LGT OIL	14,800	5,453,311	80,709.0	469,657	4.73	31.73
25. POLK #1 TOTAL	**250**	**141,948**	**76.3**	**84.5**	**98.6**	**10,085**		**-**	**-**	**1,431,564.7**	**2,879,078**	**2.03**	**-**
26. POLK #2 CT GAS	150	49,621	44.5	-	-	10,539	GAS	508,700	1,028,072	522,980.0	2,793,780	5.63	5.49
27. POLK #2 CT OIL	150	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
28. POLK #2 TOTAL	**150**	**49,621**	**44.5**	**83.5**	**97.0**	**10,539**		**-**	**-**	**522,980.0**	**2,793,780**	**5.63**	**-**
29. POLK #3 GAS	**150**	**39600**	**35.5**	**69.9**	**96.4**	**10,538**	**GAS**	**405,900**	**1,028,049**	**417,285.0**	**2,229,203**	**5.63**	**5.49**
30. CITY OF TAMPA GAS	**6**	**1977**	**44.3**	**100.0**	**96.3**	**9,598**	**GAS**	**18,459**	**1,028,008**	**18,976.0**	**92,101**	**4.66**	**4.99**
31. GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#1	12	1,264	14.2	64.9	98.4	19,698	LGT OIL	4,296	5,795,624	24,898.0	130,019	10.29	30.27
33. B.B.C.T.#2	66	8,510	17.3	69.1	92.1	15,964	LGT OIL	23,440	5,795,947	135,857.0	709,413	8.34	30.27
34. B.B.C.T.#3	66	7,727	15.7	69.1	94.4	15,845	LGT OIL	21,124	5,795,872	122,432.0	639,319	8.27	30.27
35. C.T. TOTAL (OIL)	**144**	**17,501**	**16.3**	**68.7**	**32.8**	**16,181**	**LGT OIL**	**48,860**	**5,795,886**	**283,187.0**	**1,478,751**	**8.45**	**30.27**
36. TOT COAL (GN,BB,POLK)	**3,053**	**1,640,456**	**67.8**	**72.1**	**9.2**	**10,541**	**COAL**	**690,810**	**23,504,637**	**16,237,238.6**	**32,468,563**	**2.11**	**47.00**
37. SYSTEM	**3,537**	**1,674,069**	**63.6**	**78.5**	**6.4**	**10,573**	**-**	**-**	**-**	**17,700,367.6**	**40,084,800**	**2.39**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SCHEDULE E4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

ESTIMATED FOR THE PERIOD: SEPTEMBER 2002

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. H.P.#1	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
2. H.P.#2	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
3. H.P.#3	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
4. H.P.#4	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
5. H.P.#5	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
6. H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
7. GAN.#1	114	55,129	67.2	75.0	93.0	11,492	COAL	26,397	23,999,886	633,525.0	1,085,452	1.97	41.12
8. GAN.#2	98	40,577	57.5	71.1	96.3	12,294	COAL	20,785	24,000,289	498,846.0	854,685	2.11	41.12
9. GAN.#3	145	53,588	51.3	63.9	89.5	12,119	COAL	33,683	19,280,082	649,411.0	1,385,055	2.58	41.12
10. GAN.#4	159	61,563	53.8	65.0	87.8	12,141	COAL	38,766	19,280,246	747,418.0	1,594,069	2.59	41.12
11. GAN.#5	208	85,615	57.2	66.9	79.0	10,784	COAL	38,499	23,980,846	923,238.6	1,583,090	1.85	41.12
12. GAN.#6	372	170,362	63.6	78.1	83.7	10,742	COAL	73,392	24,936,037	1,830,105.6	3,017,900	1.77	41.12
13. GANNON STA.	**1,096**	**466,834**	**59.2**	**71.2**	**14.8**	**11,316**	**COAL**	**231,522**	**22,816,597**	**5,282,544.2**	**9,520,251**	**2.04**	**41.12**
14. B.B.#1	416	223,051	74.5	80.3	84.8	10,276	COAL	94,225	24,325,821	2,292,100.5	4,460,348	2.00	47.34
15. B.B.#2	416	162,060	54.1	55.0	88.5	9,937	COAL	66,698	24,144,839	1,610,412.5	3,157,297	1.95	47.34
16. B.B.#3	433	231,809	74.4	79.7	84.2	10,017	COAL	95,667	24,272,970	2,322,122.2	4,528,609	1.95	47.34
17. B.B. 1 - 3	1,265	616,920	67.7	71.8	28.6	10,090	COAL	256,590	24,259,072	6,224,635.2	12,146,254	1.97	47.34
18. B.B.#4	442	248,921	78.2	87.6	84.7	10,136	COAL	113,265	22,276,616	2,523,160.9	6,454,917	2.59	56.99
19. B.B. STA.	**1,707**	**865,841**	**70.4**	**75.9**	**21.4**	**10,103**	**COAL**	**369,855**	**23,651,961**	**8,747,796.1**	**18,601,171**	**2.15**	**50.29**
20. PHILLIPS #1 (HVY OIL)	17	8,927	72.9	91.0	98.3	9,352	HVY OIL	13,295	6,279,218	83,482.2	324,404	3.63	24.40
21. PHILLIPS #2 (HVY OIL)	17	8,872	72.5	91.0	98.5	9,352	HVY OIL	13,214	6,278,780	82,967.8	322,427	3.63	24.40
22. SEB-PHILLIPS TOTAL	**34**	**17,799**	**72.7**	**91.0**	**49.2**	**9,352**	**HVY OIL**	**26,509**	**6,279,000**	**166,450.0**	**646,831**	**3.63**	**24.40**
23. POLK #1 GASIFIER	250	128,229	71.2	-	-	10,231	COAL	52,300	25,085,493	1,311,971.3	2,329,818	1.82	44.55
24. POLK #1 CT OIL	250	9,652	5.4	-	-	8,121	LGT OIL	14,400	5,443,194	78,382.0	451,203	4.67	31.33
25. POLK #1 TOTAL	**250**	**137,881**	**76.6**	**84.6**	**99.0**	**10,084**		**-**	**-**	**1,390,353.3**	**2,781,021**	**2.02**	**-**
26. POLK #2 CT GAS	150	63,625	58.9	-	-	10,511	GAS	650,500	1,028,069	668,759.0	3,573,652	5.62	5.49
27. POLK #2 CT OIL	150	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
28. POLK #2 TOTAL	**150**	**63,625**	**58.9**	**83.5**	**99.1**	**10,511**		**-**	**-**	**668,759.0**	**3,573,652**	**5.62**	**-**
29. POLK #3 GAS	**150**	**50857**	**47.1**	**70.0**	**96.6**	**10,571**	GAS	**523,000**	1,027,945	**537,615.0**	**2,872,787**	**5.65**	**5.49**
30. CITY OF TAMPA GAS	**6**	**2558**	**59.2**	**100.0**	**96.5**	**9,599**	GAS	**23,886**	1,028,008	**24,555.0**	**118,993**	**4.65**	**4.98**
31. GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#1	12	729	8.4	65.0	99.6	19,674	LGT OIL	2,475	5,794,747	14,342.0	74,381	10.20	30.05
33. B.B.C.T.#2	66	4,685	9.9	68.9	94.6	15,868	LGT OIL	12,826	5,796,039	74,340.0	385,459	8.23	30.05
34. B.B.C.T.#3	66	4,388	9.2	68.9	95.0	15,823	LGT OIL	11,979	5,796,143	69,432.0	360,004	8.20	30.05
35. C.T. TOTAL (OIL)	**144**	**9,802**	**9.5**	**68.6**	**33.0**	**16,131**	**LGT OIL**	**27,280**	**5,795,968**	**158,114.0**	**819,844**	**8.36**	**30.05**
36. TOT COAL (GN,BB,POLK)	**3,053**	**1,460,904**	**66.5**	**68.0**	**9.1**	**10,502**	**COAL**	**653,677**	**23,470,784**	**15,342,311.6**	**30,451,240**	**2.08**	**46.58**
37. SYSTEM	**3,537**	**1,615,197**	**63.4**	**75.0**	**6.2**	**10,510**	**-**	**-**	**-**	**16,976,186.6**	**38,934,550**	**2.41**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: OCTOBER 2002

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. H.P.#1	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
2. H.P.#2	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
3. H.P.#3	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
4. H.P.#4	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
5. H.P.#5	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
6. H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
7. GAN.#1	114	41,799	49.3	58.1	93.1	11,398	COAL	19,851	24,000,403	476,432.0	827,439	1.98	41.68
8. GAN.#2	98	41,525	57.0	55.0	96.3	12,001	COAL	20,764	24,000,482	498,346.0	865,495	2.08	41.68
9. GAN.#3	145	11,460	10.6	13.8	90.8	12,014	COAL	7,141	19,280,633	137,683.0	297,654	2.60	41.68
10. GAN.#4	169	49,570	39.4	52.5	83.1	12,016	COAL	30,895	19,279,722	595,647.0	1,287,780	2.60	41.68
11. GAN.#5	227	89,514	53.0	67.0	73.3	10,546	COAL	39,366	23,980,514	944,016.9	1,640,872	1.83	41.68
12. GAN.#6	392	103,191	35.4	45.4	80.0	10,569	COAL	43,736	24,935,675	1,090,586.7	1,823,024	1.77	41.68
13. GANNON STA.	**1,145**	**337,059**	**39.6**	**48.8**	**13.7**	**11,104**	**COAL**	**161,753**	**23,138,437**	**3,742,711.6**	**6,742,264**	**2.00**	**41.68**
14. B.B.#1	426	225,679	71.2	80.3	81.1	10,187	COAL	95,752	24,008,804	2,298,891.0	4,513,639	2.00	47.14
15. B.B.#2	426	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
16. B.B.#3	433	216,688	67.3	79.7	77.7	10,017	COAL	91,838	23,634,922	2,170,584.0	4,329,138	2.00	47.14
17. B.B. 1 - 3	1,285	442,367	46.3	53.5	26.5	10,104	COAL	187,590	23,825,764	4,469,475.0	8,842,777	2.00	47.14
18. B.B.#4	447	268,698	80.8	87.8	87.5	10,020	COAL	120,857	22,276,687	2,692,293.6	6,864,214	2.55	56.80
19. B.B. STA.	**1,732**	**711,065**	**55.2**	**62.3**	**20.7**	**10,072**	**COAL**	**308,447**	**23,218,798**	**7,161,768.6**	**15,706,991**	**2.21**	**50.92**
20. PHILLIPS #1 (HVY OIL)	17	7,557	59.7	91.0	97.9	9,351	HVY OIL	11,254	6,278,923	70,663.0	278,970	3.69	24.79
21. PHILLIPS #2 (HVY OIL)	17	7,503	59.3	91.0	98.1	9,351	HVY OIL	11,173	6,279,245	70,158.0	276,962	3.69	24.79
22. SEB-PHILLIPS TOTAL	**34**	**15,060**	**59.5**	**91.0**	**49.0**	**9,351**	**HVY OIL**	**22,427**	**6,279,083**	**140,821.0**	**555,932**	**3.69**	**24.79**
23. POLK #1 GASIFIER	250	132,509	71.2	-	-	10,231	COAL	54,100	25,060,213	1,355,757.5	2,418,943	1.83	44.71
24. POLK #1 CT OIL	250	9,974	5.4	-	-	8,121	LGT OIL	14,800	5,473,122	81,002.2	459,278	4.60	31.03
25. POLK #1 TOTAL	**250**	**142,483**	**76.6**	**84.6**	**98.9**	**10,084**		**-**	**-**	**1,436,759.7**	**2,878,221**	**2.02**	**-**
26. POLK #2 CT GAS	180	51,317	38.3	-	-	10,470	GAS	522,600	1,028,079	537,274.0	2,801,711	5.46	5.36
27. POLK #2 CT OIL	180	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
28. POLK #2 TOTAL	**180**	**51,317**	**38.3**	**83.5**	**83.6**	**10,470**		**-**	**-**	**537,274.0**	**2,801,711**	**5.46**	**-**
29. POLK #3 GAS	**180**	**43018**	**32.1**	**69.9**	**84.4**	**10,433**	**GAS**	**436,600**	**1,028,000**	**448,825.0**	**2,340,438**	**5.44**	**5.36**
30. CITY OF TAMPA GAS	**6**	**2126**	**47.6**	**100.0**	**96.5**	**9,602**	**GAS**	**19,857**	**1,028,000**	**20,413.0**	**96,457**	**4.54**	**4.86**
31. GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#1	17	800	6.3	65.0	98.0	17,983	LGT OIL	2,482	5,796,132	14,386.0	74,291	9.29	29.93
33. B.B.C.T.#2	80	4,242	7.1	69.1	96.4	15,471	LGT OIL	11,323	5,796,167	65,630.0	338,917	7.99	29.93
34. B.B.C.T.#3	80	4,079	6.9	69.1	96.2	15,463	LGT OIL	10,882	5,796,269	63,075.0	325,717	7.99	29.93
35. C.T. TOTAL (OIL)	**177**	**9,121**	**6.9**	**68.7**	**33.0**	**15,688**	**LGT OIL**	**24,687**	**5,796,209**	**143,091.0**	**738,925**	**8.10**	**29.93**
36. TOT COAL (GN,BB,POLK)	**3,127**	**1,180,633**	**50.7**	**52.4**	**9.2**	**10,384**	**COAL**	**524,300**	**23,384,012**	**12,260,237.7**	**24,868,198**	**2.11**	**47.43**
37. SYSTEM	**3,704**	**1,311,249**	**47.6**	**61.7**	**6.1**	**10,396**	**-**	**-**	**-**	**13,631,663.9**	**31,860,939**	**2.43**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SCHEDULE E4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

ESTIMATED FOR THE PERIOD: NOVEMBER 2002

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. H.P.#1	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
2. H.P.#2	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
3. H.P.#3	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
4. H.P.#4	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
5. H.P.#5	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
6. H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	HVY OIL	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
7. GAN.#1	114	26,532	32.3	40.0	93.5	11,358	COAL	12,556	24,000,876	301,355.0	514,241	1.94	40.96
8. GAN.#2	98	20,591	29.2	37.9	96.8	11,906	COAL	10,215	24,000,196	245,162.0	418,364	2.03	40.96
9. GAN.#3	145	56,951	54.6	71.1	88.9	12,002	COAL	34,693	19,702,447	683,537.0	1,420,880	2.49	40.96
10. GAN.#4	169	16,432	13.5	17.4	88.4	11,965	COAL	9,979	19,702,876	196,615.0	408,698	2.49	40.96
11. GAN.#5	227	82,208	50.3	66.9	69.5	10,504	COAL	36,009	23,980,708	863,521.3	1,474,778	1.79	40.96
12. GAN.#6	392	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
13. GANNON STA.	**1,145**	**202,714**	**24.6**	**32.1**	**11.5**	**11,298**	COAL	**103,452**	**22,137,709**	**2,290,190.3**	**4,236,961**	**2.09**	**40.96**
14. B.B.#1	426	218,051	71.1	80.3	81.0	10,191	COAL	91,353	24,325,822	2,222,236.8	4,325,662	1.98	47.35
15. B.B.#2	426	8,106	2.6	2.8	86.5	9,923	COAL	3,332	24,141,417	80,439.2	157,774	1.95	47.35
16. B.B.#3	433	220,175	70.6	79.7	81.8	9,969	COAL	90,425	24,272,803	2,194,868.2	4,281,721	1.94	47.35
17. B.B. 1 - 3	1,285	446,332	48.2	54.4	27.2	10,077	COAL	185,110	24,296,603	4,497,544.2	8,765,157	1.96	47.35
18. B.B.#4	447	227,633	70.7	84.9	82.7	10,050	COAL	102,693	22,276,592	2,287,650.1	5,809,728	2.55	56.57
19. B.B. STA.	**1,732**	**673,965**	**54.0**	**62.3**	**20.6**	**10,068**	COAL	**287,803**	**23,575,829**	**6,785,194.3**	**14,574,885**	**2.16**	**50.64**
20. PHILLIPS #1 (HVY OIL)	17	6,953	56.8	91.0	98.3	9,352	HVY OIL	10,356	6,278,756	65,022.8	264,122	3.80	25.50
21. PHILLIPS #2 (HVY OIL)	17	6,900	56.4	91.0	98.3	9,352	HVY OIL	10,276	6,279,408	64,527.2	262,082	3.80	25.50
22. SEB-PHILLIPS TOTAL	**34**	**13,853**	**56.6**	**91.0**	**49.1**	**9,352**	HVY OIL	**20,632**	**6,279,081**	**129,550.0**	**526,204**	**3.80**	**25.50**
23. POLK #1 GASIFIER	250	128,101	71.2	-	-	10,232	COAL	52,300	25,062,023	1,310,743.8	2,351,807	1.84	44.97
24. POLK #1 CT OIL	250	9,642	5.4	-	-	8,122	LGT OIL	14,400	5,438,083	78,308.4	419,756	4.35	29.15
25. POLK #1 TOTAL	**250**	**137,743**	**76.5**	**84.6**	**98.9**	**10,084**		**-**	**-**	**1,389,052.2**	**2,771,563**	**2.01**	**-**
26. POLK #2 CT GAS	180	44,732	34.5	-	-	10,402	GAS	452,600	1,028,071	465,305.0	2,485,951	5.56	5.49
27. POLK #2 CT OIL	180	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
28. POLK #2 TOTAL	**180**	**44,732**	**34.5**	**83.5**	**85.7**	**10,402**		**-**	**-**	**465,305.0**	**2,485,951**	**5.56**	**-**
29. POLK #3 GAS	**180**	**27729**	**21.4**	**53.6**	**87.0**	**10,358**	GAS	**279,400**	1,027,953	**287,210.0**	**1,534,632**	**5.53**	**5.49**
30. CITY OF TAMPA GAS	**6**	**1610**	**37.3**	**100.0**	**96.2**	**9,600**	GAS	**15,035**	1,028,001	**15,456.0**	**75,004**	**4.66**	**4.99**
31. GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#1	17	912	7.5	65.0	99.3	17,974	LGT OIL	2,828	5,796,322	16,392.0	84,441	9.26	29.86
33. B.B.C.T.#2	80	4,905	8.5	68.9	95.8	15,459	LGT OIL	13,082	5,796,209	75,826.0	390,613	7.96	29.86
34. B.B.C.T.#3	80	4,693	8.1	68.9	94.6	15,470	LGT OIL	12,526	5,796,024	72,601.0	374,012	7.97	29.86
35. C.T. TOTAL (OIL)	**177**	**10,510**	**8.2**	**68.5**	**33.0**	**15,682**	LGT OIL	**28,436**	**5,796,139**	**164,819.0**	**849,066**	**8.08**	**29.86**
36. TOT COAL (GN,BB,POLK)	**3,127**	**1,004,780**	**44.6**	**46.2**	**9.4**	**10,337**	COAL	**443,555**	**23,415,649**	**10,386,128.4**	**21,163,653**	**2.11**	**47.71**
37. SYSTEM	**3,704**	**1,112,856**	**41.7**	**55.7**	**6.1**	**10,358**	-	**-**	**-**	**11,526,776.8**	**27,054,266**	**2.43**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: DECEMBER 2002

	(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1.	H.P.#1	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
2.	H.P.#2	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
3.	H.P.#3	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
4.	H.P.#4	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
5.	H.P.#5	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
6.	**H.P. STATION**	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
7.	GAN.#1	114	46,127	54.4	75.0	86.1	11,421	COAL	21,951	23,999,499	526,813.0	894,677	1.94	40.76
8.	GAN.#2	98	31,817	43.6	71.0	87.5	11,929	COAL	15,814	24,000,632	379,546.0	644,546	2.03	40.76
9.	GAN.#3	145	57,538	53.3	71.0	86.3	12,025	COAL	35,118	19,702,403	691,909.0	1,431,337	2.49	40.76
10.	GAN.#4	169	62,133	49.4	65.1	82.6	12,003	COAL	37,853	19,702,586	745,802.0	1,542,810	2.48	40.76
11.	GAN.#5	227	82,439	48.8	66.9	67.5	10,476	COAL	36,015	23,980,819	863,669.2	1,467,897	1.78	40.76
12.	GAN.#6	392	99,746	34.2	45.3	77.6	10,561	COAL	42,244	24,935,861	1,053,390.5	1,721,778	1.73	40.76
13.	**GANNON STA.**	**1,145**	**379,800**	**44.6**	**60.9**	**12.7**	**11,219**	**COAL**	**188,995**	**22,546,256**	**4,261,129.7**	**7,703,045**	**2.03**	**40.76**
14.	B.B.#1	426	222,343	70.2	80.2	81.0	10,136	COAL	92,642	24,325,839	2,253,594.4	4,357,161	1.96	47.03
15.	B.B.#2	426	245,639	77.5	82.5	84.5	9,914	COAL	100,861	24,144,925	2,435,281.3	4,743,719	1.93	47.03
16.	B.B.#3	433	208,378	64.7	79.7	74.8	10,006	COAL	85,899	24,272,727	2,085,003.0	4,040,023	1.94	47.03
17.	B.B. 1 - 3	1,285	676,360	70.7	80.8	26.7	10,015	COAL	279,402	24,244,203	6,773,878.7	13,140,903	1.94	47.03
18.	B.B.#4	447	70,136	21.1	31.2	79.6	10,028	COAL	31,573	22,276,581	703,338.5	1,793,008	2.56	56.79
19.	**B.B. STA.**	**1,732**	**746,496**	**57.9**	**68.0**	**19.9**	**10,016**	**COAL**	**310,975**	**24,044,432**	**7,477,217.2**	**14,933,911**	**2.00**	**48.02**
20.	PHILLIPS #1 (HVY OIL)	17	5,647	44.6	91.0	93.3	9,327	HVY OIL	8,387	6,279,957	52,670.0	215,604	3.82	25.71
21.	PHILLIPS #2 (HVY OIL)	17	5,552	43.9	91.0	93.8	9,327	HVY OIL	8,248	6,278,371	51,784.0	212,031	3.82	25.71
22.	**SEB-PHILLIPS TOTAL**	**34**	**11,199**	**44.3**	**91.0**	**46.8**	**9,327**	**HVY OIL**	**16,635**	**6,279,170**	**104,454.0**	**427,635**	**3.82**	**25.71**
23.	POLK #1 GASIFIER	250	131,626	70.8	-	-	10,235	COAL	53,700	25,087,844	1,347,217.2	2,471,404	1.88	46.02
24.	POLK #1 CT OIL	250	9,907	5.3	-	-	8,125	LGT OIL	14,800	5,438,601	80,491.3	435,131	4.39	29.40
25.	**POLK #1 TOTAL**	**250**	**141,533**	**76.1**	**84.5**	**98.3**	**10,087**		**-**	**-**	**1,427,708.5**	**2,906,535**	**2.05**	**-**
26.	POLK #2 CT GAS	180	25,384	19.0	-	-	10,545	GAS	260,400	1,027,888	267,662.0	1,461,521	5.76	5.61
27.	POLK #2 CT OIL	180	0	0.0	-	-	0	LGT OIL	0	0	0.0	0	0.00	0.00
28.	**POLK #2 TOTAL**	**180**	**25,384**	**19.0**	**83.5**	**77.1**	**10,545**		**-**	**-**	**267,662.0**	**1,461,521**	**5.76**	**-**
29.	**POLK #3 GAS**	**180**	**15391**	**11.5**	**69.9**	**75.0**	**10,580**	**GAS**	**158,400**	**1,028,037**	**162,841.0**	**889,036**	**5.78**	**5.61**
30.	**CITY OF TAMPA GAS**	**6**	**613**	**13.7**	**100.0**	**95.5**	**9,600**	**GAS**	**5,724**	**1,028,127**	**5,885.0**	**29,053**	**4.74**	**5.08**
31.	GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32.	B.B.C.T.#1	17	370	2.9	64.9	94.6	18,054	LGT OIL	1,152	5,798,611	6,680.0	34,374	9.29	29.84
33.	B.B.C.T.#2	80	2,535	4.3	69.1	88.0	15,645	LGT OIL	6,843	5,795,850	39,661.0	204,184	8.05	29.84
34.	B.B.C.T.#3	80	2,070	3.5	69.1	86.3	15,652	LGT OIL	5,590	5,795,886	32,399.0	166,796	8.06	29.84
35.	**C.T. TOTAL (OIL)**	**177**	**4,975**	**3.8**	**68.7**	**31.6**	**15,827**	**LGT OIL**	**13,585**	**5,796,099**	**78,740.0**	**405,354**	**8.15**	**29.84**
36.	**TOT COAL (GN,BB,POLK)**	**3,127**	**1,257,922**	**54.1**	**60.0**	**8.4**	**10,403**	**COAL**	**553,670**	**23,634,230**	**13,085,564.1**	**25,108,360**	**2.00**	**45.35**
37.	**SYSTEM**	**3,704**	**1,325,391**	**48.1**	**68.1**	**6.2**	**10,401**	**-**	**-**	**-**	**13,785,637.4**	**28,756,090**	**2.17**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
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SEB-PHIL = SEBRING-PHILLIPS

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	8,696	9,353	13,760	7,097	8,436	18,613
3. UNIT COST ($/BBL)	31.61	31.47	29.64	29.44	29.06	26.69
4. AMOUNT ($)	274,865	294,382	407,901	208,939	245,182	496,788
5. BURNED:						
6. UNITS (BBL)	8,696	9,353	13,760	7,097	8,436	18,613
7. UNIT COST ($/BBL)	30.74	31.43	30.81	30.50	30.38	28.35
8. AMOUNT ($)	267,340	293,929	423,881	216,472	256,278	527,624
9. ENDING INVENTORY:						
10. UNITS (BBL)	59,129	59,129	59,129	59,129	59,129	59,129
11. UNIT COST ($/BBL)	26.59	26.74	26.64	26.60	26.54	26.20
12. AMOUNT ($)	1,572,062	1,580,955	1,575,440	1,572,786	1,569,132	1,549,169
13. DAYS SUPPLY:	176	180	159	110	87	77
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	40,288	36,178	49,891	50,460	32,085	68,218
16. UNIT COST ($/BBL)	35.65	34.98	33.73	32.38	31.17	30.29
17. AMOUNT ($)	1,436,371	1,265,671	1,682,764	1,633,774	1,000,107	2,066,664
18. BURNED:						
19. UNITS (BBL)	28,598	29,183	42,088	41,776	21,042	57,069
20. UNIT COST ($/BBL)	34.94	34.74	34.26	33.67	33.41	32.02
21. AMOUNT ($)	999,295	1,013,913	1,441,938	1,406,581	702,939	1,827,418
22. ENDING INVENTORY:						
23. UNITS (BBL)	113,465	113,465	113,465	113,465	113,465	113,465
24. UNIT COST ($/BBL)	34.47	34.57	34.35	33.79	33.21	32.20
25. AMOUNT ($)	3,910,931	3,922,736	3,897,476	3,834,382	3,768,008	3,653,645
26. DAYS SUPPLY: NORMAL	75	76	69	56	46	50
27. DAYS SUPPLY: EMERGENCY	16	16	16	16	16	16
COAL						
28. PURCHASES:						
29. UNITS (TONS)	608,000	790,000	712,000	494,000	608,000	663,000
30. UNIT COST ($/TON)	46.51	47.05	46.56	46.55	47.12	45.88
31. AMOUNT ($)	28,281,027	37,172,730	33,147,962	22,993,885	28,650,809	30,419,414
32. BURNED:						
33. UNITS (TONS)	643,239	547,442	529,065	498,208	617,782	661,694
34. UNIT COST ($/TON)	45.84	46.34	46.94	47.26	47.06	46.88
35. AMOUNT ($)	29,484,272	25,370,267	24,835,472	23,547,417	29,073,710	31,017,189
36. ENDING INVENTORY:						
37. UNITS (TONS)	941,581	1,184,139	1,367,074	1,362,866	1,353,084	1,354,390
38. UNIT COST ($/TON)	45.65	46.58	46.71	46.76	47.15	47.02
39. AMOUNT ($)	42,979,973	55,152,409	63,859,797	63,730,263	63,801,273	63,684,908
40. DAYS SUPPLY:	54	64	71	63	61	61
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	165,088	110,200	299,642	461,959	557,896	911,496
43. UNIT COST ($/MCF)	4.89	4.27	4.26	5.26	5.43	5.42
44. AMOUNT ($)	807,564	470,059	1,276,948	2,431,829	3,027,461	4,944,497
45. BURNED:						
46. UNITS (MCF)	165,088	110,200	299,642	461,959	557,896	911,496
47. UNIT COST ($/MCF)	4.89	4.27	4.26	5.26	5.43	5.42
48. AMOUNT ($)	807,564	470,059	1,276,948	2,431,829	3,027,462	4,944,498
49. ENDING INVENTORY:						
50. UNITS (MCF)	0	0	0	0	0	0
51. UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00
52. AMOUNT ($)	0	0	0	0	0	0
53. DAYS SUPPLY:	0	0	0	0	0	0
NUCLEAR						
54. BURNED:						
55. UNITS (MMBTU)	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0
OTHER						
58. PURCHASES:						
59. UNITS (MMBTU)	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0
62. BURNED:						
63. UNITS (MMBTU)	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0
66. ENDING INVENTORY:						
67. UNITS (MMBTU)	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	TOTAL
HEAVY OIL							
1. PURCHASES:							
2. UNITS (BBL)	21,819	22,293	26,509	22,427	20,632	16,635	196,270
3. UNIT COST ($/BBL)	24.80	23.57	23.94	24.51	25.49	25.25	26.11
4. AMOUNT ($)	541,216	525,359	634,610	549,699	525,934	420,015	5,124,890
5. BURNED:							
6. UNITS (BBL)	21,819	22,293	26,509	22,427	20,632	16,635	196,270
7. UNIT COST ($/BBL)	26.30	24.79	24.40	24.79	25.50	25.71	26.84
8. AMOUNT ($)	573,919	552,745	646,831	555,932	526,204	427,635	5,268,790
9. ENDING INVENTORY:							
10. UNITS (BBL)	59,129	59,129	59,129	59,129	59,129	59,129	59,129
11. UNIT COST ($/BBL)	25.82	25.53	25.48	25.54	25.68	25.70	25.70
12. AMOUNT ($)	1,526,876	1,509,715	1,506,533	1,509,965	1,518,342	1,519,455	1,519,455
13. DAYS SUPPLY:	76	78	90	114	153	185	-
LIGHT OIL							
14. PURCHASES:							
15. UNITS (BBL)	82,857	74,826	50,040	47,073	50,908	37,907	620,731
16. UNIT COST ($/BBL)	29.96	29.74	29.76	29.81	27.86	29.92	30.99
17. AMOUNT ($)	2,482,034	2,225,614	1,489,266	1,403,045	1,418,451	1,134,124	19,237,885
18. BURNED:							
19. UNITS (BBL)	71,673	63,660	41,680	39,487	42,836	28,385	507,477
20. UNIT COST ($/BBL)	31.11	30.61	30.50	30.34	29.62	29.61	31.82
21. AMOUNT ($)	2,229,445	1,948,408	1,271,047	1,198,203	1,268,822	840,485	16,148,494
22. ENDING INVENTORY:							
23. UNITS (BBL)	113,465	113,465	113,465	113,465	113,465	113,465	113,465
24. UNIT COST ($/BBL)	31.39	30.86	30.57	30.37	29.57	29.66	29.66
25. AMOUNT ($)	3,562,022	3,501,356	3,468,454	3,446,370	3,355,123	3,364,854	3,364,854
26. DAYS SUPPLY: NORMAL	61	70	76	86	100	103	-
27. DAYS SUPPLY: EMERGENCY	16	16	16	16	16	16	-
COAL							
28. PURCHASES:							
29. UNITS (TONS)	699,000	673,000	595,000	556,000	374,000	556,000	7,328,000
30. UNIT COST ($/TON)	46.79	46.02	45.81	46.25	46.64	44.50	46.33
31. AMOUNT ($)	32,708,149	30,974,557	27,258,458	25,713,635	17,443,569	24,740,420	339,502,615
32. BURNED:							
33. UNITS (TONS)	687,447	690,810	653,677	524,300	443,555	553,670	7,050,889
34. UNIT COST ($/TON)	47.14	47.00	46.58	47.43	47.71	45.35	46.77
35. AMOUNT ($)	32,403,497	32,468,563	30,451,240	24,868,198	21,163,653	25,108,360	329,791,838
36. ENDING INVENTORY:							
37. UNITS (TONS)	1,365,943	1,348,133	1,289,456	1,321,156	1,251,601	1,253,931	1,253,931
38. UNIT COST ($/TON)	47.19	47.05	47.01	46.79	46.72	46.67	46.67
39. AMOUNT ($)	64,459,162	63,431,592	60,620,653	61,823,236	58,476,329	58,525,510	58,525,510
40. DAYS SUPPLY:	67	76	77	75	66	65	-
NATURAL GAS							
41. PURCHASES:							
42. UNITS (MCF)	940,096	933,059	1,197,386	979,057	747,035	424,524	7,727,438
43. UNIT COST ($/MCF)	5.45	5.48	5.48	5.35	5.48	5.61	5.37
44. AMOUNT ($)	5,126,654	5,115,084	6,565,431	5,238,606	4,095,587	2,379,610	41,479,331
45. BURNED:							
46. UNITS (MCF)	940,096	933,059	1,197,386	979,057	747,035	424,524	7,727,438
47. UNIT COST ($/MCF)	5.45	5.48	5.48	5.35	5.48	5.61	5.37
48. AMOUNT ($)	5,126,654	5,115,084	6,565,432	5,238,606	4,095,587	2,379,610	41,479,333
49. ENDING INVENTORY:							
50. UNITS (MCF)	0	0	0	0	0	0	0
51. UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52. AMOUNT ($)	0	0	0	0	0	0	0
53. DAYS SUPPLY:	0	0	0	0	0	0	-
NUCLEAR							
54. BURNED:							
55. UNITS (MMBTU)	0	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0	0
OTHER							
58. PURCHASES:							
59. UNITS (MMBTU)	0	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0	0
62. BURNED:							
63. UNITS (MMBTU)	0	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0	0
66. ENDING INVENTORY:							
67. UNITS (MMBTU)	0	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0	-

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

POWER SOLD
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

(1)	(2)	(3)		(4)	(5)	(6)	(7)		(8)	(9)
MONTH	SOLD TO	TYPE & SCHEDULE		TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)	TOTAL COST $ (6)X(7B)
Jan-02										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	6,206.0	0.0	6,206.0	1.510	1.510	93,700.0	93,700.00
	HPP	SEPARATED	CONTRACT	53,940.0	0.0	53,940.0	2.405	3.453	1,297,000.0	1,862,300.00
	VARIOUS	JURISD.	MKT. BASE	15,027.0	0.0	15,027.0	2.104	2.104	316,100.0	316,100.00
	VARIOUS	GAINS							135,800.0	
	TOTAL			75,173.0	0.0	75,173.0	2.451	3.022	1,842,600.00	2,272,100.00
Feb-02										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	6,118.0	0.0	6,118.0	1.484	1.484	90,800.0	90,800.00
	HPP	SEPARATED	CONTRACT	48,720.0	0.0	48,720.0	2.506	3.554	1,221,000.0	1,731,600.00
	VARIOUS	JURISD.	MKT. BASE	16,375.0	0.0	16,375.0	2.078	2.078	340,300.0	340,300.00
	VARIOUS	GAINS							151,800.0	
	TOTAL			71,213.0	0.0	71,213.0	2.533	3.037	1,803,900.00	2,162,700.00
Mar-02										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	6,205.0	0.0	6,205.0	1.510	1.510	93,700.0	93,700.00
	HPP	SEPARATED	CONTRACT	64,728.0	0.0	64,728.0	2.539	3.587	1,643,200.0	2,321,600.00
	VARIOUS	JURISD.	MKT. BASE	25,086.0	0.0	25,086.0	3.081	3.081	772,900.0	772,900.00
	VARIOUS	GAINS							433,500.0	
	TOTAL			96,019.0	0.0	96,019.0	3.065	3.320	2,943,300.00	3,188,200.00
Apr-02										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	5,884.0	0.0	5,884.0	1.411	1.411	83,000.0	83,000.00
	HPP	SEPARATED	CONTRACT	62,640.0	0.0	62,640.0	2.552	3.600	1,598,700.0	2,255,200.00
	VARIOUS	JURISD.	MKT. BASE	10,926.0	0.0	10,926.0	2.083	2.083	227,600.0	227,600.00
	VARIOUS	GAINS							169,800.0	
	TOTAL			79,450.0	0.0	79,450.0	2.617	3.229	2,079,100.00	2,565,800.00
May-02										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	6,055.0	0.0	6,055.0	1.465	1.465	88,700.0	88,700.00
	HPP	SEPARATED	CONTRACT	37,758.0	0.0	37,758.0	2.597	3.645	980,400.0	1,376,100.00
	VARIOUS	JURISD.	MKT. BASE	23,257.0	0.0	23,257.0	2.186	2.186	508,300.0	508,300.00
	VARIOUS	GAINS							248,700.0	
	TOTAL			67,070.0	0.0	67,070.0	2.723	2.942	1,826,100.00	1,973,100.00
Jun-02										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	6,176.0	0.0	6,176.0	1.501	1.501	92,700.0	92,700.00
	HPP	SEPARATED	CONTRACT	36,540.0	0.0	36,540.0	2.612	3.660	954,500.0	1,337,400.00
	VARIOUS	JURISD.	MKT. BASE	25,608.0	0.0	25,608.0	2.316	2.316	593,200.0	593,200.00
	VARIOUS	GAINS							463,400.0	
	TOTAL			68,324.0	0.0	68,324.0	3.079	2.961	2,103,800.00	2,023,300.00

POWER SOLD
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

(1)	(2)	(3)		(4)	(5)	(6)	(7)		(8)	(9)
							CENTS/KWH			
MONTH	SOLD TO	TYPE & SCHEDULE		TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)	TOTAL COST $ (6)X(7B)
Jul-02										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	6,054.0	0.0	6,054.0	1.465	1.465	88,700.0	88,700.00
	HPP	SEPARATED	CONTRACT	37,758.0	0.0	37,758.0	2.641	3.690	997,300.0	1,393,100.00
	VARIOUS	JURISD.	MKT. BASE	22,659.0	0.0	22,659.0	2.618	2.618	593,200.0	593,200.00
	VARIOUS	GAINS							552,700.0	
	TOTAL			66,471.0	0.0	66,471.0	3.358	3.122	2,231,900.00	2,075,000.00
Aug-02										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	6,055.0	0.0	6,055.0	1.465	1.465	88,700.0	88,700.00
	HPP	SEPARATED	CONTRACT	37,758.0	0.0	37,758.0	2.645	3.693	998,700.0	1,394,400.00
	VARIOUS	JURISD.	MKT. BASE	28,347.0	0.0	28,347.0	2.588	2.588	733,700.0	733,700.00
	VARIOUS	GAINS							542,100.0	
	TOTAL			72,160.0	0.0	72,160.0	3.275	3.072	2,363,200.00	2,216,800.00
Sep-02										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	6,030.0	0.0	6,030.0	1.458	1.458	87,900.0	87,900.00
	HPP	SEPARATED	CONTRACT	26,100.0	0.0	26,100.0	2.631	3.679	686,800.0	960,300.00
	VARIOUS	JURISD.	MKT. BASE	13,234.0	0.0	13,234.0	2.070	2.070	274,000.0	274,000.00
	VARIOUS	GAINS							135,100.0	
	TOTAL			45,364.0	0.0	45,364.0	2.610	2.915	1,183,800.00	1,322,200.00
Oct-02										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	6,054.0	0.0	6,054.0	1.465	1.465	88,700.0	88,700.00
	HPP	SEPARATED	CONTRACT	53,940.0	0.0	53,940.0	2.592	3.640	1,398,200.0	1,963,500.00
	VARIOUS	JURISD.	MKT. BASE	7,184.0	0.0	7,184.0	2.105	2.105	151,200.0	151,200.00
	VARIOUS	GAINS							61,300.0	
	TOTAL			67,178.0	0.0	67,178.0	2.530	3.280	1,699,400.00	2,203,400.00
Nov-02										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	5,972.0	0.0	5,972.0	1.438	1.438	85,900.0	85,900.00
	HPP	SEPARATED	CONTRACT	24,012.0	0.0	24,012.0	2.590	3.638	621,900.0	873,500.00
	VARIOUS	JURISD.	MKT. BASE	13,427.0	0.0	13,427.0	2.071	2.071	278,100.0	278,100.00
	VARIOUS	GAINS							115,500.0	
	TOTAL			43,411.0	0.0	43,411.0	2.537	2.851	1,101,400.00	1,237,500.00
Dec-02										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	5,995.0	0.0	5,995.0	1.446	1.446	86,700.0	86,700.00
	HPP	SEPARATED	CONTRACT	2,157.0	0.0	2,157.0	2.596	3.644	56,000.0	78,600.00
	VARIOUS	JURISD.	MKT. BASE	15,768.0	0.0	15,768.0	2.046	2.046	322,600.0	322,600.00
	VARIOUS	GAINS							140,800.0	
	TOTAL			23,920.0	0.0	23,920.0	2.534	2.040	606,100.00	487,900.00
Jan-02	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
THRU	VARIOUS	JURISD.	SCH. -D	72,804.0	0.0	72,804.0	1.469	1.469	1,069,200.00	1,069,200.00
Dec-02	HPP	SEPARATED	CONTRACT	486,051.0	0.0	486,051.0	2.562	3.610	12,453,700.00	17,547,600.00
	VARIOUS	JURISD.	MKT. BASE	216,898.0	0.0	216,898.0	2.356	2.356	5,111,200.00	5,111,200.00
	VARIOUS	GAINS							3,150,500.00	
	TOTAL			775,753.0	0.0	775,753.0	2.808	3.059	21,784,600.00	23,728,000.00

PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (7)X(8A)
Jan-02									
	VARIOUS	SCH. J	2,664.0	0.0	1,772.0	892.0	5.807	5.807	51,800.0
	HPP	IPP	67,561.0	0.0	0.0	67,561.0	5.217	5.217	3,524,800.0
	VARIOUS	OTHER	24,494.0	0.0	0.0	24,494.0	6.700	6.700	1,641,100.0
	VARIOUS	MKT BASED	13,029.0	0.0	0.0	13,029.0	6.914	6.914	900,800.0
	TOTAL		**107,748.0**	**0.0**	**1,772.0**	**105,976.0**	**5.773**	**5.773**	**6,118,500.00**
Feb-02									
	VARIOUS	SCH. J	2,577.0	0.0	1,638.0	939.0	5.804	5.804	54,500.0
	HPP	IPP	57,292.0	0.0	0.0	57,292.0	5.222	5.222	2,991,900.0
	VARIOUS	OTHER	35,292.0	0.0	0.0	35,292.0	6.906	6.906	2,437,300.0
	VARIOUS	MKT BASED	75,557.0	0.0	0.0	75,557.0	4.847	4.847	3,662,100.0
	TOTAL		**170,718.0**	**0.0**	**1,638.0**	**169,080.0**	**5.409**	**5.409**	**9,145,800.00**
Mar-02									
	VARIOUS	SCH. J	7,249.0	0.0	4,339.0	2,910.0	5.808	5.808	169,000.0
	HPP	IPP	62,608.0	0.0	0.0	62,608.0	5.143	5.143	3,219,800.0
	VARIOUS	OTHER	55,705.0	0.0	0.0	55,705.0	5.862	5.862	3,265,200.0
	VARIOUS	MKT BASED	94,385.0	0.0	0.0	94,385.0	4.838	4.838	4,566,700.0
	TOTAL		**219,947.0**	**0.0**	**4,339.0**	**215,608.0**	**5.204**	**5.204**	**11,220,700.00**
Apr-02									
	VARIOUS	SCH. J	18,236.0	0.0	10,699.0	7,537.0	5.809	5.809	437,800.0
	HPP	IPP	59,240.0	0.0	0.0	59,240.0	4.777	4.777	2,829,800.0
	VARIOUS	OTHER	62,614.0	0.0	0.0	62,614.0	6.060	6.060	3,794,400.0
	VARIOUS	MKT BASED	150,109.0	0.0	0.0	150,109.0	5.213	5.213	7,825,000.0
	TOTAL		**290,199.0**	**0.0**	**10,699.0**	**279,500.0**	**5.326**	**5.326**	**14,887,000.00**
May-02									
	VARIOUS	SCH. J	8,539.0	0.0	5,055.0	3,484.0	5.809	5.809	202,400.0
	HPP	IPP	74,341.0	0.0	0.0	74,341.0	4.322	4.322	3,213,300.0
	VARIOUS	OTHER	24,800.0	0.0	0.0	24,800.0	4.950	4.950	1,227,600.0
	VARIOUS	MKT BASED	26,951.0	0.0	0.0	26,951.0	7.021	7.021	1,892,200.0
	TOTAL		**134,631.0**	**0.0**	**5,055.0**	**129,576.0**	**5.044**	**5.044**	**6,535,500.00**
Jun-02									
	VARIOUS	SCH. J	30,899.0	0.0	17,460.0	13,439.0	7.186	7.186	965,700.0
	HPP	IPP	113,091.0	0.0	0.0	113,091.0	4.409	4.409	4,986,300.0
	VARIOUS	OTHER	31,036.0	0.0	0.0	31,036.0	6.313	6.313	1,959,300.0
	VARIOUS	MKT BASED	71,495.0	0.0	0.0	71,495.0	6.995	6.995	5,001,100.0
	TOTAL		**246,521.0**	**0.0**	**17,460.0**	**229,061.0**	**5.637**	**5.637**	**12,912,400.00**

PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (7)X(8A)
Jul-02									
	VARIOUS	SCH. J	37,701.0	0.0	18,935.0	18,766.0	10.596	10.596	1,988,500.0
	HPP	IPP	119,924.0	0.0	0.0	119,924.0	4.477	4.477	5,368,900.0
	VARIOUS	OTHER	32,721.0	0.0	0.0	32,721.0	8.322	8.322	2,723,100.0
	VARIOUS	MKT BASED	71,319.0	0.0	0.0	71,319.0	7.888	7.888	5,625,800.0
	TOTAL		**261,665.0**	**0.0**	**18,935.0**	**242,730.0**	**6.471**	**6.471**	**15,706,300.00**
Aug-02									
	VARIOUS	SCH. J	34,885.0	0.0	17,673.0	17,212.0	9.685	9.685	1,667,000.0
	HPP	IPP	119,441.0	0.0	0.0	119,441.0	4.464	4.464	5,331,800.0
	VARIOUS	OTHER	33,722.0	0.0	0.0	33,722.0	8.264	8.264	2,786,700.0
	VARIOUS	MKT BASED	62,760.0	0.0	0.0	62,760.0	7.644	7.644	4,797,100.0
	TOTAL		**250,808.0**	**0.0**	**17,673.0**	**233,135.0**	**6.255**	**6.255**	**14,582,600.00**
Sep-02									
	VARIOUS	SCH. J	55,087.0	0.0	29,190.0	25,897.0	5.809	5.809	1,504,300.0
	HPP	IPP	131,535.0	0.0	0.0	131,535.0	4.477	4.477	5,888,300.0
	VARIOUS	OTHER	12,227.0	0.0	0.0	12,227.0	6.356	6.356	777,200.0
	VARIOUS	MKT BASED	118,656.0	0.0	0.0	118,656.0	6.144	6.144	7,290,100.0
	TOTAL		**317,505.0**	**0.0**	**29,190.0**	**288,315.0**	**5.362**	**5.362**	**15,459,900.00**
Oct-02									
	VARIOUS	SCH. J	58,850.0	0.0	32,210.0	26,640.0	5.809	5.809	1,547,500.0
	HPP	IPP	104,536.0	0.0	0.0	104,536.0	4.463	4.463	4,665,600.0
	VARIOUS	OTHER	39,602.0	0.0	0.0	39,602.0	4.037	4.037	1,598,900.0
	VARIOUS	MKT BASED	213,831.0	0.0	0.0	213,831.0	4.667	4.667	9,978,700.0
	TOTAL		**416,819.0**	**0.0**	**32,210.0**	**384,609.0**	**4.626**	**4.626**	**17,790,700.00**
Nov-02									
	VARIOUS	SCH. J	20,955.0	0.0	10,508.0	10,447.0	5.809	5.809	606,900.0
	HPP	IPP	62,004.0	0.0	0.0	62,004.0	4.727	4.727	2,931,200.0
	VARIOUS	OTHER	75,131.0	0.0	0.0	75,131.0	4.037	4.037	3,033,400.0
	VARIOUS	MKT BASED	196,442.0	0.0	0.0	196,442.0	3.932	3.932	7,724,500.0
	TOTAL		**354,532.0**	**0.0**	**10,508.0**	**344,024.0**	**4.156**	**4.156**	**14,296,000.00**
Dec-02									
	VARIOUS	SCH. J	3,308.0	0.0	2,039.0	1,269.0	5.808	5.808	73,700.0
	HPP	IPP	78,776.0	0.0	0.0	78,776.0	4.522	4.522	3,561,900.0
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.0
	VARIOUS	MKT BASED	22,567.0	0.0	0.0	22,567.0	4.775	4.775	1,077,600.0
	TOTAL		**104,651.0**	**0.0**	**2,039.0**	**102,612.0**	**4.593**	**4.593**	**4,713,200.00**
Jan-02	VARIOUS	SCH. J	280,950.0	0.0	151,518.0	129,432.0	7.161	7.161	9,269,100.00
THRU	HPP	IPP	1,050,349.0	0.0	0.0	1,050,349.0	4.619	4.619	48,513,600.00
Dec-02	VARIOUS	OTHER	427,344.0	0.0	0.0	427,344.0	5.907	5.907	25,244,200.00
	VARIOUS	MKT BASED	1,117,101.0	0.0	0.0	1,117,101.0	5.402	5.402	60,341,700.00
	TOTAL		**2,875,744.0**	**0.0**	**151,518.0**	**2,724,226.0**	**5.263**	**5.263**	**143,368,600.00**

ENERGY PAYMENT TO QUALIFYING FACILITIES SCHEDULE E8
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (7)X(8A)
Jan-02	VARIOUS	CO-GEN.	39,069.0	0.0	0.0	39,069.0	2.175	2.175	849,700.00
Feb-02	VARIOUS	CO-GEN.	34,868.0	0.0	0.0	34,868.0	2.013	2.013	701,900.00
Mar-02	VARIOUS	CO-GEN.	39,069.0	0.0	0.0	39,069.0	2.061	2.061	805,100.00
Apr-02	VARIOUS	CO-GEN.	39,704.0	0.0	0.0	39,704.0	2.145	2.145	851,500.00
May-02	VARIOUS	CO-GEN.	41,027.0	0.0	0.0	41,027.0	2.292	2.292	940,200.00
Jun-02	VARIOUS	CO-GEN.	39,704.0	0.0	0.0	39,704.0	2.463	2.463	977,900.00
Jul-02	VARIOUS	CO-GEN.	41,027.0	0.0	0.0	41,027.0	2.505	2.505	1,027,800.00
Aug-02	VARIOUS	CO-GEN.	41,027.0	0.0	0.0	41,027.0	2.500	2.500	1,025,700.00
Sep-02	VARIOUS	CO-GEN.	39,704.0	0.0	0.0	39,704.0	2.483	2.483	986,000.00
Oct-02	VARIOUS	CO-GEN.	41,027.0	0.0	0.0	41,027.0	2.441	2.441	1,001,500.00
Nov-02	VARIOUS	CO-GEN.	37,809.0	0.0	0.0	37,809.0	2.148	2.148	812,100.00
Dec-02	VARIOUS	CO-GEN.	39,069.0	0.0	0.0	39,069.0	2.005	2.005	783,300.00
TOTAL			**473,104.0**	**0.0**	**0.0**	**473,104.0**	**2.275**	**2.275**	**10,762,700.00**

SCHEDULE E9

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
						COST IF GENERATED		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT (4)X(5)	(A) CENTS PER KWH	(B) ($000)	FUEL SAVINGS (7B)-(6)
Jan-02	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Feb-02	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Mar-02	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Apr-02	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
May-02	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Jun-02	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Jul-02	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Aug-02	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Sep-02	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Oct-02	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Nov-02	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Dec-02	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL			**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**

SCHEDULE E10

RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1000 KWH
TAMPA ELECTRIC COMPANY

ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	TOTAL
Base Rate Revenue	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92
Fuel Recovery Revenue	33.13	33.13	33.13	33.13	33.13	33.13	33.13	33.13	33.13	33.13	33.13	33.13	33.13
Conservation Revenue *	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14
Capacity Revenue	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79
Environmental Revenue	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59
Revenue Refund	(1.59)	(1.59)	(1.59)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.40)
Florida Gross Receipts Tax Revenue	2.31	2.31	2.31	2.35	2.35	2.35	2.35	2.35	2.35	2.35	2.35	2.35	2.34
TOTAL REVENUE	**$ 92.29**	**$ 92.29**	**$ 92.29**	**$ 93.92**	**$ 93.92**	**$ 93.92**	**$ 93.92**	**$ 93.92**	**$ 93.92**	**$ 93.92**	**$ 93.92**	**$ 93.92**	**$ 93.51**

*** Reflects current conservation factors for 2001. Factors for 2002 will be filed on October 5, 2001.**

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY

SCHEDULE H1

PERIOD: JANUARY THROUGH DECEMBER

	ACTUAL 1999	ACTUAL 2000	ACT/EST 2001	EST 2002	DIFFERENCE (%) 2000-1999	2001-2000	2002-2001
FUEL COST OF SYSTEM NET GENERATION ($)							
1 HEAVY OIL [1]	8,023,069	13,177,783	4,576,567	5,268,790	64.2%	-65.3%	15.1%
2 LIGHT OIL [1]	9,521,504	18,731,595	15,687,603	16,148,494	96.7%	-16.3%	2.9%
3 COAL	314,787,487	324,328,956	331,725,269	329,791,838	3.0%	2.3%	-0.6%
4 NATURAL GAS	0	8,529,409	18,669,389	41,479,333	0.0%	118.9%	122.2%
5 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6 OTHER	0	0	0	0	0.0%	0.0%	0.0%
7 TOTAL ($)	**332,332,060**	**364,767,743**	**370,658,828**	**392,688,455**	**9.8%**	**1.6%**	**5.9%**
SYSTEM NET GENERATION (MWH)							
8 HEAVY OIL [1]	206,534	224,919	107,091	131,838	8.9%	-52.4%	23.1%
9 LIGHT OIL [1]	249,154	243,391	218,654	241,140	-2.3%	-10.2%	10.3%
10 COAL	15,379,323	16,679,276	16,076,801	15,848,013	8.5%	-3.6%	-1.4%
11 NATURAL GAS	0	135,455	326,840	758,310	0.0%	141.1%	132.2%
12 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
13 OTHER	0	0	0	0	0.0%	0.0%	0.0%
14 TOTAL (MWH)	**15,835,011**	**17,283,041**	**16,729,186**	**16,979,301**	**9.1%**	**-3.2%**	**1.5%**
UNITS OF FUEL BURNED							
15 HEAVY OIL (BBL) [1]	506,617	504,288	165,814	196,270	-0.5%	-67.1%	18.4%
16 LIGHT OIL (BBL) [1]	457,077	502,319	443,857	507,477	9.9%	-11.6%	14.3%
17 COAL (TON)	7,319,377	7,550,403	7,233,950	7,050,889	3.2%	-4.2%	-2.5%
18 NATURAL GAS (MCF)	0	1,592,351	3,565,437	7,727,438	0.0%	123.9%	116.7%
19 NUCLEAR (MMBTU)	0	0	0	0	0.0%	0.0%	0.0%
20 OTHER	0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)							
21 HEAVY OIL [1]	3,207,490	3,196,842	1,040,146	1,232,378	-0.3%	-67.5%	18.5%
22 LIGHT OIL [1]	2,657,999	2,899,482	2,889,826	2,882,291	9.1%	-0.3%	-0.3%
23 COAL	163,641,112	173,986,540	169,407,480	165,442,088	6.3%	-2.6%	-2.3%
24 NATURAL GAS	0	1,552,203	3,557,601	7,944,073	0.0%	129.2%	123.3%
25 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
26 OTHER	0	0	0	0.0	0.0%	0.0%	0.0%
27 TOTAL (MMBTU)	**169,506,601**	**181,635,067**	**176,895,052**	**177,500,830**	**7.2%**	**-2.6%**	**0.3%**
GENERATION MIX (% MWH)							
28 HEAVY OIL [1]	1.30	1.30	0.64	0.78	-	-	-
29 LIGHT OIL [1]	1.57	1.41	1.31	1.42	-	-	-
30 COAL	97.13	96.51	96.10	93.33	-	-	-
31 NATURAL GAS	0.00	0.78	1.95	4.47	-	-	-
32 NUCLEAR	0.00	0.00	0.00	0.00	-	-	-
33 OTHER	0.00	0.00	0.00	0.00	-	-	-
34 TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	-	-	-
FUEL COST PER UNIT							
35 HEAVY OIL ($/BBL) [1]	15.84	26.13	27.60	26.84	65.0%	5.6%	-2.8%
36 LIGHT OIL ($/BBL) [1]	20.83	37.29	35.34	31.82	79.0%	-5.2%	-10.0%
37 COAL ($/TON)	43.01	42.96	45.86	46.77	-0.1%	6.8%	2.0%
38 NATURAL GAS ($/MCF)	0.00	5.36	5.24	5.37	0.0%	-2.2%	2.5%
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
40 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
FUEL COST PER MMBTU ($/MMBTU)							
41 HEAVY OIL [1]	2.50	4.12	4.40	4.28	64.8%	6.8%	-2.7%
42 LIGHT OIL [1]	3.58	6.46	5.43	5.60	80.4%	-15.9%	3.1%
43 COAL	1.92	1.86	1.96	1.99	-3.1%	5.4%	1.5%
44 NATURAL GAS	0.00	5.50	5.25	5.22	0.0%	-4.5%	-0.6%
45 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
46 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
47 TOTAL ($/MMBTU)	**1.96**	**2.01**	**2.10**	**2.21**	**2.6%**	**4.5%**	**5.2%**
BTU BURNED PER KWH (BTU/KWH)							
48 HEAVY OIL [1]	15,530	14,213	9,713	9,348	-8.5%	-31.7%	-3.8%
49 LIGHT OIL [1]	10,668	11,913	13,216	11,953	11.7%	10.9%	-9.6%
50 COAL	10,640	10,431	10,537	10,439	-2.0%	1.0%	-0.9%
51 NATURAL GAS	0	11,459	10,892	10,476	0.0%	-4.9%	-3.8%
52 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
53 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
54 TOTAL (BTU/KWH)	10,705	10,509	10,574	10,454	-1.8%	0.6%	-1.1%
GENERATED FUEL COST PER KWH (cents/KWH)							
55 HEAVY OIL [1]	3.88	5.86	4.27	4.00	51.0%	-27.1%	-6.3%
56 LIGHT OIL [1]	3.82	7.70	7.17	6.70	101.6%	-6.9%	-6.6%
57 COAL	2.05	1.94	2.06	2.08	-5.4%	6.2%	1.0%
58 NATURAL GAS	0.00	6.30	5.72	5.47	0.0%	-9.2%	-4.4%
59 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
60 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61 TOTAL (cents/KWH)	2.10	2.11	2.22	2.31	0.5%	5.2%	4.1%

[1] DISTILLATE (BBLS, MWH & $) USED FOR FIRING, HOT STANDBY, ETC. IS INCLUDED IN FOSSIL STEAM PLANTS.

TAMPA ELECTRIC COMPANY
DOCKET NO. 010001-EI
FILED: 9/20/01

EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 3

DEFERRED REVENUE PLAN

EXHIBIT NO. _____
DOCKET NO. 000001-EI
TAMPA ELECTRIC COMPANY
(JDJ-3)
DOCUMENT NO. 3

Tampa Electric Company
$6.37 Million Earnings Refund for 1999

January 2002 through March 2002

	Beginning Balance ($)	Projected Retail Sales (MWH)	Projected Revenue ($)	Ending Balance ($)
January 2002	$6,366,000	1,442,504	2,279,513	4,086,487
February 2002	4,086,487	1,304,241	2,061,024	2,025,462
March 2002	2,025,462	1,281,737	2,025,462	-
TOTAL		**4,028,482**	**$ 6,366,000**	
		Levelized Factor:	**0.158**	**cents/kWh**

Refund Credit Adjusted for Line Loss Variations				
Group	Rate Schedule	Average Refund (cents/kWh)	Line Loss Factor	Group Rate (cents/kWh)
A	RS, GS, TS	0.158	1.0035	0.159
A1	SL, OL	0.158	1.0035	0.159
B	GSD, GSLD, SBF	0.158	1.0009	0.158
C	IS, SBI	0.158	0.9792	0.155

TAMPA ELECTRIC COMPANY
DOCKET NO. 010001-EI
FILED: 9/20/01

EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 4

PROPOSED 2002 COST RECOVERY FACTORS
RESIDENTIAL BILL COMPOSITE EFFECT

EXHIBIT NO. _____
DOCKET NO. 000001-EI
TAMPA ELECTRIC COMPANY
(JDJ-3)
DOCUMENT NO. 4

RESIDENTIAL BILL COMPARISON

1,000 kWh MONTHLY USAGE

Bill Component	January 2002 through March 2002	April 2002 through December 2002	April 2001 through December 2001
Customer Charge	$8.50	$8.50	$8.50
Energy Charge	43.42	43.42	43.42
Fuel	33.13	33.13	28.30
Capacity	3.79	3.79	2.56
Energy Conservation[1]	1.14	1.14	1.14
Environmental	1.59	1.59	1.65
Deferred Earnings	(1.59)	0.00	0.00
Subtotal	**$89.98**	**$91.57**	**$85.57**
Gross Receipts Tax	2.31	2.35	2.19
TOTAL	**$92.29**	**$93.92**	**$87.76**

(1) The projected 2002 Energy Conservation factor was not available at time of filing. The factor shown is the current 2001 factor. Conservation will be filed on October 5, 2001 in Docket No. 010002-EI.

EXHIBIT NO. _____

DOCKET NO: 010001-EI

COMPANY: Tampa Electric Company

WITNESSES: J. Denise Jordan
W. Lynn Brown
Mark J. Hornick

DESCRIPTION: COMPOSITE EXHIBIT:

1) Transcript of W. Lynn Brown's deposition taken on October 25, 2001;
2) Late-filed exhibits of W. Lynn Brown's deposition taken on October 25, 2001; numbers 2 through 7;
3) Prepared direct and rebuttal testimony of W. Lynn Brown in Docket No. 990001-EI;
4) TECO's responses to staff's second set of interrogatories in Docket No. 010001-EI, numbers 2, 3, 4, 5, 6 and 8; (redacted copies of interrogatories 5 and 6)
5) TECO's responses to staff's fourth set of interrogatories in Docket No. 010001-EI, Numbers 149, 150, 155, 156 and 157; (redacted copies of interrogatories 149 and 150)
6) Transcript of J. Denise Jordan's deposition taken on October 25, 2001;
7) Late-filed exhibits of J. Denise Jordan's deposition taken on October 25, 2001;
8) Transcript of Mark J. Hornick's deposition taken on October 26, 2001

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 4
COMPANY/ WITNESS. Staff
DATE: 11-20-01

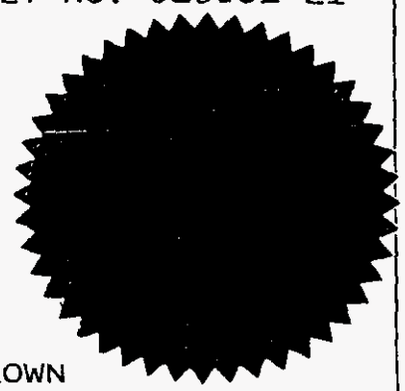
BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of

DOCKET NO. 010001-EI

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE AND GENERATING PERFORMANCE INCENTIVE FACTOR.

_____/



DEPOSITION OF:	W. LYNN BROWN
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
DATE:	Thursday, October 25, 2001
TIME:	Commenced at 1:00 p.m. Concluded at 5:20 p.m.
LOCATION:	Gerald L. Gunter Building Room 362 2540 Shumard Oak Boulevard Tallahassee, Florida
REPORTED BY:	MARY ALLEN NEEL, RPR Notary Public, State of Florida at Large

ACCURATE STENOTYPE REPORTERS, INC.
100 SALEM COURT
TALLAHASSEE, FLORIDA 32301
(850) 878-2221

BUREAU OF REPORTING
RECEIVED 11-1-01

APPEARANCES:

JAMES D. BEASLEY, Ausley & McMullen, 217 South Calhoun Street, Tallahassee, Florida 32301, appearing on behalf of Tampa Electric Company.

JOHN McWHIRTER, McWhirter Reeves Law Firm, P.O. Box 3350, Tampa, Florida 33601-3350, appearing on behalf of the Florida Industrial Power Users Group.

ROBERT VANDIVER, Deputy Public Counsel, Office of Public Counsel, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

MARLENE STERN, Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0870, appearing on behalf of the Commission Staff.

ALSO PRESENT:

LESLIE J. PAUGH, Landers & Parsons, 310 West College Avenue, 32301, Tallahassee, Florida 32301, on behalf of Johnson Controls.

J. DENISE JORDAN, Tampa Electric Company.

TODD BOHRMAN, MATTHEW BRINKLEY, ELISABETH DRAPER, ROLAND FLOYD, JUDY HARLOW, PETER LESTER, and WILLIAM McNULTY, Commission Staff.

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S T I P U L A T I O N S

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure; that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

PROCEEDINGS

MS. STERN: Shall we take appearances? I'm Marlene Stern on behalf of staff.

MR. BEASLEY: I'm Jim Beasley. I represent Tampa Electric Company.

MR. McWHIRTER: John McWhirter for the Florida Industrial Power Users Group.

MS. PAUGH: Leslie Paugh. I represent Johnson Controls. We have not yet intervened in this docket.

MR. VANDIVER: Rob Vandiver appearing on behalf of the citizens of the State of Florida.

Thereupon,

W. LYNN BROWN

the witness herein, having been first duly sworn on oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. STERN:

Q I'll just get started with some questions so hopefully we won't be here all afternoon.

Mr. Brown, do you have your testimony with you, your direct testimony in the docket?

A Yes.

Q Would you just turn to the first page and look at lines 21 through 24? Take your time.

A Okay.

Q I have a series of questions to ask you about those lines. Is it correct that you've been the Director of Wholesale Marketing and Sales since August 1998?

A That's correct.

Q And in that position, you were responsible for wholesale energy purchases and sales?

A That's correct.

Q Is it correct that if I ask a question about a decision Tampa Electric made regarding wholesale energy purchases or sales since August 1998, you would be the appropriate witness to respond to the question?

A Yes.

Q Is it correct that if I ask a question about a decision Tampa Electric had made regarding wholesale energy purchases or sales since August 1998, your response would be based on firsthand knowledge?

A Generally, yes. Understand, I have a number of people who work for me. We have a staff of about 13 people, and so it would be either work that I've done myself or one of my staff was involved with.

Q I see. But when it comes to decisions about purchasing or selling wholesale energy, do you

have final decision-making authority?

A Generally speaking.

Q All right. Who else is involved in the decision-making?

A It depends on the nature of the purchase or the sale, the terms of the purchase or the sale, the size of it. If it's a substantially large purchase or sale, then my boss, who is an officer of the company, will be involved, and perhaps his boss will be involved.

Q Could you tell me the names of those two people, please?

A My boss's name is Hugh Smith. He is Vice President of Trading and Services, and his boss is John Ramil, who is the president of Tampa Electric Company.

Q Thank you. Do you have knowledge of TECO's wholesale energy purchases and sales prior to 1998?

A Some.

Q And what's the basis of your knowledge?

A Well, I worked in the Wholesale Trading Group beginning April of '97 as Manager of Short-term Trading, and so naturally, I would have knowledge of all of the short-term activities from '97 up until now. As far as long-term is concerned, the longer

term trading is concerned, I was not responsible for that area until, as you asked me earlier, August of 1998.

Q Okay. Thank you. Would you turn, please, to page 6 of your direct testimony and take a look at line 19?

A Okay.

Q On line 19 you say the forwards market price was $86.31 per megawatt-hour for the period January through August 2001, indexed to December 200C is that correct?

A That's correct.

Q Would you please explain how you calculate that value?

A What we did is, we looked at the publishec forwards market for Entergy, for the Entergy Hub in December of 2000, and what I did is, I took an averag of the days of December that the hub was published in Megawatt Daily. The Megawatt Daily is a standard publication. It's a daily publication that provides pricing, both current pricing as well as forwards pricing in various hubs around the United States. Ar I took that average for the days of December, and that's how I determined the $86.31.

Q Are there other methodologies that could

have been used to determine the price per megawatt-hour other than the one you just described?

A There may be.

Q Are you aware of any other methodologies?

A I'm not aware of other methodologies. I am aware of other publications, but the pricing should be approximately the same.

Q Okay. Thank you. Is the Entergy Hub volume valid for the peninsular Florida market?

A We've watched the Entergy Hub for a couple of years now, and we've found that it is fairly close to Florida. Florida is actually a little bit above the Entergy Hub, and we simply know that because of our experience in actual purchases and sales. But we find that it's pretty close. It's not an exact match, though.

Q Thank you. Would you turn again to page 6 of your direct testimony and take a look at line 20 this time?

A Okay.

Q There you state that Tampa Electric's total purchased power cost in 2001, including capacity payments, is less than the forwards energy market; correct?

A Yes.

Q What is the basis of that statement?

A What I did is, if you'll look back at lin 17, I said that Tampa Electric paid an average of $57.36 per megawatt-hour for total energy purchases, and I compared that, of course, to the forwards market, which we just talked about, which was 86.31 for the same period, January through August of 2001. And what I did is, I took the 57.36 and added to tha the capacity payments that we have paid for that power.

Understand, the 57.36 per megawatt-hour represents the energy payments. And I simply added the capacity payments to that and found that the tot of those two is still under the forwards market of 86.31. Understand, the forwards market is not a capacity market. It's an energy market. It's an energy-only market. So even including the capacity payments, we were still under the forwards market.

Q Would you turn now, please, to page 7 you direct testimony and take a line look at line 14?

A Yes.

Q You state there that this year, HPP's energy price of $53.99 per megawatt-hour was below t $76.37 per megawatt-hour forwards market price as of December 2000.

A Right.

Q Okay. Was the $76.37 value calculated in the same fashion as the $86.31 value that you identified on page 6 of your testimony?

A Yes, it was. The only difference -- the reason that number is different than the number on page 6 is that I was looking at a different term. The term on page 6 is January through August of 2001, and the term on page 7, which corresponds to the $76.37 number, is January through July of 2001.

Q Okay. Thank you. Would you take a look at page 10, line 5, of your testimony, please?

A Okay.

Q Okay. You say there that the physical and financial hedges provide measurable market price volatility protection; however, they come for a price; is that correct?

A Yes.

Q Would you please discuss what the price is that you were referring to in that statement?

A What I was referring to, and I believe I mentioned that in my testimony, if I can find it --

Q Take your time.

A Well, in fact, in the very next sentence I say that the price can be quite high in a developing

market such as Florida's wholesale energy market, and that's essentially what I meant when I said they come with a price. Are we on the same line?

Q Yes, I see it.

A Okay.

Q Is there a difference in this price that you refer to for physical hedges as opposed to financial hedges?

A Well, the price of a hedge is dependent on the measure of protection that you are purchasing. And by protection I mean the measure of protection against price volatility. The more protection that you want against price volatility, the more expensive obviously, the hedge. And that's true whether you ar interested in a physical hedge or a financial hedge. That's a simple, I guess, formula, if you will.

Q Okay. Would you take a look in your testimony, please, at page 10, line 7? There you tal about how the price can be high in a developing market. Can you explain how risk and risk premiums affect price in a developing market such as Florida's?

A I'm not sure I understand your question.

Q Okay. The price can be quite high in a developing market such as Florida's developing wholesale energy market. Why is that? Could you

A I think the value of a premium, first of all, has to be determined I think in advance between the entity that's going to purchase that risk instrument, which in this case we're talking about utilities purchasing these risk instruments, and the Public Service Commission.

The Public Service Commission I would think would need to -- or at least the Public Service Commission staff would need to work with the utility in determining what is the value of purchasing a particular risk instrument. In other words, they would have to lay out -- it's all part of laying out a risk management strategy in advance.

I don't know if I'm really addressing the question totally, but --

Q Well, when you say that the utility and the Commission would have to work out a strategy for risk management, one element of that strategy for risk management would be risk avoidance, how you avoid risk or minimize risk for ratepayers; is that correct?

A That's right.

Q But to determine if the premium that's being paid for that risk avoidance -- how do you determine if that's a fair premium?

A You would shop the market for the

explain the basis for that statement?

A In a market where there is low liquidity and low public price information, the cost of hedging instruments is correspondingly high, because the seller of the hedging instrument will take on more risk than if there was high liquidity and a high level of price publication, public price information, that is.

Q Okay. So in a developing market like Florida's wholesale energy market, there's low liquidity?

A There's low liquidity and there's low public price information.

Q And that is associated with a higher risk?

A That's correct.

Q And so the risk premium would be higher as well?

A Yes, would be higher.

Q Okay. Thank you. Could you explain how one measures the value of risk avoidance for ratepayers to determine if a risk premium is fair?

A Repeat that, please.

Q I'm sorry. How does one measure the value of risk avoidance for ratepayers to determine if a risk premium is fair?

particular risk, risk management, either financial or physical financial risk management instrument that you're looking for, and you would simply get the best price or the best terms.

Q I see.

A And obviously, it would need to correspond to the risk management strategy that you and, of course, the Commission have agreed to to begin with.

Q Okay. Thank you. How much volatility is acceptable for Tampa Electric?

A I can only speak to the purchased power side. I can't speak to the fuel side.

Q Okay.

A But as far as purchased power is concerned, we don't have written policies as far as defining exactly what volatility is acceptable. We do have a strategy, however, a risk management strategy, whereby we enter into both long-term and short-term purchased power contracts which minimize our spot market risk, but at the same time give us some opportunity to take advantage of lower spot market prices.

Q Okay. Let's move a little bit down the page, a little bit further down the page. We're inching our way down page 10. Would you take a look at line 15, please?

A Yes.

Q Okay. Would you discuss what you mean by qualitative costs and benefits of physical and financial hedging?

A I think the qualitative would be -- a measure of that would be the measure of risk that the Commission and the utility would be willing to accep regarding purchased power prices, purchased power price volatility.

Q Okay. So -- I just want to make sure I understand you. Qualitative would be something base on an agreement or an understanding between the utility and the Public Service Commission. Would tha involve judgment?

A It would involve judgment. It would be t strategy. It would involve the strategy that you la out. Understand, there are many different types of risk. There's regulatory risk, there's technology risk, there's price risk, and so forth.

Some of those parts of the strategy can b quantified, but there are also qualitative issues, depending on what type of risk you want to take or h you're willing to take it. Often numbers cannot be applied to those, and that's the qualitative side tha I was talking about.

Q Could you give me some examples of what the qualitative issues would be?

A If you decide to build a power plant today as opposed to entering into a purchased power agreement, a quantitative risk assessment would be perhaps the cost of the fuel under the purchased power agreement versus what you could expect to buy fuel for if you build a power plant. But a qualitative risk assessment might be a determination of whether the technology that you use for that power plant will be outdated in a short period of time.

Q I see. Would possible fluctuations in the cost of wholesale energy be a -- is that a risk you can quantify, or is that a qualitative risk? Say you have a purchased power agreement that goes for five years, or let's say it goes for ten years, versus building a power plant. If you have a purchased power agreement, you're buying power, so you would have to get a handle on how the cost of that power would fluctuate. If you are building a power plant, you have to worry about the cost of fuel, so you would want to get a handle on that.

A Absolutely.

Q In order to figure out how much the cost of, say, fuel would fluctuate over ten years, is that

a qualitative or quantitative assessment, the volatility of the cost of fuel?

A I would think that's a quantitative assessment.

Q That's a quantitative assessment?

A I would think so.

Q What about the cost of buying energy in your purchased power agreement? Well, I guess that's quantitative also.

A That would be a quantitative assessment. But the type of fuel that you use, or if you use a backup fuel in the power plant, would be more of a qualitative, perhaps, assessment of risk.

Q The backup fuel?

A Yes.

Q Okay. Thank you. Now would you please look at Schedule A1, page 2 of 2, Schedule A1 for December 2000?

A I'm not familiar with these schedules.

Q Oh, okay.

A I'll be happy to look at it, but I'm not sure I can answer your questions.

Q Do you know who is familiar with those schedules?

A That would be Witness Jordan.

Q Okay. Thank you. We'll just skip the questions on that exhibit.

Okay. Back to your direct testimony. Would you please refer -- I'm going to direct you to two sentences and then ask you about them. Page 4, line 13, and page 5, line 7, take a look at those.

MR. VANDIVER: What was that reference again, please?

MS. STERN: Page 4, line 13, and page 5, line 7.

MR. VANDIVER: Thank you.

THE WITNESS: Okay.

BY MS. STERN:

Q Okay. From this testimony, it seems to imply that natural gas and wholesale energy prices are correlated. Would you agree with that?

A Somewhat. There are other issues, but that is certainly one input into the wholesale prices.

Q Okay. Would you say that a strong or weak correlation exists between natural gas and wholesale energy prices?

A Fairly strong, depending on the region.

Q How about for the purchases for the region Tampa Electric is in?

A I would say it would be medium to strong.

It's a little bit less for Florida.

Q Why is that?

A Because of the fact that there's a sufficient amount of oil-fired generation in Florida that is on the increment, particularly during peak times in the summer, as opposed to other regions of the country, where it's primarily natural gas on the increment. So it's not quite purely a natural gas market in Florida. That's one reason.

Another reason is that there is an electric transmission constraint coming into Florida. Therefore, the prices of power in Florida often are related to the loading of that transmission line, or those lines, should I say. And hence, if those lines are loaded and Florida's weather is much hotter than the rest of the nation or much colder than the rest of the Southeast, then the market is affected regardless of the price of gas.

Q Okay. Thank you. Prior to August 1, 2001, has Tampa Electric analyzed whether it can cost-effectively manage the risks associated with its wholesale energy purchases by cross-hedging natural gas?

A Could you please repeat that question?

Q Sure. I'm sorry. Prior to August 1, 2001,

has Tampa Electric analyzed whether it can cost-effectively manage the risks associated with its wholesale energy purchases by cross-hedging natural gas?

A Any questions that you may have concerning fuel should better be directed to our witness, Joann Wehle, who I believe will be here tomorrow.

Q Okay. Thank you. Would you turn to page 6 of your direct testimony, please, and take a look at lines 5 through 9?

A Yes.

Q Okay. In that testimony, you discuss the lease of 39 portable generators during the summer of 2001; correct?

A Yes.

Q Is TECO still leasing these generators?

A Not totally. We are leasing 30 of those at this time.

Q What's the duration of the lease?

A The current generators, the 30 current generators that are being leased will be leased through September of next year.

Q Okay. Where were these generators located?

A These units were located at our Hookers Point power plant, and then the remaining generators

of the 39 were located in electrical substations on our system.

Q What fuel did the generators burn? Do you know?

A I believe -- I'm not sure, but I believe it was diesel fuel.

Q Do you know how the fuel was transported to the site?

A No, I don't.

Q Did TECO forecast its system reserve margin would drop below the 15% planning criterion at any time during the period when the generators were leased?

A Could you please repeat that question?

Q Did TECO forecast its system reserve margin could drop below the 15% planning criterion at any time during the period when these generators were leased?

A No.

Q Did TECO perform a cost-effectiveness analysis for the lease?

A I'm not sure. The lease was handled by a group other than Wholesale Marketing, so I'm really not sure.

Q Do you know what group?

A It was handled by Resource Planning.

Q Could you tell me the person who is the head of the Resource Planning Group?

A Bill Smotherman.

Q Are there any environmental issues or restrictions associated with the operation of the portable generators?

A I don't know.

Q Could you tell me who would know?

A I believe Bill Smotherman.

Q Could you tell me who the lease was with?

A The lease was with -- well, this is confidential information, I believe.

Q Okay. We'll just not answer that question, because there's a phone line. We'll skip that.

Could you tell me how the contract was priced for the lease?

A I believe that's confidential information also.

Q I'm sorry. And I assume then that the per megawatt-hour cost is confidential information?

A I believe so.

Q Are there any non-cost advantages to TECO of leasing these portable generators versus a purchased power contract?

A There's certainly more control over the units than a purchased power contract. That is, the units were on our system, on our property, and we were able to dispatch them throughout the day based on our needs. That is, we could start them up, shut them down, start them back up, and shut them back down very quickly. And often with purchased power contracts, there are restrictions as far as when you can nominate energy and when you can't and what the startup rate is and so forth. So these units gave us a great deal of flexibility in dispatching this energy for our system.

Q I see. Thank you. What was TECO's expected reserve margin without the capacity from the lease?

A I don't know.

Q Again, would you turn to page 5, lines 15 through 19 of your direct testimony, please?

In that part of your testimony, you stated that 50% of TECO's 2001 purchased power was purchased to avoid running more costly generation; is that correct?

A That's correct.

Q Okay. Are you referring strictly to short-term non-firm contracts?

A No, not necessarily. I believe in

determining this 50%, I was looking at the cost of generation that was on the increment at any given time, that is, our generation, versus the cost of purchased power. And the cost of purchased power could be a long-term contract or it could be a short-term contract. Again, I'm looking at energy.

Q Wouldn't the cost of purchased power be different if you were looking at a long-term contract versus a short-term contract?

A Often it is.

Q Could you describe the decision-making process in which TECO determines that it's more cost-effective to purchase rather than run generation?

A Repeat that.

Q Could you explain how TECO decides -- the decision-making process in deciding whether to purchase power or to just generate it from TECO's plants? Tell me about that decision-making process. How does that work?

A At the time that we determine that we need additional capacity, in order to maintain a 15 percent reserve margin, we will look out into the marketplace and compare what we could buy versus what we could build for. But that's strictly from a capacity standpoint.

From an energy standpoint, our system is dispatched by -- not by us, but by a group of people that look at what the next incremental cost would be as far as generation is concerned from our own system, incremental cost, including O&M, as well as fuel and startup costs, because there may be significant startup costs involved in bringing another unit on-line to serve load, and they compare that to what my group can go out on the market and purchase for perhaps several hours or perhaps just one hour.

There is a constant decision-making process going on in balancing running our own generation versus buying on the market, and that's a day-to-day process. The longer term process I described earlier as far as building generation.

Q What's the other group that looks at the cost of running the plant?

A That's our System Operations Group.

Q Are the people in your group and the people in that group then in communication every day?

A Yes, we are in communication. However, we are functionally unbundled from that group as per FERC Order 888 and 889. We are the marketing group, and they are the reliability group. That is, they operate the system, and we in turn buy power and sell power.

Q So if you're functionally unbundled from them -- okay. But you do communicate with them?

A We do communicate. We are allowed to communicate certain things between each other.

Q Who makes the ultimate decision? Who takes the information from your group and the information from the System Operations Group and --

A System Operations does.

Q System Operations will make the ultimate decision about whether to purchase power or generate it from your own units?

A That's correct.

Q I see. Could you please turn to page 7 of your testimony and take a look at lines 2 through 4?

A Okay.

Q Okay. You state that TECO has not entered into any firm separated or non-separated wholesale sales since 1998; is that correct?

A That's correct.

Q What's the most recent firm wholesale sale made by TECO?

A As I recall, and I believe this was provided in response to one of the interrogatories, I believe it was a non-separated firm sale to Reedy Creek.

Q Do you know what the megawatt capacity of the contract is?

A Well, it was only for 1998. It was a nine-month sale, only for 1998. But I would have to dig through and find the appropriate interrogatory to answer that question. Right offhand I can't tell you without finding the information.

MS. STERN: Any objection to going off the record for minute?

MR. BEASLEY: NO.

(Discussion off the record.)

BY MS. STERN:

Q Mr. Brown, would you please provide us a late-filed exhibit that contains the lease contract for the 39 portable generators and a cost-effectiveness analysis that shows how TECO determined that leasing those generators was cost-effective?

A Sure.

MS. STERN: Okay. Thank you. I would like to take a ten-minute break now.

MR. BEASLEY: That would be Late-Filed Exhibit 1.

MS. STERN: Yes. Sorry.

MR. BEASLEY: You want to just call it

Leased Generator Information?

MS. STERN: Contract for Leasing Generators.

MR. BEASLEY: Okay.

(Late-Filed Deposition Exhibit 1 was identified.)

MR. VANDIVER: I would like to be served with a copy of that exhibit, please.

MR. MCWHIRTER: We've signed a confidentiality agreement. We would like to see it as well.

MS. STERN: Okay. We'll just take a ten-minute break.

(Short recess.)

BY MS. STERN:

Q Okay. I just want to clarify that the late-filed exhibit that you will be providing entitled "Contract for Leasing Generators" will be Late-Filed Exhibit 1, and it will contain the contract for leasing the 39 portable generators and the cost-effectiveness analysis associated with that contract.

And I would also at this point like to back up to a question that I asked you earlier in the deposition, Mr. Brown. And that question referred to

page 6, line 19 of your testimony, so turn there and take your time looking at it.

A Okay.

Q And we had asked about the forwards market price of $86.31 per megawatt-hour. You said that that forwards market price for the period January through August 2001 was indexed to December 2000. Why did you choose December 2000?

A Because it was the most recent month before the period in question.

Q Did you look at what the price would have been for, say, January 2001, or November?

A November would have been the next closest month to look at the forwards market, and, no, I didn't look at November.

Q Okay. Is it your habit to pick the month that's the closest to the period that you are setting the forwards market price for?

A It's as accurate a forecast of the forwards market as you're going to get before the market actually exists.

Q So that's what you routinely use, the month prior to the period for which you need to set a price?

A Typically when we enter into a purchased power agreement, we look at the forwards market at the

time we are entering into the purchased power agreement, the immediate information on the forwards market, whatever that time is. And so if we're looking, for example, for a purchased power agreement for the next five months, then we will look at the most recent forwards market information that we have. We will not look at something a month old.

Q Okay. Thank you. I'm going to refer to Interrogatory No. 4. Do you have your response to that interrogatory?

A Okay.

Q Okay. In your response to that interrogatory, you indicated that the Reedy Creek Improvement District sale began in June 1995, with a contract term from January '98 to December 2017; is that correct?

A Yes.

Q Okay. Why is the date the sale began different from the start date of the contract term?

A The date the contract was entered into, which is the B as in boy portion of the answer to the interrogatory, is simply the date that the contract was actually signed and agreed upon. The date that the sale began -- I see what you're talking about. There may be a typo there. I'll have to go back and

look at that.

Q Okay. That's a clarification we would also like as a late-filed exhibit, if you don't mind.

A Sure.

MS. STERN: And that would be Late-Filed Exhibit 2, and that would be titled "Contract with Reedy Creek Improvement District for Contract Term from January 1998 to December 2017." And in that late-filed exhibit you will explain why the date the sale began is different from the start date of the contract term?

THE WITNESS: Sure.

MS. STERN: Okay. Thank you very much.

(Late-filed Deposition Exhibit 2 was identified.)

BY MS. STERN:

Q Okay. What is the total megawatts of TECO's firm wholesale sales contracts that are currently in place?

A I believe this was also provided in an interrogatory. I would have to refer to that to give you the exact numbers.

Q Okay. But you believe it was provided in an interrogatory?

A Yes.

Q Okay. Thank you. Now would you turn to page 7 of your testimony, please? I'm not going to direct you to a line, so just take some time to review that whole page, however much time you need.

A Okay.

Q Okay. When did TECO sign its most recent Hardee Power contract?

A Well, it was amended in May of 2000. If you're asking about the date that the contract was actually signed, I don't have that information with me. I'm sure I could get that information.

Q Okay. Thank you. Did TECO petition the Commission for cost recovery approval of the Hardee contract outside of the fuel proceeding?

A No, not to my knowledge.

Q Okay. Why did TECO choose not to petition the Commission for approval to recover the costs associated with the Hardee Power contract at the time the agreement was signed?

A I don't know.

Q Do you know who would know?

A Perhaps Witness Jordan.

Q Okay. Thank you. Did TECO make any comparisons of the costs of the Hardee contract to other available options?

A Yes.

Q Could you describe those comparisons?

A And let me make sure I'm clear. We're talking about the Hardee contract that was signed in May of 2000?

Q Yes.

A The answer is yes.

Q All right. Could you describe the comparisons that TECO did make between the Hardee contract and other available options? What other available options did you look at?

A We looked at purchased power. And as I recall, in the 1999 fuel and purchased power docket, there is testimony and discovery information which describes the efforts that we went through. I don't have that information in front of me, but I was a witness in that docket, and I remember testifying and being asked questions regarding justification of that power purchase.

Q So you recall that you compared that contract with the option of a purchased power agreement?

A That's correct.

Q Do you recall comparing it with any other options?

A Well, this actually is a purchased power agreement also, so we were comparing this with other purchased power agreements. We did not to my knowledge compare it to a self-build option, although it may have been considered by our Resource Planning Department, but I wasn't involved in that.

Q Okay. Thank you. Now would you please turn to page 7 of your testimony and review lines 13 through 17?

A Okay.

Q On an energy price basis, how did the Hardee contract compare to the forwards market price at the time the contract was signed?

A Well, that's difficult to answer, because the energy price of the Hardee contract is based on the natural gas market at the time. And, of course, the natural gas market constantly moves, so it's not a fixed fuel contract. The fuel is a pass-through. It's a cost-based contract whereby both capacity and energy are sold to Tampa Electric on a cost-based rate basis. And in this case, the capacity payment is fixed; however, the fuel is a floating fuel based on market, whatever the actual purchase price of the fuel is.

So as to whether or not it was above or

below the then-current forwards market, I really can't answer that. The forwards market is generally only available for 12 months, 12 months out, the published forwards market.

Q Okay. Also, I have a question about the same testimony. You state that Hardee is less costly than the forwards market, even if capacity payments are included; is that correct?

A Yes. And I was looking at -- I believe I was referring to my testimony on the previous page, page 7, lines 10 through 17.

Q Okay. And we had asked you about this. You touched on this a little bit earlier, I believe.

A Yes.

Q Okay. With respect to this particular contract, to determine -- how did you determine that Hardee is less costly than the forwards market, even if capacity payments are included? You added energy payments plus the capacity payments?

A That's correct. I took the $53.99 per megawatt-hour, which is on line 14 of page 7, and I added the capacity payments to that, and it was less than the $76.37, which is also on line 14 of that page.

Q Okay. Thank you.

A I essentially did the same analysis there as I did on the previous page.

Q Okay. I'm sorry about the distraction.

If capacity payments are included, how did the Hardee contract compare with the forwards market price at the time the contract was signed?

A I really can't answer that question, because the Hardee contract is a very long-term contract. The forwards market is not published for that same period of time. It's generally just published for the next 12 months, as I mentioned before. So it would be difficult. It would just be difficult to compare the two, so our comparison was against other purchased power opportunities.

Q I see. Were the other purchased power opportunities of the same duration?

A They were typically of the same duration, yes.

Q Okay. Were they other opportunities that were available to TECO or --

A Yes.

Q Okay. Thank you. Now would you please turn to page 8 of your testimony, and take whatever time you need to look that over.

A Okay.

Q Could you describe how TECO evaluates the cost-effectiveness of the short-term purchases referenced in your testimony versus building additional peaking capacity?

A Sure. What we do is, we look at the forwards market, and we compare it to the purchased power opportunities that we have, and we compare the two, understanding, though, that the forwards market -- there is no such published market for firm power. The forwards market that is published is for non-firm, 16-hour-a-day, five-day-a-week, or 16-hour-a-day, seven-day-a-week take, liquidated damages product, which is different often than a capacity and energy firm purchase, but it's close. It's about as close as we can get to comparing the value, the relative value of the purchase opportunities. And that's basically what we do if we're looking to purchase a schedule as opposed to a call option.

Q Okay. Is the 50 megawatts of distributed generation mentioned on page 8 of your testimony a purchase or a lease?

A It's a lease. That's the same small generators, the 30 generators that I mentioned earlier that are located at the power plant. That's the same generators that will be there this summer.

Q Okay. Is there any relationship -- we'll skip that. You answered that question.

In your testimony you discuss several short-term purchases that TECO has made or plans to make in order to achieve its planning reserve margin. Do you believe that relying on the short-term market rather than owned capacity exposes customers to risk due to the price volatility of the wholesale market?

A It could.

Q Under what circumstances?

A If the short-term market were very, very, high, that is, if the spot market were extremely high, then it could expose them, obviously, to the price volatility that goes along with that. But if the spot market or the short-term market were fairly low or fairly stable, then it wouldn't. And you generally don't know that until after it has happened.

Q Then how do you decide if you're going to go with the short-term market or owned capacity?

A Well, therein lies the strategy that I kind of referred to earlier, the purchased power strategy, where we don't put all of our eggs in one basket. That is, we don't enter into all long-term purchases, and we don't enter into all short-term purchases. It's a combination of the two. And basically we enter

into some long-term purchases for stability reasons, stability of price and stability of supply, supply availability. And then we enter into short-term purchases, because sometimes the short-term market is much below the forwards market. The spot market is way below the forwards market sometimes.

So it's similar to any business. If you lock yourself into 100% long-term contracts at fixed prices, the spot market may be below that at some time, and then your costs, of course, are higher than the spot. So we do a combination of the two.

On the other hand, we don't do all spot market prices either. Otherwise, you're subjecting yourself entirely to risk there.

Q Okay. Thank you. Would you turn now again to Interrogatory No. 4, please, specifically Schedule D, the Seminole contract? And in Interrogatory No. 4, you stated that the Schedule D sale with Seminole Electric is recallable to serve firm retail load; is that correct, staff's Interrogatory No. 4?

A Yes.

Q Okay. Has TECO recalled this sale to serve firm load at any time over the life of the contract?

A Yes. Let me explain. The Seminole D contract is actually a wholesale contract that

provides power to interruptible retail customers which are located outside of our service territory. And so if we have to cut interruptible customer load, then we will cut this contract, because they are served by this contract. That's why I call it a non-firm contract.

Q What is TECO's policy regarding recalling a sale versus interrupting retail non-firm customers in a capacity shortfall situation?

A I believe I've answered this in response to an interrogatory, but the policy is that our non-firm sales are cut before we would interrupt a non-firm customer. Understand that -- and I think also I have answered this in an interrogatory, that in some cases we will give the buyer of that non-firm power a very short period of time to ramp out the schedule, in other words, to find power elsewhere. But we won't give them very much time. They have to act very quickly, because we're cutting the schedule.

Q I see. Do you first cut -- for your interruptible customers -- I assume you have interruptible customers that are in TECO's service territory as well.

A Yes.

Q Is it your policy to cut the power to the

interruptible customers outside the service territory before --

A I don't actually cut the power. That's done in our System Operations Group. But my understanding is they consider them all together.

Q Okay. Is it correct that the Seminole sale could be terminated as early as June 2002 with three years' notification?

A That's correct. However, they have not given us notification.

Q Okay. Would you please turn to Interrogatory No. 5?

A Sure. Okay.

Q Okay. That interrogatory discusses each of the interruptions of non-firm retail customers during 1998 through 2001; correct?

A Yes.

Q Was TECO making any recallable sales during these interruptions?

A By recallable sales, do you mean non-firm sales?

Q Yes.

A Not to my knowledge. If we did, it would have been only for a few minutes to ramp those sales out quickly, but not to my knowledge.

Q Would you describe the different firmness levels of a Schedule D versus a Schedule J sale or purchase?

A Sure. A Schedule D contract is simply a type of contract that is used. The firmness is specified in the terms of the contract. Typically Schedule D is a firm contract for the purchase or sale of power, but not always. It is generally, but not always. Typically a Schedule J is a non-firm contract, but not always. Again, the specific details of the firmness are described in the contracts themselves. It's just simply a type of contract that we use, and we label them with letters, T, J, A, C, X, and so forth.

Q Are these like boilerplates?

A Generally, yes.

Q I mean, before you actually fill in the terms for a specific contract --

A That's correct. These are agreements that are typically boilerplate, and both the Schedule D and the Schedule J are cost-based contracts.

Q Okay. What are the basic characteristics of a Schedule MA sale or purchase?

A An MA is a market-based contract.

Q Has there been any period within the past

three years when TECO has purchased and sold to Hardee Power Partners at the same time?

A Yes.

Q Under what conditions did that occur?

A Well, we entered into a sale to Hardee -- a cost-based sale to Hardee Power Partners, which is our Big Bend 4 sale of 145 megawatts back in the early '90s, and they in turn sold that to Seminole Electric Cooperative. They simply passed it through. They didn't mark it up. They simply passed it through at cost to Seminole.

At the same time, Seminole, Tampa Electric, and Hardee Power Partners, the three agreed to build Hardee power plant. So Seminole and Tampa Electric became purchasers of capacity and energy from Hardee Power Partners from Hardee power station when the power plant was built. So Hardee Power Partners sells capacity and energy out of Hardee power plant to Tampa Electric and to Seminole, and Tampa Electric sells the Big Bend 145 to Hardee Power Partners, who passes it on to Seminole.

Q I see.

A So since the early '90s, we have been purchasing and selling to Hardee Power Partners.

Q Okay. Has there been any period within the

past three years when TECO has purchased power from TECO Power Services while at the same time interrupting non-firm retail customers?

A We do not have any agreements with TECO Power Services to purchase power in that vein. All of our purchases are from Hardee Power Partners. I realize we make other purchases, but we do not make any from TECO Power Services.

Q How does TECO select the entity through which buy-through power is purchased for TECO's non-firm retail customers?

A We shop the market. We presently do business with over 30 counterparties, 30 possible providers, inside the state as well as outside the State of Florida. And we shop pretty aggressively, every hour, as well as on a daily basis. We get the best deal we can find.

And, of course, price is not all of it. We have to get the power here, in other words, get it to our system, which is often a challenge. That is, we have to find transmission line capability, we have to reserve transmission, and we have to pay for the losses and so forth. And so we find the best sources, and we do that every hour. We are a seven-by-24 operation.

Q Okay. Do you have with you the July 2000 fuel schedules?

A I don't think so, but maybe we can find it here. Is it here? July?

Q July 2000.

A These aren't labeled fuel schedules. Perhaps if you could point me to a particular exhibit or a particular page, I'll try to answer questions, but I'm not sure what you're looking for.

MS. STERN: Okay. Any objection to going off the record?

MR. BEASLEY: Not a bit.

(Discussion off the record.)

BY MS. STERN:

Q Okay. I've asked you to look at Schedule A1 for the July 2000 fuel schedules. Are you familiar with the criteria used by TECO when TECO determines that it will engage in wholesale sales and wholesale purchases?

A I'm not sure I understand that question.

Q Does TECO have criteria that it uses to judge whether or not to make a wholesale sale or a wholesale purchase?

A Yes.

Q Are you familiar with those criteria?

A Yes.

Q Can you describe the criteria TECO uses to determine when an economy purchase is made?

A Yes. We look -- actually, System Operations looks at the next incremental cost of a unit. And I think I described this before. They consider the fuel, the O&M, the startup costs, and so forth, and they compare that with the market that -- we're constantly interviewing and gathering market price information every hour, and they determine whether they're going to run a unit or ramp a unit or purchase on the market. And we actually do the purchasing.

Q And is that the same process that's followed when an economy sale is made as opposed to an economy purchase?

A Yes.

Q Okay. Do you have any written criteria that you're aware of that TECO follows?

A Not that I'm aware of.

Q Do you have with you Schedule A4?

A For which month?

Q For July of 2000.

A Yes.

Q Okay. I'm going to ask you this question

and if you don't understand it, just ask me to repeat it. Is the type of generating unit data appearing in either Columns M or N used in determining when TECO makes wholesale sales or purchases?

A Well, the type of data in a general sense is used. However, specifically, no. My understanding of this A schedule is that Column N, which is entitled "Fuel Cost Per Kilowatt-hour," is the average for the entire month for each unit.

Q Okay.

A But when we are considering purchasing economy energy, we're looking at the exact cost that next hour, not the average for the entire month. And the next hour cost will vary dramatically, both higher and lower than the average for the month.

Q Is Column D, net capacity factor, used in determining whether TECO makes wholesale sales or purchases?

A No. The net capacity factor is essentially the percentage of the time the unit was used during that month, that 30- or 31-day period.

Q What about Column E? Is that used in determining when TECO makes wholesale sales or purchases?

A Generally, no. Column E is the equivalent

availability factor expressed in percent, and that's simply a measure of whether the unit was available or what percentage of that month the unit was available.

Q So other than Columns M and N, or in addition to Columns M and N, are there any other columns that TECO uses in deciding whether it's going to make a wholesale sale or purchase?

A Well, certainly we need to know that the unit is available for the upcoming hour. Now, even though the availability might be 88% for the month, as I see some numbers here, that doesn't mean it's available the next hour. So availability certainly is an issue. Fuel cost is certainly an issue. But we're really looking at a much shorter time frame than what this schedule really describes.

Q Are you familiar with Schedule A6 for July 2000?

A No, but I'll try to answer any questions on it.

Q Okay. The type of data appearing anywhere in that schedule, is it used in determining whether TECO makes a wholesale sale or purchase?

A My understanding of this schedule is that this is a summary of power sold for the month of July 2000, and each counterparty is identified here who we

have sold power to, and the schedule that we have sold it under, that is, Schedule C, Schedule D, Schedule J, and so forth, is also identified. This is simply, I think, a summary of what we have sold.

Q Okay. That's fine.

A And that's about the extent of my understanding.

Q Do you know what the difference between Column 6A and Column 6B is?

A Well, 6A is labeled "Fuel Cost," and B is labeled "Total Cost." And, frankly, I'm not familiar enough with this schedule to tell you exactly what is included in total cost that's in addition to Column A.

Q Okay. Here's a hard question. What is the difference between Column 6 on Schedule A6 for July 2000 and Column M on Schedule A4 for July 2000, if you know?

A Well, Schedule A4 is a summary of system net generation for the month, and Schedule A6 is a summary of power sold. I'm not really sure that there's any relation between the two, because it appears to me that all of the information on Schedule A4, it's a list of all of our generating units, how much each one generated that month, and what the fuel cost was for each one that month.

And looking back over Schedule A6, these are just simply sales. This is a summary of sales that we made, wholesale sales.

That's about the best I can do. I'm sorry.

Q Okay. Thank you. Thank you for trying.

Would you turn again to Schedule A6?

A Okay.

Q Is it normal for economy energy purchases to be priced higher than the purchases shown on Schedule A6?

A I don't know.

Q Okay. Would you agree that TECO has estimated an increased need for purchased power in 2002?

A I guess I need clarification of the question. Increased compared to what?

Q Okay. I'll -- maybe this will help. TECO's 2002 E7 schedule -- let me give you a synopsis, and you can listen, and then we'll start looking at the pages. I think that would be the best way.

TECO's 2002 E7 schedule estimates that over $60 million in market-based power purchases, $48 million in purchases from Hardee Power Partners, and $9 million in Schedule D purchases will be needed in 2002. These estimates have increased significantly

over the purchase estimates provided by TECO in 2000 for the same types of purchases. And the question is, what are the primary reasons TECO estimates an increased need for purchased power in 2002?

A You mentioned 2002, but then you also mentioned 2000. Are you really comparing the 2001 estimate to 2002, or are you comparing the 2000 estimate to 2002?

Q The 2000.

MS. STERN: Do you mind if we go off the record?

MR. BEASLEY: Sure.

(Discussion off the record.)

BY MS. STERN:

Q I'm sorry. The answer to your question is that we're comparing the 2001 estimate to the 2002 estimate.

A My understanding of the reason for the increase in the estimate, one reason is that the estimate uses the actual power purchased for a certain number of months of 2001. In other words, it uses an actual plus an estimated 2001. So the 2002 estimate uses the most recent information, both actual and estimate, as far as volume is concerned, and it factors in the load increase between 2001 -- the

retail load increase between 2001 and 2002.

As far as wholesale sales are concerned, 2002 will actually have slightly less wholesale sales. I'm sure that they also factor in -- in looking at the actuals for 2001, they factor in the unit availability forecast for 2002. They factor in -- in the unit availability forecast, they factor in both planned outages and unplanned outages of units, and they are compared to 2000 and 2001.

So it's a combination of those reasons or a combination of those factors that determines the forecasted volume. And I'm speaking of the volume here of purchased power. Then we look at the market forecast of purchased power, and we apply that to the volume, and we come up with the total cost. So there's many factors that go into it. I hope I've --

Q Yes. Yes, you have. Thank you.

Okay. I'm going to read sort of a lengthy statement and then ask a question. Take your time to think about it and ask for clarification if you need to.

TECO's Schedule E7 indicates that the expected average price of market-based purchases for 2002 is 5.73 cents per kilowatt-hour, while Schedule E6 shows an expected sales price of 2.356 cents per

kilowatt-hour for market-based sales. That's the statement.

What are the primary reasons why TECO expects the sales price for market-based sales to be less than the purchase price per kilowatt-hour?

A The primary reason is that our market-based sales are made on the shoulder hours and on the shoulder months, that is, off-peak times and so forth. And our purchases are primarily over peak hours.

Q Okay. Are there times when TECO simultaneously purchases capacity and energy for retail customers' needs while it is making firm wholesale sales?

A Yes.

Q In your opinion, is it prudent for a utility to make wholesale sales at the same time that the utility is purchasing capacity and energy?

A Well, when a utility considers entering into a firm wholesale sale, the utility looks at their generating reserve margin, at least we do, and we do not make a firm wholesale sale unless we have a forecasted 15%, at least, generation reserve margin, including the sale.

After the fact, several years -- let me go

back. If you make a long-term sale, as most of ours are -- in fact, all of ours are. The firm capacity sales are all long-term. If you go back after the fact five or ten years down the road and you look at the then-current immediate market, short-term market, the short-term market may be higher than those cost-based long-term sales, or it may be lower. The market is going to change. It's up and down.

So determining that after the fact, probably anybody could make a case at any given time, going one way or another, on the prudency of making a sale. But the analysis that we've gone through is to look at our forecasted reserve margin and determine if we can afford to make a sale from a capacity standpoint and determine if we can recover those costs and then make a profit on the sale, understanding, though, that all of our firm sales are cost-based. We do not have any firm market-based sales.

Q Okay. I have a few more questions to go.

A Sure.

Q How are TECO's interruptible customers impacted by wholesale sales and purchases?

A Well, certainly they are impacted by wholesale purchases, because we purchase for them optional provision power, which they have asked us to

do.

As far as wholesale sales are concerned, the capacity of firm wholesale sales is removed from rate base, that is, the sales are separated. I think Witness Jordan referred to that earlier. And so they are not required to pay any capacity costs associated with that capacity, nor are our other retail customers for that matter.

Q Okay. Has TECO interrupted its interruptible customers to make any new firm separated or non-separated wholesale sales?

A Well, we have not made any new firm wholesale sales, separated or non-separated, since 1998. I think I mentioned that earlier. So if that's the time frame that you're talking about, we have not made any.

Q Does TECO have a policy of interrupting its interruptible customers in order to make non-firm wholesale sales?

A No.

Q I think you answered this, but I'll ask it just to make sure. Is TECO currently engaging in firm non-separated sales?

A We currently do not have any firm non-separated sales.

Q Okay. Would you turn to page 9 of your testimony, please, and review lines 19 through 22?

A Did you say page 9?

Q Yes. I'm sorry.

A Lines 19 --

Q Lines 19 through 22.

A Yes.

Q Okay. What is the rationale for approximately half of Tampa Electric's 2001 purchased power contracts being long-term?

A Well, we don't have a magic formula that defines half. We simply assess the market. And the reason I put that information in my testimony was to demonstrate that we look at both long- and short-term markets, and we have a diversified portfolio of purchased power. That is, we don't put all our eggs in one basket, and it happens to work out to about 50-50 right now.

MS. STERN: Okay. Thank you. I would like to take a ten-minute break if we could.

(Short recess.)

BY MS. STERN:

Q Mr. Brown, would you turn to Schedule A1 for December 2000, please, specifically page 2 of 2?

A Okay.

Q Does row 12 of this page indicate that Tampa Electric purchased 2,691,658 megawatt-hours of wholesale energy during 2000?

A Yes, that appears to be the case.

Q What percentage of those megawatt-hours, the approximately 2.7 million, did Tampa Electric purchase to serve its base load?

A I don't know. And perhaps it's provided here and I just can't see it because I'm not that familiar with the schedule. Let me see if it's here.

I don't see a line that indicates that in this schedule.

Q Okay. What percent of the 2.7 million megawatt-hours did Tampa Electric purchase to serve its intermediate load?

A I'm sorry. What do you define as intermediate load?

MS. STERN: Let's go off the record, please.

(Discussion off the record.)

BY MS. STERN:

Q Intermediate load is something that's not base and not peaking. It's between the 20 and 80% capacity factor, would replace the 20 to 80% capacity factor.

A I don't know of this 2.7 million figure how much was purchased for intermediate load, and I don't believe that that information is provided in this schedule.

Q Okay. What percent of the 2.7 million megawatt-hours did TECO purchase to serve its peaking load?

A I don't know.

Q Okay. Subject to check, would you agree that TECO's wholesale energy purchases are about 13% of the total energy available to TECO in 2000?

A I believe that's what I said in my testimony. I believe the number 13% is correct. Let me check this for a moment, please.

Q Okay. Thank you.

A On page 5, line 13 of my testimony, I state that Tampa Electric generated 89% of its customers' total energy needs from 1998 through 2000 and 83% for the first eight months of 2001. The remaining 17% of customers' 2001 energy needs were provided with purchased power. And I'm sorry. I don't recall the time frame of your question. What year were you talking about?

Q 2000.

A Well, I haven't isolated the year 2000 out

of that three-year period that I looked at, so I guess I don't know the answer.

Q Okay. Thank you. Subject to check, had TECO estimated that the energy costs of its wholesale energy purchases would be $41.36 per megawatt-hour in 2000?

A I don't know. If that's on an A schedule somewhere, perhaps, but I just don't know.

Q Okay. We'll just disregard that question.

I have a few more questions I want to ask. It relates to a series of questions I asked you earlier, and that was the questions where you said that you used December 2000 as an index for pricing from January through August of 2001. Do you recall our discussion of that?

A Yes.

Q Okay. What percentage of your purchased power for January through August 2001 was procured through long-term contracts signed during 2000?

A I don't know. I could find the information.

Q That would be very helpful to us if we could get that as a late-filed exhibit. Would you do that?

A Sure.

MS. STERN: Okay. That would be Late-Filed Exhibit 3, I believe.

MR. BEASLEY: Have you got a title for it? Percentage of purchased power?

MS. STERN: Percentage of purchased power for January through August 2001 that was procured from long-term contracts signed during 2000.

(Late-Filed Deposition Exhibit 3 was identified.)

MS. STERN: Would the court reporter please read back what I titled the exhibit?

(Requested portion read by the reporter.)

BY MS. STERN:

Q Okay. During what month or months of 2001 were most of the purchased power for -- okay. Is it correct that a certain number of purchased power agreements for delivery were signed between January and August of 2001?

A You're talking about long-term agreements, short-term agreements, or what agreements?

Q I'm talking about both, long-term and short-term. Did you sign any long-term purchased power agreements for delivery in 2001?

A For delivery in 2001 between what months?

Q January and August.
A Yes, I believe we did.
Q You signed long-term agreements?
A Well, the definition of long-term may be different to different people. But we did, as I recall, sign -- and this is subject to check. I'll have to go back in our records. But I believe we did sign an agreement that was at least a month long, which could be considered long-term, if you will, between those months.
Q Okay. Did you sign short-term purchased power agreements for delivery for January, the agreements being active during the period January through August 2001?
A Yes. And short-term I'm interpreting as an hour up to about a month long. We entered into many, many short-term agreements during that time.
Q Okay. During what month or months in 2001 were most of the purchased power for delivery in January through August 2001 signed?
MS. STERN: Do you mind if we go off the record?
MR. BEASLEY: No.
(Discussion off the record.)
BY MS. STERN:

Q During what month or months of 2000 was most of the purchased power signed for delivery in January through August of 2001?

A I don't know.

Q Do you know who would know?

A I could find that information for you.

Q You mean you yourself could find the information needed to answer this question?

A Yes.

Q Okay. That is information that's important to us, and we would like to get it as a late-filed exhibit. That would be Late-Filed Exhibit Number 4.

A Excuse me. It sounds to me like what you're looking for -- correct me if I'm wrong. You're looking for the long-term purchases that we made for January for August of 2001, whenever we signed those contracts, whether we signed them in 2000 or 2001. Is that right?

MS. STERN: Do you mind if we go off the record again?

MR. BEASLEY: No.

(Discussion off the record.)

BY MS. STERN:

Q Mr. Brown, you've agreed to provide us with Late-Filed Exhibit 4, which will consist of a listing

of megawatt-hours by month and the cost of those megawatt-hours by month for the months January 2001 through August 2001 for megawatt-hours delivered under long-term contracts signed in 2000 and 2001. Also in that late-filed exhibit you will provide us with your definition of long-term contracts, whatever you define long-term contracts to be.

A Sure.

MS. STERN: And this Late-Filed Exhibit 4 will be titled "Deliveries Between January and August 2001."

(Late-Filed Deposition Exhibit 4 was identified.)

BY MS. STERN:

Q I just have four more questions for you, and I very much appreciate your patience.

Did natural gas spot prices rise from June 2000 to January 2001?

A Is that a question?

Q Yes.

A I think I mentioned that in my testimony, or I mentioned something about the gas pricing changing. I'm looking.

Q I think --

A Yes, page 4, line 17. I said that in 2000,

concern was focused on natural gas prices, which began rising in June of 2000 and peaked in January of 2001. Is that the section that you're looking at?

Q Yes. And I'm wondering, what about natural gas spot prices?

A Well, that is essentially the natural gas spot prices.

Q Okay. Thank you. Would that rise in natural gas spot prices from June 2000 to January '01, would that translate to higher prices for purchased power?

A Yes.

Q Okay. Why wouldn't a month preceding December 2000 -- this is referring back to Late-Filed Exhibit 4 for deliveries made between January and August 2001 under contracts signed in 2000. You had mentioned earlier you had used December 2000 as an index for contracts for deliveries for the following year. Why wouldn't a month preceding December 2000 be a suitable reference month for calculating a forwards market energy price for January through August 2001?

A It could be.

Q Okay. Why did you choose December 2000?

A I simply chose December because it was the most recent -- just before the immediate term, that

is, January through August, it was the most recent forwards market information. But I could have chosen any previous month as long as I didn't choose any month prior to August of 2000, because you only get 12 months out.

Q Okay. So you couldn't have chosen a month prior to August 2000.

A That's right.

Q You had to choose between August and December 2000. And --

A I could have chosen January and February of 2001.

Q Okay. I think the concern here is that the prices for gas are highest in 2000, and so to use that as an index creates some -- to use that as an index to compare costs for delivery, it would be a very favorable index for TECO.

A What I was trying to demonstrate is that if we had entered into long-term contracts late in 2000 for this period of time, January through August of 2001, based on the forwards market, which I calculated as $86 and change, then we would have paid more for purchased power than we did.

What we paid for purchased power was something under that, because we had a purchased power

strategy that included long-term contracts. And by long-term I mean contracts that have been around for almost ten years, as well as contracts we entered into in 2000 for 2001, as well as short-term purchases. It was a combination strategy that resulted in lower cost power purchases for that eight-month period, the first eight months of 2001, than if we had just entered in those contracts late in 2000 for 2001. That was what I was demonstrating or trying to demonstrate in my testimony.

Q Would you please provide the average forward energy price for each month from August to November 2000?

A August through November?

Q Yes.

A Sure. Is that another exhibit?

Q If it's not something you know. You don't know that?

A Oh, no.

MS. STERN: Okay. Then that would be Late-Filed Exhibit 5, and we'll title that "Average Forward Energy Price from August to November 2000." And the content of that exhibit, for clarification purposes, will be the average monthly forward energy price for each

month from August to November 2000.

THE WITNESS: Okay.

(Late-Filed Deposition Exhibit 5 was identified.)

MS. STERN: Thank you very much. We don't have any more questions.

Shall we take a brief break?

MR. MCWHIRTER: Not for me.

MR. VANDIVER: Not for me. Mr. Brown, it's your call.

THE WITNESS: Pardon me?

MR. VANDIVER: It's your call.

MR. MCWHIRTER: How about the court reporter?

THE REPORTER: I'm fine.

CROSS EXAMINATION

BY MR. VANDIVER:

Q Good afternoon. My name is Rob Vandiver. I'm with the Office of Public Counsel.

I had several questions concerning the temporary generators. I think they were referenced on a page early in your testimony. Let me find the reference. Yes, it was on page 6 of your testimony, Mr. Brown. And I know part of this is confidential. Please stop me, and I'm sure Mr. Beasley will be on

top of it.

You indicated that the contract for those 19 odd -- is it 19 generators?

A Thirty-nine.

Q Thirty-nine. I'm sorry. Expired in 2002, September of 2002; is that correct?

A No. I believe what I said is that 30 of them will -- we will lease them through September of 2002, and the remainder were only used for the summer of 2001.

Q That nine would be used --

A Thirty and nine I believe was the way it broke out.

Q Okay. So 30 are leased through 2002. And when did that lease start?

A That lease started in June, June the 1st of 2001.

Q And how about the nine generators? Were they just leased for the summer of 2001?

A Yes, they were. And I believe -- and this is subject to check. This is some of the information I was going to go back and provide, but I believe their contract started May the 15th or May the 16th of 2001.

Q Is the generation capacity of the

individual generating units confidential information?

A No.

Q What is it?

A As I recall, it's 1.825 megawatts each.

Q Is this kind of self-contained portable generation unit unusual in the TECO system?

A I don't know what you mean by unusual. It's the only type of generation like that that we have on our system currently. I guess I --

Q I mean unusual in this sense. I don't ever remember seeing reference to these in the ten-year site plan. Am I wrong on that?

A I'm not responsible for the ten-year site plan. I don't recall. I really don't know.

Q When is the last time that TECO employed this kind of generation?

A I believe we had some units in substations in 2000.

Q You're using this for 70 megawatts of peaking power?

A That's correct.

Q And I'm just curious as to this quantity. I guess you would use this on an emergency base, but I'm curious as to this quantity, and that's what kind of piques my curiosity, this amount on the system.

I'm just not familiar with this type of generation.

A These units are leased. It's a temporary installation that provides us capacity that helps us achieve 15% reserve margin for this period of time. They're simply a temporary -- we do not own the generation. We simply lease it, and we provide the fuel. The fuel is a pass-through. Operation and maintenance is a pass-through. And we dispatch the units along with our other system.

Q And you're unaware if it's part of the ten-year site plan or if it has been addressed in it?

A I do not know if these units were included in our reserve margin in the most recent ten-year site plan.

Q I also had some questions concerning your testimony on pages 9 and 10.

A Okay.

Q There you had reference to Tampa Electric's -- whether you engaged in physical or financial hedging practices. You were in the room when I asked Ms. Jordan concerning Tampa Electric's position on hedging, were you not?

A Yes, I was.

Q Do you agree with her position as to -- well, let me ask you, would Tampa Electric object to a

delaying the issues in this docket concerning hedging so that the Commission might have more information, delaying these issues into 2002 into a workshop process or into the 2002 docket?

A Well, I would agree with Witness Jordan, in that I don't believe we would object to delaying it.

However, I do know that we have provided responses to numerous interrogatories and productions of documents on this subject. There have been two workshops here at the Commission, I believe both of them this year. This is a current topic. It has been a topic that has been discussed is repeatedly. And I guess after our response, our efforts that we went through to respond to everything in a timely manner, to just take to it this point and postpone it, it concerns me, but I don't think we would object to it.

MR. VANDIVER: Okay. Fair enough.

That's all the questions I have.

CROSS EXAMINATION

BY MR. MCWHIRTER:

Q Mr. Brown, you talked about buying electricity for a later period of time. How is that different than the hedging that you contemplate, that you're talking about?

A Well, we do not actually hedge any of our

power purchases at this time. And by hedging, I define that as purchasing a derivative, such as a physical or financial derivative. The hedging that we do, if you will, and I put hedging in quotes, is that we have a purchased power strategy whereby we -- first of all, we purchase physical power. We do not purchase financial instruments.

Secondly, we purchase various terms, various products. We don't put all of our eggs in one basket. It's the description that I was giving earlier. We buy short-term, we buy long-term, we buy capacity, we buy just energy, we buy schedules, we buy call options. It's a combination of those things. It's a strategy that we use. But as far as purchasing financial instruments, we do not do that from power purchase standpoint.

Q All right. How is a financial instrument different that a call?

A Calls that we buy are actual physical options whereby if we strike on the option, power is delivered, physically delivered to our system. A hedging instrument that's a call could also be a physically delivered product.

However, I think of a hedge call as more of a financial instrument whereby, if the price of a

given commodity reaches a certain point, you can call on that commodity or make a call on that financial option, financial hedge, and thereby collect cash rather than actually receive the commodity.

Q So what you do now is, you'll place a call on 50 megawatts of power in January for a specified price, and January comes along, and if it's mild weather and you find you don't need it, rather than buying the power, you'll just lose the premium that you paid for the call?

A That's right.

Q And how is that premium you paid treated in the fuel clause?

A I'm not totally sure how it's treated in the clause. Witness Jordan may be able to assist you there. But the premium, the capacity premium that we pay is paid for by retail customers. Now, what clause it's in, whether it's in the fuel clause or in the capacity clause, I do not know.

Q Now, this financial hedging you're talking about, the derivative, what you do is buy a contract to purchase power in January, and then if the futures price of that contract went up, instead of buying the power, you could sell the contract?

A You could do that. Sure, you could do

that.

Q And how would that money be treated?

A If the cost of that option is -- that is, the premium that you pay for the option to buy at a certain price, if that is paid for by retail customers, then it seems logical that if you exercise that option as a hedge, in other words, against price volatility, the benefits of that exercise should go to the retail customers.

Q Well, what is all this about? What's so different in your planning that requires approval? What will you be able to do if this financial derivatives program is approved that you aren't able to do now?

A Well, it depends on the program, obviously. But let's assume for the moment that the Commission approves financial hedging of all fuel and purchased power. Then a strategy would be set up where guidelines would be set as to, you know, here's how much you hedge, here's what you do, here's the price volatility that we will allow. In other words, limits are set, and we go out and actually purchase the instruments and then exercise those options or swaps or puts, or whatever you happen to purchase. We exercise them as appropriate.

Q Well, your holding company could do that today, couldn't they?

A I guess they could.

Q What is the benefit to consumers to have you do this within the confines of the load-serving utility?

A It reduces price volatility.

Q To whom?

A To the retail customers. However, it may also increase their rates.

Q Well, hedging is a time-honored concept, and I perceived from your discussion earlier you've been doing that for years. You're buying power ahead of time and taking delivery of it or not taking delivery of it, and that's to protect you against the volatility of the market; isn't that correct?

A We have a physical power purchase strategy that could be considered a hedge or a risk management strategy against volatile spot market prices.

Q And that's a good thing. I mean, nobody could protest that, but I want to understand what it is that you want to do different.

A I think the difference is the purchase of derivatives. The purchase of a derivative is not actually purchasing the power itself, but rather

purchasing an instrument that's related to a price of the related commodity. In this case, it's electrical energy. And this is also true, of course, in the fuels market as well. But the purchase of this derivative is like insurance against price movement, and it's a sunk cost.

Q As your current option an insurance contract too, isn't it?

A Yes, to some degree, although we don't engage in entirely option purchases. We engage in a multitude of purchases. But you're right. It is a sunk cost just like the purchase of a physical option, a capacity option is a sunk cost.

Q So based on your earlier explanation, you would look for the Commission to establish guidelines and criteria for the types of derivative transactions you could enter into; is that correct?

A I think, yes, I agree. But I would say one thing further. I think it's a team effort between the utility and the Commission to determine the right strategy for each company, because each company's strategy may very well be different.

Q Have you proffered any evidence in this case that demonstrates what's right for your company?

A No. We haven't gone that far. We're not

that far along.

Q Well, it has been suggested it might be better -- and I think you suggested it might be better to continue looking at the problem until you can develop the issues that the Commission could look at. Is that essentially what you're saying?

A Yes.

Q But in the meantime, you can still utilize the hedging process to protect you against price volatility; is that correct?

A Well, it -- yes, it protects against price volatility, while at the same time getting ourselves to take advantage of lower spot market prices when we find that to be the case, yes.

Q You obviously don't have enough installed generation to meet all the demand on your system, so you have to purchase power in order to meet your peak periods; isn't that correct?

A That's correct.

Q And what are the criteria in a purchased contract that qualifies that contract to be considered part of your utility's reserve margin?

A The criteria is that we have firm call on that facility, such as the generators that we were talking about, the 39 generators we were talking about

at the substation, or in the substations and the Hookers Point power plant. We have first call on those. Nobody else has a call. And whoever is selling that capacity generally designates that first call right in writing in the contract.

Q Is there a period of time? Do you have to have the call for a period of six months or a year before it could qualify to be used in the reserve margin calculation for available capacity?

A Not to my knowledge.

Q So if you had a contract 24 hours ahead and there were a moment in time you determined the utility's reserve margin, if you had a right to purchase that's 24 hours away and would expire after that, it could be used as part of your determination of capacity that's available?

A Well, I suppose it could. However, the 15% reserve margin is really a margin that you must have during peak times, peak winter and peak summer. Now, when that will be, you don't always know.

Q That's right.

A And so you generally have to enter into these capacity, first call capacity contracts in advance for the season, not on an hourly basis or not on a daily basis, but rather a season, at least a

season, and often longer, in order to provide the 15% percent reserve margin.

Q My question was just whether there's a criteria you use in order to be able to use it in the available capacity component of your reserve margin calculation, or is it just a gut feeling that this will be there when I need it?

A As I understand your question, I believe the answer is that the capacity that you're purchasing, determining whether or not it's going to be available, first of all, is provided -- that information is provided for in the terms of the agreement, obviously.

Q Right.

A If the terms of the agreement provide anybody else the option of getting that capacity ahead of you during that time of peak load, then you certainly have to consider that. It doesn't mean that it cancels that as a first call option, but you have to consider the specific terms of the agreement.

Q All I'm asking you is, does your company have a policy that says if a contract is for a period of 30 days in July when we think that the summer peak may occur, we will use this capacity as part of our reserve margin calculation? Or many that's a dumb

question. Maybe you just make that calculation in January and then go on about your life.

A Well, we do calculate a peak for the summer and a peak for the winter, and we calculate what month that peak will occur.

Q Right.

A So if you have first call capacity in that month, just that month, then it possibly could be used toward your 15% reserve margin. That makes sense.

However, it's often difficult to purchase capacity, this type of first call capacity that we're talking about, for just one month. You have to purchase it for a year, or maybe many years, or maybe a season.

Q That's what I'm trying to get at. What is the length of it that you normally have to have before you can qualify it as part of your installed capacity?

A Typically you'll purchase it for a year or maybe more, or maybe -- obviously, you can find it. If you're willing to pay enough money, you can find it for one month, the peak month in question, but you'll pay dearly for that month. So you have to consider the season versus the longer term, what the value of one would be versus the value of another. Obviously, all of that has to be considered in determining how to

purchase it.

Q For example -- well, I don't know that this is relevant. In November of the year 2000, you did a forecast of what your fuel costs would be for the year 2001. Of course, that forecast was made in August, but you reaffirmed it in the November hearing. And by the first of February in 2001, you found that that was in error by $23 million, according to the testimony we heard this morning from Ms. Jordan. Would it be fair to say then that that was typical, or was it atypical?

A I don't know, because I'm not involved in those calculations. I couldn't compare it to anything else, because I just don't have the knowledge of those calculations.

Q Is it unusual that your fuel costs would go up that high in a period of 60 days in an unforeseen fashion?

MR. BEASLEY: I think the witness indicated he's not familiar with that.

MR. MCWHIRTER: Well, he's in the purchasing business.

A Well, certainly the purchased power market moves up and down. The gas market moves up and down. The coal markets move up and down.

Q But you're 93% coal in your fuel.

A And what results in that 23 million, it could be a combination of factors, and so for me to just say it was this, I really don't know.

Q Well, your coal cost didn't go up 23 million in December and January, did it?

A I don't know.

Q Let me address your attention to page 7. We've spent a lot of time talking about this. And I also asked Ms. Jordan some questions about it, and you may recall those questions were dealing with the power sold to Hardee Power Partners, or that you anticipate selling to Hardee Power Partners from the period January through December. And the energy price is going to be $25.62, and there's going to be another dollar charge for O&M --

MR. BEASLEY: Could I ask what you're referring to?

MR. McWHIRTER: I'm looking at page 47 of Exhibit E6.

MR. BEASLEY: Who sponsors that exhibit?

MR. McWHIRTER: Schedule 6, page 2 of 2.

MR. BEASLEY: I mean who is the witness?

MR. McWHIRTER: Jordan.

MR. BEASLEY: Isn't she the person to respond to questions about her exhibit?

MR. MCWHIRTER: Well, I asked her a question about that, and she said that Mr. Brown would be the man to ask about it. The question I asked her was on --

MR. BEASLEY: Well, let me get to that page. What page is it, John?

MR. MCWHIRTER: Page 47.

BY MR. MCWHIRTER:

Q Okay. I really want to ask about page 49. On page 49 we have HPP, Hardee Power, and you estimate that you will pay $46.19 a megawatt-hour for that power next year. But that's not the total cost you're going to pay Hardee Power, is it? Won't you pay them something else through the capacity clause?

A I'm not totally certain what the 46.19 includes, but I think it includes the capacity factor.

Q Well, at the top it says fuel cost.

A Right.

Q And B is total cost, so I would presume that cost is fuel cost only.

A Well, I'm not sure that's the case. I understand what you're looking at, but I'm not sure that's the case. The capacity payment may be included in the 46.19, but I'm not sure.

Q So you're recovering the capacity payment

through the fuel clause as opposed to --

A I said I'm not sure.

Q She said she didn't know either.

On your page 7 at line 13, you said this year HPP's energy price of 53.99 was below the 76.37 forwards market price as of December 2000. Did you distinguish there between the price you pay for energy as opposed to the price you pay for capacity?

A I was just looking at the energy total, $53.99. And that was for the period January through July of 2001, actual.

Q Does that number include the capacity payment, or is that just what you paid for the energy component of that contract?

A That's the energy component.

Q Do you know what you paid for the capacity component?

A Not offhand. But my statement here is that even after adding the capacity component to the 53.99, the total was less than 76.37.

MR. McWHIRTER: Would you do this as Late-Filed Exhibit Number 5, Mr. Beasley?

MR. BEASLEY: I'm listening.

MR. McWHIRTER: Is it Late-Filed Exhibit Number 5?

MR. BRINKLEY: I believe so, yes.

MR. McWHIRTER: Would you do that calculation for us on --

MR. BRINKLEY: No, I'm sorry. That's Number 6.

MR. McWHIRTER: Number 6? Would you do that calculation for us in Late-Filed 6 and add the capacity payment that you refer to on line 16 to the 53.99.

THE WITNESS: Sure.

(Late-Filed Deposition Exhibit 6 was identified.)

BY MS. McWHIRTER:

Q Now, the 76.37, the forwards market price as of December 2000, does that number include capacity as well as energy, or is that the energy component of the forwards market only?

A That's the energy component.

Q So in addition to the 76.37, there would have been a capacity payment?

A Yes.

Q Where would you find that on --

A You won't. It's not a published indices.

Q When you go out and buy market, do you still buy it -- in your spot market contracts and

short-term contracts, do you still buy it on the basis of a capacity and an energy charge, or do you just pay a market price for it?

A If you're buying short-term, you're generally buying non-firm power. You're not buying firm power, and so you're paying an energy charge only.

Q You're paying a charge that has more than one component. If somebody is selling you power, they're not going to sell it to you just for the fuel cost, are they?

A Oh, absolutely. It will have fuel and O&M and profit and transmission and everything in it, ancillary services also. But you're buying an energy product that is non-firm.

Q So that $76, was that a firm price or was that a non-firm price?

A A non-firm price.

Q So that includes your capacity and ancillary charges and the energy charges and all those other components?

A The 76.37 is basically, if you look at the indexes that are published, it's a 5-by-16 or a 7-by-16 index, such that if you want to buy that product, you have to take it 16 hours a day, five days

a week or seven days a week. It's sold both ways. And if the product is cut, in other words if it's discontinued, then they do not find replacement power for you, but what they will typically do is give you liquidated damages for non-delivery. And that is a non-firm product.

Q They will pay you or charge you?

A They will pay you liquidated damages.

Q If they don't deliver?

A That's correct.

Q What question were you answering with that answer?

A I know the question. I think you were asking me if the 76.37 was an energy-only product and what did it include.

Q And your response was that that's the whole ball game on a 5/16 transaction?

A That's right. And that index is typically a monthly index. It's not a weekly index, so you have to buy it for the month.

Q Sixteen hours a day, five days a week. I guess the 16 hours are the on-peak hours?

A Yes.

Q And that changes depending on the time of the year?

A Yes, it does.

Q Do you handle the wholesale transactions for Tampa Electric only or for TECO Energy as a whole?

A Tampa Electric Company. However, we do sell Hardee power plant when neither Seminole nor Tampa Electric needs it. According to the contract terms, we will sell it on the hourly market if it's available to sell, but very little of that is done.

Q Where is TECO Energy's trading floor?

A I don't think TECO Energy has a trading floor.

Q If it had power it was producing in Texas and wanted to market that power in Illinois, would you handle that transaction?

A No.

Q Who handles that transaction?

A I think you're talking about TECO Power Services. I believe TECO Power Services handles that transaction. We do not handle any of their transactions, with the exception of that occasional hourly sale off of Hardee when neither Seminole nor Tampa Electric needs it.

Q TECO Power Services has its trading floor just like yours?

A Well, to my knowledge, they are in the

process of developing a trading floor.

Q So at this point of time, the only real trades that are being made are the ones within the State of Florida?

A I don't know what TECO Power Services is doing, frankly. We have a code of conduct between Tampa Electric and TECO Power Services, an affiliate code of conduct, and I'm not allowed to know what they're doing, frankly, and they're not allowed to know what we're doing. So I understand they are developing a trading floor, but how they sell their plants outside of the State of Florida I really don't know.

Q I didn't put this in exhibit form, but it's short. It was in last Wednesday's Tampa Tribune. It says, "TECO wholesale power boosts bottom line," and it says, "TECO Energy saw third-quarter profits rise 19% on the strength of wholesale power operations, which operates mostly outside of Florida." So that's not your operation. That's TECO Power Services?

A That's correct.

Q Do you sell power outside of Florida?

A Occasionally.

Q Would that be included in this profitability figure?

A I don't believe that's what that article is referring to. I believe that article is talking about TECO Power Services.

Q You mentioned the Entergy Hub. Where is the Entergy Hub physically located?

A Well, typically it's at Entergy.

Q Which is in Louisiana?

A It's actually in Louisiana, Mississippi, and Arkansas, the Entergy system.

Q The Henry Hub is essentially Mobile Bay. Does the Entergy have a central location like that?

A Not electrically.

Q Give me a word picture of your trading floor. Is it a bunch of people at desks in front of TV sets, or a bunch of people at desks with phones at their ears, or what would it look like if I walked into the trading room?

A We have a small trading operation, although it is 7-by-24. We have all the tools and capabilities of an Enron type trading floor, but we are a much smaller operation in numbers.

Q That's a room 7 feet wide by 24 feet long?

A I don't know what the size of the room is.

Q How big is it?

A It's about the size of this room.

Q And how many people will be in there?

A Either one or two real-time traders on at all times.

Q And what are they doing? Talking on the phone?

A Well, it's really quite an involved process. It's not as simple as it used to be. As you may recall, the energy broker in Florida was around for many, many years, and that simplified the trading process. That was a cost-based software system that worked very well for many years. But wholesale energy trading today is much more complicated and much more elaborate.

Typically what they do, if we just kind of step through a day, you know, an hour, say an hour in a real-time trader's life, at the top of an hour, they will begin to look at the needs of the system for the following hour. In other words, at 8:00 a.m., they will look at the needs of Tampa Electric's system, the retail load for the hour 9:00 a.m. to 10:00 a.m. And that's called hour ending 10:00, of course.

Q And they get that from Operations?

A That's correct. They receive that information from Operations.

Q They can see that on a television monitor?

A Yes. Everything is on-line. Everything is computer-driven, of course. And through phone calls also with Operations, they receive information as to how many megawatts the operations sides of the company has extra to sell or needs, or perhaps they have the megawatts, but maybe they want to buy economy. Instead of running those units, they'll buy economy. So that conversation goes on around the top of every hour.

And let's just take a scenario here where they're wanting to buy power instead of running some more expensive generating units. They will communicate the incremental cost of what it would take to run the next 100 megawatts, for example, of generation for the hour 9:00 to 10:00, and they know that they need that 100 megawatts, because load is coming up. It's increasing. And they know exactly what the ramp rate is of the load. They determine exactly what they need and when they need it. And they issue a call out to us to see if you can buy 100 megawatts for the coming hour at less than $60, because they determined that $60 is their incremental price of ramping that generation up.

At that point, our real-time traders go into action. They begin to completely pan the entire

market, both inside and outside the state. And the market includes utilities, power marketers, anyone who has the power or possibly has the power to sell or resell to us.

Q How do you connect? All by phone?

A It's all done by phone. And the fact is, they do this every hour, so they pretty much know who's in the market and who's out of the market, who's in the money and who's out of the money, who's really giving the best deals and who's not. And it changes constantly throughout the day. But they'll typically call five or six entities who they know are really on the edge of the price.

Q Cutting edge.

A Cutting edge of the price that next hour. And they'll find the best deal they can find. But price is not the only thing, because they've got to get the power delivered to Tampa Electric Company, and that can sometimes be the hardest part. Finding the best price is nice, but if you can't get it here, it's not worth much.

So once they find the best deal, then they go out onto the transmission information system, which is called OASIS, which is probably a familiar term, and they determine if transmission is available by

looking at the OASIS paths, the transmission paths from the potential seller's point to Tampa Electric Company.

Q Now, how do they do that? By phone, or --

A No. That's all done through the Internet.

They determine if they can find a reliable path with sufficient capacity to ship that 100 megawatts to Tampa Electric Company. Let's assume they find a path. They call the entity back who has the best price on this 100 megawatts, and they say, "Let's do the deal."

And then really the real work starts, because then they have to go back on the OASIS system and reserve transmission. And to reserve it, they actually have to enter a request into the computer system. And if they have to wheel that power through several transmission systems, then that request has to go to each one of those transmission systems.

Once they get that done, they put the request in, and then they have to initiate an e-tag, what we call an e-tag. It's an electronic tag. It's a descriptor that describes the transaction. That tag has all the information about that transaction on it. It's electronic. Nothing is on paper. And that tag contains information like who the selling entity and

who the buying entity are, what the source is, what the different transmission providers will be, who is going to pay for losses, where the losses will be paid, what the ramp rates are, the time of the transaction, and so forth and so on. It's a tag. It's an identifier that -- if you look at that tag, you can tell anything about that 100 megawatts, when it's going to start, when it's going to stop. The only thing that's not on the tag is the price. The price --

Q Is not on the tag.

A Is not on the tag.

Then they initiate that tag, and that tag goes to all of the different entities who will handle that transaction. In other words, a copy goes to the originating seller, and a copy goes to each of the transmission providers. All this is done electronically on-line. Each entity that handles that transaction then has to approve their piece of that tag. All those approvals have to be done within so many minutes. Everything is timed very, very closely.

Q They have so many minutes, and then the deal aborts?

A That's correct, it aborts. And then you have to find replacement power very quickly. And

we're talking down to seconds to approve transactions. People have to be on-line and have to be paying attention to get it done within the time requirements.

Let's assume it's all done. It all has to be done by 20 minutes till the hour so that the selling entity can ramp their generators up 100 megawatts and that power can flow starting at the top of the hour.

Q It has to be completed by 20 minutes to 1:00.

A Twenty minutes till 9:00 in my example. And during that 20 minutes, let's assume everything is done, the power is going to flow, all the tags are approved, transmission has been obtained, everything is working. During that 20 minutes, our real-time trader looks over the deal and documents it into our energy tracking system. We track every deal, every detail.

And about the time he finishes, it's the top of the hour, and he repeats the process over again.

Q And this happens every hour?

A Every hour, 24 hours a day.

Q And what happens with respect to purchases? Is that the other guy in the room doing

that, or does the same guy do that?

A If we have two people on duty at the same time -- generally we're not selling and purchasing at the same time, because we're talking about non-firm. This is hourly, short-term, hour. Typically they will divide up duties. If we get real, real busy, one of them will take the tagging and OASIS duties, and the other will take the telephone dealing duties and the energy tracking input. They will divide up the responsibilities. But the norm is just to have one person on duty. He does it all.

Q Buying and selling?

A Buying and selling, doing the tagging, the transmission, the tracking, all the paperwork, all the deal.

Q And do you stand in another room and look at it all through a plate glass window, or are you in there with them?

A I visit occasionally.

Q Now, Hardee Power Partners, is that owned by TECO Power Services, or is that an independent entity?

A I'm not certain of the relationship, but I believe they are a subsidiary of TECO Power Services, if I'm not mistaken.

Q Then Hardee Power Partners obviously knows the price you're paying to buy from it and knows the price you're selling to it. How do you avoid the Chinese Wall prohibition in your ethical conduct?

A Well, the way we avoid it is that both of those transactions, the buying from Hardee power station and the selling of Big Bend 4 to them, are cost-based agreements. They're not market-based transactions. And because of that, we are allowed to meet the FERC guidelines, because they're cost-based transactions.

Q So the price fluctuates with the price of whatever the fuel is at the time?

A That's right.

Q And do you have a first -- you don't have first call on all that power? Seminole can bump you if it wants to on part of it?

A No. Actually, the terms of the agreement state that Seminole must be experiencing an outage in order to have first call.

Q That's the new agreement, but the old agreement did not provide that --

A No, that's the old agreement. Under the new agreement, we have first call, period.

Q At what point -- what criteria have to be

present for Seminole to get first call on that power?

A On the new agreement?

Q No, on the old agreement.

A They must experience a unit outage.

Q And it's not just a matter of them wanting it. They have to have an outage.

A That's correct.

Q Don't you have some sales contracts that have a 100% load factor?

A No.

Q I remember back in FMPA it showed a 100% load factor on transactions --

A Well, FMPA expired 3/15/01.

Q I understand.

A But today, we do not have any contracts that I can think of that have a 100% load factor.

Q With respect to -- that reminds me. Ms. Jordan suggested that you would be the appropriate one to give a late-filed exhibit which gives the codes for each of your wholesale contracts. Would you give us a late-filed exhibit that gives the codes for each contract, like JA, JC, A, B, C, X?

A The schedules?

Q The schedules.

A Yes.

Q How about Schedule D? What is that?
A Typically a Schedule D contract is a cost-based long-term agreement.
Q For less than five years?
A For more than one year.
Q For more than one year. So since you've been in place in 1978, there have not been any new Schedule D agreements?
A Since when? I'm sorry.
Q Since 1998 when you took over, you said you've entered into no additional firm agreements?
A That's correct.
Q So no Schedule D agreements have been renewed?
A That's correct.
Q Now, the agreements with Kissimmee and Fort Meade and Wauchula and the ones that were in the 1993 rate case that were separated out, those were Schedule D contracts. Have those all expired now?
A Yes. They expired some years ago.
Q And you no longer sell to those entities?
A No. Actually, in the response to interrogatories, I detailed all of our long-term sales, and you will see that we still do sell to those entities, but our sales are all done under our AR-1

tariff.

Q What schedule?

A All-Requirements tariff to Fort Meade and Wauchula and others.

Q And those contracts are separated contracts?

A Yes.

Q And what is the life term of those contracts?

A That information is also provided in the interrogatories, but as I recall -- I would have to go back. It's different terms for different contracts, and I can't make a blanket statement. They expire at different time frames.

Q Now, when you say they're cost-based contracts, does the fuel fluctuate on an hourly basis?

A It fluctuates on a monthly basis.

Q On a monthly basis. And how do you do that?

A Well, I think Ms. Jordan addressed some of that. And, frankly, I don't know all the details of how the billing is done to those customers, but I do know that the cost of purchased power is factored in. Those customers, for all practical purposes, are treated similarly to firm retail load of Tampa

Electric Company, so they pay their fair share of purchased power through the fuel clause.

Q On your Schedule 6, Ms. Stern was asking you about it indicates that for the next year that the fuel cost and total cost on those contracts is going to run somewhere around $23.56. And that looks a lot different than the price that you're paying for purchased power for the retail consumer. Can you explain that difference?

A What are you looking at? I'm sorry.

Q I was looking at Schedule E6 on page 47.

A Okay. Could you repeat what you were saying? I'm sorry.

Q All right. Let's look at --

MR. BEASLEY: I don't believe that Ms. Jordan deferred any questions concerning page 47 to this witness.

MR. McWHIRTER: Well, I'm trying to clarify what he said based upon the information that's in evidence, and what he said was that on the sales contracts, those Schedule D people are treated just like retail consumers.

THE WITNESS: No, I said the AR-1 tariff people, not Schedule D.

BY MR. McWHIRTER:

Q I see. And Kissimmee and Wauchula and St. Cloud and those people are not Schedule D contracts anymore? They're AR-1 contracts?

A Fort Meade, Wauchula, St. Cloud, Florida Power, and Reedy Creek are all-requirements contracts.

Q And what is your commitment on those all-requirements contracts?

A We essentially treat them the same as retail, firm retail load, and that is basically what I was describing earlier, that fuel and purchased power is passed on to them, just like a retail customer.

Q Well, in Ms. Jordan's schedule on page 47, she's got 72,000 megawatt-hours that were sold at a total cost of $14.69. Who are those people?

A That's the Schedule D?

Q Yes, sir.

A I don't know.

MR. BEASLEY: When you get to a point where we can take about five minutes, I would appreciate it.

MR. MCWHIRTER: Sure.

(Short recess.)

BY MR. MCWHIRTER:

Q Mr. Brown, I just handed you a copy of the Wall Street Journal that has the DJ Electrical

Indexes. And we think that's probably all right and it shouldn't be idices. But how do the numbers that appear on there relate to the things you've been talking about today?

A These are typical of the information that we've been talking about today. This does not have the forwards market information in it. This actually has historical information in it. But it provides information on deals that were done for the past four days.

Q How does the Wall Street Journal get ahold of the price that was paid on those transactions? Where is that posted?

A For some hubs like California-Oregon Border, Palo Verde, Mid Columbia, those are published. That's published information because of the power exchange that exists in California and the West. For PJM, that's also published, the PJM Western Hub. Synergy, some of that is published and some of it is not. I suspect what they do is, they get what they can, and then they may make phone calls. They have contacts in the industry and so forth where there is no published exchange.

Q Now, Entergy's forward market, that is published or not published?

A That is published. It's a published forecast, and it is published in several publications in the industry.

Q And if Entergy published that it had 50 megawatts on 5/16 for the month of January, would that be something that you could go buy a month away?

A You might be able to, if you could get it delivered to your system.

Q Is there anything similar for central Florida that shows transactional prices that are posted like in those places?

A No. Really, the closest hub to Florida is TVA, and TVA's liquidity is so low that we don't use it. It's not reliable for pricing. The next closest is Entergy that has enough liquidity that we feel the prices are fairly close to what we would see in Florida.

Q Megawatt Daily posts something called the Florida Border. Are you familiar with that?

A Yes.

Q What is that all about?

A It's the Florida-Georgia Border. It's not a very reliable number because of the low liquidity, although its good information.

Q It's interesting, but not reliable?

A It's not reliable, and you won't see any forwards prices on the Florida-Georgia Border. You'll only see historical figures.

Q How is that information obtained?

A By telephone.

Q Who is it that calls up and gets the prices?

A The editors of Megawatt Daily or the editors of whoever the newsletter is. They will call power marketers who have done deals. They know who deals in the Southeast, and under confidentiality agreements with them, they will get them to just give them numbers, prices that they settled at for that day.

Q Wouldn't it be very beneficial to your operation to have an established exchange similar to the PJM? Instead of calling around to ten places, you could have 100 places available to you on a bulletin board.

A It would certainly save a lot of telephone time.

Q What is the reality of something like that coming into being?

A Well, I think in the original GridFlorida proposal there was some type of a balance -- it was a

balancing market, actually, which was a real-time exchange, if you will, certainly not developed like these other hubs have developed their exchanges, their published pricing. But I believe GridFlorida was a step towards this type of public pricing information, that is, what power is costing you at any given time, or will cost you.

But to set something like this up would require the cooperation of market participants and would require a lot of money, I'm sure, to set up the system, because this is a market-based price system. It's not a cost-based price system we're talking about. I think market liquidity, that is, participation, is key to the success or failure of any exchange.

Q Couldn't you do a lot better on your purchases if you went to Florida Power or Florida Power & Light, who are required by FERC to sell power at market -- or cost-based as opposed to market-based?

A Well, we do buy power from both of them. However, they both have market-based pricing authority outside of the state. They do have cost-based pricing authority inside the state. However, they can still make a profit on those transactions within certain guidelines as specified by the FERC.

Q How is that?

A If the availability and the price of the product from them is the best, then that's who we'll buy from. But if it is not, then we don't buy from them.

Q So when they say their price is cost-based, it's not the same kind of cost that the Public Service Commission looks at when it sets retail rates; is that correct?

A Well, it's similar. Their contracts specify -- and we used to have cost-based pricing also. For example, the J contract is what we used, and it specified that we could make so much above our cost. It established a cap, in other words. And sometimes, for some entities, that cap is specified in dollars and cents, and in some entities it's specified as a percentage, in other words, a percent above your cost. And in our case it was dollars and cents above our cost, regardless of what the sale price was.

Q When Florida Power & Light filed its tariff back in 1993 with FERC, it asked to have an opportunity price cost. Did that go into being?

A I can't really address that. I don't know for Florida Power & Light.

Q In dealing with Florida Power & Light, they

don't give you an opportunity cost?

A They give us a price for a commodity, 50 megawatts, for example, for the next hour. And it's up to them to justify to FERC that it's a cost-based transaction under their agreements.

Q Do you attempt to audit it to determine whether it's cost-based or not?

A No. We're simply looking for the best product at the best cost.

Q With respect to these 39 generators, are they leased from a third party, or are they leased from an affiliated company?

A A third party.

Q They burn No. 6 fuel oil?

A I believe they do.

Q Do you recognize that document?

A Yes, I do.

Q Tell us what that document is.

A As I recall, this was an exhibit that was submitted as part of Jerry Kordecki's deposition, and it was a stacking order of power sources.

Q Did you help Mr. Beasley prepare that document, or did somebody else do it?

A I recall helping Mr. Beasley, yes.

Q And down there at the bottom you have $125

at must-buy?

A Must-take, yes.

Q Must-take. Is there a corresponding requirement that you must charge that to the retail customers?

A Well, if we must take the power at $125, yes, it's passed on to the retail customers at $125.

Q Is there any requirement by Commission order, rule, regulation, or statutes that requires you to pass that on to the retail customer?

A I don't know.

MR. MCWHIRTER: I tender the witness.

MR. BEASLEY: Did you want to mark that late-filed exhibit that was Number 3 for Ms. Jordan as a late-filed exhibit for Mr. Brown?

MR. MCWHIRTER: Yes.

MR. BEASLEY: It will be Late-Filed Exhibit 7, and we'll use the same title we discussed earlier.

MR. MCWHIRTER: Yes, sir.

(Late-Filed Deposition Exhibit 7 was identified.)

MR. BEASLEY: I just had one redirect, if I can find it.

CROSS EXAMINATION

BY MR. BEASLEY:

Q We talked a lot about these 39 generators, Mr. Brown. Can you describe any benefits of having these units available on your system vis-a-vis attempting to buy power from another source?

A Well, certainly the 39 generators -- and I think I may have mentioned a little bit of this before. They are available 24 hours a day at a moment's notice. They start very quickly. They can be shut down and restarted numerous times. In other words, they provide us a lot of flexibility as far as dispatching is concerned.

In trying to compare the cost of these to something that we might find on the market, it's going to be like comparing apples to oranges, because these units provide us a terrific amount of flexibility that you can't get necessarily from a purchased power agreement, because typically a purchased power agreement for this 70 megawatts, for example, is probably either a must-take, you must take it 16 hours a day, five days a week, or it's an option.

It would be an option whereby you have to strike on it on a day-ahead basis. In other words, you have to strike on it 24 hours ahead of when you

need it. And then when you strike, you generally have to take it for 16 hours. And the strike price would be dependent upon the premium of the option.

So that's kind of the comparison that you're going to have to look at, the purchased power versus these generators.

MR. BEASLEY: Thank you. That's all I have.

MR. MCWHIRTER: Can I recross on that?

RECROSS EXAMINATION

BY MR. MCWHIRTER:

Q With respect to the must-take that you mentioned, what happens if you don't take it? Do you pay liquidated damages?

A It's take or pay. You either take it or pay for it, but you're doing to pay for it whether you take it or not.

Q You pay the total price of it?

A That's correct. That's the product that I was describing that's even in the Wall Street Journal that you were referring to. These are 16-hour products. If you don't take it, you've already committed to it, so you're going to pay for it anyway.

Q And there's no provision, since they didn't burn the fuel, that you can get a reduced price to

eliminate all or part of the fuel cost?

A Well, from a practical standpoint, you're just not going to refuse it. If you refuse it, they will still bill you for it, and they will bill you at full price, so you may as well take it.

Q And a contract that you had that would require you -- that would give you the right to walk away, that would be a more expensive contract?

A Oh, sure. If you wanted that option in the contract, you would pay for that option, absolutely. And I'm not saying that you couldn't get that option. If you wanted it, certainly -- everything is available at a cost.

Q And you can do that today without any specific approval for hedging by the Commission?

A These types of contracts generally are longer term. So the answer is no. I generally involve my boss in those kinds of decisions.

MR. MCWHIRTER: That's all.

MR. BEASLEY: That concludes the deposition.

(Deposition concluded at 5:20 p.m.)

CERTIFICATE OF ADMINISTERING OATH

STATE OF FLORIDA)
COUNTY OF LEON)

I, MARY ALLEN NEEL, Notary Public in and for the State of Florida at Large:

DO HEREBY CERTIFY that on the date and place indicated on the title page of the foregoing transcript, an oath was duly administered by me to the designated witness before testimony was taken.

WITNESS my hand and official seal this 29th day of October, 2001.

MARY ALLEN NEEL, RPR
100 Salem Court
Tallahassee, Florida 32301

Mary Allen Neel
MY COMMISSION # CC 782020
EXPIRES: October 10, 2002
Bonded Thru Troy Fain Insurance

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, MARY ALLEN NEEL, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter transcribed under my supervision; and that the foregoing pages numbered 1 through 114 are a true and correct transcription of my stenographic notes.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, or relative or employee of such attorney or counsel, or financially interested in the action.

DATED THIS 29th day of October, 2001.

MARY ALLEN NEEL, RPR
100 Salem Court
Tallahassee, Florida 32301
(850) 878-2221

NOV - 7 2001

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor	))))	DOCKET NO. 010001-EI FILED: November 6, 2001

TAMPA ELECTRIC COMPANY'S

LATE-FILED DEPOSITION EXHIBITS (NOS. 1-7)

OF

W. LYNN BROWN

Tampa Electric files this its Late-Filed Deposition Exhibits of Witness W. Lynn Brown (Nos.1-7), requested during his deposition held on October 25, 2001.

TAMPA ELECTRIC COMPANY
DOCKET NO. 010001-EI
DEPOSITION OF W. LYNN BROWN
LATE-FILED DEPOSITION EXHIBITS
FILED: NOVEMBER 6, 2001

INDEX

LATE - FILED EXHIBIT	TITLE
1	Contract of Leasing Generators
2	Contract with Reedy Creek Improvement District for Contract Term from January 1998 to December 2017
3	Percentage of Purchased Power for January Through August 2001 Procured from Long-Term Contracts Signed in 2000
4	Deliveries Between January and August 2001
5	Average Forward Energy Price from August to November 2000
6	HPP 2001 Energy Price Including Capacity Payments
7	Schedule Classifications Used by Tampa Electric Company in Its Wholesale Transactions

1. Provide the lease contract for the 39 portable generators and the cost-effectiveness analysis prepared by Tampa Electric.

A. See the attached documents. The cost-effectiveness analysis methodology and results are provided on page 2 of the exhibit. Also attached are the lease contracts and environmental permitting information.

Contract Concerning the Lease
of 39 Portable Generators

Pages 2 – 80

Filed Separately Pursuant to a
Motion for Protective Order

DISTRIBUTED GENERATION UNITS

ENVIRONMENTAL INFORMATION

Hookers Point Power Station

On January 23, 2001, Tampa Electric Company requested permission from the Florida Department of Environmental Protection to construct and operate thirty Caterpillar XQ2000 Power Modules. On April 20, 2001, the Department granted this request by issuing permit number 0570038-002-AC. These power modules may operate for up to 22,100 aggregate hours per year and must emit less than 53 pounds of NO_x per hour. Ringhaver Equipment Company installed and operated thirty Caterpillar XQ2000 Power Modules at Tampa Electric Hookers Point power station.

Substation Generation Program

Rule 62-210.300(3)(a)21 of the Florida Administrative Code provides an exemption from permitting from any internal combustion engine that consumes less than 32,000 gallons of fuel oil per year. Ringhaver Equipment Company installed and operated one Caterpillar XQ2000 Power Module at each of eleven Tampa Electric substations under this exemption. In a letter dated March 5, 2001, Tampa Electric Company notified the Florida Department of Environmental Protection that it intended to site eleven of the above mentioned internal combustion engines at eleven different substations, and in a letter dated May 1, 2001, the Department authorized this activity.

FINAL DETERMINATION

Tampa Electric Company
Hookers Point Station
Installation of 30 Internal Combustion Engines
DEP File Number 0570038-002-AC

An Intent to Issue an Air Construction Permit to Tampa Electric Company Hookers Point Station, located at 1700 Hemlock Street, Tampa, Hillsborough County, Florida, was distributed on March 30, 2001. The Public Notice of Intent to Issue Air Construction Permit was published in the Tampa Tribune on April 4, 2001. Copies of the draft air construction permit were available for public inspection at the Department offices in Tampa and Tallahassee.

The Environmental Protection Agency (EPA) submitted a comment regarding the netting analysis for the project. EPA suggests the final permit should contain practically enforceable limits on fuel oil consumption and/or hours of operation, which correspond to 582 tons per year (tpy) of NO_x emissions from the IC engines.

The Department in agreement with the applicant will modify the permit to restrict the hours of operation of the 30 IC engines to 22,100 hours per year cumulative. This corresponds to 582 tpy of NO_x emissions from the 30 IC engines. The changes will be reflected in Specific Condition 12 and 14 for Emission Units 007-036, and Specific Condition 2 for Emission Units 001-006.

Specific Condition 12 will be changed to:

Fuel Oil Consumption: The maximum No. 2 fuel oil allowed to be burned in thirty internal combustion engines combined is ~~3,180,152~~ 2,713,880 gallons per year, which is equivalent to ~~25,897~~ 22,100 engine-hours per year at 100% load. **[Rule 62-210.200, F.A.C. (Definitions-PTE)]**

Specific Condition 14 will be changed to:

Hours of Operation: The thirty internal combustion engines shall operate no more than ~~25,897~~ 22,100 engine-hours during any consecutive 12-month period. The permittee shall install, calibrate, operate and maintain a monitoring system to measure the hours of operation on each internal combustion engine. **[Rule 62-210.200, F.A.C. (Definitions-PTE)]**

Specific Condition 2 will be changed to:

For each 12-month period that the thirty internal combustion engines (EU007-EU036) operate below ~~25,897~~ 22,100 engine-hours, the existing emission units 001 through 006 may operate to reach the facility-wide NO_x cap of 682 tpy. NO_x emissions from the existing emission units (EU001-EU006) shall not exceed 100 tpy. The existing emission units shall use the CEM system to demonstrate compliance with the emission limits for NO_x. **[Rule 62-212.400, F.A.C. (PSD avoidance)]**

The Department in agreement with the applicant will modify Specific Conditions 20 and 21 relating to Emissions Performance Testing for Emission Units 007-036. Initial performance test will be required on a sample of five randomly picked IC engines for the first year and then a different randomly picked five from the remaining 25 IC engines for the second year. Annual testing will be required on only those IC engines that have operated more than 3,700 hours, which corresponds to 100 tons of NO_x emissions.

Specific Condition 20 will be changed to:

Initial Tests Required: Initial performance tests to demonstrate compliance with the emission standards specified in this permit shall be conducted within 60 days after achieving at least 90% of permitted capacity, but not later than 180 days after initial operation of the emissions unit. Initial performance tests shall be conducted for NO_x and visible emissions on ~~one of the internal combustion engines~~ a sample of 5 (five) randomly picked internal combustion engines for the first year. A different set of randomly picked five engines from the remaining 25 (twenty five) internal combustion engines will be tested during the second year of operation. **[Rule 62-297.310(7)(a)1., and 62-297.310(7)(c), F.A.C.]**

Specific Condition 21 will be changed to:

Annual Performance Tests: To demonstrate compliance with the emission standards specified in this permit, the permittee shall conduct annual performance tests for NO_x and visible emissions on the emission units that operated for more than ~~400 hours~~ 3,700 hours in the preceding 12-month period. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). **[Rule 62-297.310(7)(a)4., and 62-297.310(7)(c), F.A.C.]**

The Department in agreement with the applicant will make a change in the table, which gives the Emissions Unit Description preceding the specific conditions. The change removes the restriction of operating the IC engines only at 100 percent load.

The table will be changed to:

EU ID No.	Emissions Unit Description
001-006#	Six boilers that are fired using No. 6 fuel oil.
007-036*	30 Caterpillar XQ2000 Power Modules. Each Power Module consists of one Caterpillar 3516B 16-cylinder, 4-stroke cycle diesel internal combustion (IC) engine and one Caterpillar SR4B generator. The Caterpillar 3516B IC engine has a power rating of 2,593 brake horsepower (bhp) at 100 percent load. The Caterpillar SR4B generator has a power output rating of 1,825 kilowatts (kW) at 100 percent load. The IC engines will be fired exclusively with low-sulfur (maximum of 0.05 weight percent sulfur) diesel fuel oil ~~and will only operate at 100 percent load~~.

The final action of the Department is to issue the permit with the changes noted above.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit

Mr. Darryl Scott, General Manager
Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601-0111

Permit: 0570038-002-AC

Enclosed is the FINAL Permit, which allows installation of 30 (thirty) Internal Combustion Engines, each, rated at 1.825 MW nominal at Hookers Point Station in Hillsborough County. This permit is issued pursuant to Chapter 403, Florida Statutes and 62-4 through 297, F.A.C and 40 CFR 52.21 - Prevention of Significant Deterioration(PSD).

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

for C.H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 4/20/01 to the person(s) listed:

Mr. Darryl Scott, TEC*
Mr. Gregg Worley, EPA
Mr. Bill Thomas, DEP SWD
Mr. Jerry Campbell, HCEPC
Mr. Tom Davis, P.E., ECT

Clerk Stamp

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

Charlotte J. Hayes (Clerk) 4/20/01 (Date)

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

PERMITTEE:

Tampa Electric Company
Hookers Point Station
1700 Hemlock Street
Tampa, Florida 33605-6660

Authorized Representative:
Mr. Darryl Scott
General Manager

ARMS Permit No.	0570038-002-AC
Facility ID No.	0570038
SIC No.	4911
Expires:	December 1, 2001

PROJECT AND LOCATION

The proposed project authorizes the installation of thirty internal combustion engines with electrical generator sets. The thirty engines are capable of producing a nominal 54.75 MW of electricity.

The project will be located in Hillsborough County at 1700 Hemlock Street, Tampa. The UTM coordinates are Zone 17, 358 km E, 3091 km N.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix GC - Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources Management

"More Protection, Less Process"

Printed on recycled paper.

FACILITY DESCRIPTION

The existing facility consists of six oil-fired steam boilers (Units Nos. 1 through 6) at the Hookers Point Station located at 1700 Hemlock Street, Tampa, Hillsborough County. All the boilers are fired using No. 6 fuel oil. The boilers may also fire a limited quantity of on-specification used oil. The total generating capacity at this facility is 227 megawatts. Also located at this facility are miscellaneous unregulated/insignificant emissions units and/or activities. Title V Final Permit No. 0570038-001-AV currently authorizes operation of the existing steam boilers. Final Title V Permit was issued with an effective date of January 1, 1998 and expires on January 1, 2002. Completion of this project will result in the installation of thirty internal combustion engines with generators capable of providing a nominal 54.75 MW of electrical power.

REGULATORY CLASSIFICATION

Acid Rain: This facility is subject to the acid rain provisions of the Clean Air Act (Title IV).

Title V Major Source: This facility is a Title V major source of air pollution.

PSD Major Source: Each pollutant with potential emissions greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C. requires a PSD review and Best Available Control Technology (BACT) determination. For this project, emissions of no pollutant are significant or subject to BACT standards, provided that the Emission Unit is operated as specified in this permit. However, the existing facility is classified as a PSD Major Source.

PERMIT SCHEDULE

- 01-23-01: Date of Receipt of Permit Application
- 02-07-01: Application deemed complete
- 03-30-01: Intent issued
- 04-04-01: Notice published in the Tampa Tribune

RELEVANT DOCUMENTS

The documents listed form the basis of the permit. They are specifically related to this permitting action. These documents are on file with the Department.

- Application received 1-23-01
- Department letter dated 1-30-01
- Company letters dated 2-06-01 and 2-15-01
- Technical Evaluation and Preliminary Determination dated 3-21-01
- EPA's letter dated April 17, 2001

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (DEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number 850/488-0114.

2. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Air Management Division, Hillsborough County Environmental Protection Commission, 1900 Ninth Avenue, Tampa, Florida 33605. The phone number is 813/272-5960 and the fax number is 813/272-5157.

3. Terminology: The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code.

4. General Conditions: The owner and operator are subject to, and shall operate under, the attached General Conditions listed in *Appendix GC* of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. **[Rule 62-4.160, F.A.C.]**

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-110, 62-204, 62-212, 62-213, 62-296, 62-297 and the Code of Federal Regulations Title 40, Part 60, adopted by reference in the Florida Administrative Code (F.A.C.) regulations. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting or regulations. **[Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]**

6. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. **[Rule 62-4.080, F.A.C.]**

7. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. **[Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]**

8. Expiration: This air construction permit shall expire on **December 1, 2001**. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation prior to 60 days before the expiration of the permit. **[Rules 62-210.300(1), 62-4.070(4) 62-4.080, and 62-4.210, F.A.C]**

9. Title V Permit: This permit authorizes construction and/or installation of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The owner or operator shall apply for a Title V operation permit at least ninety days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation, and a copy sent to the Department's Southwest District office. **[Rules 62-4.030, 62-4.050, 62-4.220, and 62-213.420, F.A.C.]**

This permit addresses the following emissions units.

EU ID No.	EMISSIONS UNIT DESCRIPTION
001 – 006#	Six boilers that are fired using No. 6 fuel oil.
007 – 036*	30 Caterpillar XQ2000 Power Modules. Each Power Module consists of one Caterpillar 3516B 16-cylinder, 4-stroke cycle diesel internal combustion (IC) engine and one Caterpillar SR4B generator. The Caterpillar 3516B IC engine has a power rating of 2,593 brake horsepower (bhp) at 100 percent load. The Caterpillar SR4B generator has a power output rating of 1,825 kilowatts (kW) at 100 percent load. The IC engines will be fired exclusively with low-sulfur (maximum of 0.05 weight percent sulfur) diesel fuel oil.

Existing Emission units

* New Emission units

The following Specific Conditions apply to the new emission units 007-036:

PERFORMANCE RESTRICTIONS

1. Internal Combustion Engines: The permittee is authorized to install, tune, operate and maintain thirty new internal combustion engines with electrical generator sets (Caterpillar XQ2000 Power modules). The thirty generators are designed to produce a maximum 54.75 MW of electrical power. **[Applicant Request]**

2. Future PSD Review: The internal combustion engines shall not exceed the permitted hours of operation, nor the permitted NO_x emission limits allowed by this permit. This restriction is based on the permittee's request, which formed the basis of the PSD non-applicability determination and resulted in the emission standards specified in this permit. For any request to modify this emission unit in any way (whether a physical or operational modification, including a change in the allowable hours of operation or heat input) the permittee shall submit a full PSD permit application. **[Rules 62-212.400(2)(g) and 62-212.400(6)(b), F.A.C.]**

3. Allowable Fuel: The internal combustion engine shall be fired primarily with No. 2 fuel oil. The permittee shall demonstrate compliance with the fuel sulfur limit by keeping the records specified in this permit. **[Applicant Request, Rule 62-210.200, F.A.C. (Definition - PTE)]**

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

5. Noise Nuisance: The permittee shall comply with the noise nuisance ordinances as outlined in Chapter 1-10 of the Rules of Environmental Protection Commission of Hillsborough County. **[Rule 1-10.01(B)(9) and Rule 1-10.03, EPCHC]**

EMISSIONS CONTROLS

6. Unconfined Emissions of Particulate Matter: [Rule 62-296.320(4)(c), F.A.C.]

(a) No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity, including vehicular movement; transportation of materials; construction, alteration, demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling; without taking reasonable precautions to prevent such emissions.

(b) Any permit issued to a facility with emissions of unconfined particulate matter shall specify the reasonable precautions to be taken by that facility to control the emissions of unconfined particulate matter.

(c) Reasonable precautions include the following:

- Paving and maintenance of roads, parking areas and yards.
- Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing.
- Application of asphalt, water, oil, chemicals or other dust suppressants to unpaved roads, yards, open stock piles and similar activities.
- Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the facility to prevent re-entrainment, and from buildings or work areas to prevent particulate from becoming airborne.
- Landscaping or planting of vegetation.
- Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter.
- Confining abrasive blasting where possible.
- Enclosure or covering of conveyor systems.

(d) In determining what constitutes reasonable precautions for a particular source, the Department shall consider the cost of the control technique or work practice, the environmental impacts of the technique or practice, and the degree of reduction of emissions expected from a particular technique or practice.

EMISSION STANDARDS

7. Nitrogen Oxides (NO_X):

NO_X emissions from each internal combustion engine shall not exceed 53 lb/hr. Additionally, annual emissions of NO_X in tpy from these emission units shall be calculated by using the NO_x emission rate of 53 lb/hr multiplied by the total operating hours for the thirty engines divided by 2000. This NO_x emission in tpy when combined with the NO_x emissions for the existing emission units (EU001-EU006) in tpy shall not exceed 682 TPY, based upon a consecutive 12-month period. This facility-wide annual emissions cap shall become effective on the fifth day of the month following the start-up of the first internal combustion engine, and compliance shall begin based upon the first twelve months of operation thereafter. NO_x emissions from the existing emission units (EU001-EU006) shall not exceed 100 TPY. NO_x emissions from the existing emission units shall be determined using CEM's and converted to tpy.

[Rule 62-212.400, F.A.C. (PSD avoidance)]

8. General Visible Emissions Standard:

Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer, or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density if which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20% opacity). The test

method for visible emissions shall be EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C. **[Rule 62-296.320(4)(b)1, F.A.C.]**

EXCESS EMISSIONS

9. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. **[Rule 62-210.700(4), F.A.C.]**

10. Excess Emissions Allowed: Providing the permittee adheres to best operational practices to minimize the amount and duration of excess emissions, the following conditions shall apply:

    (a) During startup and shutdown, visible emissions shall not exceed 27% opacity for up to 2 hours in any 24-hour period. **[Design; Rule 62-210.700(1), F.A.C.]**

OPERATIONAL LIMITATIONS

11. Fuel Oil Specification: Only No. 2 fuel oil can be fired in the internal combustion engines. The maximum sulfur content of the No. 2 fuel oil shall not exceed 0.05 percent, by weight. **[Rule 62-210.200, F.A.C. (Definitions – PTE)]**

12. Fuel Oil Consumption: The maximum No. 2 fuel oil allowed to be burned in thirty internal combustion engines combined is 2,713,880 gallons per year, which is equivalent to 22,100 engine-hours per year at 100% load. **[Rule 62-210.200, F.A.C. (Definitions – PTE)]**

13. Permitted Capacity: The heat input to each internal combustion engine from firing No. 2 fuel oil shall not exceed 17 MMBtu per hour at 100% load. **[Design, Rule 62-210.200, F.A.C. (Definition - PTE)]**

14. Hours of Operation: The thirty internal combustion engines shall operate no more than 22,100 engine-hours during any consecutive 12-month period. The permittee shall install, calibrate, operate and maintain a monitoring system to measure the hours of operation on each internal combustion engine. **[Rule 62-210.200, F.A.C. (Definitions - PTE)]**

15. Operational Period: The thirty internal combustion engines shall cease operation in June 2003. **[Applicant Request]**

EMISSIONS PERFORMANCE TESTING

16. Sampling Facilities: The permittee shall design the internal combustion engine stack to accommodate adequate testing and sampling locations in order to determine compliance with the applicable emission limits specified by this permit. **[Rule 62-297.310(6), F.A.C.]**

17. Performance Test Methods: Initial (I) and Annual (A) compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C.

    (a) EPA Method 7 or 7E – Determination of Nitrogen Oxide Emissions from Stationary Sources (I, A);

    (b) EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources (I, A);

No other test methods may be used for compliance testing unless prior DEP approval is received, in writing, from the DEP Emissions Monitoring Section Administrator.

18. Fuel Oil Monitoring: The fuel shall be monitored initially and annually for the sulfur content using ASTM D4294 Method (or equivalent). The permittee shall also maintain daily records of fuel oil consumption for the emission units. **[Rules 62-297.440, F.A.C., and 62-210.200, F.A.C.]**

19. Test Notification: The permittee shall notify the Compliance Authority in writing at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator. **[Rule 62-297.310(7)(a)9., F.A.C.]**

20. Initial Tests Required: Initial performance tests to demonstrate compliance with the emission standards specified in this permit shall be conducted within 60 days after achieving at least 90% of permitted capacity, but not later than 180 days after initial operation of the emissions unit. Initial performance tests shall be conducted for NO_X and visible emissions on a sample of 5 (five) randomly picked internal combustion engines for the first year. A different set of randomly picked five engines from the remaining 25 (twenty five) internal combustion engines will be tested during the second year of operation. **[Rule 62-297.310(7)(a)1., and 62-297.310(7)(c), F.A.C.]**

21. Annual Performance Tests: To demonstrate compliance with the emission standards specified in this permit, the permittee shall conduct annual performance tests for NO_X and visible emissions on the emission units that operated for more than 3,700 hours in the preceding 12-month period. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). **[Rule 62-297.310(7)(a)4., and 62-297.310(7)(c), F.A.C.]**

22. Tests Prior to Permit Renewal: Prior to renewing the air operation permit, the permittee shall conduct performance tests for NO_X and visible emissions on one of the internal combustion engines. These tests shall be conducted within the 12-month period prior to renewing the air operation permit. For pollutants required to be tested annually, the permittee may submit the most recent annual compliance test to satisfy the requirements of this provision. **[Rule 62-297.310(7)(a)3., F.A.C.]**

23. Internal Combustion Engine Testing Capacity: Performance tests for compliance with standards specified in this permit shall be conducted with the emission unit operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit. If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited to 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C. **[Rule 62-297.310(2), F.A.C.]**

24. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. **[Rule 62-297.310(3), F.A.C.]**

25. Applicable Test Procedures

    (a) Required Sampling Time.

        1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. **[Rule 62-297.310(4)(a)1., F.A.C.]**

2. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. **[Rule 62-297.310(4)(a)2., F.A.C.]**

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet. **[Rule 62-297.310(4)(b), F.A.C.]**

(c) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C. **[Rule 62-297.310(4)(d), F.A.C.]**

26. Determination of Process Variables

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. **[Rule 62-297.310(5)(a), F.A.C.]**

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value. **[Rule 62-297.310(5)(b), F.A.C.]**

27. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. **[Rule 62-297.310(7)(b), F.A.C.]**

RECORDKEEPING AND REPORTING REQUIREMENTS

28. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. **[Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]**

29. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. **[Rule 62-297.310(8), F.A.C.]**

30. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the 12-month hours of operation of the internal combustion engines, 12-month emission totals for NO_x and amount of the No. 2 fuel oil fired for the internal combustion engines. The information shall be recorded in a written or electronic log and shall be available for inspection and/or printing within at least one day of a request from the Compliance Authority. **[Rule 62-4.160(15), F.A.C.]**

31. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. **[Rule 62-210.370(2), F.A.C.]**

The following Specific Conditions apply to the existing emission units 001-006:

1. The existing emission units shall comply with all the requirements of 0570038-001-AV with the exceptions listed below in conditions 2 through 4. **[Title V Permit Requirements]**
2. For each 12-month period that the thirty internal combustion engines (EU007-EU036) operate below 22,100 engine-hours, the existing emission units 001 through 006 may operate to reach the facility-wide NO_x cap of 682 tpy. NO_x emissions from the existing emission units (EU001-EU006) shall not exceed 100 tpy. The existing emission units shall use the CEM system to demonstrate compliance with the emission limits for NO_x. **[Rule 62-212.400, F.A.C. (PSD avoidance)]**
3. The existing emission units may not operate simultaneously with the internal combustion engines unless the facility must do so to avoid interrupting customers. In the event that the facility does operate the two sources together, upon request from the Department, shall provide the necessary documentation to show the necessity of operating the two sources simultaneously. **[Applicant Request]**
4. The existing emission units may operate with a NO_x emissions cap of 100 tpy after the internal combustion engines ceases operation in June 2003. **[Applicant Request]**

APPENDIX GC
GENERAL PERMIT CONDITIONS [F.A.C. 62-4.160]

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

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

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a) Have access to and copy and records that must be kept under the conditions of the permit;
b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a) A description of and cause of non-compliance; and
b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages, which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology ( )
b) Determination of Prevention of Significant Deterioration ( ); and
c) Compliance with New Source Performance Standards ( ).

G.14 The permittee shall comply with the following:

a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law, which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

TECO SM
TAMPA ELECTRIC

March 5, 2001

Mr. Clair Fancy
Florida Department of Environmental Protection
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, Florida 32399-2400

Via FedEx
Airbill No. 7919 9024 3542

Re: Tampa Electric Rental of Additional Generation to Meet Summer Load

Dear Mr. Fancy:

In order to meet an increasing demand for electricity this summer, Tampa Electric Company (TEC) intends to utilize eleven rented mobile generators at eleven different substations throughout Hillsborough and Polk Counties. Each unit is a Caterpillar XQ 2000 Power Module capable of providing up to 1.825 MW of additional generation to serve load during periods of peak demand. The units will be fired exclusively with low sulfur distillate oil and will be limited to 32,000 gallons of fuel oil consumed per year. At this time, the units are expected to be placed in service in late May and operate until October 2001. Below is the list of substations where TEC intends to temporarily site these units.

Hillsborough County
- Clearview Substation
- Eleventh Avenue Substation
- Maritime Substation
- Juneau Substation
- Dale Mabry Substation
- Hampton Substation
- State Road 60 Substation
- Ruskin Substation

Polk County
- Mulberry Substation
- Lake Gum Substation
- South Eloise Substation

Based on this information, TEC believes that these units are exempt from permitting per 62-210.300(3)(a)21 and requests written concurrence from the Department. TEC appreciates the consideration of the Department in this matter.

If you have any questions, please feel free to telephone Shannon Todd or me at (813) 641-5125.

Sincerely,

for

Patrick L. Shell, P.E.
Administrator-Air Programs
Environmental Affairs

EP\gm\SKT241

c: Mr. Jerry Campbell, EPCHC
Ms. Alice Harman, EPCHC
Mr. Jerry Kissel, FDEP SW

bc: H.W. Smith
G.M. Nelson
J.E. Currier
W.A. Smotherman
T.J. Panoff
P.D. Lester ←
M. McKeon
L.N. Curtin, H&K
PR 66
C 2.1

r: L.A. Brown
R. Calderon
J.J. Hunter
S.K. Todd
T.B. Wenning

TAMPA ELECTRIC COMPANY
DOCKET NO. 010001-EI
WITNESS: W. LYNN BROWN
LATE-FILED DEPOSITION
EXHIBIT NO. 3
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3. Provide the percentage of purchased power for January through August 2001 procured from long-term contracts signed in 2000.

A.

MWHrs	13.0%
$	19.2%

Excludes Hardee purchases

TAMPA ELECTRIC COMPANY
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4. Provide the deliveries between January and August 2001.

A.

	Jan	Feb	Mar	Apr	May	June
MWHrs.	33,192	2,640	9,075	58,409	76,705	62,411
$ (1000's)	$3,279.2	$764.7	$1,377.9	$3,919.8	$5,966.9	$6,971.7

	July	Aug	Total
MWHrs.	38,287	27,200	307,919
$ (1000's)	$5,065.7	$4,995.2	$32,341.1

Excludes Hardee purchases

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5. Provide the Average Forward Energy Price from August to November 2000.

A.

January – August, 2001

Forwards Market @ Entergy	Reference Month
$64.85	August, 2000
69.31	September, 2000
72.59	October, 2000
74.72	November, 2000

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6. Provide the HPP 2001 Energy Price Including Capacity Payments.

A.

Capacity Payment (Hardee)	$20.18/MWHr.
Energy Payment (Hardee)	$53.99/MWHr.
Total	$74.17/MWHr.

7. Provide an exhibit that describes the wholesale schedules under which Tampa Electric does business.

A. Emergency Interchange Service: Interchange Service Type A
Interchange Service Schedule A was established to facilitate the sale and purchase of cost-based capacity and energy, which are surplus to the needs of the selling utility, during a specified period of time, after the purchasing utility has experienced a forced outage of a generating resource.

A utility typically purchases Schedule A Service during periods when it lacks sufficient generating capacity and energy to serve its load due to

1) the unexpected loss of a generating resource or an entitlement to a generating resource or a restriction on the operation of such a resource; or
2) unanticipated high loads.

The length of time that Schedule A Service is available to a purchasing utility is a maximum of seventy-two hours, except for Florida Power and Light Company, which has a maximum term of twenty-four hours. Schedule A sales are non-firm and are served immediately after the selling utility serves its firm native load and firm wholesale power sale commitments.

Scheduled/Short-Term Firm Interchange Service: Interchange Service Type B
Interchange Service Schedule B was established to facilitate the sale and purchase of cost-based capacity and energy, which are surplus to the needs of the selling utility, during a period of time after the purchasing utility has experienced a forced outage of a generating resource, and the length of time that service is available under Schedule A has expired.

A utility typically purchases Schedule B Service during periods when it lacks sufficient generating capacity or energy or desires to purchase additional capacity or energy to

1) serve its load due to the unexpected loss of a generating resource or an entitlement to a generating resource or a restriction on the operation of such a resource, and the length of time that service is available under Schedule A has expired;
2) serve existing off-system power sales commitments (if service to such customers cannot be suspended per contract provisions), and the length of time that service is available under Schedule A has expired;
3) serve its load and existing off-system power sales commitments during a planned or scheduled maintenance outage or an extended forced outage;
4) provide for additional operating and/or installed reserves;
5) serve unanticipated high loads.

The length of time that Schedule B service is available to a purchasing utility is a maximum of twelve months. Schedule B sales are non-firm and are served immediately after the selling utility serves its firm native load and firm wholesale power sale commitments. The day prior to the beginning of the transaction and each day thereafter, the purchasing utility provides the selling utility a schedule of the amount of capacity and energy it expects to purchase under Schedule B during each hour of the following day.

Economy Energy Interchange Service: Interchange Service Type C
Interchange Service Schedule C was established to facilitate the sale and purchase of cost-based excess energy on an hourly basis.

Schedule C energy sold is surplus, at the time, to the needs of the selling utility and economically usable on the system of the purchasing utility. "Economy energy" transactions are hourly, "split-the-savings" sales or purchases of non-firm energy. An "economy energy" sale or purchase is a transaction under which a seller with available excess energy sells such energy on a non-firm basis to a buyer at a transaction price that is greater than the seller's sell quote and less than the buyer's buy quote. Buy and sell quotes are cost-based and the transaction price is the mid-point between those quotes. Interchange Service Schedule C became dormant when the Energy Broker Network, Inc. (EBN) was discontinued August 22, 2000. Effective August 1, 2001, Tampa Electric terminated all of its Interchange Service Schedules C pursuant to a Federal Energy Regulatory Commission filing.

Long-Term Interchange Service: Interchange Service Type D
Service typically available under Schedule D is firm, cost-based, long-term capacity or energy which is surplus, at the time, to the needs of the selling utility and which is economically usable on the system of the purchasing utility.

A letter of commitment for Schedule D service defines details such as how the purchasing utility will be served with respect to the selling utility's existing power sale commitments and the components of the capacity and energy charges. The length of Schedule D transactions is normally one year or more. Letters of commitment must be filed with, and accepted by, the FERC prior to the commencement of Schedule D service. Effective August 1, 2001, Tampa Electric terminated all but one of its Interchange Service Schedules D pursuant to a Federal Energy Regulatory Commission filing.

Backup/Reserve Interchange Service: Interchange Service Type G

Service typically available under Schedule G is considered to be a "first call" on cost-based, firm capacity or energy which is surplus, at the time, to the needs of the selling utility and which is economically usable on the system of the purchasing utility.

When utilities execute a letter of commitment under Service Schedule G, the selling utility assumes an obligation to sell backup or reserve interchange service to the purchasing utility upon request. The purchasing utility pays a reservation charge that entitles the purchasing utility to request energy in the amount of its reservation during any hour during the term of the letter of commitment. Effective August 1, 2001, Tampa Electric terminated all of its Interchange Service Schedules G pursuant to a Federal Energy Regulatory Commission filing.

Negotiated Interchange Service: Interchange Service Type J

Service typically available under Schedule J is cost-based capacity or energy, which is normally non-firm and which is surplus, at the time, to the needs of the selling utility.

A letter of commitment for Schedule J service defines details such as how the purchasing utility will be served with respect to the selling utility's existing power sale commitments and the components of the capacity and energy charges. Effective August 1, 2001, Tampa Electric terminated all but two of its Interchange Service Schedule J letters of commitment pursuant to a Federal Energy Regulatory Commission filing. The two remain in effect to afford other utilities the opportunity to use this Schedule to make sales to Tampa Electric.

Extended Economy Interchange Service: Interchange Service Type X

Service available under Schedule X is non-firm, extended economy energy. The energy sold is surplus, at the time, to the needs of the selling utility and economically usable on the system of the purchasing utility.

Schedule X transactions are essentially extended Schedule C transactions that allow utilities with higher cost generating resources to realize savings by not running those resources by purchasing energy from another utility with lower cost generating resources. The utilities with lower cost generating resources realize revenues by more fully utilizing those resources and selling available energy. Schedule X Service transactions are non-firm, as-available and voluntary. Schedule X sales have a greater priority than Schedule C sales.

Schedule X service is priced similarly to Schedule C, on a split-the-savings basis between the two utilities involved in a transaction. The length of time that

Schedule X service is available is more than one hour but not more than seven days.

Effective August 1, 2001, Tampa Electric terminated all of its Interchange Service Schedules X pursuant to a Federal Energy Regulatory Commission filing.

Market-Based Sales Tariff (MA/MB):
Tampa Electric's Market-Based Sales Tariff became effective on April 1, 1999 and provides for sales of wholesale electric capacity or energy at market-based rates.

Service under the Market-Based Sales Tariff is available to any electric utility, rural electric cooperative, municipality, power authority, or agency. Transactions designated "MA" are sales that are made from Tampa Electric's resources, and "MB" transactions are re-sales that are made from outside resources. Tampa Electric may provide capacity or energy in varying amounts, at varying levels of firmness or priorities of service, and in accordance with varying delivery schedules. Tampa Electric provides service under the Market-Based Sales Tariff, and the Customer takes service under the tariff when Tampa Electric and the customer mutually agree on the rates, terms and conditions of a transaction. The customer and Tampa Electric must execute a Service Agreement. Tampa Electric files the executed Service Agreement with the FERC no later than 30 days following the date on which service commences.

Requirements Service Tariff (AR-1):
Tampa Electric's all requirements ("AR") tariff provides full requirements ("FR") and partial requirements ("PR") service to qualified customers.

When a utility that does not own or have entitlements to generating resources purchases FR service, it commits to purchase all of its electric service requirements from the selling utility for a specified period of time, usually in excess of five years. FR service is load-following electric service, and the purchasing utility is invoiced according to the amount of capacity and energy delivered during the billing month or period. When a utility that does own or have entitlements to generating resources purchases PR service, it commits to purchase a portion of its electric service requirements from the selling utility for a specified period of time, usually in excess of five years. The particular terms and conditions associated with FR and PR service are documented in "service agreements". A service agreement is executed by the parties and linked to the tariff. Any specific terms and conditions associated with the service are described within the service agreement. Once a requirements service tariff is

accepted by the FERC, it becomes available to any qualified applicant that requests service.

Requirements service tariffs contain general terms and conditions, including provisions that define how and which types of services may be requested and the charges associated with the service. Tampa Electric's AR-1 tariff is cost-based. The non-fuel rates for service under the tariff represent the composite cost of the generating assets (which also serve firm retail customers) when the tariff is made effective by the FERC. The fuel rates for service under the tariff reflect the actual cost of fuel and purchased power and include fuel adjustment factors.

Big Bend Station Unit No. 4 Contract

This cost-based agreement between Tampa Electric Company and Hardee Power Partners Limited ("HPP") provides for the sale by Tampa Electric Company of unit-based power from its Big Bend Station Unit No. 4 ("BB4") to HPP. HPP resells this capacity and energy on an "at cost" basis (no markup) to Seminole Electric Cooperative.

HPP is entitled to 145 MW of unit-based capacity and corresponding energy from BB4. This right is subject to the following annual energy limitations:

Year	GWh
2001	480
2002	490

The BB4 Contract was executed on July 27, 1989. Service under the BB4 Contract commenced on January 1, 1993 and will continue until December 31, 2002.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

W. L. BROWN

Q. Please state your name, address, occupation and employer.

A. My name is Lynn Brown. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director-Wholesale Marketing and Sales.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelors degree in Electrical Engineering from Louisiana State University in 1972 and subsequently joined Tampa Electric. I have held various engineering, operations and managerial positions in Energy Delivery from 1973 through 1997. I became Manager of Short Term Wholesale Trading in April 1997 and was promoted to Director-Wholesale Marketing and Sales in August of last year. I am responsible for short and long-term wholesale power purchases.

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

A. The purpose of my testimony is to provide an overview of the purchased power agreements that Tampa Electric has entered into and is seeking to recover through the Fuel and Purchased Power Cost Recovery and Capacity Cost Recovery Clauses. I will also provide an overview of the wholesale energy market, its changes over the past several years and its impact on purchased power costs.

Q. Has Tampa Electric entered into any purchased power agreements that were not included in the company's last purchased power projections?

A. Yes. Tampa Electric has signed several agreements for the purchase of firm capacity and energy for 1999, 2000 and beyond. The company is also in the process of negotiating for additional capacity and energy for the year 2000 to achieve desired operating reserves.

The company has entered into five contracts with four suppliers of capacity and energy. Three of the suppliers are qualifying facilities: Okeelanta Corporation, Farmland Hydro, and Auburndale Power Partners. The fourth supplier is Hardee Power Partners Limited ("HPP"). The Company's purchase from HPP was accomplished through an amendment to the purchased power agreement originally

signed on July 27, 1989 and approved by this Commission in Docket No. 880309-EC and Order No. 22335.

Q. What are the terms of these agreements?

A. The terms of the agreements are as follows:

Okeelanta Corp. (1)	May 1, 1999 - June 30, 1999
Farmland Hydro	June 1, 1999 - September 30, 2000
Auburndale Power	July 1, 1999 - ~~September 30~~ December 31, 2000
Okeelanta Corp. (2)	September 1, 1999 - March 31, 2000
Hardee Power Partners	May 15, 2000 - December 31, 2012

Q. Why did Tampa Electric enter into these five purchased power agreements?

A. Tampa Electric entered into these five agreements in order to maintain overall system reliability for its retail ratepayers. As the company has reported in its Ten-Year Site Plan, retail load has increased since 1997 at a higher than expected rate causing a significant increase in the use of demand-side management ("DSM") programs. Accordingly, the company has modified its planning criteria to not only plan for a minimum 15 percent reserve margin but to improve the quality of its

reserve margin by planning for a minimum of 7 percent supply-side resources. The company plans to achieve the desired system reliability for its retail customers by accelerating new generating unit construction and acquiring firm capacity purchases. This enhanced planning criteria is described in detail in Tampa Electric witness Mark D. Ward's testimony filed in Docket No. 981890-EU.

Q. How did the company determine that the terms of the purchased power agreements were prudent?

A. In determining the appropriateness and need for purchased power agreements, it is important to understand the wholesale market in Florida and the rest of the country. This market has changed significantly over the past few years. From a State perspective, retail demand and energy usage have increased at higher-than-expected rates and existing generation and DSM resources have been utilized at high capacity factors and frequency. The State is experiencing lower planning and operating reserve margins, there is greater reliance on DSM resources and there are limited import capabilities. Until recently, utilities have deferred construction of capacity additions. The same is true in the southeast

and several other regions of the United States. Some affected utilities, including Tampa Electric, have recognized State and jurisdictional needs. Resource plans have been modified to meet this growth in demand, but until additional capacity is constructed, utilities have had to rely heavily on DSM and purchased power at higher costs to meet the needs of their retail customers.

Additionally, an energy shortage in another geographic region can affect the price and availability of energy within our state. Hence, Florida utilities are now concerned with both the balance of in-state and out-of-state supply and demand. For example, when price spikes occur in other regions, Florida utilities may find that significant amounts of wholesale energy have been exported out of state to more lucrative markets. This means that if a Florida utility requires energy during such times, it must be willing to pay high spot prices, contract for firm purchases, or build additional generation resources to mitigate its exposure to such prices. Tampa Electric has found that forward energy prices for the eastern United States trading hubs such as Cinergy are good indicators of prices in Florida. These prices have increased rapidly over the last 18 months.

The nature of these purchases has also changed. Today, utilities must balance firm and non-firm "block" purchases and hourly purchases to serve their retail load. "Blocks" of firm or non-firm energy transactions are typically purchased and sold for periods of eight to 16 hours per day. The amount of energy available to be purchased and sold on an hourly basis on a given day is impacted by the quantity of block purchases and sales conducted on that day. Several years ago, most non-firm energy bought and sold on the wholesale market was "next-hour," cost-based economy energy. Today less of this type of energy is available for purchase. Whenever Tampa Electric anticipates a shortfall, it generally purchases a combination of blocks and hourly energy to meet native load requirements.

Given these market characteristics and the lead time needed to construct new generating units, Tampa Electric recognized the need to secure purchased power agreements for its native load needs and to mitigate costs and availability risks. In early 1999, Tampa Electric solicited bids from potential power suppliers for specific periods for 1999, 2000 and beyond. Based upon the responses, Tampa Electric negotiated the five purchases mentioned above. Each purchase is for firm

capacity and energy priced at the best available market price for the required periods of time.

Q. Please describe the availability of purchased power in late July 1999.

A. At the end of July, the New England and Midwest regions of the United States were experiencing generation shortfalls. As a result, most of the available energy in Florida was being exported to this lucrative market. Tampa Electric was in need of purchased power to serve its native load customers on July 29, 30 and 31. In an effort to mitigate the high market price of purchased power, the company offered to cogenerators in its service area to purchase any energy they could make available and export to the company's system. The offer was made to every Tampa Electric cogeneration customer based on a fixed price for a fixed period of time with advance notice given by the company. The purchase price offer was higher than standard cogeneration firm and as-available energy rates but was lower than the prevailing market price. Several of the cogenerators took advantage of this offer and were able to provide needed energy to Tampa Electric's system.

Q. How were these transactions treated?

A. These transactions were treated in the same manner as other non-firm, short-term purchases and were included in the company's purchased power expense for July 1999.

Q. Are the capacity and energy costs associated with these purchased power transactions included in the company's Fuel and Purchased Power Cost Recovery and Capacity Cost Recovery factors for 2000?

A. Yes. The capacity and energy costs are included in the schedules submitted by Tampa Electric witness Karen O. Zwolak in Schedule E-7.

Q. As you described the wholesale market, you indicated that hourly availability of energy has changed. Please describe how Tampa Electric utilizes Florida's Energy Broker Network ("broker") for short-term, non-firm transactions?

A. From time to time, Tampa Electric utilizes the broker to make short-term, non-firm sales and purchases. At one time, the broker was the most effective available method of matching buyers and sellers but that has changed.

Today, many utilities either make hourly or block energy sales off the broker at market-based prices. Since the broker ~~is~~ was limited to cost-based transactions, it has experienced a steady decline in usage due to greater profit opportunities elsewhere for those seeking to sell power.

Q. What is the most effective means of conducting economy energy transactions today?

A. While the broker can be the best means for a buyer to enter into a cost-based hourly transaction, other more lucrative opportunities exist for sellers in today's market. These include market-based, hourly, off-broker transactions and same day or next day market-based block sales.

Q. Please describe the types of economy sales that Tampa Electric has entered into that are made with or without the use of the broker.

A. Tampa Electric has entered into FERC-approved non-separated, economy sales transactions arranged with and without the use of the broker. Economy sales, either Schedule C (Economy Interchange Service) or Schedule X

(Extended Economy Interchange Service) sales, are short-term, non-firm sales. Schedule C sales are traditional, cost-based, "split the savings," hourly economy sales transactions that can be made either with or without the use of the broker. Schedule X sales are traditional, cost-based, "split the savings," multi-hour, economy sales transactions that can not be made with the use of the broker.

Q. In general, how are Schedule C and X transactions made?

A. These transactions are based upon matching a buyer's quote of higher incremental costs to a seller's quote with lower incremental costs. The transaction price results in a 50/50 sharing of the difference between the quotes. Schedule C and X transactions are subject to immediate cancellation by the seller if the capacity is needed to meet other commitments.

Q. Does the "split the savings" concept for economy sales change if the broker is not utilized?

A. No. The method utilized for matching the buyer and seller is different, however, the same cost-based, "split the savings" schedules are employed. Therefore, there is no

need to make a differentiation between non-separated energy sales made with or without the use of the broker.

Q. Does Tampa Electric enter into other non-firm sales transactions?

A. Yes. Tampa Electric also enters into intermediate-term (less than one year), non-firm sales under Schedule J (Negotiated Interchange Service) letters of commitment. Schedule J sales are not "split the savings" transactions. These sales are negotiated, non-firm energy transactions. All proceeds from these sales are currently credited through the Fuel and Purchased Power Cost Recovery Clause. No Schedule J sales are made through the broker and these are not an issue in this proceeding.

Q. Please summarize your testimony.

A. In order to maintain its overall system reliability for its retail ratepayers, Tampa Electric entered into five purchased power agreements beginning in 1999. Although four of the agreements affect only 1999 and 2000, the fifth is a long-term purchased power agreement with HPP. This cost-based agreement was contemplated as an option in the original agreement with HPP and Seminole Electric Cooperative entered into in 1989 that was reviewed by

this Commission and approved by the FERC. Based upon changing market conditions and a diligent evaluation of alternatives, these agreements were deemed to provide firm capacity and energy at the best available prices for the periods of time needed.

Q. Does this conclude your testimony?

A. Yes, it does.

EAG

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
FILED: 11/1/99

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED REBUTTAL TESTIMONY

OF

W. L. BROWN

Q. Please state your name, address, occupation and employer.

A. My name is Lynn Brown. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or company") as Director-Wholesale Marketing and Sales.

Q. Are you the same Lynn Brown who filed direct testimony in this docket?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address the issues raised by FIPUG witness Kent D. Taylor with respect to the Hardee Power Partners purchased power agreement ("HPP agreement").

DOCUMENT NUMBER-DATE
13385 NOV-1 99
FPSC-RECORDS/REPORTING

Q. Have you prepared an exhibit in supporting your rebuttal testimony?

A. Yes. Exhibit __ (WLB-2) contains two documents.

Q. Has the HPP agreement been available for review by FIPUG?

A. Yes. The underlying agreement between HPP and Tampa Electric dated July 27, 1989 has been on file with and approved by the Federal Energy Regulatory Commission ("FERC") for nearly a decade. Subsequent amendments to the agreement dated September 28, 1989 and December 13, 1990 were also approved by the FERC and are on file and available for public inspection.

The third and fourth amendments to the HPP and Tampa Electric agreement, both dated as of September 15, 1999 and filed with the FERC on that date, were approved by the FERC on October 15, 1999 in Docket Nos. ER99-4453-000 and ER99-4454-000. These amendments are also on file and available for public inspection. They are also available through the FERC's Internet web site. Tampa Electric has notified this Commission each time its agreement with HPP has been amended. The most recent amendments to the agreement are included in Document 1 of my exhibit. Also

included in my exhibit as Document 2 is the petition HPP filed with FERC regarding the HPP agreement.

Q. How did the opportunity to purchase firm power under the HPP agreement arise?

A. This opportunity arose by virtue of HPP's having the ability to use Seminole Electric Cooperative's ("SEC") Hardee site for the Phase II build out. HPP's ability to use this site together with its opportunity to purchase a 75-megawatt ("MW") combustion turbine ("CT") provided a unique opportunity to obtain a critical firm 75-MW purchase without using Tampa Electric's Polk site. This is important since the company already has accelerated its plans to build out the Polk site which includes two 180-MW CT additions between now and May 2002.

Q. Please describe the basic provisions of the HPP agreement.

A. In Order No. 22335 issued in Docket No. 880309-EC on December 22, 1989, this Commission determined the need for construction of the Hardee Power Station to serve the needs of SEC with the project also serving the needs of Tampa Electric's customers. The project was to be

constructed by Tampa Electric's affiliate, TECO Power Services Corporation, in two phases. Phase I of the project, consisting of one 220-MW combined cycle unit and one 75-MW CT, was constructed and placed in service in 1993. SEC retained the option to call for the construction of Phase II consisting of an additional 145 MWs of capacity (one 75-MW CT and two heat recovery steam generators with associated steam turbines) scheduled to be placed in service in 2003.

On May 24, 1999 SEC waived its option under its agreement with HPP to require construction of Phase II. Accordingly, Tampa Electric exercised its option under the agreement to require HPP to begin construction. The first phase of the Phase II build out will consist of the construction of a 75-MW CT next to the existing CT which HPP expects to have in service by May 15, 2000. Tampa Electric has the ability to complete the Phase II build out and is required to notify HPP of this option by December 1, 2000. The first phase of the Phase II build out is reflected in the fourth amendment to the agreement for the sale and purchase of capacity and energy between HPP and Tampa Electric.

The purchased power agreement in the fourth amendment becomes effective May 15, 2000 and expires December 31, 2012. Capacity payments are $6.23 per kilowatt month and energy charges are priced similar to those of the original agreement. Tampa Electric and SEC entered into a subsequent agreement whereby SEC has a non-firm, second call on the unit and pays a daily capacity charge and energy charge whenever they exercise their call. These charges are the same as those paid by Tampa Electric to HPP and all revenues from sales to SEC will be credited to Tampa Electric's retail customers.

Q. What are alternatives that Tampa Electric would consider under the circumstances?

A. A Florida utility requiring energy in the current market has the option of: (1) being willing to pay high spot prices for non-firm energy and take the risk that the power may not be available, (2) building additional generation resources to mitigate its exposure to such prices, or (3) entering into short and long-term contracts for capacity and energy purchases.

Q. What approach has Tampa Electric taken under these circumstances?

A. Tampa Electric has taken a balanced approach using several different strategies to meet its customers' needs. Provision of reliable service is paramount. The company believes it is extremely important to immediately address the reliability needs of the company's customers in ways that provide reasonable assurance that the resources will be available. With that in mind, the company determined that it would be beneficial and prudent to accelerate its Polk Unit 2 construction, a 180-MW CT from January 2001 to October 2000 and its Polk Unit 3, a 180-MW CT from January 2003 to May 2002. Next, the company negotiated several short-term firm agreements with Okeelanta Corp., Farmland Hydro Inc., and Auburndale Power Partners. Finally, the company negotiated with HPP for the purchase of firm power from May 15, 2000 to December 31, 2012.

Q. How did Tampa Electric evaluate the terms of the HPP agreement to other market opportunities?

A. With respect to the HPP agreement, Tampa Electric received responses to its solicitation from Florida Power and Light and Florida Power Corporation and both proposed higher pricing than the HPP agreement pricing. This analysis is supported in the rebuttal testimony of Tampa

Electric witness Mark D. Ward. The company also received a proposal from the City of Lakeland that initially appeared to have the potential to provide a lower price than the HPP agreement but it was subsequently withdrawn.

Q. Have you looked at the energy futures market to compare the prices to be paid under these purchased power agreements with the published forward energy prices for the eastern United States trading hubs?

A. Yes. Tampa Electric found that the HPP contracted prices are below the competitive bid price for the twelve-year term. The contracted prices for each purchased power agreement the company entered into for 1999 and 2000 were also lower than published forward prices for specific periods in 1999 and 2000.

Q. How does Tampa Electric justify the prudence of the purchase of power under the HPP agreement?

A. As described in Mr. Ward's testimony, the company performed several production cost analyses to ensure the HPP agreement was a cost effective and prudent investment that met the company's integrated resource plan.

Q. How do the total costs of this additional 75 MW compare to the total costs of the original HPP agreement?

A. The costs are lower.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor	))))	DOCKET NO. 010001-EI FILED: July 26, 2001

REDACTED VERSION

TAMPA ELECTRIC COMPANY'S

ANSWERS TO SECOND SET OF INTERROGATORIES (NOS. 2-8)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (Nos.2-8) propounded and served on June 21, 2001, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY

DOCKET NO. 010001-EI

INDEX TO STAFF'S 2ND SET OF INTERROGATORIES (NOS. 2-8)

Number	Subject	Bate Stamped
2	TECO's annual total capacity and energy sales, by separated sales and non-separated sales, for the years 1996 through 2000, in terms of total megawatt hours sold and total revenues received.	1
3	The annual total cost of purchased power and total megawatt hours purchased by TECO for the years 1996 through 2000.	2
4	TECO's wholesale sales with contracts currently in place, including both separated and non-separated sales.	3
5	All interruptions imposed on retail non-firm customers for the years 1998 through 2001.	7
6	Additional information for each interruption listed in response to FIPUG's Interrogatory No. 10.	16
7	For the period 1999 through 2000, list all time periods in which TECO bought power from and sold power to the same entity.	29
8	Explanation on how TECO notifies interruptible customers of pending interruption periods and the availability of buy-through power.	207

2. Please indicate TECO's annual total capacity and energy sales, by separated sales and non-separated sales, for the years 1996 through 2000, in terms of total megawatt hours sold and total revenues received. Please indicate the average dollar per megawatt hour sold for each year, by separated sales and non-separated sales.

A.

Year	Separated Sales			Non-Separated Sales		
	MWH	Revenues	Avg. $/MWH	MWH	Revenues	Avg. $/MWH
1996	841,860	$45,084,458	$53.55	2,399,526	$48,211,762	$20.09
1997	1,349,779	$57,447,488	$42.56	1,810,319	$36,836,634	$20.35
1998	1,589,782	$64,504,547	$40.57	896,197	$25,168,897	$28.08
1999	1,868,449	$77,360,139	$41.40	291,745	$8,911,384	$30.55
2000	1,231,135	$68,687,483	$55.79	1,332,771	$40,472,581	$30.37

3. Please indicate the annual total cost of purchased power and total megawatt hours purchased by TECO for the years 1996 through 2000. Please indicate the average dollar per megawatt hour purchased for each year.

A.

	MWH	Purchased Cost	Avg. $/MWH
1996	915,824	$48,999,048	$53.50
1997	1,297,252	$67,765,854	$52.24
1998	2,150,224	$88,199,351	$41.02
1999	3,058,491	$140,735,518	$46.01
2000	2,922,744	$192,126,966	$65.74

4. For each of TECO's wholesale sales with contracts currently in place, including both separated and non-separated sales, please provide the following:

a. the name of the purchasing entity;

b. the date each contract was entered into;

c. the date power sales began under each contract;

d. the term (length/period) of the contract;

e. an indication of whether the sale is recallable to serve firm retail load; i.e., the priority of the sale in relation to firm retail load;

f. TECO's expected reserve margin for the term of the contract, as of the date the contract was entered into;

g. TECO's forecasted power prices on the date the contract was entered through the end of the contract term; and

h. the date, if any, that TECO notified the Florida Public Service Commission of the contract or included the sale in its load forecast and Ten-Year Site Plan.

A.

a.		b.	c.	d.	e.
PURCHASER	SCHEDULE TYPE	DATE CONTRACT ENTERED	DATE SALE BEGAN	CONTRACT TERM	Can sale be recalled to serve firm retail load?
City of Fort Meade	Partial Requirements	01/05/1993	01/01/1997	01/01/1997 - 12/31/2013	NO; level of interruption equal to firm retail load
City of St. Cloud	Partial Requirements	10/28/1993	01/01/1997	01/01/1997 - 12/31/2012	NO; level of interruption equal to firm retail load
City of Wauchula	Partial Requirements	04/12/1993	01/01/1997	01/01/1997 - 12/31/2013	NO; level of interruption equal to firm retail load
Florida Power Corporation	Partial Requirements	03/30/1993	10/01/1993	10/01/1993 - 02/28/2011	NO; level of interruption equal to firm retail load
Reedy Creek Improvement District	Requirements Contract	03/29/1995	06/01/1995	01/01/1998 - 12/31/2017	NO; level of interruption equal to firm retail load
Seminole Electric Cooperative	Schedule D	12/18/1991	06/01/1992	06/01/1992 - 06/01/2002 (1)	YES
TECO Power Services	Contract - BB4	07/27/1989	01/01/1993	01/01/1993 - 12/31/2002	NO

(1) Contract termination can be as early as June 1, 2002 with three years written not

EXHIBIT NO.

TAMPA ELECTRIC COMPANY
DOCKET NO. 010001-EI
STAFF'S 2ND SET OF
INTERROGATORIES
INTERROGATORY NO. 4
PAGE 2 OF 4
FILED: JULY 26, 2001

f. According to Tampa Electric's Ten Year Site Plans, following are reported planned reserve margins.

WINTER								
	1989 TYSP	1991 TYSP	1992 TYSP	1993 TYSP	1994 TYSP	1995 TYSP	1996 TYSP	1997 TYSP
1988-89	22%							
1989-90	20%							
1990-91	20%	26%						
1991-92	19%	24%	25%					
1992-93	21%	33%	28%	28%				
1993-94	21%	29%	26%	24%	26%			
1994-95	21%	29%	23%	22%	23%	31%		
1995-96	21%	28%	27%	24%	22%	28%	28%	
1996-97	20%	27%	28%	27%	28%	34%	33%	30%
1997-98	20%	27%	27%	24%	25%	31%	30%	26%
1998-99	20%	27%	24%	23%	22%	27%	27%	22%
1999-00		26%	24%	23%	19%	25%	25%	20%
2000-01			24%	23%	20%	25%	22%	17%
2001-02				24%	20%	25%	23%	17%
2002-03					20%	28%	26%	17%
2003-04						28%	27%	20%
2004-05							27%	18%
2005-06								16%

SUMMER								
	1989 TYSP	1991 TYSP	1992 TYSP	1993 TYSP	1994 TYSP	1995 TYSP	1996 TYSP	1997 TYSP
1989	28%							
1990	21%							
1991	18%	32%						
1992	21%	27%	32%					
1993	26%	38%	29%	27%				
1994	23%	36%	29%	33%	35%			
1995	24%	33%	26%	30%	28%	31%		
1996	21%	33%	31%	29%	19%	27%	26%	
1997	23%	36%	32%	32%	28%	30%	36%	33%
1998	20%	30%	31%	29%	22%	29%	26%	28%
1999		34%	28%	28%	19%	28%	27%	19%
2000		28%	27%	28%	21%	27%	21%	22%
2001			27%	27%	21%	26%	24%	21%
2002				27%	21%	26%	22%	17%
2003					25%	28%	27%	17%
2004						28%	27%	19%
2005				181			27%	18%
2006								16%

g. At the time these contracts were entered, all contracts were cost-based, and Tampa Electric did not have authority to make market-based sales. There was no need to forecast fuel expense since it was a pass-through and paid by the purchaser.

h.

PURCHASER	SCHEDULE TYPE	DATE FPSC NOTIFIED
City of Fort Meade	Partial Requirements	01/12/1993
City of St. Cloud	Partial Requirements	12/17/1993
City of Wauchula	Partial Requirements	06/29/1993
Florida Power Corporation	Partial Requirements	03/31/1993
Reedy Creek Improvement District	Requirements Contract	03/31/1995
Seminole Electric Cooperative	Schedule D	12/19/1991
TECO Power Services	Contract - BB4	01/18/1990

5. In Interrogatory No. 10 of its First Set of Interrogatories to TECO, the Florida Industrial Power Users Group asked TECO to provide a list of all interruptions imposed on retail non-firm customers for the years 1998 through 2001. For each interruption listed in response to FIPUG's Interrogatory No. 10, please respond to the following:

a. Provide a list of all TECO wholesale sales contracts in place during each period of interruption listed.

b. Indicate whether TECO made sales under any of the contracts listed in response to Interrogatory 5.a., above, during any period of interruption listed; if so, please identify:

i. the specific contract;

ii. whether the sale was recallable (i.e., the level of firmness of the sale);

iii. the total revenues received from the sale during the interruption;

iv. the dollars per megawatt hour received from the sale during the interruption;

v. the total megawatt hours sold during the interruption;

vi. the date the contract was entered into; and

vii. the date power sales began under the contract.

A. a. See attached.

b. i. See attached.

ii. See attached.

iii. See attached.

iv. See attached.

v. See attached.

vi. See attached.

vii. See attached.

		b. v.	b. iv.	b. iii.	b. v.	b. iv.	b. iii.
a.		BB4 Contract			Schedule D		
b. i.		TECO Power Services/Seminole Electric Cooperative			City of Fort Meade		
b. ii.	Recall to serve firm retail?	NO			NO		
b. vi.	Date Contract Entered	07/27/1989			01/05/1993		
b. vii	Date Power Sale Began	01/01/1993			03/15/1993		
Interruption Time	Month / Date	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars
1998							
12:52 - 13:05	April 3						
15:25 - 17:00	June 19						
13:30 - 19:09	June 22						
14:00 - 17:37	June 23						
1999							
06:37 - 08:14	January 6						
13:47 - 16:32	April 3						
17:10 - 19:14	April 5						
13:44 - 17:32	April 6						
17:00 - 18:04	April 15						
14:09 - 20:35	April 23						
12:30 - 20:04	April 24						
15:18 - 18:20	April 26						
16:00 - 18:00	May 6						
13:00 - 19:56	July 29						
16:00 - 19:00	July 30						
15:23 - 18:26	July 31						
14:00 - 16:11	August 2						
15:27 - 19:00	September 4						
14:54 - 17:00	September 28						
15:00 - 17:08	October 20						
2000							
11:54 - 12:03	January 24						
16:41 - 17:17	July 6						
15:46 - 17:05	July 19						
13:07 - 17:12	July 20						
15:30 - 18:06	October 5						
2001							
15:52 - 15:57	April 3						

NOTE: Total Revenue includes fuel but does not include capacity charges.

		b. v.	b. iv.	b. iii.	b. v.	b. iv.	b. iii.
a.		Schedule D			Schedule D		
b. i.		City of New Smyrna Beach Utilities			City of Wauchula		
b. ii.	Recall to serve firm retail?	YES			NO		
b. vi.	Date Contract Entered	11/02/1995			10/14/1991		
b. vii	Date Power Sale Began	03/01/1996			06/01/1992		
	Interruption Time / Month / Date	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars
	1998						
	12:52 - 13:05 April 3						
	15:25 - 17:00 June 19						
	13:30 - 19:09 June 22						
	14:00 - 17:37 June 23						
	1999						
	06:37 - 08:14 January 6						
	13:47 - 16:32 April 3						
	17:10 - 19:14 April 5						
	13:44 - 17:32 April 6						
	17:00 - 18:04 April 15						
	14:09 - 20:35 April 23						
	12:30 - 20:04 April 24						
	15:18 - 18:20 April 26						
	16:00 - 18:00 May 6						
	13:00 - 19:56 July 29						
	16:00 - 19:00 July 30						
	15:23 - 18:26 July 31						
	14:00 - 16:11 August 2						
	15:27 - 19:00 September 4						
	14:54 - 17:00 September 28						
	15:00 - 17:08 October 20						
	2000						
	11:54 - 12:03 January 24						
	16:41 - 17:17 July 6						
	15:46 - 17:05 July 19						
	13:07 - 17:12 July 20						
	15:30 - 18:06 October 5						
	2001						
	15:52 - 15:57 April 3						

NOTE: Total Revenue includes fuel but does not include capacity charges.

		b. v.	b. iv.	b. iii.	b. v.	b. iv.	b. iii.
a.		Schedule D			Schedule D		
b. i.		Florida Municipal Power Agency (served from purchased power part of 1998, all of 1999)			Reedy Creek Improvement District		
b. ii.	Recall to serve firm retail?	NO			NO		
b. vi.	Date Contract Entered	10/02/1996			10/16/1991		
b. vii	Date Power Sale Began	12/16/1996			01/01/1992		
Interruption Time	Interruption Month	Interruption Date	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars
1998								
12:52 - 13:05	April	3						
15:25 - 17:00	June	19						
13:30 - 19:09	June	22						
14:00 - 17:37	June	23						
1999								
06:37 - 08:14	January	6						
13:47 - 16:32	April	3						
17:10 - 19:14	April	5						
13:44 - 17:32	April	6						
17:00 - 18:04	April	15						
14:09 - 20:35	April	23						
12:30 - 20:04	April	24						
15:18 - 18:20	April	26						
16:00 - 18:00	May	6						
13:00 - 19:56	July	29						
16:00 - 19:00	July	30						
15:23 - 18:26	July	31						
14:00 - 16:11	August	2						
15:27 - 19:00	September	4						
14:54 - 17:00	September	28						
15:00 - 17:08	October	20						
2000								
11:54 - 12:03	January	24						
16:41 - 17:17	July	6						
15:46 - 17:05	July	19						
13:07 - 17:12	July	20						
15:30 - 18:06	October	5						
2001								
15:52 - 15:57	April	3						

NOTE: Total Revenue includes fuel but does not include capacity charges.

		b. v.	b. iv.	b. iii.	b. v.	b. iv.	b. iii.
a.		Schedule D			Schedule D		
b. i.		Seminole Electric Cooperative Hardee Station Service			Seminole Electric Cooperative PRECO		
b. ii.	Recall to serve firm retail?	YES			YES		
b. vi.	Date Contract Entered	12/18/1991			12/18/1991		
b. vii	Date Power Sale Began	06/01/1992			06/01/1992		
	Interruption Time / Month / Date	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars
	1998						
	12:52 - 13:05 April 3						
	15:25 - 17:00 June 19						
	13:30 - 19:09 June 22						
	14:00 - 17:37 June 23						
	1999						
	06:37 - 08:14 January 6						
	13:47 - 16:32 April 3						
	17:10 - 19:14 April 5						
	13:44 - 17:32 April 6						
	17:00 - 18:04 April 15						
	14:09 - 20:35 April 23						
	12:30 - 20:04 April 24						
	15:18 - 18:20 April 26						
	16:00 - 18:00 May 6						
	13:00 - 19:56 July 29						
	16:00 - 19:00 July 30						
	15:23 - 18:26 July 31						
	14:00 - 16:11 August 2						
	15:27 - 19:00 September 4						
	14:54 - 17:00 September 28						
	15:00 - 17:08 October 20						
	2000						
	11:54 - 12:03 January 24						
	16:41 - 17:17 July 6						
	15:46 - 17:05 July 19						
	13:07 - 17:12 July 20						
	15:30 - 18:06 October 5						
	2001						
	15:52 - 15:57 April 3						

NOTE: Total Revenue includes fuel but does not include capacity charges.

		b. v.	b. iv.	b. iii.	b. v.	b. iv.	b. iii.
a.		Schedule J			Schedule J		
b. i.		City of New Smyrna Beach Utilities			Reedy Creek Improvement District		
b. ii.	Recall to serve firm retail?	YES			NO		
b. vi.	Date Contract Entered	03/27/1997			10/29/1997		
b. vii	Date Power Sale Began	06/01/1997			01/01/1998		
	Interruption Time / Month / Date	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars
	1998						
	12:52 - 13:05 April 3	[redacted]					
	15:25 - 17:00 June 19						
	13:30 - 19:09 June 22						
	14:00 - 17:37 June 23						
	1999						
	06:37 - 08:14 January 6						
	13:47 - 16:32 April 3						
	17:10 - 19:14 April 5						
	13:44 - 17:32 April 6						
	17:00 - 18:04 April 15						
	14:09 - 20:35 April 23						
	12:30 - 20:04 April 24						
	15:18 - 18:20 April 26						
	16:00 - 18:00 May 6						
	13:00 - 19:56 July 29						
	16:00 - 19:00 July 30						
	15:23 - 18:26 July 31						
	14:00 - 16:11 August 2						
	15:27 - 19:00 September 4						
	14:54 - 17:00 September 28						
	15:00 - 17:08 October 20						
	2000						
	11:54 - 12:03 January 24	[redacted]					
	16:41 - 17:17 July 6						
	15:46 - 17:05 July 19						
	13:07 - 17:12 July 20						
	15:30 - 18:06 October 5						
	2001						
	15:52 - 15:57 April 3	[redacted]					

NOTE: Total Revenue includes fuel but does not include capacity charges.

		b. v.	b. iv.	b. iii.	b. v.	b. iv.	b. iii.
a.		Partial Requirements			Partial Requirements		
b. i.		City of Fort Meade			City of St. Cloud		
b. ii.	Recall to serve firm retail?	NO; level of interruption equal to firm retail load			NO; level of interruption equal to firm retail load		
b. vi.	Date Contract Entered	01/05/1993			10/28/1993		
b. vii	Date Power Sale Began	01/01/1997			01/01/1997		
Interruption Time	Interruption Month	Interruption Date	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars
1998								
12:52 - 13:05	April	3						
15:25 - 17:00	June	19						
13:30 - 19:09	June	22						
14:00 - 17:37	June	23						
1999								
06:37 - 08:14	January	6						
13:47 - 16:32	April	3						
17:10 - 19:14	April	5						
13:44 - 17:32	April	6						
17:00 - 18:04	April	15						
14:09 - 20:35	April	23						
12:30 - 20:04	April	24						
15:18 - 18:20	April	26						
16:00 - 18:00	May	6						
13:00 - 19:56	July	29						
16:00 - 19:00	July	30						
15:23 - 18:26	July	31						
14:00 - 16:11	August	2						
15:27 - 19:00	September	4						
14:54 - 17:00	September	28						
15:00 - 17:08	October	20						
2000								
11:54 - 12:03	January	24						
16:41 - 17:17	July	6						
15:46 - 17:05	July	19						
13:07 - 17:12	July	20						
15:30 - 18:06	October	5						
2001								
15:52 - 15:57	April	3						

NOTE: Total Revenue includes fuel but does not include capacity charges.

		b. v.	b. iv.	b. iii.	b. v.	b. iv.	b. iii.
a.		Partial Requirements			Partial Requirements		
b. i.		City of Wauchula			Florida Power Corporation		
b. ii.	Recall to serve firm retail?	NO; level of interruption equal to firm retail load			NO; level of interruption equal to firm retail load		
b. vi.	Date Contract Entered	04/12/1993			03/30/1993		
b. vii	Date Power Sale Began	01/01/1997			10/01/1993		
	Interruption Time / Month / Date	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars
	1998						
	12:52 - 13:05 April 3						
	15:25 - 17:00 June 19						
	13:30 - 19:09 June 22						
	14:00 - 17:37 June 23						
	1999						
	06:37 - 08:14 January 6						
	13:47 - 16:32 April 3						
	17:10 - 19:14 April 5						
	13:44 - 17:32 April 6						
	17:00 - 18:04 April 15						
	14:09 - 20:35 April 23						
	12:30 - 20:04 April 24						
	15:18 - 18:20 April 26						
	16:00 - 18:00 May 6						
	13:00 - 19:56 July 29						
	16:00 - 19:00 July 30						
	15:23 - 18:26 July 31						
	14:00 - 16:11 August 2						
	15:27 - 19:00 September 4						
	14:54 - 17:00 September 28						
	15:00 - 17:08 October 20						
	2000						
	11:54 - 12:03 January 24						
	16:41 - 17:17 July 6						
	15:46 - 17:05 July 19						
	13:07 - 17:12 July 20						
	15:30 - 18:06 October 5						
	2001						
	15:52 - 15:57 April 3						

NOTE: Total Revenue includes fuel but does not include capacity charges.

		b. v.	b. iv.	b. iii.
a.		Requirements Contract		
b. i.		Reedy Creek Improvement District		
b. ii.	Recall to serve firm retail?	NO; level of interruption equal to firm retail load		
b. vi.	Date Contract Entered	03/29/1995		
b. vii	Date Power Sale Began	06/01/1995		
	Interruption	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars
Time	Month Date			
1998				
12:52 - 13:05	April 3			
15:25 - 17:00	June 19			
13:30 - 19:09	June 22			
14:00 - 17:37	June 23			
1999				
06:37 - 08:14	January 6			
13:47 - 16:32	April 3			
17:10 - 19:14	April 5			
13:44 - 17:32	April 6			
17:00 - 18:04	April 15			
14:09 - 20:35	April 23			
12:30 - 20:04	April 24			
15:18 - 18:20	April 26			
16:00 - 18:00	May 6			
13:00 - 19:56	July 29			
16:00 - 19:00	July 30			
15:23 - 18:26	July 31			
14:00 - 16:11	August 2			
15:27 - 19:00	September 4			
14:54 - 17:00	September 28			
15:00 - 17:08	October 20			
2000				
11:54 - 12:03	January 24			
16:41 - 17:17	July 6			
15:46 - 17:05	July 19			
13:07 - 17:12	July 20			
15:30 - 18:06	October 5			
2001				
15:52 - 15:57	April 3			

NOTE: Total Revenue includes fuel but does not include capacity charges.

6. For each interruption listed in response to FIPUG's Interrogatory No. 10, please respond to the following:

a. Indicate those periods of interruption during which buy-through power was available to interruptible customers.

b. For each period of interruption during which buy-through power was available, provide a list of all TECO wholesale sales contracts in place.

c. Indicate whether TECO made sales under any of the contracts listed in response to Interrogatory 6.b., above, during any period when buy-through power was accepted by interruptible customers; if so, please identify:

i. the specific contract;

ii. whether the sale was recallable (i.e., the level of firmness of the sale);

iii. the total revenues received from the sale during the interruption;

iv. the dollars per megawatt hour received from the sale during the interruption

v. the total megawatt hours sold during the interruption;

vi. the date the contract was entered into; and

vii. the date power sales began under the contract.

d. For each period of interruption during which buy-through power was accepted by interruptible customers, identify the entity or entities from whom the power was purchased.

e. For each period of interruption during which buy-through power was accepted by interruptible customers, provide a comparison of the buy-through rate to the rate the interruptible customers would have paid if TECO had adequate capacity to serve the customer.

A. a. See attached.

b. See attached.

c. i. See attached.

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ii. See attached.

iii. See attached.

iv. See attached.

v. See attached.

vi. See attached.

vii. See attached.

d. See attached.

e. See attached.

	a.			c. v.	c. iv.	c. iii.	c. v.	c. iv.	c. iii.
b.				BB4 Contract			Schedule D		
c. i.				TECO Power Services/Seminole Electric Cooperative			City of Fort Meade		
c. ii.	Recall to serve firm retail?			NO			NO		
c. vi.	Date Contract Entered			07/27/1989			01/05/1993		
c. vii	Date Power Sale Began			01/01/1993			03/15/1993		
	Interruption			MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars
	Time	Month	Date						
	1998								
	15:25 - 17:00	June	19						
	13:30 - 19:09	June	22						
	14:00 - 17:37	June	23						
	1999								
	06:37 - 08:14	January	6						
	13:47 - 16:32	April	3						
	17:10 - 19:14	April	5						
	13:44 - 17:32	April	6						
	17:00 - 18:04	April	15						
	14:09 - 20:35	April	23						
	12:30 - 20:04	April	24						
	16:00 - 18:00	May	6						
	13:00 - 19:56	July	29						
	16:00 - 19:00	July	30						
	15:23 - 18:26	July	31						
	14:00 - 16:11	August	2						
	15:27 - 19:00	September	4						
	14:54 - 17:00	September	28						
	15:00 - 17:08	October	20						
	2000								
	11:54 - 12:03	January	24						
	15:46 - 17:05	July	19						
	13:07 - 17:12	July	20						
	15:30 - 18:06	October	5						

NOTE: Total Revenue includes fuel but does not include capacity charges.

	a.			c. v.	c. iv.	c. iii.	c. v.	c. iv.	c. iii.
b.				Schedule D			Schedule D		
c. i.				City of New Smyrna Beach Utilities			City of Wauchula		
c. ii.	Recall to serve firm retail?			YES			NO		
c. vi.	Date Contract Entered			11/02/1995			10/14/1991		
c. vii	Date Power Sale Began			03/01/1996			06/01/1992		
	Interruption			MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars
	Time	Month	Date						
	1998								
	15:25 - 17:00	June	19						
	13:30 - 19:09	June	22						
	14:00 - 17:37	June	23						
	1999								
	06:37 - 08:14	January	6						
	13:47 - 16:32	April	3						
	17:10 - 19:14	April	5						
	13:44 - 17:32	April	6						
	17:00 - 18:04	April	15						
	14:09 - 20:35	April	23						
	12:30 - 20:04	April	24						
	16:00 - 18:00	May	6						
	13:00 - 19:56	July	29						
	16:00 - 19:00	July	30						
	15:23 - 18:26	July	31						
	14:00 - 16:11	August	2						
	15:27 - 19:00	September	4						
	14:54 - 17:00	September	28						
	15:00 - 17:08	October	20						
	2000								
	11:54 - 12:03	January	24						
	15:46 - 17:05	July	19						
	13:07 - 17:12	July	20						
	15:30 - 18:06	October	5						

NOTE: Total Revenue includes fuel but does not include capacity charges.

	a.			c. v.	c. iv.	c. iii.	c. v.	c. iv.	c. iii.
b.				Schedule D			Schedule D		
c. i.				Florida Municipal Power Agency (served from purchased power part of 1998, all of 1999)			Reedy Creek Improvement District		
c. ii.	Recall to serve firm retail?			NO			NO		
c. vi.	Date Contract Entered			10/02/1996			10/16/1991		
c. vii	Date Power Sale Began			12/16/1996			01/01/1992		
	Interruption			MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars
	Time	Month	Date						
	1998								
	15:25 - 17:00	June	19						
	13:30 - 19:09	June	22						
	14:00 - 17:37	June	23						
	1999								
	06:37 - 08:14	January	6						
	13:47 - 16:32	April	3						
	17:10 - 19:14	April	5						
	13:44 - 17:32	April	6						
	17:00 - 18:04	April	15						
	14:09 - 20:35	April	23						
	12:30 - 20:04	April	24						
	16:00 - 18:00	May	6						
	13:00 - 19:56	July	29						
	16:00 - 19:00	July	30						
	15:23 - 18:26	July	31						
	14:00 - 16:11	August	2						
	15:27 - 19:00	September	4						
	14:54 - 17:00	September	28						
	15:00 - 17:08	October	20						
	2000								
	11:54 - 12:03	January	24						
	15:46 - 17:05	July	19						
	13:07 - 17:12	July	20						
	15:30 - 18:06	October	5						

NOTE: Total Revenue includes fuel but does not include capacity charges.

	a.			c. v.	c. iv.	c. iii.	c. v.	c. iv.	c. iii.
b.				Schedule D			Schedule D		
c. i.				Seminole Electric Cooperative Hardee Station Service			Seminole Electric Cooperative PRECO		
c. ii.	Recall to serve firm retail?			YES			YES		
c. vi.	Date Contract Entered			12/18/1991			12/18/1991		
c. vii	Date Power Sale Began			06/01/1992			06/01/1992		
	Interruption			MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars
	Time	Month	Date						
	1998								
	15:25 - 17:00	June	19						
	13:30 - 19:09	June	22						
	14:00 - 17:37	June	23						
	1999								
	06:37 - 08:14	January	6						
	13:47 - 16:32	April	3						
	17:10 - 19:14	April	5						
	13:44 - 17:32	April	6						
	17:00 - 18:04	April	15						
	14:09 - 20:35	April	23						
	12:30 - 20:04	April	24						
	16:00 - 18:00	May	6						
	13:00 - 19:56	July	29						
	16:00 - 19:00	July	30						
	15:23 - 18:26	July	31						
	14:00 - 16:11	August	2						
	15:27 - 19:00	September	4						
	14:54 - 17:00	September	28						
	15:00 - 17:08	October	20						
	2000								
	11:54 - 12:03	January	24						
	15:46 - 17:05	July	19						
	13:07 - 17:12	July	20						
	15:30 - 18:06	October	5						

NOTE: Total Revenue includes fuel but does not include capacity charges.

	a.			c. v.	c. iv.	c. iii.	c. v.	c. iv.	c. iii.
b.				Schedule J			Schedule J		
c. i.				City of New Smyrna Beach Utilities			Reedy Creek Improvement District		
c. ii.	Recall to serve firm retail?			YES			NO		
c. vi.	Date Contract Entered			03/27/1997			10/29/1997		
c. vii	Date Power Sale Began			06/01/1997			01/01/1998		
	Interruption			MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars
	Time	Month	Date						
	1998								
	15:25 - 17:00	June	19						
	13:30 - 19:09	June	22						
	14:00 - 17:37	June	23						
	1999								
	06:37 - 08:14	January	6						
	13:47 - 16:32	April	3						
	17:10 - 19:14	April	5						
	13:44 - 17:32	April	6						
	17:00 - 18:04	April	15						
	14:09 - 20:35	April	23						
	12:30 - 20:04	April	24						
	16:00 - 18:00	May	6						
	13:00 - 19:56	July	29						
	16:00 - 19:00	July	30						
	15:23 - 18:26	July	31						
	14:00 - 16:11	August	2						
	15:27 - 19:00	September	4						
	14:54 - 17:00	September	28						
	15:00 - 17:08	October	20						
	2000								
	11:54 - 12:03	January	24						
	15:46 - 17:05	July	19						
	13:07 - 17:12	July	20						
	15:30 - 18:06	October	5						

NOTE: Total Revenue includes fuel but does not include capacity charges.

	a.			c. v.	c. iv.	c. iii.	c. v.	c. iv.	c. iii.
b.				Partial Requirements			Partial Requirements		
c. i.				City of Fort Meade			City of St. Cloud		
c. ii.	Recall to serve firm retail?			NO; level of interruption equal to firm retail load			NO; level of interruption equal to firm retail load		
c. vi.	Date Contract Entered			01/05/1993			10/28/1993		
c. vii	Date Power Sale Began			01/01/1997			01/01/1997		
	Interruption			MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars
	Time	Month	Date						
	1998								
	15:25 - 17:00	June	19						
	13:30 - 19:09	June	22						
	14:00 - 17:37	June	23						
	1999								
	06:37 - 08:14	January	6						
	13:47 - 16:32	April	3						
	17:10 - 19:14	April	5						
	13:44 - 17:32	April	6						
	17:00 - 18:04	April	15						
	14:09 - 20:35	April	23						
	12:30 - 20:04	April	24						
	16:00 - 18:00	May	6						
	13:00 - 19:56	July	29						
	16:00 - 19:00	July	30						
	15:23 - 18:26	July	31						
	14:00 - 16:11	August	2						
	15:27 - 19:00	September	4						
	14:54 - 17:00	September	28						
	15:00 - 17:08	October	20						
	2000								
	11:54 - 12:03	January	24						
	15:46 - 17:05	July	19						
	13:07 - 17:12	July	20						
	15:30 - 18:06	October	5						

NOTE: Total Revenue includes fuel but does not include capacity charges.

	a.			c. v.	c. iv.	c. iii.	c. v.	c. iv.	c. iii.
b.				Partial Requirements			Partial Requirements		
c. i.				City of Wauchula			Florida Power Corporation		
c. ii.	Recall to serve firm retail?			NO; level of interruption equal to firm retail load			NO; level of interruption equal to firm retail load		
c. vi.	Date Contract Entered			04/12/1993			03/30/1993		
c. vii	Date Power Sale Began			01/01/1997			10/01/1993		
	Interruption Time	Month	Date	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars	MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars
	1998								
	15:25 - 17:00	June	19						
	13:30 - 19:09	June	22						
	14:00 - 17:37	June	23						
	1999								
	06:37 - 08:14	January	6						
	13:47 - 16:32	April	3						
	17:10 - 19:14	April	5						
	13:44 - 17:32	April	6						
	17:00 - 18:04	April	15						
	14:09 - 20:35	April	23						
	12:30 - 20:04	April	24						
	16:00 - 18:00	May	6						
	13:00 - 19:56	July	29						
	16:00 - 19:00	July	30						
	15:23 - 18:26	July	31						
	14:00 - 16:11	August	2						
	15:27 - 19:00	September	4						
	14:54 - 17:00	September	28						
	15:00 - 17:08	October	20						
	2000								
	11:54 - 12:03	January	24						
	15:46 - 17:05	July	19						
	13:07 - 17:12	July	20						
	15:30 - 18:06	October	5						

NOTE: Total Revenue includes fuel but does not include capacity charges.

	a.			c. v.	c. iv.	c. iii.
b.				Requirements Contract		
c. i.				Reedy Creek Improvement District		
c. ii.	Recall to serve firm retail?			NO; level of interruption equal to firm retail load		
c. vi.	Date Contract Entered			03/29/1995		
c. vii	Date Power Sale Began			06/01/1995		
	Interruption			MWh for Interruption Period	Energy Charge ($/MWh)	Total Revenue Dollars
	Time	Month	Date			
	1998					
	15:25 - 17:00	June	19	[redacted]		
	13:30 - 19:09	June	22			
	14:00 - 17:37	June	23			
	1999					
	06:37 - 08:14	January	6	[redacted]		
	13:47 - 16:32	April	3			
	17:10 - 19:14	April	5			
	13:44 - 17:32	April	6			
	17:00 - 18:04	April	15			
	14:09 - 20:35	April	23			
	12:30 - 20:04	April	24			
	16:00 - 18:00	May	6			
	13:00 - 19:56	July	29			
	16:00 - 19:00	July	30			
	15:23 - 18:26	July	31			
	14:00 - 16:11	August	2			
	15:27 - 19:00	September	4			
	14:54 - 17:00	September	28			
	15:00 - 17:08	October	20			
	2000					
	11:54 - 12:03	January	24	[redacted]		
	15:46 - 17:05	July	19			
	13:07 - 17:12	July	20			
	15:30 - 18:06	October	5			

NOTE: Total Revenue includes fuel but does not include capacity charges.

d.

INTERRUPTION MONTH	INTERRUPTION DATE	SELLER(S)
1998		
June	19	
June	22	
June	23	
1999		
January	6	
April	3	
April	5	
April	6	
April	15	
April	23	
April	24	
May	6	
July	29	

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INTERRUPTION MONTH	INTERRUPTION DATE	SELLER(S)
1999, cont.		
July	30	
July	31	
August	2	
September	4	
September	28	
October	20	
2000		
January	24	
July	19	
July	20	
October	5	

e.

INTERRUPTION		BUY-THROUGH RATE ($/MWh)						INTERRUPTIBLE RATE ($/MWh)					
MONTH	DATE	IS-1	IST-1	SBIT-1	IS-3	IST-3	SBIT-3	IS-1	IST-1	SBIT-1	IS-3	IST-3	SBIT-3
1998													
June													
June													
June													
1999													
January													
April													
April													
April													
April													
April													
April													
May													
July													
July													
July													
August													
September													
September													
October													
2000													
January													
July													
July													
October													

8. Please explain in detail how TECO notifies interruptible customers of pending interruption periods and the availability of buy-through power. In your response, please indicate whether customers taking service under TECO's interruptible tariffs are required to take buy-through power. Also in your response, please indicate whether such customers are aware of the buy-through rate prior to the interruption period.

A. Tampa Electric's primary method of notifying its interruptible service customers of pending interruption periods is a paging system. Tampa Electric has issued text-messaging pagers to all interruptible service customers. When an interruption is expected, a page is sent to the interruptible service customers.

Tampa Electric also uses this paging system to inform interruptible service customers of the availability of optional provision power. Each morning during the summer and other times when relevant, Tampa Electric sends a page to all interruptible service customers that reflects the estimated probability of optional provision power purchases. The page also contains the probability of interruption for that day and indicates the estimated price of optional provision [(1)].

In addition to the paging system, Tampa Electric uses a recorded telephone message system and the Internet to communicate with its interruptible service customers. When practical, Tampa Electric's account managers call interruptible service customers in advance of any interruptions.

Tampa Electric's interruptible retail tariffs include an optional provision for "buy-through" power purchases that is entirely voluntary. This provision is exercised entirely at the customer's discretion and direction. All of Tampa Electric's customers taking service under the interruptible service rates have requested this option. The terms and conditions of this agreement can be found in Tampa Electric's tariff on file with the Commission.

[(1)] Due to the competitive nature of the wholesale energy market in Florida, Tampa Electric has agreed to inform its interruptible service customers of the anticipated price of optional provision power only if the customer has signed a non-disclosure agreement. When an agreement is in effect, Tampa Electric provides access to the anticipated optional provision price levels using its recorded telephone message system and the related Internet web site.

149. Provide a detailed listing of each transaction reported in TECO's Schedule A6 for the month of July 2000. Please identify the beginning and ending time of each transaction listed.

A. See attached.

SCHEDULE A6 JULY 2000
DETAIL OF HARDEE POWER PARTNERS

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/01/2000	11	SEC	TEC	BB4	145	[redacted]			
07/01/2000	12	SEC	TEC	BB4	145				
07/01/2000	13	SEC	TEC	BB4	145				
07/01/2000	14	SEC	TEC	BB4	145				
07/01/2000	15	SEC	TEC	BB4	145				
07/01/2000	16	SEC	TEC	BB4	145				
07/01/2000	17	SEC	TEC	BB4	145				
07/01/2000	18	SEC	TEC	BB4	145				
07/01/2000	19	SEC	TEC	BB4	145				
07/01/2000	20	SEC	TEC	BB4	145				
07/01/2000	21	SEC	TEC	BB4	145				
07/01/2000	22	SEC	TEC	BB4	45				
07/02/2000	11	SEC	TEC	BB4	20				
07/02/2000	12	SEC	TEC	BB4	145				
07/02/2000	13	SEC	TEC	BB4	145				
07/02/2000	14	SEC	TEC	BB4	145				
07/02/2000	15	SEC	TEC	BB4	145				
07/02/2000	16	SEC	TEC	BB4	145				
07/02/2000	17	SEC	TEC	BB4	145				
07/02/2000	18	SEC	TEC	BB4	145				
07/02/2000	19	SEC	TEC	BB4	145				
07/02/2000	20	SEC	TEC	BB4	145				
07/02/2000	21	SEC	TEC	BB4	145				
07/02/2000	22	SEC	TEC	BB4	145				
07/02/2000	23	SEC	TEC	BB4	50				
07/03/2000	11	SEC	TEC	BB4	75				
07/03/2000	12	SEC	TEC	BB4	145				
07/03/2000	13	SEC	TEC	BB4	145				
07/03/2000	14	SEC	TEC	BB4	145				
07/03/2000	15	SEC	TEC	BB4	145				
07/03/2000	16	SEC	TEC	BB4	145				
07/03/2000	17	SEC	TEC	BB4	145				
07/03/2000	18	SEC	TEC	BB4	145				
07/03/2000	19	SEC	TEC	BB4	145				
07/03/2000	20	SEC	TEC	BB4	145				
07/03/2000	21	SEC	TEC	BB4	145				
07/03/2000	22	SEC	TEC	BB4	145				
07/03/2000	23	SEC	TEC	BB4	120				
07/04/2000	11	SEC	TEC	BB4	145				
07/04/2000	12	SEC	TEC	BB4	145				
07/04/2000	13	SEC	TEC	BB4	145				
07/04/2000	14	SEC	TEC	BB4	145				
07/04/2000	15	SEC	TEC	BB4	145				
07/04/2000	16	SEC	TEC	BB4	145				
07/04/2000	17	SEC	TEC	BB4	145				
07/04/2000	18	SEC	TEC	BB4	145				
07/04/2000	19	SEC	TEC	BB4	145				
07/04/2000	20	SEC	TEC	BB4	145				
07/04/2000	21	SEC	TEC	BB4	145				
07/04/2000	22	SEC	TEC	BB4	145				
07/05/2000	11	SEC	TEC	BB4	145				
07/05/2000	12	SEC	TEC	BB4	145				
07/05/2000	13	SEC	TEC	BB4	145				
07/05/2000	14	SEC	TEC	BB4	145				
07/05/2000	15	SEC	TEC	BB4	145				

SCHEDULE A6 JULY 2000
DETAIL OF HARDEE POWER PARTNERS

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/05/2000	16	SEC	TEC	BB4	145	[redacted]			
07/05/2000	17	SEC	TEC	BB4	145				
07/05/2000	18	SEC	TEC	BB4	145				
07/05/2000	19	SEC	TEC	BB4	145				
07/05/2000	20	SEC	TEC	BB4	145				
07/05/2000	21	SEC	TEC	BB4	145				
07/05/2000	22	SEC	TEC	BB4	145				
07/05/2000	23	SEC	TEC	BB4	145				
07/05/2000	24	SEC	TEC	BB4	145				
07/06/2000	1	SEC	TEC	BB4	145				
07/06/2000	8	SEC	TEC	BB4	65				
07/06/2000	9	SEC	TEC	BB4	145				
07/06/2000	10	SEC	TEC	BB4	145				
07/06/2000	11	SEC	TEC	BB4	145				
07/06/2000	12	SEC	TEC	BB4	145				
07/06/2000	13	SEC	TEC	BB4	145				
07/06/2000	14	SEC	TEC	BB4	145				
07/06/2000	15	SEC	TEC	BB4	145				
07/06/2000	16	SEC	TEC	BB4	145				
07/06/2000	17	SEC	TEC	BB4	145				
07/06/2000	18	SEC	TEC	BB4	145				
07/06/2000	19	SEC	TEC	BB4	145				
07/06/2000	20	SEC	TEC	BB4	145				
07/06/2000	21	SEC	TEC	BB4	145				
07/06/2000	22	SEC	TEC	BB4	145				
07/06/2000	23	SEC	TEC	BB4	145				
07/06/2000	24	SEC	TEC	BB4	100				
07/07/2000	10	SEC	TEC	BB4	145				
07/07/2000	11	SEC	TEC	BB4	145				
07/07/2000	12	SEC	TEC	BB4	145				
07/07/2000	13	SEC	TEC	BB4	145				
07/07/2000	14	SEC	TEC	BB4	145				
07/07/2000	15	SEC	TEC	BB4	145				
07/07/2000	16	SEC	TEC	BB4	145				
07/07/2000	17	SEC	TEC	BB4	145				
07/07/2000	18	SEC	TEC	BB4	145				
07/07/2000	19	SEC	TEC	BB4	145				
07/07/2000	20	SEC	TEC	BB4	145				
07/07/2000	21	SEC	TEC	BB4	145				
07/07/2000	22	SEC	TEC	BB4	145				
07/07/2000	23	SEC	TEC	BB4	145				
07/07/2000	24	SEC	TEC	BB4	145				
07/08/2000	9	SEC	TEC	BB4	40				
07/08/2000	10	SEC	TEC	BB4	145				
07/08/2000	11	SEC	TEC	BB4	145				
07/08/2000	12	SEC	TEC	BB4	145				
07/08/2000	13	SEC	TEC	BB4	145				
07/08/2000	14	SEC	TEC	BB4	145				
07/08/2000	15	SEC	TEC	BB4	145				
07/08/2000	16	SEC	TEC	BB4	145				
07/08/2000	17	SEC	TEC	BB4	145				
07/08/2000	18	SEC	TEC	BB4	145				
07/08/2000	19	SEC	TEC	BB4	145				
07/08/2000	20	SEC	TEC	BB4	145				
07/08/2000	21	SEC	TEC	BB4	145				

SCHEDULE A6 JULY 2000
DETAIL OF HARDEE POWER PARTNERS

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/08/2000	22	SEC	TEC	BB4	145				
07/08/2000	23	SEC	TEC	BB4	90				
07/09/2000	10	SEC	TEC	BB4	40				
07/09/2000	11	SEC	TEC	BB4	145				
07/09/2000	12	SEC	TEC	BB4	145				
07/09/2000	13	SEC	TEC	BB4	145				
07/09/2000	14	SEC	TEC	BB4	145				
07/09/2000	15	SEC	TEC	BB4	145				
07/09/2000	16	SEC	TEC	BB4	145				
07/09/2000	17	SEC	TEC	BB4	145				
07/09/2000	18	SEC	TEC	BB4	145				
07/09/2000	19	SEC	TEC	BB4	145				
07/09/2000	20	SEC	TEC	BB4	145				
07/09/2000	21	SEC	TEC	BB4	145				
07/09/2000	22	SEC	TEC	BB4	145				
07/09/2000	23	SEC	TEC	BB4	145				
07/10/2000	10	SEC	TEC	BB4	50				
07/10/2000	11	SEC	TEC	BB4	145				
07/10/2000	12	SEC	TEC	BB4	145				
07/10/2000	13	SEC	TEC	BB4	145				
07/10/2000	14	SEC	TEC	BB4	145				
07/10/2000	15	SEC	TEC	BB4	145				
07/10/2000	16	SEC	TEC	BB4	145				
07/10/2000	17	SEC	TEC	BB4	145				
07/10/2000	18	SEC	TEC	BB4	145				
07/10/2000	19	SEC	TEC	BB4	145				
07/10/2000	20	SEC	TEC	BB4	145				
07/10/2000	21	SEC	TEC	BB4	145				
07/10/2000	22	SEC	TEC	BB4	145				
07/10/2000	23	SEC	TEC	BB4	145				
07/10/2000	24	SEC	TEC	BB4	145				
07/11/2000	10	SEC	TEC	BB4	100				
07/11/2000	11	SEC	TEC	BB4	145				
07/11/2000	12	SEC	TEC	BB4	145				
07/11/2000	13	SEC	TEC	BB4	145				
07/11/2000	14	SEC	TEC	BB4	145				
07/11/2000	15	SEC	TEC	BB4	145				
07/11/2000	16	SEC	TEC	BB4	145				
07/11/2000	17	SEC	TEC	BB4	145				
07/11/2000	18	SEC	TEC	BB4	145				
07/11/2000	19	SEC	TEC	BB4	145				
07/11/2000	20	SEC	TEC	BB4	145				
07/11/2000	21	SEC	TEC	BB4	145				
07/11/2000	22	SEC	TEC	BB4	145				
07/11/2000	23	SEC	TEC	BB4	145				
07/11/2000	24	SEC	TEC	BB4	145				
07/12/2000	1	SEC	TEC	BB4	95				
07/12/2000	10	SEC	TEC	BB4	120				
07/12/2000	11	SEC	TEC	BB4	145				
07/12/2000	12	SEC	TEC	BB4	145				
07/12/2000	13	SEC	TEC	BB4	145				
07/12/2000	14	SEC	TEC	BB4	145				
07/12/2000	15	SEC	TEC	BB4	145				
07/12/2000	16	SEC	TEC	BB4	145				
07/12/2000	17	SEC	TEC	BB4	145				

SCHEDULE A6 JULY 2000
DETAIL OF HARDEE POWER PARTNERS

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/12/2000	18	SEC	TEC	BB4	145				
07/12/2000	19	SEC	TEC	BB4	145				
07/12/2000	20	SEC	TEC	BB4	145				
07/12/2000	21	SEC	TEC	BB4	145				
07/12/2000	22	SEC	TEC	BB4	145				
07/12/2000	23	SEC	TEC	BB4	145				
07/12/2000	24	SEC	TEC	BB4	145				
07/13/2000	10	SEC	TEC	BB4	145				
07/13/2000	11	SEC	TEC	BB4	145				
07/13/2000	12	SEC	TEC	BB4	145				
07/13/2000	13	SEC	TEC	BB4	145				
07/13/2000	14	SEC	TEC	BB4	145				
07/13/2000	15	SEC	TEC	BB4	145				
07/13/2000	16	SEC	TEC	BB4	145				
07/13/2000	17	SEC	TEC	BB4	145				
07/13/2000	18	SEC	TEC	BB4	145				
07/13/2000	19	SEC	TEC	BB4	145				
07/13/2000	20	SEC	TEC	BB4	145				
07/13/2000	21	SEC	TEC	BB4	145				
07/13/2000	22	SEC	TEC	BB4	145				
07/13/2000	23	SEC	TEC	BB4	145				
07/14/2000	10	SEC	TEC	BB4	145				
07/14/2000	11	SEC	TEC	BB4	145				
07/14/2000	12	SEC	TEC	BB4	145				
07/14/2000	13	SEC	TEC	BB4	145				
07/14/2000	14	SEC	TEC	BB4	145				
07/14/2000	15	SEC	TEC	BB4	145				
07/14/2000	16	SEC	TEC	BB4	145				
07/14/2000	17	SEC	TEC	BB4	145				
07/14/2000	18	SEC	TEC	BB4	145				
07/14/2000	19	SEC	TEC	BB4	145				
07/14/2000	20	SEC	TEC	BB4	145				
07/14/2000	21	SEC	TEC	BB4	145				
07/14/2000	22	SEC	TEC	BB4	145				
07/14/2000	23	SEC	TEC	BB4	85				
07/15/2000	10	SEC	TEC	BB4	75				
07/15/2000	11	SEC	TEC	BB4	145				
07/15/2000	12	SEC	TEC	BB4	145				
07/15/2000	13	SEC	TEC	BB4	145				
07/15/2000	14	SEC	TEC	BB4	145				
07/15/2000	15	SEC	TEC	BB4	145				
07/15/2000	16	SEC	TEC	BB4	145				
07/15/2000	17	SEC	TEC	BB4	145				
07/15/2000	18	SEC	TEC	BB4	145				
07/15/2000	19	SEC	TEC	BB4	145				
07/15/2000	20	SEC	TEC	BB4	145				
07/15/2000	21	SEC	TEC	BB4	145				
07/15/2000	22	SEC	TEC	BB4	145				
07/15/2000	23	SEC	TEC	BB4	75				
07/16/2000	10	SEC	TEC	BB4	145				
07/16/2000	11	SEC	TEC	BB4	145				
07/16/2000	12	SEC	TEC	BB4	145				
07/16/2000	13	SEC	TEC	BB4	145				
07/16/2000	14	SEC	TEC	BB4	145				
07/16/2000	15	SEC	TEC	BB4	145				

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SCHEDULE A6 JULY 2000
DETAIL OF HARDEE POWER PARTNERS

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/16/2000	16	SEC	TEC	BB4	145				
07/16/2000	17	SEC	TEC	BB4	145				
07/16/2000	18	SEC	TEC	BB4	145				
07/16/2000	19	SEC	TEC	BB4	145				
07/16/2000	20	SEC	TEC	BB4	145				
07/16/2000	21	SEC	TEC	BB4	145				
07/16/2000	22	SEC	TEC	BB4	145				
07/16/2000	23	SEC	TEC	BB4	145				
07/17/2000	9	SEC	TEC	BB4	20				
07/17/2000	10	SEC	TEC	BB4	145				
07/17/2000	11	SEC	TEC	BB4	145				
07/17/2000	12	SEC	TEC	BB4	145				
07/17/2000	13	SEC	TEC	BB4	145				
07/17/2000	14	SEC	TEC	BB4	145				
07/17/2000	15	SEC	TEC	BB4	145				
07/17/2000	16	SEC	TEC	BB4	145				
07/17/2000	17	SEC	TEC	BB4	145				
07/17/2000	18	SEC	TEC	BB4	145				
07/17/2000	19	SEC	TEC	BB4	145				
07/17/2000	20	SEC	TEC	BB4	145				
07/17/2000	21	SEC	TEC	BB4	145				
07/17/2000	22	SEC	TEC	BB4	145				
07/17/2000	23	SEC	TEC	BB4	145				
07/17/2000	24	SEC	TEC	BB4	145				
07/18/2000	10	SEC	TEC	BB4	115				
07/18/2000	11	SEC	TEC	BB4	145				
07/18/2000	12	SEC	TEC	BB4	145				
07/18/2000	13	SEC	TEC	BB4	145				
07/18/2000	14	SEC	TEC	BB4	145				
07/18/2000	15	SEC	TEC	BB4	145				
07/18/2000	16	SEC	TEC	BB4	145				
07/18/2000	17	SEC	TEC	BB4	145				
07/18/2000	18	SEC	TEC	BB4	145				
07/18/2000	19	SEC	TEC	BB4	145				
07/18/2000	20	SEC	TEC	BB4	145				
07/18/2000	21	SEC	TEC	BB4	145				
07/18/2000	22	SEC	TEC	BB4	145				
07/18/2000	23	SEC	TEC	BB4	145				
07/18/2000	24	SEC	TEC	BB4	75				
07/19/2000	10	SEC	TEC	BB4	85				
07/19/2000	11	SEC	TEC	BB4	145				
07/19/2000	12	SEC	TEC	BB4	145				
07/19/2000	13	SEC	TEC	BB4	145				
07/19/2000	14	SEC	TEC	BB4	145				
07/19/2000	15	SEC	TEC	BB4	145				
07/19/2000	16	SEC	TEC	BB4	145				
07/19/2000	17	SEC	TEC	BB4	145				
07/19/2000	18	SEC	TEC	BB4	145				
07/19/2000	19	SEC	TEC	BB4	145				
07/19/2000	20	SEC	TEC	BB4	145				
07/19/2000	21	SEC	TEC	BB4	145				
07/19/2000	22	SEC	TEC	BB4	145				
07/19/2000	23	SEC	TEC	BB4	145				
07/19/2000	24	SEC	TEC	BB4	145				
07/20/2000	8	SEC	TEC	BB4	25				

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SCHEDULE A6 JULY 2000
DETAIL OF HARDEE POWER PARTNERS

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/20/2000	9	SEC	TEC	BB4	50				
07/20/2000	10	SEC	TEC	BB4	145				
07/20/2000	11	SEC	TEC	BB4	145				
07/20/2000	12	SEC	TEC	BB4	145				
07/20/2000	13	SEC	TEC	BB4	145				
07/20/2000	14	SEC	TEC	BB4	145				
07/20/2000	15	SEC	TEC	BB4	145				
07/20/2000	16	SEC	TEC	BB4	145				
07/20/2000	17	SEC	TEC	BB4	145				
07/20/2000	18	SEC	TEC	BB4	145				
07/20/2000	19	SEC	TEC	BB4	145				
07/20/2000	20	SEC	TEC	BB4	145				
07/20/2000	21	SEC	TEC	BB4	145				
07/20/2000	22	SEC	TEC	BB4	145				
07/20/2000	23	SEC	TEC	BB4	145				
07/21/2000	10	SEC	TEC	BB4	145				
07/21/2000	11	SEC	TEC	BB4	145				
07/21/2000	12	SEC	TEC	BB4	145				
07/21/2000	13	SEC	TEC	BB4	145				
07/21/2000	14	SEC	TEC	BB4	145				
07/21/2000	15	SEC	TEC	BB4	145				
07/21/2000	16	SEC	TEC	BB4	145				
07/21/2000	17	SEC	TEC	BB4	145				
07/21/2000	18	SEC	TEC	BB4	145				
07/21/2000	19	SEC	TEC	BB4	145				
07/21/2000	20	SEC	TEC	BB4	145				
07/21/2000	21	SEC	TEC	BB4	145				
07/21/2000	22	SEC	TEC	BB4	145				
07/21/2000	23	SEC	TEC	BB4	100				
07/22/2000	11	SEC	TEC	BB4	145				
07/22/2000	12	SEC	TEC	BB4	145				
07/22/2000	13	SEC	TEC	BB4	145				
07/22/2000	14	SEC	TEC	BB4	145				
07/22/2000	15	SEC	TEC	BB4	145				
07/22/2000	16	SEC	TEC	BB4	145				
07/22/2000	17	SEC	TEC	BB4	145				
07/22/2000	18	SEC	TEC	BB4	145				
07/22/2000	19	SEC	TEC	BB4	145				
07/22/2000	20	SEC	TEC	BB4	145				
07/22/2000	21	SEC	TEC	BB4	145				
07/23/2000	11	SEC	TEC	BB4	145				
07/23/2000	12	SEC	TEC	BB4	145				
07/23/2000	13	SEC	TEC	BB4	145				
07/23/2000	14	SEC	TEC	BB4	145				
07/23/2000	15	SEC	TEC	BB4	145				
07/23/2000	16	SEC	TEC	BB4	145				
07/23/2000	17	SEC	TEC	BB4	145				
07/23/2000	18	SEC	TEC	BB4	145				
07/23/2000	19	SEC	TEC	BB4	145				
07/23/2000	20	SEC	TEC	BB4	145				
07/23/2000	21	SEC	TEC	BB4	85				
07/23/2000	22	SEC	TEC	BB4	15				
07/24/2000	12	SEC	TEC	BB4	110				
07/24/2000	13	SEC	TEC	BB4	145				
07/24/2000	14	SEC	TEC	BB4	145				

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SCHEDULE A6 JULY 2000
DETAIL OF HARDEE POWER PARTNERS

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/24/2000	15	SEC	TEC	BB4	145				
07/24/2000	16	SEC	TEC	BB4	145				
07/24/2000	17	SEC	TEC	BB4	145				
07/24/2000	18	SEC	TEC	BB4	85				
07/24/2000	19	SEC	TEC	BB4	125				
07/24/2000	20	SEC	TEC	BB4	135				
07/24/2000	21	SEC	TEC	BB4	40				
07/25/2000	12	SEC	TEC	BB4	80				
07/25/2000	13	SEC	TEC	BB4	145				
07/25/2000	14	SEC	TEC	BB4	145				
07/25/2000	15	SEC	TEC	BB4	145				
07/25/2000	16	SEC	TEC	BB4	145				
07/25/2000	17	SEC	TEC	BB4	145				
07/25/2000	18	SEC	TEC	BB4	145				
07/25/2000	19	SEC	TEC	BB4	145				
07/25/2000	20	SEC	TEC	BB4	145				
07/25/2000	21	SEC	TEC	BB4	145				
07/26/2000	12	SEC	TEC	BB4	90				
07/26/2000	13	SEC	TEC	BB4	145				
07/26/2000	14	SEC	TEC	BB4	145				
07/26/2000	15	SEC	TEC	BB4	145				
07/26/2000	16	SEC	TEC	BB4	145				
07/26/2000	17	SEC	TEC	BB4	145				
07/26/2000	18	SEC	TEC	BB4	145				
07/26/2000	19	SEC	TEC	BB4	145				
07/26/2000	20	SEC	TEC	BB4	145				
07/26/2000	21	SEC	TEC	BB4	145				
07/26/2000	22	SEC	TEC	BB4	120				
07/27/2000	11	SEC	TEC	BB4	145				
07/27/2000	12	SEC	TEC	BB4	145				
07/27/2000	13	SEC	TEC	BB4	145				
07/27/2000	14	SEC	TEC	BB4	145				
07/27/2000	15	SEC	TEC	BB4	145				
07/27/2000	16	SEC	TEC	BB4	145				
07/27/2000	17	SEC	TEC	BB4	145				
07/27/2000	18	SEC	TEC	BB4	145				
07/27/2000	19	SEC	TEC	BB4	145				
07/27/2000	20	SEC	TEC	BB4	145				
07/27/2000	21	SEC	TEC	BB4	145				
07/27/2000	22	SEC	TEC	BB4	145				
07/27/2000	23	SEC	TEC	BB4	145				
07/27/2000	24	SEC	TEC	BB4	75				
07/28/2000	11	SEC	TEC	BB4	145				
07/28/2000	12	SEC	TEC	BB4	145				
07/28/2000	13	SEC	TEC	BB4	145				
07/28/2000	14	SEC	TEC	BB4	145				
07/28/2000	15	SEC	TEC	BB4	145				
07/28/2000	16	SEC	TEC	BB4	145				
07/28/2000	17	SEC	TEC	BB4	145				
07/28/2000	18	SEC	TEC	BB4	145				
07/28/2000	19	SEC	TEC	BB4	145				
07/28/2000	20	SEC	TEC	BB4	145				
07/28/2000	21	SEC	TEC	BB4	145				
07/28/2000	22	SEC	TEC	BB4	145				
07/28/2000	23	SEC	TEC	BB4	145				

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SCHEDULE A6 JULY 2000
DETAIL OF HARDEE POWER PARTNERS

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/28/2000	24	SEC	TEC	BB4	75				
07/29/2000	11	SEC	TEC	BB4	100				
07/29/2000	12	SEC	TEC	BB4	145				
07/29/2000	13	SEC	TEC	BB4	145				
07/29/2000	14	SEC	TEC	BB4	145				
07/29/2000	15	SEC	TEC	BB4	145				
07/29/2000	16	SEC	TEC	BB4	145				
07/29/2000	17	SEC	TEC	BB4	145				
07/29/2000	18	SEC	TEC	BB4	145				
07/29/2000	19	SEC	TEC	BB4	145				
07/29/2000	20	SEC	TEC	BB4	145				
07/29/2000	21	SEC	TEC	BB4	145				
07/29/2000	22	SEC	TEC	BB4	75				
07/30/2000	3	SEC	TEC	BB4	145				
07/30/2000	4	SEC	TEC	BB4	75				
07/30/2000	5	SEC	TEC	BB4	75				
07/30/2000	6	SEC	TEC	BB4	75				
07/30/2000	7	SEC	TEC	BB4	100				
07/30/2000	8	SEC	TEC	BB4	145				
07/30/2000	9	SEC	TEC	BB4	145				
07/30/2000	10	SEC	TEC	BB4	145				
07/30/2000	11	SEC	TEC	BB4	145				
07/30/2000	12	SEC	TEC	BB4	145				
07/30/2000	13	SEC	TEC	BB4	145				
07/30/2000	14	SEC	TEC	BB4	145				
07/30/2000	15	SEC	TEC	BB4	145				
07/30/2000	16	SEC	TEC	BB4	145				
07/30/2000	17	SEC	TEC	BB4	145				
07/30/2000	18	SEC	TEC	BB4	145				
07/30/2000	19	SEC	TEC	BB4	145				
07/30/2000	20	SEC	TEC	BB4	145				
07/30/2000	21	SEC	TEC	BB4	145				
07/30/2000	22	SEC	TEC	BB4	145				
07/30/2000	23	SEC	TEC	BB4	145				
07/30/2000	24	SEC	TEC	BB4	145				
07/31/2000	1	SEC	TEC	BB4	100				
07/31/2000	6	SEC	TEC	BB4	70				
07/31/2000	7	SEC	TEC	BB4	145				
07/31/2000	8	SEC	TEC	BB4	145				
07/31/2000	9	SEC	TEC	BB4	145				
07/31/2000	10	SEC	TEC	BB4	145				
07/31/2000	11	SEC	TEC	BB4	145				
07/31/2000	12	SEC	TEC	BB4	145				
07/31/2000	13	SEC	TEC	BB4	145				
07/31/2000	14	SEC	TEC	BB4	145				
07/31/2000	15	SEC	TEC	BB4	145				
07/31/2000	16	SEC	TEC	BB4	145				
07/31/2000	17	SEC	TEC	BB4	145				
07/31/2000	18	SEC	TEC	BB4	145				
07/31/2000	19	SEC	TEC	BB4	145				
07/31/2000	20	SEC	TEC	BB4	145				
07/31/2000	21	SEC	TEC	BB4	145				
07/31/2000	22	SEC	TEC	BB4	145				
07/31/2000	23	SEC	TEC	BB4	145				

SCHEDULE A6 JULY 2000
DETAIL OF HARDEE POWER PARTNERS

	A6	DETAIL	VARIANCE	EXPLANATION
MWH	60,695	60,695	0	
FUEL	$1,454,252.20	$1,464,570.35	$10,318.15	A6 reflects the estimated costs billed, the detail shows the actual after adjustments.
O&M	$506,803.25	$489,808.65	($16,994.60)	A6 reflects the estimated costs billed, the detail shows the actual after adjustments.
Adjustment	($6,676.45)	$0.00	$6,676.45	Total adjustment included in detail. A6 for August 2000 shows the adjustment.
TOTAL	**$1,954,379.00**	**$1,954,379.00**	**$0.00**	

SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - HARDEE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/01/2000	1	SEC HPPSS	TEC	D	4				
07/01/2000	2	SEC HPPSS	TEC	D	3				
07/01/2000	3	SEC HPPSS	TEC	D	4				
07/01/2000	4	SEC HPPSS	TEC	D	3				
07/01/2000	5	SEC HPPSS	TEC	D	3				
07/01/2000	6	SEC HPPSS	TEC	D	3				
07/01/2000	7	SEC HPPSS	TEC	D	3				
07/01/2000	8	SEC HPPSS	TEC	D	3				
07/01/2000	9	SEC HPPSS	TEC	D	4				
07/01/2000	10	SEC HPPSS	TEC	D	3				
07/01/2000	11	SEC HPPSS	TEC	D	0				
07/01/2000	12	SEC HPPSS	TEC	D	0				
07/01/2000	13	SEC HPPSS	TEC	D	0				
07/01/2000	14	SEC HPPSS	TEC	D	0				
07/01/2000	15	SEC HPPSS	TEC	D	0				
07/01/2000	16	SEC HPPSS	TEC	D	0				
07/01/2000	17	SEC HPPSS	TEC	D	0				
07/01/2000	18	SEC HPPSS	TEC	D	0				
07/01/2000	19	SEC HPPSS	TEC	D	0				
07/01/2000	20	SEC HPPSS	TEC	D	0				
07/01/2000	21	SEC HPPSS	TEC	D	0				
07/01/2000	22	SEC HPPSS	TEC	D	3				
07/01/2000	23	SEC HPPSS	TEC	D	3				
07/01/2000	24	SEC HPPSS	TEC	D	3				
07/02/2000	1	SEC HPPSS	TEC	D	0				
07/02/2000	2	SEC HPPSS	TEC	D	0				
07/02/2000	3	SEC HPPSS	TEC	D	0				
07/02/2000	4	SEC HPPSS	TEC	D	0				
07/02/2000	5	SEC HPPSS	TEC	D	3				
07/02/2000	6	SEC HPPSS	TEC	D	3				
07/02/2000	7	SEC HPPSS	TEC	D	3				
07/02/2000	8	SEC HPPSS	TEC	D	3				
07/02/2000	9	SEC HPPSS	TEC	D	3				
07/02/2000	10	SEC HPPSS	TEC	D	3				
07/02/2000	11	SEC HPPSS	TEC	D	3				
07/02/2000	12	SEC HPPSS	TEC	D	3				
07/02/2000	13	SEC HPPSS	TEC	D	3				
07/02/2000	14	SEC HPPSS	TEC	D	4				
07/02/2000	15	SEC HPPSS	TEC	D	3				
07/02/2000	16	SEC HPPSS	TEC	D	0				
07/02/2000	17	SEC HPPSS	TEC	D	0				
07/02/2000	18	SEC HPPSS	TEC	D	0				
07/02/2000	19	SEC HPPSS	TEC	D	0				
07/02/2000	20	SEC HPPSS	TEC	D	0				
07/02/2000	21	SEC HPPSS	TEC	D	0				
07/02/2000	22	SEC HPPSS	TEC	D	0				
07/02/2000	23	SEC HPPSS	TEC	D	0				
07/02/2000	24	SEC HPPSS	TEC	D	0				
07/03/2000	1	SEC HPPSS	TEC	D	0				
07/03/2000	2	SEC HPPSS	TEC	D	3				
07/03/2000	3	SEC HPPSS	TEC	D	4				
07/03/2000	4	SEC HPPSS	TEC	D	4				
07/03/2000	5	SEC HPPSS	TEC	D	4				
07/03/2000	6	SEC HPPSS	TEC	D	4				
07/03/2000	7	SEC HPPSS	TEC	D	4				

SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - HARDEE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/03/2000	8	SEC HPPSS	TEC	D	3				
07/03/2000	9	SEC HPPSS	TEC	D	4				
07/03/2000	10	SEC HPPSS	TEC	D	4				
07/03/2000	11	SEC HPPSS	TEC	D	0				
07/03/2000	12	SEC HPPSS	TEC	D	0				
07/03/2000	13	SEC HPPSS	TEC	D	0				
07/03/2000	14	SEC HPPSS	TEC	D	0				
07/03/2000	15	SEC HPPSS	TEC	D	0				
07/03/2000	16	SEC HPPSS	TEC	D	0				
07/03/2000	17	SEC HPPSS	TEC	D	0				
07/03/2000	18	SEC HPPSS	TEC	D	0				
07/03/2000	19	SEC HPPSS	TEC	D	0				
07/03/2000	20	SEC HPPSS	TEC	D	0				
07/03/2000	21	SEC HPPSS	TEC	D	0				
07/03/2000	22	SEC HPPSS	TEC	D	0				
07/03/2000	23	SEC HPPSS	TEC	D	0				
07/03/2000	24	SEC HPPSS	TEC	D	0				
07/04/2000	1	SEC HPPSS	TEC	D	0				
07/04/2000	2	SEC HPPSS	TEC	D	3				
07/04/2000	3	SEC HPPSS	TEC	D	3				
07/04/2000	4	SEC HPPSS	TEC	D	3				
07/04/2000	5	SEC HPPSS	TEC	D	3				
07/04/2000	6	SEC HPPSS	TEC	D	3				
07/04/2000	7	SEC HPPSS	TEC	D	3				
07/04/2000	8	SEC HPPSS	TEC	D	3				
07/04/2000	9	SEC HPPSS	TEC	D	3				
07/04/2000	10	SEC HPPSS	TEC	D	4				
07/04/2000	11	SEC HPPSS	TEC	D	4				
07/04/2000	12	SEC HPPSS	TEC	D	0				
07/04/2000	13	SEC HPPSS	TEC	D	0				
07/04/2000	14	SEC HPPSS	TEC	D	0				
07/04/2000	15	SEC HPPSS	TEC	D	0				
07/04/2000	16	SEC HPPSS	TEC	D	0				
07/04/2000	17	SEC HPPSS	TEC	D	0				
07/04/2000	18	SEC HPPSS	TEC	D	0				
07/04/2000	19	SEC HPPSS	TEC	D	0				
07/04/2000	20	SEC HPPSS	TEC	D	0				
07/04/2000	21	SEC HPPSS	TEC	D	3				
07/04/2000	22	SEC HPPSS	TEC	D	4				
07/04/2000	23	SEC HPPSS	TEC	D	4				
07/04/2000	24	SEC HPPSS	TEC	D	4				
07/05/2000	1	SEC HPPSS	TEC	D	3				
07/05/2000	2	SEC HPPSS	TEC	D	3				
07/05/2000	3	SEC HPPSS	TEC	D	3				
07/05/2000	4	SEC HPPSS	TEC	D	3				
07/05/2000	5	SEC HPPSS	TEC	D	3				
07/05/2000	6	SEC HPPSS	TEC	D	3				
07/05/2000	7	SEC HPPSS	TEC	D	3				
07/05/2000	8	SEC HPPSS	TEC	D	3				
07/05/2000	9	SEC HPPSS	TEC	D	3				
07/05/2000	10	SEC HPPSS	TEC	D	3				
07/05/2000	11	SEC HPPSS	TEC	D	4				
07/05/2000	12	SEC HPPSS	TEC	D	1				
07/05/2000	13	SEC HPPSS	TEC	D	0				
07/05/2000	14	SEC HPPSS	TEC	D	0				

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SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - HARDEE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/05/2000	15	SEC HPPSS	TEC	D	0	[redacted]			
07/05/2000	16	SEC HPPSS	TEC	D	0				
07/05/2000	17	SEC HPPSS	TEC	D	0				
07/05/2000	18	SEC HPPSS	TEC	D	0				
07/05/2000	19	SEC HPPSS	TEC	D	0				
07/05/2000	20	SEC HPPSS	TEC	D	0				
07/05/2000	21	SEC HPPSS	TEC	D	0				
07/05/2000	22	SEC HPPSS	TEC	D	0				
07/05/2000	23	SEC HPPSS	TEC	D	0				
07/05/2000	24	SEC HPPSS	TEC	D	0				
07/06/2000	1	SEC HPPSS	TEC	D	0				
07/06/2000	2	SEC HPPSS	TEC	D	3				
07/06/2000	3	SEC HPPSS	TEC	D	3				
07/06/2000	4	SEC HPPSS	TEC	D	3				
07/06/2000	5	SEC HPPSS	TEC	D	3				
07/06/2000	6	SEC HPPSS	TEC	D	3				
07/06/2000	7	SEC HPPSS	TEC	D	3				
07/06/2000	8	SEC HPPSS	TEC	D	3				
07/06/2000	9	SEC HPPSS	TEC	D	3				
07/06/2000	10	SEC HPPSS	TEC	D	4				
07/06/2000	11	SEC HPPSS	TEC	D	1				
07/06/2000	12	SEC HPPSS	TEC	D	0				
07/06/2000	13	SEC HPPSS	TEC	D	0				
07/06/2000	14	SEC HPPSS	TEC	D	0				
07/06/2000	15	SEC HPPSS	TEC	D	0				
07/06/2000	16	SEC HPPSS	TEC	D	0				
07/06/2000	17	SEC HPPSS	TEC	D	0				
07/06/2000	18	SEC HPPSS	TEC	D	0				
07/06/2000	19	SEC HPPSS	TEC	D	0				
07/06/2000	20	SEC HPPSS	TEC	D	0				
07/06/2000	21	SEC HPPSS	TEC	D	0				
07/06/2000	22	SEC HPPSS	TEC	D	0				
07/06/2000	23	SEC HPPSS	TEC	D	0				
07/06/2000	24	SEC HPPSS	TEC	D	0				
07/07/2000	1	SEC HPPSS	TEC	D	2				
07/07/2000	2	SEC HPPSS	TEC	D	3				
07/07/2000	3	SEC HPPSS	TEC	D	3				
07/07/2000	4	SEC HPPSS	TEC	D	3				
07/07/2000	5	SEC HPPSS	TEC	D	3				
07/07/2000	6	SEC HPPSS	TEC	D	3				
07/07/2000	7	SEC HPPSS	TEC	D	3				
07/07/2000	8	SEC HPPSS	TEC	D	4				
07/07/2000	9	SEC HPPSS	TEC	D	3				
07/07/2000	10	SEC HPPSS	TEC	D	0				
07/07/2000	11	SEC HPPSS	TEC	D	0				
07/07/2000	12	SEC HPPSS	TEC	D	0				
07/07/2000	13	SEC HPPSS	TEC	D	0				
07/07/2000	14	SEC HPPSS	TEC	D	0				
07/07/2000	15	SEC HPPSS	TEC	D	0				
07/07/2000	16	SEC HPPSS	TEC	D	0				
07/07/2000	17	SEC HPPSS	TEC	D	0				
07/07/2000	18	SEC HPPSS	TEC	D	0				
07/07/2000	19	SEC HPPSS	TEC	D	0				
07/07/2000	20	SEC HPPSS	TEC	D	0				
07/07/2000	21	SEC HPPSS	TEC	D	0				

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SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - HARDEE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/07/2000	22	SEC HPPSS	TEC	D	0	[redacted]			
07/07/2000	23	SEC HPPSS	TEC	D	0				
07/07/2000	24	SEC HPPSS	TEC	D	0				
07/08/2000	1	SEC HPPSS	TEC	D	0				
07/08/2000	2	SEC HPPSS	TEC	D	2				
07/08/2000	3	SEC HPPSS	TEC	D	4				
07/08/2000	4	SEC HPPSS	TEC	D	4				
07/08/2000	5	SEC HPPSS	TEC	D	4				
07/08/2000	6	SEC HPPSS	TEC	D	4				
07/08/2000	7	SEC HPPSS	TEC	D	4				
07/08/2000	8	SEC HPPSS	TEC	D	4				
07/08/2000	9	SEC HPPSS	TEC	D	4				
07/08/2000	10	SEC HPPSS	TEC	D	2				
07/08/2000	11	SEC HPPSS	TEC	D	0				
07/08/2000	12	SEC HPPSS	TEC	D	0				
07/08/2000	13	SEC HPPSS	TEC	D	0				
07/08/2000	14	SEC HPPSS	TEC	D	0				
07/08/2000	15	SEC HPPSS	TEC	D	0				
07/08/2000	16	SEC HPPSS	TEC	D	0				
07/08/2000	17	SEC HPPSS	TEC	D	0				
07/08/2000	18	SEC HPPSS	TEC	D	0				
07/08/2000	19	SEC HPPSS	TEC	D	1				
07/08/2000	20	SEC HPPSS	TEC	D	3				
07/08/2000	21	SEC HPPSS	TEC	D	4				
07/08/2000	22	SEC HPPSS	TEC	D	3				
07/08/2000	23	SEC HPPSS	TEC	D	3				
07/08/2000	24	SEC HPPSS	TEC	D	3				
07/09/2000	1	SEC HPPSS	TEC	D	3				
07/09/2000	2	SEC HPPSS	TEC	D	3				
07/09/2000	3	SEC HPPSS	TEC	D	3				
07/09/2000	4	SEC HPPSS	TEC	D	3				
07/09/2000	5	SEC HPPSS	TEC	D	3				
07/09/2000	6	SEC HPPSS	TEC	D	3				
07/09/2000	7	SEC HPPSS	TEC	D	3				
07/09/2000	8	SEC HPPSS	TEC	D	3				
07/09/2000	9	SEC HPPSS	TEC	D	4				
07/09/2000	10	SEC HPPSS	TEC	D	3				
07/09/2000	11	SEC HPPSS	TEC	D	0				
07/09/2000	12	SEC HPPSS	TEC	D	0				
07/09/2000	13	SEC HPPSS	TEC	D	0				
07/09/2000	14	SEC HPPSS	TEC	D	0				
07/09/2000	15	SEC HPPSS	TEC	D	0				
07/09/2000	16	SEC HPPSS	TEC	D	0				
07/09/2000	17	SEC HPPSS	TEC	D	0				
07/09/2000	18	SEC HPPSS	TEC	D	0				
07/09/2000	19	SEC HPPSS	TEC	D	0				
07/09/2000	20	SEC HPPSS	TEC	D	0				
07/09/2000	21	SEC HPPSS	TEC	D	0				
07/09/2000	22	SEC HPPSS	TEC	D	0				
07/09/2000	23	SEC HPPSS	TEC	D	0				
07/09/2000	24	SEC HPPSS	TEC	D	3				
07/10/2000	1	SEC HPPSS	TEC	D	3				
07/10/2000	2	SEC HPPSS	TEC	D	3				
07/10/2000	3	SEC HPPSS	TEC	D	3				
07/10/2000	4	SEC HPPSS	TEC	D	3				

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SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - HARDEE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/10/2000	5	SEC HPPSS	TEC	D	4				
07/10/2000	6	SEC HPPSS	TEC	D	4				
07/10/2000	7	SEC HPPSS	TEC	D	4				
07/10/2000	8	SEC HPPSS	TEC	D	4				
07/10/2000	9	SEC HPPSS	TEC	D	4				
07/10/2000	10	SEC HPPSS	TEC	D	4				
07/10/2000	11	SEC HPPSS	TEC	D	4				
07/10/2000	12	SEC HPPSS	TEC	D	0				
07/10/2000	13	SEC HPPSS	TEC	D	0				
07/10/2000	14	SEC HPPSS	TEC	D	0				
07/10/2000	15	SEC HPPSS	TEC	D	0				
07/10/2000	16	SEC HPPSS	TEC	D	0				
07/10/2000	17	SEC HPPSS	TEC	D	0				
07/10/2000	18	SEC HPPSS	TEC	D	0				
07/10/2000	19	SEC HPPSS	TEC	D	0				
07/10/2000	20	SEC HPPSS	TEC	D	0				
07/10/2000	21	SEC HPPSS	TEC	D	0				
07/10/2000	22	SEC HPPSS	TEC	D	0				
07/10/2000	23	SEC HPPSS	TEC	D	0				
07/10/2000	24	SEC HPPSS	TEC	D	2				
07/11/2000	1	SEC HPPSS	TEC	D	3				
07/11/2000	2	SEC HPPSS	TEC	D	3				
07/11/2000	3	SEC HPPSS	TEC	D	4				
07/11/2000	4	SEC HPPSS	TEC	D	3				
07/11/2000	5	SEC HPPSS	TEC	D	3				
07/11/2000	6	SEC HPPSS	TEC	D	3				
07/11/2000	7	SEC HPPSS	TEC	D	3				
07/11/2000	8	SEC HPPSS	TEC	D	3				
07/11/2000	9	SEC HPPSS	TEC	D	4				
07/11/2000	10	SEC HPPSS	TEC	D	1				
07/11/2000	11	SEC HPPSS	TEC	D	0				
07/11/2000	12	SEC HPPSS	TEC	D	0				
07/11/2000	13	SEC HPPSS	TEC	D	0				
07/11/2000	14	SEC HPPSS	TEC	D	0				
07/11/2000	15	SEC HPPSS	TEC	D	0				
07/11/2000	16	SEC HPPSS	TEC	D	0				
07/11/2000	17	SEC HPPSS	TEC	D	0				
07/11/2000	18	SEC HPPSS	TEC	D	0				
07/11/2000	19	SEC HPPSS	TEC	D	0				
07/11/2000	20	SEC HPPSS	TEC	D	0				
07/11/2000	21	SEC HPPSS	TEC	D	0				
07/11/2000	22	SEC HPPSS	TEC	D	0				
07/11/2000	23	SEC HPPSS	TEC	D	0				
07/11/2000	24	SEC HPPSS	TEC	D	0				
07/12/2000	1	SEC HPPSS	TEC	D	0				
07/12/2000	2	SEC HPPSS	TEC	D	0				
07/12/2000	3	SEC HPPSS	TEC	D	2				
07/12/2000	4	SEC HPPSS	TEC	D	3				
07/12/2000	5	SEC HPPSS	TEC	D	3				
07/12/2000	6	SEC HPPSS	TEC	D	3				
07/12/2000	7	SEC HPPSS	TEC	D	4				
07/12/2000	8	SEC HPPSS	TEC	D	2				
07/12/2000	9	SEC HPPSS	TEC	D	0				
07/12/2000	10	SEC HPPSS	TEC	D	0				
07/12/2000	11	SEC HPPSS	TEC	D	0				

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SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - HARDEE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/12/2000	12	SEC HPPSS	TEC	D	0				
07/12/2000	13	SEC HPPSS	TEC	D	0				
07/12/2000	14	SEC HPPSS	TEC	D	0				
07/12/2000	15	SEC HPPSS	TEC	D	0				
07/12/2000	16	SEC HPPSS	TEC	D	0				
07/12/2000	17	SEC HPPSS	TEC	D	0				
07/12/2000	18	SEC HPPSS	TEC	D	0				
07/12/2000	19	SEC HPPSS	TEC	D	0				
07/12/2000	20	SEC HPPSS	TEC	D	0				
07/12/2000	21	SEC HPPSS	TEC	D	0				
07/12/2000	22	SEC HPPSS	TEC	D	0				
07/12/2000	23	SEC HPPSS	TEC	D	0				
07/12/2000	24	SEC HPPSS	TEC	D	0				
07/13/2000	1	SEC HPPSS	TEC	D	0				
07/13/2000	2	SEC HPPSS	TEC	D	0				
07/13/2000	3	SEC HPPSS	TEC	D	0				
07/13/2000	4	SEC HPPSS	TEC	D	0				
07/13/2000	5	SEC HPPSS	TEC	D	0				
07/13/2000	6	SEC HPPSS	TEC	D	0				
07/13/2000	7	SEC HPPSS	TEC	D	0				
07/13/2000	8	SEC HPPSS	TEC	D	0				
07/13/2000	9	SEC HPPSS	TEC	D	0				
07/13/2000	10	SEC HPPSS	TEC	D	0				
07/13/2000	11	SEC HPPSS	TEC	D	0				
07/13/2000	12	SEC HPPSS	TEC	D	0				
07/13/2000	13	SEC HPPSS	TEC	D	0				
07/13/2000	14	SEC HPPSS	TEC	D	0				
07/13/2000	15	SEC HPPSS	TEC	D	0				
07/13/2000	16	SEC HPPSS	TEC	D	0				
07/13/2000	17	SEC HPPSS	TEC	D	0				
07/13/2000	18	SEC HPPSS	TEC	D	0				
07/13/2000	19	SEC HPPSS	TEC	D	0				
07/13/2000	20	SEC HPPSS	TEC	D	0				
07/13/2000	21	SEC HPPSS	TEC	D	0				
07/13/2000	22	SEC HPPSS	TEC	D	0				
07/13/2000	23	SEC HPPSS	TEC	D	0				
07/13/2000	24	SEC HPPSS	TEC	D	0				
07/14/2000	1	SEC HPPSS	TEC	D	0				
07/14/2000	2	SEC HPPSS	TEC	D	0				
07/14/2000	3	SEC HPPSS	TEC	D	0				
07/14/2000	4	SEC HPPSS	TEC	D	0				
07/14/2000	5	SEC HPPSS	TEC	D	0				
07/14/2000	6	SEC HPPSS	TEC	D	0				
07/14/2000	7	SEC HPPSS	TEC	D	0				
07/14/2000	8	SEC HPPSS	TEC	D	0				
07/14/2000	9	SEC HPPSS	TEC	D	0				
07/14/2000	10	SEC HPPSS	TEC	D	0				
07/14/2000	11	SEC HPPSS	TEC	D	0				
07/14/2000	12	SEC HPPSS	TEC	D	0				
07/14/2000	13	SEC HPPSS	TEC	D	0				
07/14/2000	14	SEC HPPSS	TEC	D	0				
07/14/2000	15	SEC HPPSS	TEC	D	0				
07/14/2000	16	SEC HPPSS	TEC	D	0				
07/14/2000	17	SEC HPPSS	TEC	D	0				
07/14/2000	18	SEC HPPSS	TEC	D	0				

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SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - HARDEE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/14/2000	19	SEC HPPSS	TEC	D	0	[redacted]			
07/14/2000	20	SEC HPPSS	TEC	D	0				
07/14/2000	21	SEC HPPSS	TEC	D	0				
07/14/2000	22	SEC HPPSS	TEC	D	0				
07/14/2000	23	SEC HPPSS	TEC	D	0				
07/14/2000	24	SEC HPPSS	TEC	D	0				
07/15/2000	1	SEC HPPSS	TEC	D	0				
07/15/2000	2	SEC HPPSS	TEC	D	3				
07/15/2000	3	SEC HPPSS	TEC	D	3				
07/15/2000	4	SEC HPPSS	TEC	D	3				
07/15/2000	5	SEC HPPSS	TEC	D	3				
07/15/2000	6	SEC HPPSS	TEC	D	3				
07/15/2000	7	SEC HPPSS	TEC	D	3				
07/15/2000	8	SEC HPPSS	TEC	D	3				
07/15/2000	9	SEC HPPSS	TEC	D	3				
07/15/2000	10	SEC HPPSS	TEC	D	0				
07/15/2000	11	SEC HPPSS	TEC	D	0				
07/15/2000	12	SEC HPPSS	TEC	D	0				
07/15/2000	13	SEC HPPSS	TEC	D	0				
07/15/2000	14	SEC HPPSS	TEC	D	0				
07/15/2000	15	SEC HPPSS	TEC	D	0				
07/15/2000	16	SEC HPPSS	TEC	D	0				
07/15/2000	17	SEC HPPSS	TEC	D	0				
07/15/2000	18	SEC HPPSS	TEC	D	0				
07/15/2000	19	SEC HPPSS	TEC	D	3				
07/15/2000	20	SEC HPPSS	TEC	D	3				
07/15/2000	21	SEC HPPSS	TEC	D	3				
07/15/2000	22	SEC HPPSS	TEC	D	3				
07/15/2000	23	SEC HPPSS	TEC	D	3				
07/15/2000	24	SEC HPPSS	TEC	D	3				
07/16/2000	1	SEC HPPSS	TEC	D	3				
07/16/2000	2	SEC HPPSS	TEC	D	3				
07/16/2000	3	SEC HPPSS	TEC	D	3				
07/16/2000	4	SEC HPPSS	TEC	D	3				
07/16/2000	5	SEC HPPSS	TEC	D	3				
07/16/2000	6	SEC HPPSS	TEC	D	3				
07/16/2000	7	SEC HPPSS	TEC	D	3				
07/16/2000	8	SEC HPPSS	TEC	D	3				
07/16/2000	9	SEC HPPSS	TEC	D	3				
07/16/2000	10	SEC HPPSS	TEC	D	3				
07/16/2000	11	SEC HPPSS	TEC	D	4				
07/16/2000	12	SEC HPPSS	TEC	D	2				
07/16/2000	13	SEC HPPSS	TEC	D	0				
07/16/2000	14	SEC HPPSS	TEC	D	0				
07/16/2000	15	SEC HPPSS	TEC	D	0				
07/16/2000	16	SEC HPPSS	TEC	D	0				
07/16/2000	17	SEC HPPSS	TEC	D	0				
07/16/2000	18	SEC HPPSS	TEC	D	0				
07/16/2000	19	SEC HPPSS	TEC	D	0				
07/16/2000	20	SEC HPPSS	TEC	D	0				
07/16/2000	21	SEC HPPSS	TEC	D	0				
07/16/2000	22	SEC HPPSS	TEC	D	0				
07/16/2000	23	SEC HPPSS	TEC	D	0				
07/16/2000	24	SEC HPPSS	TEC	D	0				
07/17/2000	1	SEC HPPSS	TEC	D	0				

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SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - HARDEE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/17/2000	2	SEC HPPSS	TEC	D	1				
07/17/2000	3	SEC HPPSS	TEC	D	3				
07/17/2000	4	SEC HPPSS	TEC	D	3				
07/17/2000	5	SEC HPPSS	TEC	D	3				
07/17/2000	6	SEC HPPSS	TEC	D	3				
07/17/2000	7	SEC HPPSS	TEC	D	2				
07/17/2000	8	SEC HPPSS	TEC	D	0				
07/17/2000	9	SEC HPPSS	TEC	D	0				
07/17/2000	10	SEC HPPSS	TEC	D	0				
07/17/2000	11	SEC HPPSS	TEC	D	0				
07/17/2000	12	SEC HPPSS	TEC	D	0				
07/17/2000	13	SEC HPPSS	TEC	D	0				
07/17/2000	14	SEC HPPSS	TEC	D	0				
07/17/2000	15	SEC HPPSS	TEC	D	0				
07/17/2000	16	SEC HPPSS	TEC	D	0				
07/17/2000	17	SEC HPPSS	TEC	D	0				
07/17/2000	18	SEC HPPSS	TEC	D	0				
07/17/2000	19	SEC HPPSS	TEC	D	0				
07/17/2000	20	SEC HPPSS	TEC	D	0				
07/17/2000	21	SEC HPPSS	TEC	D	0				
07/17/2000	22	SEC HPPSS	TEC	D	0				
07/17/2000	23	SEC HPPSS	TEC	D	0				
07/17/2000	24	SEC HPPSS	TEC	D	0				
07/18/2000	1	SEC HPPSS	TEC	D	0				
07/18/2000	2	SEC HPPSS	TEC	D	3				
07/18/2000	3	SEC HPPSS	TEC	D	3				
07/18/2000	4	SEC HPPSS	TEC	D	3				
07/18/2000	5	SEC HPPSS	TEC	D	3				
07/18/2000	6	SEC HPPSS	TEC	D	3				
07/18/2000	7	SEC HPPSS	TEC	D	4				
07/18/2000	8	SEC HPPSS	TEC	D	1				
07/18/2000	9	SEC HPPSS	TEC	D	0				
07/18/2000	10	SEC HPPSS	TEC	D	0				
07/18/2000	11	SEC HPPSS	TEC	D	0				
07/18/2000	12	SEC HPPSS	TEC	D	0				
07/18/2000	13	SEC HPPSS	TEC	D	0				
07/18/2000	14	SEC HPPSS	TEC	D	0				
07/18/2000	15	SEC HPPSS	TEC	D	0				
07/18/2000	16	SEC HPPSS	TEC	D	0				
07/18/2000	17	SEC HPPSS	TEC	D	0				
07/18/2000	18	SEC HPPSS	TEC	D	0				
07/18/2000	19	SEC HPPSS	TEC	D	0				
07/18/2000	20	SEC HPPSS	TEC	D	0				
07/18/2000	21	SEC HPPSS	TEC	D	0				
07/18/2000	22	SEC HPPSS	TEC	D	0				
07/18/2000	23	SEC HPPSS	TEC	D	0				
07/18/2000	24	SEC HPPSS	TEC	D	0				
07/19/2000	1	SEC HPPSS	TEC	D	0				
07/19/2000	2	SEC HPPSS	TEC	D	2				
07/19/2000	3	SEC HPPSS	TEC	D	3				
07/19/2000	4	SEC HPPSS	TEC	D	3				
07/19/2000	5	SEC HPPSS	TEC	D	3				
07/19/2000	6	SEC HPPSS	TEC	D	3				
07/19/2000	7	SEC HPPSS	TEC	D	1				
07/19/2000	8	SEC HPPSS	TEC	D	0				

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SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - HARDEE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/19/2000	9	SEC HPPSS	TEC	D	0				
07/19/2000	10	SEC HPPSS	TEC	D	0				
07/19/2000	11	SEC HPPSS	TEC	D	0				
07/19/2000	12	SEC HPPSS	TEC	D	0				
07/19/2000	13	SEC HPPSS	TEC	D	0				
07/19/2000	14	SEC HPPSS	TEC	D	0				
07/19/2000	15	SEC HPPSS	TEC	D	0				
07/19/2000	16	SEC HPPSS	TEC	D	0				
07/19/2000	17	SEC HPPSS	TEC	D	0				
07/19/2000	18	SEC HPPSS	TEC	D	0				
07/19/2000	19	SEC HPPSS	TEC	D	0				
07/19/2000	20	SEC HPPSS	TEC	D	0				
07/19/2000	21	SEC HPPSS	TEC	D	0				
07/19/2000	22	SEC HPPSS	TEC	D	0				
07/19/2000	23	SEC HPPSS	TEC	D	0				
07/19/2000	24	SEC HPPSS	TEC	D	0				
07/20/2000	1	SEC HPPSS	TEC	D	0				
07/20/2000	2	SEC HPPSS	TEC	D	0				
07/20/2000	3	SEC HPPSS	TEC	D	0				
07/20/2000	4	SEC HPPSS	TEC	D	2				
07/20/2000	5	SEC HPPSS	TEC	D	3				
07/20/2000	6	SEC HPPSS	TEC	D	3				
07/20/2000	7	SEC HPPSS	TEC	D	3				
07/20/2000	8	SEC HPPSS	TEC	D	1				
07/20/2000	9	SEC HPPSS	TEC	D	0				
07/20/2000	10	SEC HPPSS	TEC	D	0				
07/20/2000	11	SEC HPPSS	TEC	D	0				
07/20/2000	12	SEC HPPSS	TEC	D	0				
07/20/2000	13	SEC HPPSS	TEC	D	0				
07/20/2000	14	SEC HPPSS	TEC	D	0				
07/20/2000	15	SEC HPPSS	TEC	D	0				
07/20/2000	16	SEC HPPSS	TEC	D	0				
07/20/2000	17	SEC HPPSS	TEC	D	0				
07/20/2000	18	SEC HPPSS	TEC	D	0				
07/20/2000	19	SEC HPPSS	TEC	D	0				
07/20/2000	20	SEC HPPSS	TEC	D	0				
07/20/2000	21	SEC HPPSS	TEC	D	0				
07/20/2000	22	SEC HPPSS	TEC	D	0				
07/20/2000	23	SEC HPPSS	TEC	D	0				
07/20/2000	24	SEC HPPSS	TEC	D	0				
07/21/2000	1	SEC HPPSS	TEC	D	0				
07/21/2000	2	SEC HPPSS	TEC	D	2				
07/21/2000	3	SEC HPPSS	TEC	D	4				
07/21/2000	4	SEC HPPSS	TEC	D	4				
07/21/2000	5	SEC HPPSS	TEC	D	4				
07/21/2000	6	SEC HPPSS	TEC	D	4				
07/21/2000	7	SEC HPPSS	TEC	D	4				
07/21/2000	8	SEC HPPSS	TEC	D	4				
07/21/2000	9	SEC HPPSS	TEC	D	4				
07/21/2000	10	SEC HPPSS	TEC	D	3				
07/21/2000	11	SEC HPPSS	TEC	D	0				
07/21/2000	12	SEC HPPSS	TEC	D	0				
07/21/2000	13	SEC HPPSS	TEC	D	0				
07/21/2000	14	SEC HPPSS	TEC	D	0				
07/21/2000	15	SEC HPPSS	TEC	D	0				

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SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - HARDEE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/21/2000	16	SEC HPPSS	TEC	D	0				
07/21/2000	17	SEC HPPSS	TEC	D	0				
07/21/2000	18	SEC HPPSS	TEC	D	0				
07/21/2000	19	SEC HPPSS	TEC	D	0				
07/21/2000	20	SEC HPPSS	TEC	D	0				
07/21/2000	21	SEC HPPSS	TEC	D	3				
07/21/2000	22	SEC HPPSS	TEC	D	3				
07/21/2000	23	SEC HPPSS	TEC	D	3				
07/21/2000	24	SEC HPPSS	TEC	D	3				
07/22/2000	1	SEC HPPSS	TEC	D	3				
07/22/2000	2	SEC HPPSS	TEC	D	3				
07/22/2000	3	SEC HPPSS	TEC	D	3				
07/22/2000	4	SEC HPPSS	TEC	D	3				
07/22/2000	5	SEC HPPSS	TEC	D	3				
07/22/2000	6	SEC HPPSS	TEC	D	3				
07/22/2000	7	SEC HPPSS	TEC	D	3				
07/22/2000	8	SEC HPPSS	TEC	D	3				
07/22/2000	9	SEC HPPSS	TEC	D	3				
07/22/2000	10	SEC HPPSS	TEC	D	3				
07/22/2000	11	SEC HPPSS	TEC	D	4				
07/22/2000	12	SEC HPPSS	TEC	D	4				
07/22/2000	13	SEC HPPSS	TEC	D	0				
07/22/2000	14	SEC HPPSS	TEC	D	0				
07/22/2000	15	SEC HPPSS	TEC	D	0				
07/22/2000	16	SEC HPPSS	TEC	D	0				
07/22/2000	17	SEC HPPSS	TEC	D	0				
07/22/2000	18	SEC HPPSS	TEC	D	0				
07/22/2000	19	SEC HPPSS	TEC	D	0				
07/22/2000	20	SEC HPPSS	TEC	D	0				
07/22/2000	21	SEC HPPSS	TEC	D	0				
07/22/2000	22	SEC HPPSS	TEC	D	0				
07/22/2000	23	SEC HPPSS	TEC	D	0				
07/22/2000	24	SEC HPPSS	TEC	D	0				
07/23/2000	1	SEC HPPSS	TEC	D	2				
07/23/2000	2	SEC HPPSS	TEC	D	3				
07/23/2000	3	SEC HPPSS	TEC	D	3				
07/23/2000	4	SEC HPPSS	TEC	D	3				
07/23/2000	5	SEC HPPSS	TEC	D	3				
07/23/2000	6	SEC HPPSS	TEC	D	3				
07/23/2000	7	SEC HPPSS	TEC	D	3				
07/23/2000	8	SEC HPPSS	TEC	D	3				
07/23/2000	9	SEC HPPSS	TEC	D	4				
07/23/2000	10	SEC HPPSS	TEC	D	2				
07/23/2000	11	SEC HPPSS	TEC	D	0				
07/23/2000	12	SEC HPPSS	TEC	D	0				
07/23/2000	13	SEC HPPSS	TEC	D	0				
07/23/2000	14	SEC HPPSS	TEC	D	0				
07/23/2000	15	SEC HPPSS	TEC	D	0				
07/23/2000	16	SEC HPPSS	TEC	D	0				
07/23/2000	17	SEC HPPSS	TEC	D	0				
07/23/2000	18	SEC HPPSS	TEC	D	0				
07/23/2000	19	SEC HPPSS	TEC	D	0				
07/23/2000	20	SEC HPPSS	TEC	D	3				
07/23/2000	21	SEC HPPSS	TEC	D	3				
07/23/2000	22	SEC HPPSS	TEC	D	3				

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SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - HARDEE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/23/2000	23	SEC HPPSS	TEC	D	3				
07/23/2000	24	SEC HPPSS	TEC	D	3				
07/24/2000	1	SEC HPPSS	TEC	D	3				
07/24/2000	2	SEC HPPSS	TEC	D	3				
07/24/2000	3	SEC HPPSS	TEC	D	3				
07/24/2000	4	SEC HPPSS	TEC	D	3				
07/24/2000	5	SEC HPPSS	TEC	D	3				
07/24/2000	6	SEC HPPSS	TEC	D	3				
07/24/2000	7	SEC HPPSS	TEC	D	3				
07/24/2000	8	SEC HPPSS	TEC	D	3				
07/24/2000	9	SEC HPPSS	TEC	D	4				
07/24/2000	10	SEC HPPSS	TEC	D	3				
07/24/2000	11	SEC HPPSS	TEC	D	0				
07/24/2000	12	SEC HPPSS	TEC	D	0				
07/24/2000	13	SEC HPPSS	TEC	D	0				
07/24/2000	14	SEC HPPSS	TEC	D	0				
07/24/2000	15	SEC HPPSS	TEC	D	0				
07/24/2000	16	SEC HPPSS	TEC	D	0				
07/24/2000	17	SEC HPPSS	TEC	D	0				
07/24/2000	18	SEC HPPSS	TEC	D	0				
07/24/2000	19	SEC HPPSS	TEC	D	0				
07/24/2000	20	SEC HPPSS	TEC	D	0				
07/24/2000	21	SEC HPPSS	TEC	D	0				
07/24/2000	22	SEC HPPSS	TEC	D	0				
07/24/2000	23	SEC HPPSS	TEC	D	0				
07/24/2000	24	SEC HPPSS	TEC	D	0				
07/25/2000	1	SEC HPPSS	TEC	D	0				
07/25/2000	2	SEC HPPSS	TEC	D	0				
07/25/2000	3	SEC HPPSS	TEC	D	3				
07/25/2000	4	SEC HPPSS	TEC	D	3				
07/25/2000	5	SEC HPPSS	TEC	D	3				
07/25/2000	6	SEC HPPSS	TEC	D	3				
07/25/2000	7	SEC HPPSS	TEC	D	4				
07/25/2000	8	SEC HPPSS	TEC	D	3				
07/25/2000	9	SEC HPPSS	TEC	D	0				
07/25/2000	10	SEC HPPSS	TEC	D	0				
07/25/2000	11	SEC HPPSS	TEC	D	0				
07/25/2000	12	SEC HPPSS	TEC	D	0				
07/25/2000	13	SEC HPPSS	TEC	D	0				
07/25/2000	14	SEC HPPSS	TEC	D	0				
07/25/2000	15	SEC HPPSS	TEC	D	0				
07/25/2000	16	SEC HPPSS	TEC	D	0				
07/25/2000	17	SEC HPPSS	TEC	D	0				
07/25/2000	18	SEC HPPSS	TEC	D	0				
07/25/2000	19	SEC HPPSS	TEC	D	0				
07/25/2000	20	SEC HPPSS	TEC	D	0				
07/25/2000	21	SEC HPPSS	TEC	D	0				
07/25/2000	22	SEC HPPSS	TEC	D	0				
07/25/2000	23	SEC HPPSS	TEC	D	2				
07/25/2000	24	SEC HPPSS	TEC	D	4				
07/26/2000	1	SEC HPPSS	TEC	D	4				
07/26/2000	2	SEC HPPSS	TEC	D	3				
07/26/2000	3	SEC HPPSS	TEC	D	3				
07/26/2000	4	SEC HPPSS	TEC	D	3				
07/26/2000	5	SEC HPPSS	TEC	D	3				

SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - HARDEE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/26/2000	6	SEC HPPSS	TEC	D	3				
07/26/2000	7	SEC HPPSS	TEC	D	3				
07/26/2000	8	SEC HPPSS	TEC	D	3				
07/26/2000	9	SEC HPPSS	TEC	D	3				
07/26/2000	10	SEC HPPSS	TEC	D	4				
07/26/2000	11	SEC HPPSS	TEC	D	2				
07/26/2000	12	SEC HPPSS	TEC	D	0				
07/26/2000	13	SEC HPPSS	TEC	D	0				
07/26/2000	14	SEC HPPSS	TEC	D	0				
07/26/2000	15	SEC HPPSS	TEC	D	0				
07/26/2000	16	SEC HPPSS	TEC	D	0				
07/26/2000	17	SEC HPPSS	TEC	D	0				
07/26/2000	18	SEC HPPSS	TEC	D	0				
07/26/2000	19	SEC HPPSS	TEC	D	0				
07/26/2000	20	SEC HPPSS	TEC	D	0				
07/26/2000	21	SEC HPPSS	TEC	D	0				
07/26/2000	22	SEC HPPSS	TEC	D	0				
07/26/2000	23	SEC HPPSS	TEC	D	0				
07/26/2000	24	SEC HPPSS	TEC	D	0				
07/27/2000	1	SEC HPPSS	TEC	D	3				
07/27/2000	2	SEC HPPSS	TEC	D	3				
07/27/2000	3	SEC HPPSS	TEC	D	3				
07/27/2000	4	SEC HPPSS	TEC	D	3				
07/27/2000	5	SEC HPPSS	TEC	D	4				
07/27/2000	6	SEC HPPSS	TEC	D	4				
07/27/2000	7	SEC HPPSS	TEC	D	4				
07/27/2000	8	SEC HPPSS	TEC	D	3				
07/27/2000	9	SEC HPPSS	TEC	D	4				
07/27/2000	10	SEC HPPSS	TEC	D	3				
07/27/2000	11	SEC HPPSS	TEC	D	0				
07/27/2000	12	SEC HPPSS	TEC	D	0				
07/27/2000	13	SEC HPPSS	TEC	D	0				
07/27/2000	14	SEC HPPSS	TEC	D	0				
07/27/2000	15	SEC HPPSS	TEC	D	0				
07/27/2000	16	SEC HPPSS	TEC	D	0				
07/27/2000	17	SEC HPPSS	TEC	D	0				
07/27/2000	18	SEC HPPSS	TEC	D	0				
07/27/2000	19	SEC HPPSS	TEC	D	0				
07/27/2000	20	SEC HPPSS	TEC	D	0				
07/27/2000	21	SEC HPPSS	TEC	D	0				
07/27/2000	22	SEC HPPSS	TEC	D	0				
07/27/2000	23	SEC HPPSS	TEC	D	0				
07/27/2000	24	SEC HPPSS	TEC	D	0				
07/28/2000	1	SEC HPPSS	TEC	D	1				
07/28/2000	2	SEC HPPSS	TEC	D	3				
07/28/2000	3	SEC HPPSS	TEC	D	3				
07/28/2000	4	SEC HPPSS	TEC	D	3				
07/28/2000	5	SEC HPPSS	TEC	D	3				
07/28/2000	6	SEC HPPSS	TEC	D	3				
07/28/2000	7	SEC HPPSS	TEC	D	3				
07/28/2000	8	SEC HPPSS	TEC	D	4				
07/28/2000	9	SEC HPPSS	TEC	D	2				
07/28/2000	10	SEC HPPSS	TEC	D	0				
07/28/2000	11	SEC HPPSS	TEC	D	0				
07/28/2000	12	SEC HPPSS	TEC	D	0				

SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - HARDEE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/28/2000	13	SEC HPPSS	TEC	D	0				
07/28/2000	14	SEC HPPSS	TEC	D	0				
07/28/2000	15	SEC HPPSS	TEC	D	0				
07/28/2000	16	SEC HPPSS	TEC	D	0				
07/28/2000	17	SEC HPPSS	TEC	D	0				
07/28/2000	18	SEC HPPSS	TEC	D	0				
07/28/2000	19	SEC HPPSS	TEC	D	0				
07/28/2000	20	SEC HPPSS	TEC	D	0				
07/28/2000	21	SEC HPPSS	TEC	D	0				
07/28/2000	22	SEC HPPSS	TEC	D	0				
07/28/2000	23	SEC HPPSS	TEC	D	0				
07/28/2000	24	SEC HPPSS	TEC	D	0				
07/29/2000	1	SEC HPPSS	TEC	D	0				
07/29/2000	2	SEC HPPSS	TEC	D	2				
07/29/2000	3	SEC HPPSS	TEC	D	4				
07/29/2000	4	SEC HPPSS	TEC	D	3				
07/29/2000	5	SEC HPPSS	TEC	D	4				
07/29/2000	6	SEC HPPSS	TEC	D	3				
07/29/2000	7	SEC HPPSS	TEC	D	3				
07/29/2000	8	SEC HPPSS	TEC	D	4				
07/29/2000	9	SEC HPPSS	TEC	D	3				
07/29/2000	10	SEC HPPSS	TEC	D	0				
07/29/2000	11	SEC HPPSS	TEC	D	0				
07/29/2000	12	SEC HPPSS	TEC	D	0				
07/29/2000	13	SEC HPPSS	TEC	D	0				
07/29/2000	14	SEC HPPSS	TEC	D	0				
07/29/2000	15	SEC HPPSS	TEC	D	0				
07/29/2000	16	SEC HPPSS	TEC	D	0				
07/29/2000	17	SEC HPPSS	TEC	D	0				
07/29/2000	18	SEC HPPSS	TEC	D	0				
07/29/2000	19	SEC HPPSS	TEC	D	0				
07/29/2000	20	SEC HPPSS	TEC	D	0				
07/29/2000	21	SEC HPPSS	TEC	D	0				
07/29/2000	22	SEC HPPSS	TEC	D	0				
07/29/2000	23	SEC HPPSS	TEC	D	2				
07/29/2000	24	SEC HPPSS	TEC	D	4				
07/30/2000	1	SEC HPPSS	TEC	D	4				
07/30/2000	2	SEC HPPSS	TEC	D	4				
07/30/2000	3	SEC HPPSS	TEC	D	4				
07/30/2000	4	SEC HPPSS	TEC	D	4				
07/30/2000	5	SEC HPPSS	TEC	D	4				
07/30/2000	6	SEC HPPSS	TEC	D	4				
07/30/2000	7	SEC HPPSS	TEC	D	3				
07/30/2000	8	SEC HPPSS	TEC	D	4				
07/30/2000	9	SEC HPPSS	TEC	D	3				
07/30/2000	10	SEC HPPSS	TEC	D	0				
07/30/2000	11	SEC HPPSS	TEC	D	0				
07/30/2000	12	SEC HPPSS	TEC	D	0				
07/30/2000	13	SEC HPPSS	TEC	D	0				
07/30/2000	14	SEC HPPSS	TEC	D	0				
07/30/2000	15	SEC HPPSS	TEC	D	0				
07/30/2000	16	SEC HPPSS	TEC	D	0				
07/30/2000	17	SEC HPPSS	TEC	D	0				
07/30/2000	18	SEC HPPSS	TEC	D	0				
07/30/2000	19	SEC HPPSS	TEC	D	0				

SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - HARDEE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/30/2000	20	SEC HPPSS	TEC	D	0	[redacted]			
07/30/2000	21	SEC HPPSS	TEC	D	0				
07/30/2000	22	SEC HPPSS	TEC	D	0				
07/30/2000	23	SEC HPPSS	TEC	D	0				
07/30/2000	24	SEC HPPSS	TEC	D	2				
07/31/2000	1	SEC HPPSS	TEC	D	3				
07/31/2000	2	SEC HPPSS	TEC	D	3				
07/31/2000	3	SEC HPPSS	TEC	D	3				
07/31/2000	4	SEC HPPSS	TEC	D	3				
07/31/2000	5	SEC HPPSS	TEC	D	3				
07/31/2000	6	SEC HPPSS	TEC	D	3				
07/31/2000	7	SEC HPPSS	TEC	D	4				
07/31/2000	8	SEC HPPSS	TEC	D	3				
07/31/2000	9	SEC HPPSS	TEC	D	0				
07/31/2000	10	SEC HPPSS	TEC	D	0				
07/31/2000	11	SEC HPPSS	TEC	D	0				
07/31/2000	12	SEC HPPSS	TEC	D	0				
07/31/2000	13	SEC HPPSS	TEC	D	0				
07/31/2000	14	SEC HPPSS	TEC	D	0				
07/31/2000	15	SEC HPPSS	TEC	D	0				
07/31/2000	16	SEC HPPSS	TEC	D	0				
07/31/2000	17	SEC HPPSS	TEC	D	0				
07/31/2000	18	SEC HPPSS	TEC	D	0				
07/31/2000	19	SEC HPPSS	TEC	D	0				
07/31/2000	20	SEC HPPSS	TEC	D	0				
07/31/2000	21	SEC HPPSS	TEC	D	0				
07/31/2000	22	SEC HPPSS	TEC	D	0				
07/31/2000	23	SEC HPPSS	TEC	D	0				
07/31/2000	24	SEC HPPSS	TEC	D	0				

SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - HARDEE

	A6	DETAIL	VARIANCE	EXPLANATION
MWH	953	953	0	
FUEL	$20,741.83	$21,631.03	$889.20	Detail includes SO_2 that is not reported in the A schedules
SO_2	$0.00	($889.22)	($889.22)	Total SO_2. Hourly detail is not available.
OPTIONAL PROV.	$0.00	$0.00	$0.00	
TOTAL	**$20,741.83**	**$20,741.81**	($0.02)	Rounding

SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - PRECO

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
06/30/00	1	SEC PRECO	TEC	D	12	[redacted]			
06/30/00	2	SEC PRECO	TEC	D	13				
06/30/00	3	SEC PRECO	TEC	D	13				
06/30/00	4	SEC PRECO	TEC	D	13				
06/30/00	5	SEC PRECO	TEC	D	13				
06/30/00	6	SEC PRECO	TEC	D	8				
06/30/00	7	SEC PRECO	TEC	D	8				
06/30/00	8	SEC PRECO	TEC	D	6				
06/30/00	9	SEC PRECO	TEC	D	3				
06/30/00	10	SEC PRECO	TEC	D	6				
06/30/00	11	SEC PRECO	TEC	D	8				
06/30/00	12	SEC PRECO	TEC	D	9				
06/30/00	13	SEC PRECO	TEC	D	9				
06/30/00	14	SEC PRECO	TEC	D	11				
06/30/00	15	SEC PRECO	TEC	D	13				
06/30/00	16	SEC PRECO	TEC	D	10				
06/30/00	17	SEC PRECO	TEC	D	8				
06/30/00	18	SEC PRECO	TEC	D	6				
06/30/00	19	SEC PRECO	TEC	D	8				
06/30/00	20	SEC PRECO	TEC	D	8				
06/30/00	21	SEC PRECO	TEC	D	8				
06/30/00	22	SEC PRECO	TEC	D	9				
06/30/00	23	SEC PRECO	TEC	D	9				
06/30/00	24	SEC PRECO	TEC	D	9				
07/01/00	1	SEC PRECO	TEC	D	8				
07/01/00	2	SEC PRECO	TEC	D	9				
07/01/00	3	SEC PRECO	TEC	D	8				
07/01/00	4	SEC PRECO	TEC	D	7				
07/01/00	5	SEC PRECO	TEC	D	8				
07/01/00	6	SEC PRECO	TEC	D	11				
07/01/00	7	SEC PRECO	TEC	D	14				
07/01/00	8	SEC PRECO	TEC	D	9				
07/01/00	9	SEC PRECO	TEC	D	7				
07/01/00	10	SEC PRECO	TEC	D	7				
07/01/00	11	SEC PRECO	TEC	D	7				
07/01/00	12	SEC PRECO	TEC	D	7				
07/01/00	13	SEC PRECO	TEC	D	6				
07/01/00	14	SEC PRECO	TEC	D	3				
07/01/00	15	SEC PRECO	TEC	D	5				
07/01/00	16	SEC PRECO	TEC	D	12				
07/01/00	17	SEC PRECO	TEC	D	12				
07/01/00	18	SEC PRECO	TEC	D	9				
07/01/00	19	SEC PRECO	TEC	D	12				
07/01/00	20	SEC PRECO	TEC	D	13				
07/01/00	21	SEC PRECO	TEC	D	13				
07/01/00	22	SEC PRECO	TEC	D	13				
07/01/00	23	SEC PRECO	TEC	D	13				
07/01/00	24	SEC PRECO	TEC	D	13				
07/02/00	1	SEC PRECO	TEC	D	14				
07/02/00	2	SEC PRECO	TEC	D	9				
07/02/00	3	SEC PRECO	TEC	D	8				
07/02/00	4	SEC PRECO	TEC	D	7				
07/02/00	5	SEC PRECO	TEC	D	9				
07/02/00	6	SEC PRECO	TEC	D	12				
07/02/00	7	SEC PRECO	TEC	D	12				

SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - PRECO

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/02/00	8	SEC PRECO	TEC	D	9				
07/02/00	9	SEC PRECO	TEC	D	8				
07/02/00	10	SEC PRECO	TEC	D	8				
07/02/00	11	SEC PRECO	TEC	D	8				
07/02/00	12	SEC PRECO	TEC	D	8				
07/02/00	13	SEC PRECO	TEC	D	10				
07/02/00	14	SEC PRECO	TEC	D	14				
07/02/00	15	SEC PRECO	TEC	D	14				
07/02/00	16	SEC PRECO	TEC	D	14				
07/02/00	17	SEC PRECO	TEC	D	13				
07/02/00	18	SEC PRECO	TEC	D	7				
07/02/00	19	SEC PRECO	TEC	D	3				
07/02/00	20	SEC PRECO	TEC	D	4				
07/02/00	21	SEC PRECO	TEC	D	6				
07/02/00	22	SEC PRECO	TEC	D	7				
07/02/00	23	SEC PRECO	TEC	D	6				
07/02/00	24	SEC PRECO	TEC	D	6				
07/03/00	1	SEC PRECO	TEC	D	7				
07/03/00	2	SEC PRECO	TEC	D	8				
07/03/00	3	SEC PRECO	TEC	D	7				
07/03/00	4	SEC PRECO	TEC	D	4				
07/03/00	5	SEC PRECO	TEC	D	3				
07/03/00	6	SEC PRECO	TEC	D	2				
07/03/00	7	SEC PRECO	TEC	D	1				
07/03/00	8	SEC PRECO	TEC	D	1				
07/03/00	9	SEC PRECO	TEC	D	1				
07/03/00	10	SEC PRECO	TEC	D	1				
07/03/00	11	SEC PRECO	TEC	D	1				
07/03/00	12	SEC PRECO	TEC	D	1				
07/03/00	13	SEC PRECO	TEC	D	1				
07/03/00	14	SEC PRECO	TEC	D	1				
07/03/00	15	SEC PRECO	TEC	D	1				
07/03/00	16	SEC PRECO	TEC	D	1				
07/03/00	17	SEC PRECO	TEC	D	1				
07/03/00	18	SEC PRECO	TEC	D	1				
07/03/00	19	SEC PRECO	TEC	D	1				
07/03/00	20	SEC PRECO	TEC	D	1				
07/03/00	21	SEC PRECO	TEC	D	1				
07/03/00	22	SEC PRECO	TEC	D	1				
07/03/00	23	SEC PRECO	TEC	D	1				
07/03/00	24	SEC PRECO	TEC	D	1				
07/04/00	1	SEC PRECO	TEC	D	1				
07/04/00	2	SEC PRECO	TEC	D	1				
07/04/00	3	SEC PRECO	TEC	D	1				
07/04/00	4	SEC PRECO	TEC	D	1				
07/04/00	5	SEC PRECO	TEC	D	1				
07/04/00	6	SEC PRECO	TEC	D	1				
07/04/00	7	SEC PRECO	TEC	D	1				
07/04/00	8	SEC PRECO	TEC	D	1				
07/04/00	9	SEC PRECO	TEC	D	1				
07/04/00	10	SEC PRECO	TEC	D	1				
07/04/00	11	SEC PRECO	TEC	D	1				
07/04/00	12	SEC PRECO	TEC	D	1				
07/04/00	13	SEC PRECO	TEC	D	1				
07/04/00	14	SEC PRECO	TEC	D	1				

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SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - PRECO

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/04/00	15	SEC PRECO	TEC	D	1				
07/04/00	16	SEC PRECO	TEC	D	1				
07/04/00	17	SEC PRECO	TEC	D	1				
07/04/00	18	SEC PRECO	TEC	D	1				
07/04/00	19	SEC PRECO	TEC	D	1				
07/04/00	20	SEC PRECO	TEC	D	1				
07/04/00	21	SEC PRECO	TEC	D	1				
07/04/00	22	SEC PRECO	TEC	D	1				
07/04/00	23	SEC PRECO	TEC	D	1				
07/04/00	24	SEC PRECO	TEC	D	1				
07/05/00	1	SEC PRECO	TEC	D	1				
07/05/00	2	SEC PRECO	TEC	D	1				
07/05/00	3	SEC PRECO	TEC	D	1				
07/05/00	4	SEC PRECO	TEC	D	1				
07/05/00	5	SEC PRECO	TEC	D	1				
07/05/00	6	SEC PRECO	TEC	D	1				
07/05/00	7	SEC PRECO	TEC	D	1				
07/05/00	8	SEC PRECO	TEC	D	1				
07/05/00	9	SEC PRECO	TEC	D	1				
07/05/00	10	SEC PRECO	TEC	D	1				
07/05/00	11	SEC PRECO	TEC	D	1				
07/05/00	12	SEC PRECO	TEC	D	1				
07/05/00	13	SEC PRECO	TEC	D	1				
07/05/00	14	SEC PRECO	TEC	D	1				
07/05/00	15	SEC PRECO	TEC	D	1				
07/05/00	16	SEC PRECO	TEC	D	1				
07/05/00	17	SEC PRECO	TEC	D	1				
07/05/00	18	SEC PRECO	TEC	D	1				
07/05/00	19	SEC PRECO	TEC	D	1				
07/05/00	20	SEC PRECO	TEC	D	1				
07/05/00	21	SEC PRECO	TEC	D	1				
07/05/00	22	SEC PRECO	TEC	D	1				
07/05/00	23	SEC PRECO	TEC	D	1				
07/05/00	24	SEC PRECO	TEC	D	1				
07/06/00	1	SEC PRECO	TEC	D	1				
07/06/00	2	SEC PRECO	TEC	D	1				
07/06/00	3	SEC PRECO	TEC	D	1				
07/06/00	4	SEC PRECO	TEC	D	1				
07/06/00	5	SEC PRECO	TEC	D	1				
07/06/00	6	SEC PRECO	TEC	D	1				
07/06/00	7	SEC PRECO	TEC	D	1				
07/06/00	8	SEC PRECO	TEC	D	1				
07/06/00	9	SEC PRECO	TEC	D	1				
07/06/00	10	SEC PRECO	TEC	D	1				
07/06/00	11	SEC PRECO	TEC	D	0				
07/06/00	12	SEC PRECO	TEC	D	0				
07/06/00	13	SEC PRECO	TEC	D	0				
07/06/00	14	SEC PRECO	TEC	D	0				
07/06/00	15	SEC PRECO	TEC	D	0				
07/06/00	16	SEC PRECO	TEC	D	0				
07/06/00	17	SEC PRECO	TEC	D	0				
07/06/00	18	SEC PRECO	TEC	D	0				
07/06/00	19	SEC PRECO	TEC	D	1				
07/06/00	20	SEC PRECO	TEC	D	1				
07/06/00	21	SEC PRECO	TEC	D	1				

SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - PRECO

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/06/00	22	SEC PRECO	TEC	D	1	[redacted]			
07/06/00	23	SEC PRECO	TEC	D	1				
07/06/00	24	SEC PRECO	TEC	D	1				
07/07/00	1	SEC PRECO	TEC	D	1				
07/07/00	2	SEC PRECO	TEC	D	1				
07/07/00	3	SEC PRECO	TEC	D	1				
07/07/00	4	SEC PRECO	TEC	D	1				
07/07/00	5	SEC PRECO	TEC	D	1				
07/07/00	6	SEC PRECO	TEC	D	1				
07/07/00	7	SEC PRECO	TEC	D	1				
07/07/00	8	SEC PRECO	TEC	D	1				
07/07/00	9	SEC PRECO	TEC	D	1				
07/07/00	10	SEC PRECO	TEC	D	1				
07/07/00	11	SEC PRECO	TEC	D	1				
07/07/00	12	SEC PRECO	TEC	D	1				
07/07/00	13	SEC PRECO	TEC	D	1				
07/07/00	14	SEC PRECO	TEC	D	1				
07/07/00	15	SEC PRECO	TEC	D	1				
07/07/00	16	SEC PRECO	TEC	D	1				
07/07/00	17	SEC PRECO	TEC	D	1				
07/07/00	18	SEC PRECO	TEC	D	1				
07/07/00	19	SEC PRECO	TEC	D	1				
07/07/00	20	SEC PRECO	TEC	D	1				
07/07/00	21	SEC PRECO	TEC	D	1				
07/07/00	22	SEC PRECO	TEC	D	1				
07/07/00	23	SEC PRECO	TEC	D	1				
07/07/00	24	SEC PRECO	TEC	D	1				
07/08/00	1	SEC PRECO	TEC	D	1				
07/08/00	2	SEC PRECO	TEC	D	1				
07/08/00	3	SEC PRECO	TEC	D	1				
07/08/00	4	SEC PRECO	TEC	D	1				
07/08/00	5	SEC PRECO	TEC	D	1				
07/08/00	6	SEC PRECO	TEC	D	1				
07/08/00	7	SEC PRECO	TEC	D	1				
07/08/00	8	SEC PRECO	TEC	D	1				
07/08/00	9	SEC PRECO	TEC	D	1				
07/08/00	10	SEC PRECO	TEC	D	1				
07/08/00	11	SEC PRECO	TEC	D	1				
07/08/00	12	SEC PRECO	TEC	D	1				
07/08/00	13	SEC PRECO	TEC	D	1				
07/08/00	14	SEC PRECO	TEC	D	1				
07/08/00	15	SEC PRECO	TEC	D	1				
07/08/00	16	SEC PRECO	TEC	D	1				
07/08/00	17	SEC PRECO	TEC	D	1				
07/08/00	18	SEC PRECO	TEC	D	1				
07/08/00	19	SEC PRECO	TEC	D	1				
07/08/00	20	SEC PRECO	TEC	D	1				
07/08/00	21	SEC PRECO	TEC	D	1				
07/08/00	22	SEC PRECO	TEC	D	1				
07/08/00	23	SEC PRECO	TEC	D	1				
07/08/00	24	SEC PRECO	TEC	D	1				
07/09/00	1	SEC PRECO	TEC	D	1				
07/09/00	2	SEC PRECO	TEC	D	1				
07/09/00	3	SEC PRECO	TEC	D	1				
07/09/00	4	SEC PRECO	TEC	D	1				

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SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - PRECO

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/09/00	5	SEC PRECO	TEC	D	1	[redacted]			
07/09/00	6	SEC PRECO	TEC	D	1				
07/09/00	7	SEC PRECO	TEC	D	1				
07/09/00	8	SEC PRECO	TEC	D	1				
07/09/00	9	SEC PRECO	TEC	D	1				
07/09/00	10	SEC PRECO	TEC	D	1				
07/09/00	11	SEC PRECO	TEC	D	1				
07/09/00	12	SEC PRECO	TEC	D	1				
07/09/00	13	SEC PRECO	TEC	D	1				
07/09/00	14	SEC PRECO	TEC	D	1				
07/09/00	15	SEC PRECO	TEC	D	1				
07/09/00	16	SEC PRECO	TEC	D	1				
07/09/00	17	SEC PRECO	TEC	D	1				
07/09/00	18	SEC PRECO	TEC	D	1				
07/09/00	19	SEC PRECO	TEC	D	1				
07/09/00	20	SEC PRECO	TEC	D	1				
07/09/00	21	SEC PRECO	TEC	D	1				
07/09/00	22	SEC PRECO	TEC	D	1				
07/09/00	23	SEC PRECO	TEC	D	1				
07/09/00	24	SEC PRECO	TEC	D	1				
07/10/00	1	SEC PRECO	TEC	D	1				
07/10/00	2	SEC PRECO	TEC	D	1				
07/10/00	3	SEC PRECO	TEC	D	1				
07/10/00	4	SEC PRECO	TEC	D	1				
07/10/00	5	SEC PRECO	TEC	D	1				
07/10/00	6	SEC PRECO	TEC	D	1				
07/10/00	7	SEC PRECO	TEC	D	1				
07/10/00	8	SEC PRECO	TEC	D	1				
07/10/00	9	SEC PRECO	TEC	D	1				
07/10/00	10	SEC PRECO	TEC	D	1				
07/10/00	11	SEC PRECO	TEC	D	1				
07/10/00	12	SEC PRECO	TEC	D	1				
07/10/00	13	SEC PRECO	TEC	D	1				
07/10/00	14	SEC PRECO	TEC	D	1				
07/10/00	15	SEC PRECO	TEC	D	2				
07/10/00	16	SEC PRECO	TEC	D	1				
07/10/00	17	SEC PRECO	TEC	D	1				
07/10/00	18	SEC PRECO	TEC	D	1				
07/10/00	19	SEC PRECO	TEC	D	1				
07/10/00	20	SEC PRECO	TEC	D	1				
07/10/00	21	SEC PRECO	TEC	D	1				
07/10/00	22	SEC PRECO	TEC	D	1				
07/10/00	23	SEC PRECO	TEC	D	1				
07/10/00	24	SEC PRECO	TEC	D	1				
07/11/00	1	SEC PRECO	TEC	D	1				
07/11/00	2	SEC PRECO	TEC	D	1				
07/11/00	3	SEC PRECO	TEC	D	1				
07/11/00	4	SEC PRECO	TEC	D	1				
07/11/00	5	SEC PRECO	TEC	D	1				
07/11/00	6	SEC PRECO	TEC	D	1				
07/11/00	7	SEC PRECO	TEC	D	1				
07/11/00	8	SEC PRECO	TEC	D	1				
07/11/00	9	SEC PRECO	TEC	D	1				
07/11/00	10	SEC PRECO	TEC	D	1				
07/11/00	11	SEC PRECO	TEC	D	1				

SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - PRECO

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/11/00	12	SEC PRECO	TEC	D	1				
07/11/00	13	SEC PRECO	TEC	D	1				
07/11/00	14	SEC PRECO	TEC	D	1				
07/11/00	15	SEC PRECO	TEC	D	1				
07/11/00	16	SEC PRECO	TEC	D	1				
07/11/00	17	SEC PRECO	TEC	D	1				
07/11/00	18	SEC PRECO	TEC	D	1				
07/11/00	19	SEC PRECO	TEC	D	1				
07/11/00	20	SEC PRECO	TEC	D	1				
07/11/00	21	SEC PRECO	TEC	D	1				
07/11/00	22	SEC PRECO	TEC	D	1				
07/11/00	23	SEC PRECO	TEC	D	1				
07/11/00	24	SEC PRECO	TEC	D	1				
07/12/00	1	SEC PRECO	TEC	D	1				
07/12/00	2	SEC PRECO	TEC	D	1				
07/12/00	3	SEC PRECO	TEC	D	1				
07/12/00	4	SEC PRECO	TEC	D	1				
07/12/00	5	SEC PRECO	TEC	D	1				
07/12/00	6	SEC PRECO	TEC	D	1				
07/12/00	7	SEC PRECO	TEC	D	1				
07/12/00	8	SEC PRECO	TEC	D	1				
07/12/00	9	SEC PRECO	TEC	D	1				
07/12/00	10	SEC PRECO	TEC	D	1				
07/12/00	11	SEC PRECO	TEC	D	1				
07/12/00	12	SEC PRECO	TEC	D	1				
07/12/00	13	SEC PRECO	TEC	D	1				
07/12/00	14	SEC PRECO	TEC	D	1				
07/12/00	15	SEC PRECO	TEC	D	1				
07/12/00	16	SEC PRECO	TEC	D	0				
07/12/00	17	SEC PRECO	TEC	D	0				
07/12/00	18	SEC PRECO	TEC	D	0				
07/12/00	19	SEC PRECO	TEC	D	0				
07/12/00	20	SEC PRECO	TEC	D	0				
07/12/00	21	SEC PRECO	TEC	D	0				
07/12/00	22	SEC PRECO	TEC	D	0				
07/12/00	23	SEC PRECO	TEC	D	0				
07/12/00	24	SEC PRECO	TEC	D	0				
07/13/00	1	SEC PRECO	TEC	D	0				
07/13/00	2	SEC PRECO	TEC	D	0				
07/13/00	3	SEC PRECO	TEC	D	0				
07/13/00	4	SEC PRECO	TEC	D	0				
07/13/00	5	SEC PRECO	TEC	D	0				
07/13/00	6	SEC PRECO	TEC	D	0				
07/13/00	7	SEC PRECO	TEC	D	0				
07/13/00	8	SEC PRECO	TEC	D	0				
07/13/00	9	SEC PRECO	TEC	D	0				
07/13/00	10	SEC PRECO	TEC	D	0				
07/13/00	11	SEC PRECO	TEC	D	0				
07/13/00	12	SEC PRECO	TEC	D	1				
07/13/00	13	SEC PRECO	TEC	D	1				
07/13/00	14	SEC PRECO	TEC	D	1				
07/13/00	15	SEC PRECO	TEC	D	1				
07/13/00	16	SEC PRECO	TEC	D	1				
07/13/00	17	SEC PRECO	TEC	D	1				
07/13/00	18	SEC PRECO	TEC	D	0				

SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - PRECO

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/13/00	19	SEC PRECO	TEC	D	0				
07/13/00	20	SEC PRECO	TEC	D	0				
07/13/00	21	SEC PRECO	TEC	D	0				
07/13/00	22	SEC PRECO	TEC	D	0				
07/13/00	23	SEC PRECO	TEC	D	0				
07/13/00	24	SEC PRECO	TEC	D	0				
07/14/00	1	SEC PRECO	TEC	D	0				
07/14/00	2	SEC PRECO	TEC	D	0				
07/14/00	3	SEC PRECO	TEC	D	0				
07/14/00	4	SEC PRECO	TEC	D	0				
07/14/00	5	SEC PRECO	TEC	D	0				
07/14/00	6	SEC PRECO	TEC	D	0				
07/14/00	7	SEC PRECO	TEC	D	0				
07/14/00	8	SEC PRECO	TEC	D	0				
07/14/00	9	SEC PRECO	TEC	D	0				
07/14/00	10	SEC PRECO	TEC	D	0				
07/14/00	11	SEC PRECO	TEC	D	0				
07/14/00	12	SEC PRECO	TEC	D	0				
07/14/00	13	SEC PRECO	TEC	D	1				
07/14/00	14	SEC PRECO	TEC	D	1				
07/14/00	15	SEC PRECO	TEC	D	0				
07/14/00	16	SEC PRECO	TEC	D	0				
07/14/00	17	SEC PRECO	TEC	D	0				
07/14/00	18	SEC PRECO	TEC	D	0				
07/14/00	19	SEC PRECO	TEC	D	0				
07/14/00	20	SEC PRECO	TEC	D	0				
07/14/00	21	SEC PRECO	TEC	D	0				
07/14/00	22	SEC PRECO	TEC	D	0				
07/14/00	23	SEC PRECO	TEC	D	0				
07/14/00	24	SEC PRECO	TEC	D	0				
07/15/00	1	SEC PRECO	TEC	D	0				
07/15/00	2	SEC PRECO	TEC	D	0				
07/15/00	3	SEC PRECO	TEC	D	0				
07/15/00	4	SEC PRECO	TEC	D	0				
07/15/00	5	SEC PRECO	TEC	D	0				
07/15/00	6	SEC PRECO	TEC	D	0				
07/15/00	7	SEC PRECO	TEC	D	0				
07/15/00	8	SEC PRECO	TEC	D	0				
07/15/00	9	SEC PRECO	TEC	D	1				
07/15/00	10	SEC PRECO	TEC	D	1				
07/15/00	11	SEC PRECO	TEC	D	1				
07/15/00	12	SEC PRECO	TEC	D	1				
07/15/00	13	SEC PRECO	TEC	D	1				
07/15/00	14	SEC PRECO	TEC	D	1				
07/15/00	15	SEC PRECO	TEC	D	1				
07/15/00	16	SEC PRECO	TEC	D	1				
07/15/00	17	SEC PRECO	TEC	D	1				
07/15/00	18	SEC PRECO	TEC	D	1				
07/15/00	19	SEC PRECO	TEC	D	1				
07/15/00	20	SEC PRECO	TEC	D	1				
07/15/00	21	SEC PRECO	TEC	D	1				
07/15/00	22	SEC PRECO	TEC	D	1				
07/15/00	23	SEC PRECO	TEC	D	1				
07/15/00	24	SEC PRECO	TEC	D	1				
07/16/00	1	SEC PRECO	TEC	D	1				

SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - PRECO

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/16/00	2	SEC PRECO	TEC	D	1	[redacted]			
07/16/00	3	SEC PRECO	TEC	D	1				
07/16/00	4	SEC PRECO	TEC	D	1				
07/16/00	5	SEC PRECO	TEC	D	1				
07/16/00	6	SEC PRECO	TEC	D	1				
07/16/00	7	SEC PRECO	TEC	D	1				
07/16/00	8	SEC PRECO	TEC	D	1				
07/16/00	9	SEC PRECO	TEC	D	1				
07/16/00	10	SEC PRECO	TEC	D	1				
07/16/00	11	SEC PRECO	TEC	D	1				
07/16/00	12	SEC PRECO	TEC	D	1				
07/16/00	13	SEC PRECO	TEC	D	1				
07/16/00	14	SEC PRECO	TEC	D	1				
07/16/00	15	SEC PRECO	TEC	D	1				
07/16/00	16	SEC PRECO	TEC	D	1				
07/16/00	17	SEC PRECO	TEC	D	1				
07/16/00	18	SEC PRECO	TEC	D	1				
07/16/00	19	SEC PRECO	TEC	D	1				
07/16/00	20	SEC PRECO	TEC	D	1				
07/16/00	21	SEC PRECO	TEC	D	1				
07/16/00	22	SEC PRECO	TEC	D	1				
07/16/00	23	SEC PRECO	TEC	D	1				
07/16/00	24	SEC PRECO	TEC	D	1				
07/17/00	1	SEC PRECO	TEC	D	1				
07/17/00	2	SEC PRECO	TEC	D	1				
07/17/00	3	SEC PRECO	TEC	D	1				
07/17/00	4	SEC PRECO	TEC	D	1				
07/17/00	5	SEC PRECO	TEC	D	1				
07/17/00	6	SEC PRECO	TEC	D	1				
07/17/00	7	SEC PRECO	TEC	D	1				
07/17/00	8	SEC PRECO	TEC	D	2				
07/17/00	9	SEC PRECO	TEC	D	2				
07/17/00	10	SEC PRECO	TEC	D	5				
07/17/00	11	SEC PRECO	TEC	D	8				
07/17/00	12	SEC PRECO	TEC	D	9				
07/17/00	13	SEC PRECO	TEC	D	10				
07/17/00	14	SEC PRECO	TEC	D	8				
07/17/00	15	SEC PRECO	TEC	D	2				
07/17/00	16	SEC PRECO	TEC	D	2				
07/17/00	17	SEC PRECO	TEC	D	6				
07/17/00	18	SEC PRECO	TEC	D	9				
07/17/00	19	SEC PRECO	TEC	D	10				
07/17/00	20	SEC PRECO	TEC	D	5				
07/17/00	21	SEC PRECO	TEC	D	5				
07/17/00	22	SEC PRECO	TEC	D	5				
07/17/00	23	SEC PRECO	TEC	D	5				
07/17/00	24	SEC PRECO	TEC	D	5				
07/18/00	1	SEC PRECO	TEC	D	5				
07/18/00	2	SEC PRECO	TEC	D	6				
07/18/00	3	SEC PRECO	TEC	D	9				
07/18/00	4	SEC PRECO	TEC	D	11				
07/18/00	5	SEC PRECO	TEC	D	11				
07/18/00	6	SEC PRECO	TEC	D	11				
07/18/00	7	SEC PRECO	TEC	D	11				
07/18/00	8	SEC PRECO	TEC	D	10				

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SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - PRECO

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/18/00	9	SEC PRECO	TEC	D	4				
07/18/00	10	SEC PRECO	TEC	D	3				
07/18/00	11	SEC PRECO	TEC	D	4				
07/18/00	12	SEC PRECO	TEC	D	4				
07/18/00	13	SEC PRECO	TEC	D	5				
07/18/00	14	SEC PRECO	TEC	D	5				
07/18/00	15	SEC PRECO	TEC	D	5				
07/18/00	16	SEC PRECO	TEC	D	3				
07/18/00	17	SEC PRECO	TEC	D	1				
07/18/00	18	SEC PRECO	TEC	D	3				
07/18/00	19	SEC PRECO	TEC	D	5				
07/18/00	20	SEC PRECO	TEC	D	7				
07/18/00	21	SEC PRECO	TEC	D	10				
07/18/00	22	SEC PRECO	TEC	D	10				
07/18/00	23	SEC PRECO	TEC	D	9				
07/18/00	24	SEC PRECO	TEC	D	9				
07/19/00	1	SEC PRECO	TEC	D	6				
07/19/00	2	SEC PRECO	TEC	D	10				
07/19/00	3	SEC PRECO	TEC	D	12				
07/19/00	4	SEC PRECO	TEC	D	13				
07/19/00	5	SEC PRECO	TEC	D	12				
07/19/00	6	SEC PRECO	TEC	D	12				
07/19/00	7	SEC PRECO	TEC	D	11				
07/19/00	8	SEC PRECO	TEC	D	8				
07/19/00	9	SEC PRECO	TEC	D	4				
07/19/00	10	SEC PRECO	TEC	D	3				
07/19/00	11	SEC PRECO	TEC	D	3				
07/19/00	12	SEC PRECO	TEC	D	2				
07/19/00	13	SEC PRECO	TEC	D	3				
07/19/00	14	SEC PRECO	TEC	D	3				
07/19/00	15	SEC PRECO	TEC	D	3				
07/19/00	16	SEC PRECO	TEC	D	3				
07/19/00	17	SEC PRECO	TEC	D	1				
07/19/00	18	SEC PRECO	TEC	D	2				
07/19/00	19	SEC PRECO	TEC	D	2				
07/19/00	20	SEC PRECO	TEC	D	2				
07/19/00	21	SEC PRECO	TEC	D	10				
07/19/00	22	SEC PRECO	TEC	D	11				
07/19/00	23	SEC PRECO	TEC	D	10				
07/19/00	24	SEC PRECO	TEC	D	10				
07/20/00	1	SEC PRECO	TEC	D	11				
07/20/00	2	SEC PRECO	TEC	D	12				
07/20/00	3	SEC PRECO	TEC	D	12				
07/20/00	4	SEC PRECO	TEC	D	11				
07/20/00	5	SEC PRECO	TEC	D	6				
07/20/00	6	SEC PRECO	TEC	D	6				
07/20/00	7	SEC PRECO	TEC	D	5				
07/20/00	8	SEC PRECO	TEC	D	7				
07/20/00	9	SEC PRECO	TEC	D	12				
07/20/00	10	SEC PRECO	TEC	D	12				
07/20/00	11	SEC PRECO	TEC	D	12				
07/20/00	12	SEC PRECO	TEC	D	3				
07/20/00	13	SEC PRECO	TEC	D	2				
07/20/00	14	SEC PRECO	TEC	D	9				
07/20/00	15	SEC PRECO	TEC	D	0				

SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - PRECO

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/20/00	16	SEC PRECO	TEC	D	0	[redacted]			
07/20/00	17	SEC PRECO	TEC	D	0				
07/20/00	18	SEC PRECO	TEC	D	1				
07/20/00	19	SEC PRECO	TEC	D	4				
07/20/00	20	SEC PRECO	TEC	D	5				
07/20/00	21	SEC PRECO	TEC	D	4				
07/20/00	22	SEC PRECO	TEC	D	4				
07/20/00	23	SEC PRECO	TEC	D	4				
07/20/00	24	SEC PRECO	TEC	D	4				
07/21/00	1	SEC PRECO	TEC	D	6				
07/21/00	2	SEC PRECO	TEC	D	11				
07/21/00	3	SEC PRECO	TEC	D	8				
07/21/00	4	SEC PRECO	TEC	D	9				
07/21/00	5	SEC PRECO	TEC	D	6				
07/21/00	6	SEC PRECO	TEC	D	5				
07/21/00	7	SEC PRECO	TEC	D	6				
07/21/00	8	SEC PRECO	TEC	D	9				
07/21/00	9	SEC PRECO	TEC	D	8				
07/21/00	10	SEC PRECO	TEC	D	9				
07/21/00	11	SEC PRECO	TEC	D	9				
07/21/00	12	SEC PRECO	TEC	D	9				
07/21/00	13	SEC PRECO	TEC	D	6				
07/21/00	14	SEC PRECO	TEC	D	3				
07/21/00	15	SEC PRECO	TEC	D	8				
07/21/00	16	SEC PRECO	TEC	D	10				
07/21/00	17	SEC PRECO	TEC	D	11				
07/21/00	18	SEC PRECO	TEC	D	10				
07/21/00	19	SEC PRECO	TEC	D	10				
07/21/00	20	SEC PRECO	TEC	D	12				
07/21/00	21	SEC PRECO	TEC	D	12				
07/21/00	22	SEC PRECO	TEC	D	11				
07/21/00	23	SEC PRECO	TEC	D	11				
07/21/00	24	SEC PRECO	TEC	D	8				
07/22/00	1	SEC PRECO	TEC	D	6				
07/22/00	2	SEC PRECO	TEC	D	5				
07/22/00	3	SEC PRECO	TEC	D	6				
07/22/00	4	SEC PRECO	TEC	D	12				
07/22/00	5	SEC PRECO	TEC	D	12				
07/22/00	6	SEC PRECO	TEC	D	12				
07/22/00	7	SEC PRECO	TEC	D	11				
07/22/00	8	SEC PRECO	TEC	D	8				
07/22/00	9	SEC PRECO	TEC	D	7				
07/22/00	10	SEC PRECO	TEC	D	8				
07/22/00	11	SEC PRECO	TEC	D	6				
07/22/00	12	SEC PRECO	TEC	D	7				
07/22/00	13	SEC PRECO	TEC	D	6				
07/22/00	14	SEC PRECO	TEC	D	10				
07/22/00	15	SEC PRECO	TEC	D	6				
07/22/00	16	SEC PRECO	TEC	D	9				
07/22/00	17	SEC PRECO	TEC	D	12				
07/22/00	18	SEC PRECO	TEC	D	12				
07/22/00	19	SEC PRECO	TEC	D	13				
07/22/00	20	SEC PRECO	TEC	D	13				
07/22/00	21	SEC PRECO	TEC	D	14				
07/22/00	22	SEC PRECO	TEC	D	14				

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SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - PRECO

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/22/00	23	SEC PRECO	TEC	D	13				
07/22/00	24	SEC PRECO	TEC	D	11				
07/23/00	1	SEC PRECO	TEC	D	6				
07/23/00	2	SEC PRECO	TEC	D	6				
07/23/00	3	SEC PRECO	TEC	D	6				
07/23/00	4	SEC PRECO	TEC	D	6				
07/23/00	5	SEC PRECO	TEC	D	6				
07/23/00	6	SEC PRECO	TEC	D	3				
07/23/00	7	SEC PRECO	TEC	D	3				
07/23/00	8	SEC PRECO	TEC	D	3				
07/23/00	9	SEC PRECO	TEC	D	3				
07/23/00	10	SEC PRECO	TEC	D	2				
07/23/00	11	SEC PRECO	TEC	D	2				
07/23/00	12	SEC PRECO	TEC	D	3				
07/23/00	13	SEC PRECO	TEC	D	3				
07/23/00	14	SEC PRECO	TEC	D	3				
07/23/00	15	SEC PRECO	TEC	D	5				
07/23/00	16	SEC PRECO	TEC	D	8				
07/23/00	17	SEC PRECO	TEC	D	10				
07/23/00	18	SEC PRECO	TEC	D	10				
07/23/00	19	SEC PRECO	TEC	D	11				
07/23/00	20	SEC PRECO	TEC	D	11				
07/23/00	21	SEC PRECO	TEC	D	12				
07/23/00	22	SEC PRECO	TEC	D	11				
07/23/00	23	SEC PRECO	TEC	D	11				
07/23/00	24	SEC PRECO	TEC	D	11				
07/24/00	1	SEC PRECO	TEC	D	10				
07/24/00	2	SEC PRECO	TEC	D	6				
07/24/00	3	SEC PRECO	TEC	D	6				
07/24/00	4	SEC PRECO	TEC	D	6				
07/24/00	5	SEC PRECO	TEC	D	6				
07/24/00	6	SEC PRECO	TEC	D	5				
07/24/00	7	SEC PRECO	TEC	D	6				
07/24/00	8	SEC PRECO	TEC	D	6				
07/24/00	9	SEC PRECO	TEC	D	10				
07/24/00	10	SEC PRECO	TEC	D	10				
07/24/00	11	SEC PRECO	TEC	D	11				
07/24/00	12	SEC PRECO	TEC	D	11				
07/24/00	13	SEC PRECO	TEC	D	8				
07/24/00	14	SEC PRECO	TEC	D	6				
07/24/00	15	SEC PRECO	TEC	D	6				
07/24/00	16	SEC PRECO	TEC	D	6				
07/24/00	17	SEC PRECO	TEC	D	8				
07/24/00	18	SEC PRECO	TEC	D	11				
07/24/00	19	SEC PRECO	TEC	D	11				
07/24/00	20	SEC PRECO	TEC	D	10				
07/24/00	21	SEC PRECO	TEC	D	11				
07/24/00	22	SEC PRECO	TEC	D	10				
07/24/00	23	SEC PRECO	TEC	D	11				
07/24/00	24	SEC PRECO	TEC	D	12				
07/25/00	1	SEC PRECO	TEC	D	10				
07/25/00	2	SEC PRECO	TEC	D	11				
07/25/00	3	SEC PRECO	TEC	D	12				
07/25/00	4	SEC PRECO	TEC	D	11				
07/25/00	5	SEC PRECO	TEC	D	11				

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SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - PRECO

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/25/00	6	SEC PRECO	TEC	D	11	[redacted]			
07/25/00	7	SEC PRECO	TEC	D	11				
07/25/00	8	SEC PRECO	TEC	D	6				
07/25/00	9	SEC PRECO	TEC	D	6				
07/25/00	10	SEC PRECO	TEC	D	5				
07/25/00	11	SEC PRECO	TEC	D	6				
07/25/00	12	SEC PRECO	TEC	D	6				
07/25/00	13	SEC PRECO	TEC	D	7				
07/25/00	14	SEC PRECO	TEC	D	11				
07/25/00	15	SEC PRECO	TEC	D	12				
07/25/00	16	SEC PRECO	TEC	D	12				
07/25/00	17	SEC PRECO	TEC	D	8				
07/25/00	18	SEC PRECO	TEC	D	8				
07/25/00	19	SEC PRECO	TEC	D	10				
07/25/00	20	SEC PRECO	TEC	D	10				
07/25/00	21	SEC PRECO	TEC	D	13				
07/25/00	22	SEC PRECO	TEC	D	12				
07/25/00	23	SEC PRECO	TEC	D	12				
07/25/00	24	SEC PRECO	TEC	D	12				
07/26/00	1	SEC PRECO	TEC	D	12				
07/26/00	2	SEC PRECO	TEC	D	12				
07/26/00	3	SEC PRECO	TEC	D	13				
07/26/00	4	SEC PRECO	TEC	D	10				
07/26/00	5	SEC PRECO	TEC	D	6				
07/26/00	6	SEC PRECO	TEC	D	7				
07/26/00	7	SEC PRECO	TEC	D	7				
07/26/00	8	SEC PRECO	TEC	D	6				
07/26/00	9	SEC PRECO	TEC	D	4				
07/26/00	10	SEC PRECO	TEC	D	3				
07/26/00	11	SEC PRECO	TEC	D	8				
07/26/00	12	SEC PRECO	TEC	D	10				
07/26/00	13	SEC PRECO	TEC	D	10				
07/26/00	14	SEC PRECO	TEC	D	6				
07/26/00	15	SEC PRECO	TEC	D	4				
07/26/00	16	SEC PRECO	TEC	D	4				
07/26/00	17	SEC PRECO	TEC	D	6				
07/26/00	18	SEC PRECO	TEC	D	6				
07/26/00	19	SEC PRECO	TEC	D	6				
07/26/00	20	SEC PRECO	TEC	D	6				
07/26/00	21	SEC PRECO	TEC	D	5				
07/26/00	22	SEC PRECO	TEC	D	5				
07/26/00	23	SEC PRECO	TEC	D	7				
07/26/00	24	SEC PRECO	TEC	D	6				
07/27/00	1	SEC PRECO	TEC	D	7				
07/27/00	2	SEC PRECO	TEC	D	12				
07/27/00	3	SEC PRECO	TEC	D	13				
07/27/00	4	SEC PRECO	TEC	D	12				
07/27/00	5	SEC PRECO	TEC	D	13				
07/27/00	6	SEC PRECO	TEC	D	12				
07/27/00	7	SEC PRECO	TEC	D	13				
07/27/00	8	SEC PRECO	TEC	D	8				
07/27/00	9	SEC PRECO	TEC	D	4				
07/27/00	10	SEC PRECO	TEC	D	3				
07/27/00	11	SEC PRECO	TEC	D	2				
07/27/00	12	SEC PRECO	TEC	D	2				

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SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - PRECO

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/27/00	13	SEC PRECO	TEC	D	4				
07/27/00	14	SEC PRECO	TEC	D	4				
07/27/00	15	SEC PRECO	TEC	D	3				
07/27/00	16	SEC PRECO	TEC	D	3				
07/27/00	17	SEC PRECO	TEC	D	3				
07/27/00	18	SEC PRECO	TEC	D	3				
07/27/00	19	SEC PRECO	TEC	D	4				
07/27/00	20	SEC PRECO	TEC	D	6				
07/27/00	21	SEC PRECO	TEC	D	6				
07/27/00	22	SEC PRECO	TEC	D	10				
07/27/00	23	SEC PRECO	TEC	D	11				
07/27/00	24	SEC PRECO	TEC	D	12				
07/28/00	1	SEC PRECO	TEC	D	11				
07/28/00	2	SEC PRECO	TEC	D	11				
07/28/00	3	SEC PRECO	TEC	D	7				
07/28/00	4	SEC PRECO	TEC	D	6				
07/28/00	5	SEC PRECO	TEC	D	6				
07/28/00	6	SEC PRECO	TEC	D	6				
07/28/00	7	SEC PRECO	TEC	D	6				
07/28/00	8	SEC PRECO	TEC	D	5				
07/28/00	9	SEC PRECO	TEC	D	3				
07/28/00	10	SEC PRECO	TEC	D	3				
07/28/00	11	SEC PRECO	TEC	D	4				
07/28/00	12	SEC PRECO	TEC	D	8				
07/28/00	13	SEC PRECO	TEC	D	9				
07/28/00	14	SEC PRECO	TEC	D	7				
07/28/00	15	SEC PRECO	TEC	D	4				
07/28/00	16	SEC PRECO	TEC	D	4				
07/28/00	17	SEC PRECO	TEC	D	5				
07/28/00	18	SEC PRECO	TEC	D	4				
07/28/00	19	SEC PRECO	TEC	D	5				
07/28/00	20	SEC PRECO	TEC	D	6				
07/28/00	21	SEC PRECO	TEC	D	6				
07/28/00	22	SEC PRECO	TEC	D	7				
07/28/00	23	SEC PRECO	TEC	D	11				
07/28/00	24	SEC PRECO	TEC	D	12				
07/29/00	1	SEC PRECO	TEC	D	12				
07/29/00	2	SEC PRECO	TEC	D	12				
07/29/00	3	SEC PRECO	TEC	D	12				
07/29/00	4	SEC PRECO	TEC	D	12				
07/29/00	5	SEC PRECO	TEC	D	12				
07/29/00	6	SEC PRECO	TEC	D	12				
07/29/00	7	SEC PRECO	TEC	D	11				
07/29/00	8	SEC PRECO	TEC	D	13				
07/29/00	9	SEC PRECO	TEC	D	11				
07/29/00	10	SEC PRECO	TEC	D	7				
07/29/00	11	SEC PRECO	TEC	D	7				
07/29/00	12	SEC PRECO	TEC	D	5				
07/29/00	13	SEC PRECO	TEC	D	4				
07/29/00	14	SEC PRECO	TEC	D	3				
07/29/00	15	SEC PRECO	TEC	D	4				
07/29/00	16	SEC PRECO	TEC	D	6				
07/29/00	17	SEC PRECO	TEC	D	6				
07/29/00	18	SEC PRECO	TEC	D	6				
07/29/00	19	SEC PRECO	TEC	D	6				

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SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - PRECO

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/29/00	20	SEC PRECO	TEC	D	6				
07/29/00	21	SEC PRECO	TEC	D	2				
07/29/00	22	SEC PRECO	TEC	D	2				
07/29/00	23	SEC PRECO	TEC	D	4				
07/29/00	24	SEC PRECO	TEC	D	7				
07/30/00	1	SEC PRECO	TEC	D	12				
07/30/00	2	SEC PRECO	TEC	D	12				
07/30/00	3	SEC PRECO	TEC	D	12				
07/30/00	4	SEC PRECO	TEC	D	12				
07/30/00	5	SEC PRECO	TEC	D	12				
07/30/00	6	SEC PRECO	TEC	D	11				
07/30/00	7	SEC PRECO	TEC	D	8				
07/30/00	8	SEC PRECO	TEC	D	5				
07/30/00	9	SEC PRECO	TEC	D	4				
07/30/00	10	SEC PRECO	TEC	D	3				
07/30/00	11	SEC PRECO	TEC	D	3				
07/30/00	12	SEC PRECO	TEC	D	3				
07/30/00	13	SEC PRECO	TEC	D	4				
07/30/00	14	SEC PRECO	TEC	D	4				
07/30/00	15	SEC PRECO	TEC	D	4				
07/30/00	16	SEC PRECO	TEC	D	5				
07/30/00	17	SEC PRECO	TEC	D	6				
07/30/00	18	SEC PRECO	TEC	D	10				
07/30/00	19	SEC PRECO	TEC	D	9				
07/30/00	20	SEC PRECO	TEC	D	5				
07/30/00	21	SEC PRECO	TEC	D	5				
07/30/00	22	SEC PRECO	TEC	D	6				
07/30/00	23	SEC PRECO	TEC	D	5				
07/30/00	24	SEC PRECO	TEC	D	7				
07/31/00	1	SEC PRECO	TEC	D	6				
07/31/00	2	SEC PRECO	TEC	D	5				
07/31/00	3	SEC PRECO	TEC	D	9				
07/31/00	4	SEC PRECO	TEC	D	11				
07/31/00	5	SEC PRECO	TEC	D	12				
07/31/00	6	SEC PRECO	TEC	D	11				
07/31/00	7	SEC PRECO	TEC	D	6				
07/31/00	8	SEC PRECO	TEC	D	5				
07/31/00	9	SEC PRECO	TEC	D	5				
07/31/00	10	SEC PRECO	TEC	D	6				
07/31/00	11	SEC PRECO	TEC	D	6				
07/31/00	12	SEC PRECO	TEC	D	6				
07/31/00	13	SEC PRECO	TEC	D	6				
07/31/00	14	SEC PRECO	TEC	D	5				
07/31/00	15	SEC PRECO	TEC	D	6				
07/31/00	16	SEC PRECO	TEC	D	6				
07/31/00	17	SEC PRECO	TEC	D	6				
07/31/00	18	SEC PRECO	TEC	D	9				
07/31/00	19	SEC PRECO	TEC	D	11				
07/31/00	20	SEC PRECO	TEC	D	11				
07/31/00	21	SEC PRECO	TEC	D	9				
07/31/00	22	SEC PRECO	TEC	D	5				
07/31/00	23	SEC PRECO	TEC	D	5				
07/31/00	24	SEC PRECO	TEC	D	6				

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SCHEDULE A6 JULY 2000
DETAIL OF SEMINOLE ELECTRIC COOPERATIVE - PRECO

NOTE: Billing period for PRECO was June 30 - July 31, 2000.

	A6	DETAIL	VARIANCE	EXPLANATION
MWH	3,543	3,543	(0)	
FUEL	$75,706.49	$115,486.54	$39,780.05	Detail includes SO_2 that is not reported in the A schedules.
SO_2	$0.00	($4,328.15)	($4,328.15)	Total SO_2. Hourly detail is not available.
OPTIONAL PROV.	$0.00	($30,336.74)	($30,336.74)	Optional Provision credit due to customer
SUB-TOTAL		$80,821.65	$5,115.16	
BILLING ERROR	$0.00	($5,115.32)	($5,115.32)	July 1 was omitted from the bill.
TOTAL	**$75,706.49**	**$75,706.33**	**($0.16)**	Rounding

SCHEDULE A6 JULY 2000
DETAIL OF HARDEE POWER PARTNERS TO FLORIDA POWER CORP.

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/05/2000	16	FPC	TEH	MA	22	[redacted]			
07/05/2000	17	FPC	TEH	MA	10				
07/05/2000	18	FPC	TEH	MA	16				
07/05/2000	19	FPC	TEH	MA	9				
07/06/2000	20	FPC	TEH	MA	16				
07/10/2000	12	FPC	TEH	MA	61				
07/10/2000	16	FPC	TEH	MA	15				
07/10/2000	17	FPC	TEH	MA	18				
07/10/2000	18	FPC	TEH	MA	18				
07/10/2000	21	FPC	TEH	MA	80				
07/15/2000	14	FPC	TEH	MA	88				

SCHEDULE A6 JULY 2000
DETAIL OF HARDEE POWER PARTNERS TO FLORIDA POWER CORP.

	A6	DETAIL	VARIANCE	EXPLANATION
MWH	353	353	0	
TOTAL COST	$18,419.20	$25,415.00	$6,995.80	Detail includes transmission and earnings due Seminole Electric Coop from sales of Hardee generation
TRANSMISSION	$0.00	($528.44)	($528.44)	Total Transmission costs
SEMINOLE ELECTRIC COOP 60% CONTRACTUAL SHARE OF EARNINGS	$0.00	($6,467.36)	($6,467.36)	
TOTAL	**$18,419.20**	**$18,419.20**	**$0.00**	

SCHEDULE A6 JULY 2000
DETAIL OF HARDEE POWER PARTNERS TO FLORIDA POWER AND LIGHT

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/06/2000	22	FPL	TEH	MA	21	[redacted]			
07/15/2000	15	FPL	TEH	MA	88				
07/15/2000	16	FPL	TEH	MA	88				
07/15/2000	17	FPL	TEH	MA	88				

SCHEDULE A6 JULY 2000
DETAIL OF HARDEE POWER PARTNERS TO FLORIDA POWER AND LIGHT

	A6	DETAIL	VARIANCE	EXPLANATION
MWH	285	285	0	
TOTAL COST	$10,797.86	$13,194.00	$2,396.14	Detail includes transmission and earnings due Seminole Electric Coop. from sales of Hardee generation
TRANSMISSION	$0.00	($426.65)	($426.65)	Total Transmission costs
SEMINOLE ELECTRIC COOP. 60% CONTRACTUAL SHARE OF EARNINGS	$0.00	($1,969.49)	($1,969.49)	
TOTAL	**$10,797.86**	**$10,797.86**	**($0.00)**	

SCHEDULE A6 JULY 2000
DETAIL OF FMPA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/01/2000	1	FMPA	TEC	D	150				
07/01/2000	2	FMPA	TEC	D	150				
07/01/2000	3	FMPA	TEC	D	90				
07/01/2000	4	FMPA	TEC	D	65				
07/01/2000	5	FMPA	TEC	D	40				
07/01/2000	6	FMPA	TEC	D	40				
07/01/2000	7	FMPA	TEC	D	90				
07/01/2000	8	FMPA	TEC	D	150				
07/01/2000	9	FMPA	TEC	D	150				
07/01/2000	10	FMPA	TEC	D	150				
07/01/2000	11	FMPA	TEC	D	150				
07/01/2000	12	FMPA	TEC	D	150				
07/01/2000	13	FMPA	TEC	D	150				
07/01/2000	14	FMPA	TEC	D	150				
07/01/2000	15	FMPA	TEC	D	150				
07/01/2000	16	FMPA	TEC	D	150				
07/01/2000	17	FMPA	TEC	D	150				
07/01/2000	18	FMPA	TEC	D	150				
07/01/2000	19	FMPA	TEC	D	150				
07/01/2000	20	FMPA	TEC	D	150				
07/01/2000	21	FMPA	TEC	D	150				
07/01/2000	22	FMPA	TEC	D	150				
07/01/2000	23	FMPA	TEC	D	150				
07/01/2000	24	FMPA	TEC	D	150				
07/02/2000	1	FMPA	TEC	D	150				
07/02/2000	2	FMPA	TEC	D	150				
07/02/2000	3	FMPA	TEC	D	90				
07/02/2000	4	FMPA	TEC	D	65				
07/02/2000	5	FMPA	TEC	D	40				
07/02/2000	6	FMPA	TEC	D	40				
07/02/2000	7	FMPA	TEC	D	40				
07/02/2000	8	FMPA	TEC	D	115				
07/02/2000	9	FMPA	TEC	D	150				
07/02/2000	10	FMPA	TEC	D	150				
07/02/2000	11	FMPA	TEC	D	150				
07/02/2000	12	FMPA	TEC	D	150				
07/02/2000	13	FMPA	TEC	D	150				
07/02/2000	14	FMPA	TEC	D	150				
07/02/2000	15	FMPA	TEC	D	150				
07/02/2000	16	FMPA	TEC	D	150				
07/02/2000	17	FMPA	TEC	D	150				
07/02/2000	18	FMPA	TEC	D	150				
07/02/2000	19	FMPA	TEC	D	150				
07/02/2000	20	FMPA	TEC	D	150				
07/02/2000	21	FMPA	TEC	D	150				
07/02/2000	22	FMPA	TEC	D	150				
07/02/2000	23	FMPA	TEC	D	150				
07/02/2000	24	FMPA	TEC	D	150				
07/03/2000	1	FMPA	TEC	D	90				
07/03/2000	6	FMPA	TEC	D	90				
07/03/2000	7	FMPA	TEC	D	150				
07/03/2000	8	FMPA	TEC	D	150				
07/03/2000	9	FMPA	TEC	D	150				
07/03/2000	10	FMPA	TEC	D	150				

250

SCHEDULE A6 JULY 2000
DETAIL OF FMPA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/03/2000	11	FMPA	TEC	D	150				
07/03/2000	12	FMPA	TEC	D	150				
07/03/2000	13	FMPA	TEC	D	150				
07/03/2000	14	FMPA	TEC	D	150				
07/03/2000	15	FMPA	TEC	D	150				
07/03/2000	16	FMPA	TEC	D	150				
07/03/2000	17	FMPA	TEC	D	150				
07/03/2000	18	FMPA	TEC	D	150				
07/03/2000	19	FMPA	TEC	D	150				
07/03/2000	20	FMPA	TEC	D	150				
07/03/2000	21	FMPA	TEC	D	150				
07/03/2000	22	FMPA	TEC	D	150				
07/03/2000	23	FMPA	TEC	D	150				
07/03/2000	24	FMPA	TEC	D	150				
07/04/2000	1	FMPA	TEC	D	150				
07/04/2000	2	FMPA	TEC	D	110				
07/04/2000	8	FMPA	TEC	D	115				
07/04/2000	9	FMPA	TEC	D	150				
07/04/2000	10	FMPA	TEC	D	150				
07/04/2000	11	FMPA	TEC	D	150				
07/04/2000	12	FMPA	TEC	D	150				
07/04/2000	13	FMPA	TEC	D	150				
07/04/2000	14	FMPA	TEC	D	150				
07/04/2000	15	FMPA	TEC	D	150				
07/04/2000	16	FMPA	TEC	D	150				
07/04/2000	17	FMPA	TEC	D	150				
07/04/2000	18	FMPA	TEC	D	150				
07/04/2000	19	FMPA	TEC	D	150				
07/04/2000	20	FMPA	TEC	D	150				
07/04/2000	21	FMPA	TEC	D	150				
07/04/2000	22	FMPA	TEC	D	150				
07/04/2000	23	FMPA	TEC	D	150				
07/04/2000	24	FMPA	TEC	D	150				
07/05/2000	1	FMPA	TEC	D	115				
07/05/2000	2	FMPA	TEC	D	95				
07/05/2000	3	FMPA	TEC	D	25				
07/05/2000	6	FMPA	TEC	D	65				
07/05/2000	7	FMPA	TEC	D	150				
07/05/2000	8	FMPA	TEC	D	150				
07/05/2000	9	FMPA	TEC	D	150				
07/05/2000	10	FMPA	TEC	D	150				
07/05/2000	11	FMPA	TEC	D	150				
07/05/2000	12	FMPA	TEC	D	150				
07/05/2000	13	FMPA	TEC	D	150				
07/05/2000	14	FMPA	TEC	D	150				
07/05/2000	15	FMPA	TEC	D	150				
07/05/2000	16	FMPA	TEC	D	150				
07/05/2000	17	FMPA	TEC	D	150				
07/05/2000	18	FMPA	TEC	D	150				
07/05/2000	19	FMPA	TEC	D	150				
07/05/2000	20	FMPA	TEC	D	150				
07/05/2000	21	FMPA	TEC	D	150				
07/05/2000	22	FMPA	TEC	D	150				
07/05/2000	23	FMPA	TEC	D	150				

SCHEDULE A6 JULY 2000
DETAIL OF FMPA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/05/2000	24	FMPA	TEC	D	150				
07/06/2000	1	FMPA	TEC	D	150				
07/06/2000	2	FMPA	TEC	D	140				
07/06/2000	3	FMPA	TEC	D	70				
07/06/2000	4	FMPA	TEC	D	70				
07/06/2000	5	FMPA	TEC	D	70				
07/06/2000	6	FMPA	TEC	D	150				
07/06/2000	7	FMPA	TEC	D	150				
07/06/2000	8	FMPA	TEC	D	150				
07/06/2000	9	FMPA	TEC	D	150				
07/06/2000	10	FMPA	TEC	D	150				
07/06/2000	11	FMPA	TEC	D	150				
07/06/2000	12	FMPA	TEC	D	150				
07/06/2000	13	FMPA	TEC	D	150				
07/06/2000	14	FMPA	TEC	D	150				
07/06/2000	15	FMPA	TEC	D	150				
07/06/2000	16	FMPA	TEC	D	150				
07/06/2000	17	FMPA	TEC	D	150				
07/06/2000	18	FMPA	TEC	D	150				
07/06/2000	19	FMPA	TEC	D	150				
07/06/2000	20	FMPA	TEC	D	150				
07/06/2000	21	FMPA	TEC	D	150				
07/06/2000	22	FMPA	TEC	D	150				
07/06/2000	23	FMPA	TEC	D	150				
07/06/2000	24	FMPA	TEC	D	150				
07/07/2000	1	FMPA	TEC	D	150				
07/07/2000	2	FMPA	TEC	D	150				
07/07/2000	3	FMPA	TEC	D	150				
07/07/2000	4	FMPA	TEC	D	150				
07/07/2000	5	FMPA	TEC	D	150				
07/07/2000	6	FMPA	TEC	D	150				
07/07/2000	7	FMPA	TEC	D	150				
07/07/2000	8	FMPA	TEC	D	150				
07/07/2000	9	FMPA	TEC	D	150				
07/07/2000	10	FMPA	TEC	D	150				
07/07/2000	11	FMPA	TEC	D	150				
07/07/2000	12	FMPA	TEC	D	150				
07/07/2000	13	FMPA	TEC	D	150				
07/07/2000	14	FMPA	TEC	D	150				
07/07/2000	15	FMPA	TEC	D	150				
07/07/2000	16	FMPA	TEC	D	150				
07/07/2000	17	FMPA	TEC	D	150				
07/07/2000	18	FMPA	TEC	D	150				
07/07/2000	19	FMPA	TEC	D	150				
07/07/2000	20	FMPA	TEC	D	150				
07/07/2000	21	FMPA	TEC	D	150				
07/07/2000	22	FMPA	TEC	D	150				
07/07/2000	23	FMPA	TEC	D	150				
07/07/2000	24	FMPA	TEC	D	150				
07/08/2000	1	FMPA	TEC	D	150				
07/08/2000	2	FMPA	TEC	D	150				
07/08/2000	3	FMPA	TEC	D	150				
07/08/2000	4	FMPA	TEC	D	150				
07/08/2000	5	FMPA	TEC	D	150				

SCHEDULE A6 JULY 2000
DETAIL OF FMPA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/08/2000	6	FMPA	TEC	D	150	[redacted]			
07/08/2000	7	FMPA	TEC	D	150				
07/08/2000	8	FMPA	TEC	D	150				
07/08/2000	9	FMPA	TEC	D	150				
07/08/2000	10	FMPA	TEC	D	150				
07/08/2000	11	FMPA	TEC	D	150				
07/08/2000	12	FMPA	TEC	D	150				
07/08/2000	13	FMPA	TEC	D	150				
07/08/2000	14	FMPA	TEC	D	150				
07/08/2000	15	FMPA	TEC	D	150				
07/08/2000	16	FMPA	TEC	D	150				
07/08/2000	17	FMPA	TEC	D	150				
07/08/2000	18	FMPA	TEC	D	150				
07/08/2000	19	FMPA	TEC	D	150				
07/08/2000	20	FMPA	TEC	D	150				
07/08/2000	21	FMPA	TEC	D	150				
07/08/2000	22	FMPA	TEC	D	150				
07/08/2000	23	FMPA	TEC	D	150				
07/08/2000	24	FMPA	TEC	D	150				
07/09/2000	1	FMPA	TEC	D	150				
07/09/2000	2	FMPA	TEC	D	150				
07/09/2000	3	FMPA	TEC	D	150				
07/09/2000	4	FMPA	TEC	D	150				
07/09/2000	5	FMPA	TEC	D	150				
07/09/2000	6	FMPA	TEC	D	150				
07/09/2000	7	FMPA	TEC	D	150				
07/09/2000	8	FMPA	TEC	D	150				
07/09/2000	9	FMPA	TEC	D	150				
07/09/2000	10	FMPA	TEC	D	150				
07/09/2000	11	FMPA	TEC	D	150				
07/09/2000	12	FMPA	TEC	D	150				
07/09/2000	13	FMPA	TEC	D	150				
07/09/2000	14	FMPA	TEC	D	150				
07/09/2000	15	FMPA	TEC	D	150				
07/09/2000	16	FMPA	TEC	D	150				
07/09/2000	17	FMPA	TEC	D	150				
07/09/2000	18	FMPA	TEC	D	150				
07/09/2000	19	FMPA	TEC	D	150				
07/09/2000	20	FMPA	TEC	D	150				
07/09/2000	21	FMPA	TEC	D	150				
07/09/2000	22	FMPA	TEC	D	150				
07/09/2000	23	FMPA	TEC	D	150				
07/09/2000	24	FMPA	TEC	D	150				
07/10/2000	1	FMPA	TEC	D	150				
07/10/2000	2	FMPA	TEC	D	150				
07/10/2000	3	FMPA	TEC	D	150				
07/10/2000	4	FMPA	TEC	D	150				
07/10/2000	5	FMPA	TEC	D	150				
07/10/2000	6	FMPA	TEC	D	150				
07/10/2000	7	FMPA	TEC	D	150				
07/10/2000	8	FMPA	TEC	D	150				
07/10/2000	9	FMPA	TEC	D	150				
07/10/2000	10	FMPA	TEC	D	150				
07/10/2000	11	FMPA	TEC	D	150				

SCHEDULE A6 JULY 2000
DETAIL OF FMPA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/10/2000	12	FMPA	TEC	D	150				
07/10/2000	13	FMPA	TEC	D	150				
07/10/2000	14	FMPA	TEC	D	150				
07/10/2000	15	FMPA	TEC	D	150				
07/10/2000	16	FMPA	TEC	D	150				
07/10/2000	17	FMPA	TEC	D	150				
07/10/2000	18	FMPA	TEC	D	150				
07/10/2000	19	FMPA	TEC	D	150				
07/10/2000	20	FMPA	TEC	D	150				
07/10/2000	21	FMPA	TEC	D	150				
07/10/2000	22	FMPA	TEC	D	150				
07/10/2000	23	FMPA	TEC	D	150				
07/10/2000	24	FMPA	TEC	D	150				
07/11/2000	1	FMPA	TEC	D	115				
07/11/2000	2	FMPA	TEC	D	40				
07/11/2000	6	FMPA	TEC	D	65				
07/11/2000	7	FMPA	TEC	D	150				
07/11/2000	8	FMPA	TEC	D	150				
07/11/2000	9	FMPA	TEC	D	150				
07/11/2000	10	FMPA	TEC	D	150				
07/11/2000	11	FMPA	TEC	D	150				
07/11/2000	12	FMPA	TEC	D	150				
07/11/2000	13	FMPA	TEC	D	150				
07/11/2000	14	FMPA	TEC	D	150				
07/11/2000	15	FMPA	TEC	D	150				
07/11/2000	16	FMPA	TEC	D	150				
07/11/2000	17	FMPA	TEC	D	150				
07/11/2000	18	FMPA	TEC	D	150				
07/11/2000	19	FMPA	TEC	D	150				
07/11/2000	20	FMPA	TEC	D	150				
07/11/2000	21	FMPA	TEC	D	150				
07/11/2000	22	FMPA	TEC	D	150				
07/11/2000	23	FMPA	TEC	D	150				
07/11/2000	24	FMPA	TEC	D	150				
07/12/2000	1	FMPA	TEC	D	150				
07/12/2000	2	FMPA	TEC	D	150				
07/12/2000	3	FMPA	TEC	D	150				
07/12/2000	4	FMPA	TEC	D	90				
07/12/2000	5	FMPA	TEC	D	115				
07/12/2000	6	FMPA	TEC	D	150				
07/12/2000	7	FMPA	TEC	D	150				
07/12/2000	8	FMPA	TEC	D	150				
07/12/2000	9	FMPA	TEC	D	150				
07/12/2000	10	FMPA	TEC	D	150				
07/12/2000	11	FMPA	TEC	D	150				
07/12/2000	12	FMPA	TEC	D	150				
07/12/2000	13	FMPA	TEC	D	150				
07/12/2000	14	FMPA	TEC	D	150				
07/12/2000	15	FMPA	TEC	D	150				
07/12/2000	16	FMPA	TEC	D	150				
07/12/2000	17	FMPA	TEC	D	150				
07/12/2000	18	FMPA	TEC	D	150				
07/12/2000	19	FMPA	TEC	D	150				
07/12/2000	20	FMPA	TEC	D	150				

SCHEDULE A6 JULY 2000
DETAIL OF FMPA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/12/2000	21	FMPA	TEC	D	150				
07/12/2000	22	FMPA	TEC	D	150				
07/12/2000	23	FMPA	TEC	D	150				
07/12/2000	24	FMPA	TEC	D	150				
07/13/2000	1	FMPA	TEC	D	150				
07/13/2000	2	FMPA	TEC	D	150				
07/13/2000	3	FMPA	TEC	D	115				
07/13/2000	4	FMPA	TEC	D	65				
07/13/2000	5	FMPA	TEC	D	90				
07/13/2000	6	FMPA	TEC	D	150				
07/13/2000	7	FMPA	TEC	D	150				
07/13/2000	8	FMPA	TEC	D	150				
07/13/2000	9	FMPA	TEC	D	150				
07/13/2000	10	FMPA	TEC	D	150				
07/13/2000	11	FMPA	TEC	D	150				
07/13/2000	12	FMPA	TEC	D	150				
07/13/2000	13	FMPA	TEC	D	150				
07/13/2000	14	FMPA	TEC	D	150				
07/13/2000	15	FMPA	TEC	D	150				
07/13/2000	16	FMPA	TEC	D	150				
07/13/2000	17	FMPA	TEC	D	150				
07/13/2000	18	FMPA	TEC	D	150				
07/13/2000	19	FMPA	TEC	D	150				
07/13/2000	20	FMPA	TEC	D	150				
07/13/2000	21	FMPA	TEC	D	150				
07/13/2000	22	FMPA	TEC	D	150				
07/13/2000	23	FMPA	TEC	D	150				
07/13/2000	24	FMPA	TEC	D	150				
07/14/2000	1	FMPA	TEC	D	150				
07/14/2000	2	FMPA	TEC	D	150				
07/14/2000	3	FMPA	TEC	D	150				
07/14/2000	4	FMPA	TEC	D	125				
07/14/2000	5	FMPA	TEC	D	150				
07/14/2000	6	FMPA	TEC	D	150				
07/14/2000	7	FMPA	TEC	D	150				
07/14/2000	8	FMPA	TEC	D	150				
07/14/2000	9	FMPA	TEC	D	150				
07/14/2000	10	FMPA	TEC	D	150				
07/14/2000	11	FMPA	TEC	D	150				
07/14/2000	12	FMPA	TEC	D	150				
07/14/2000	13	FMPA	TEC	D	150				
07/14/2000	14	FMPA	TEC	D	150				
07/14/2000	15	FMPA	TEC	D	150				
07/14/2000	16	FMPA	TEC	D	150				
07/14/2000	17	FMPA	TEC	D	150				
07/14/2000	18	FMPA	TEC	D	150				
07/14/2000	19	FMPA	TEC	D	150				
07/14/2000	20	FMPA	TEC	D	150				
07/14/2000	21	FMPA	TEC	D	150				
07/14/2000	22	FMPA	TEC	D	150				
07/14/2000	23	FMPA	TEC	D	150				
07/14/2000	24	FMPA	TEC	D	150				
07/15/2000	1	FMPA	TEC	D	150				
07/15/2000	2	FMPA	TEC	D	150				

SCHEDULE A6 JULY 2000
DETAIL OF FMPA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/15/2000	3	FMPA	TEC	D	150	[redacted]			
07/15/2000	4	FMPA	TEC	D	150				
07/15/2000	5	FMPA	TEC	D	150				
07/15/2000	6	FMPA	TEC	D	150				
07/15/2000	7	FMPA	TEC	D	150				
07/15/2000	8	FMPA	TEC	D	150				
07/15/2000	9	FMPA	TEC	D	150				
07/15/2000	10	FMPA	TEC	D	150				
07/15/2000	11	FMPA	TEC	D	150				
07/15/2000	12	FMPA	TEC	D	150				
07/15/2000	13	FMPA	TEC	D	150				
07/15/2000	14	FMPA	TEC	D	150				
07/15/2000	15	FMPA	TEC	D	150				
07/15/2000	16	FMPA	TEC	D	150				
07/15/2000	17	FMPA	TEC	D	150				
07/15/2000	18	FMPA	TEC	D	150				
07/15/2000	19	FMPA	TEC	D	150				
07/15/2000	20	FMPA	TEC	D	150				
07/15/2000	21	FMPA	TEC	D	150				
07/15/2000	22	FMPA	TEC	D	150				
07/15/2000	23	FMPA	TEC	D	150				
07/15/2000	24	FMPA	TEC	D	150				
07/16/2000	1	FMPA	TEC	D	150				
07/16/2000	2	FMPA	TEC	D	40				
07/16/2000	3	FMPA	TEC	D	40				
07/16/2000	4	FMPA	TEC	D	40				
07/16/2000	5	FMPA	TEC	D	40				
07/16/2000	6	FMPA	TEC	D	40				
07/16/2000	7	FMPA	TEC	D	40				
07/16/2000	8	FMPA	TEC	D	150				
07/16/2000	9	FMPA	TEC	D	150				
07/16/2000	10	FMPA	TEC	D	150				
07/16/2000	11	FMPA	TEC	D	150				
07/16/2000	12	FMPA	TEC	D	150				
07/16/2000	13	FMPA	TEC	D	150				
07/16/2000	14	FMPA	TEC	D	150				
07/16/2000	15	FMPA	TEC	D	150				
07/16/2000	16	FMPA	TEC	D	150				
07/16/2000	17	FMPA	TEC	D	150				
07/16/2000	18	FMPA	TEC	D	150				
07/16/2000	19	FMPA	TEC	D	150				
07/16/2000	20	FMPA	TEC	D	150				
07/16/2000	21	FMPA	TEC	D	150				
07/16/2000	22	FMPA	TEC	D	150				
07/16/2000	23	FMPA	TEC	D	150				
07/16/2000	24	FMPA	TEC	D	150				
07/17/2000	1	FMPA	TEC	D	150				
07/17/2000	2	FMPA	TEC	D	150				
07/17/2000	3	FMPA	TEC	D	150				
07/17/2000	4	FMPA	TEC	D	150				
07/17/2000	5	FMPA	TEC	D	150				
07/17/2000	6	FMPA	TEC	D	150				
07/17/2000	7	FMPA	TEC	D	150				
07/17/2000	8	FMPA	TEC	D	150				

SCHEDULE A6 JULY 2000
DETAIL OF FMPA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/17/2000	9	FMPA	TEC	D	150				
07/17/2000	10	FMPA	TEC	D	150				
07/17/2000	11	FMPA	TEC	D	150				
07/17/2000	12	FMPA	TEC	D	150				
07/17/2000	13	FMPA	TEC	D	150				
07/17/2000	14	FMPA	TEC	D	150				
07/17/2000	15	FMPA	TEC	D	150				
07/17/2000	16	FMPA	TEC	D	150				
07/17/2000	17	FMPA	TEC	D	150				
07/17/2000	18	FMPA	TEC	D	150				
07/17/2000	19	FMPA	TEC	D	150				
07/17/2000	20	FMPA	TEC	D	150				
07/17/2000	21	FMPA	TEC	D	150				
07/17/2000	22	FMPA	TEC	D	150				
07/17/2000	23	FMPA	TEC	D	150				
07/17/2000	24	FMPA	TEC	D	150				
07/18/2000	1	FMPA	TEC	D	150				
07/18/2000	2	FMPA	TEC	D	150				
07/18/2000	3	FMPA	TEC	D	150				
07/18/2000	4	FMPA	TEC	D	150				
07/18/2000	5	FMPA	TEC	D	150				
07/18/2000	6	FMPA	TEC	D	150				
07/18/2000	7	FMPA	TEC	D	150				
07/18/2000	8	FMPA	TEC	D	150				
07/18/2000	9	FMPA	TEC	D	150				
07/18/2000	10	FMPA	TEC	D	150				
07/18/2000	11	FMPA	TEC	D	150				
07/18/2000	12	FMPA	TEC	D	150				
07/18/2000	13	FMPA	TEC	D	150				
07/18/2000	14	FMPA	TEC	D	150				
07/18/2000	15	FMPA	TEC	D	150				
07/18/2000	16	FMPA	TEC	D	150				
07/18/2000	17	FMPA	TEC	D	150				
07/18/2000	18	FMPA	TEC	D	150				
07/18/2000	19	FMPA	TEC	D	150				
07/18/2000	20	FMPA	TEC	D	150				
07/18/2000	21	FMPA	TEC	D	150				
07/18/2000	22	FMPA	TEC	D	150				
07/18/2000	23	FMPA	TEC	D	150				
07/18/2000	24	FMPA	TEC	D	150				
07/19/2000	1	FMPA	TEC	D	150				
07/19/2000	2	FMPA	TEC	D	150				
07/19/2000	3	FMPA	TEC	D	150				
07/19/2000	4	FMPA	TEC	D	65				
07/19/2000	5	FMPA	TEC	D	65				
07/19/2000	6	FMPA	TEC	D	65				
07/19/2000	7	FMPA	TEC	D	150				
07/19/2000	8	FMPA	TEC	D	150				
07/19/2000	9	FMPA	TEC	D	150				
07/19/2000	10	FMPA	TEC	D	150				
07/19/2000	11	FMPA	TEC	D	150				
07/19/2000	12	FMPA	TEC	D	150				
07/19/2000	13	FMPA	TEC	D	150				
07/19/2000	14	FMPA	TEC	D	150				

SCHEDULE A6 JULY 2000
DETAIL OF FMPA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/19/2000	15	FMPA	TEC	D	150	[redacted]			
07/19/2000	16	FMPA	TEC	D	150				
07/19/2000	17	FMPA	TEC	D	150				
07/19/2000	18	FMPA	TEC	D	150				
07/19/2000	19	FMPA	TEC	D	150				
07/19/2000	20	FMPA	TEC	D	150				
07/19/2000	21	FMPA	TEC	D	150				
07/19/2000	22	FMPA	TEC	D	150				
07/19/2000	23	FMPA	TEC	D	150				
07/19/2000	24	FMPA	TEC	D	150				
07/20/2000	1	FMPA	TEC	D	150				
07/20/2000	2	FMPA	TEC	D	150				
07/20/2000	3	FMPA	TEC	D	150				
07/20/2000	4	FMPA	TEC	D	150				
07/20/2000	5	FMPA	TEC	D	150				
07/20/2000	6	FMPA	TEC	D	150				
07/20/2000	7	FMPA	TEC	D	150				
07/20/2000	8	FMPA	TEC	D	150				
07/20/2000	9	FMPA	TEC	D	150				
07/20/2000	10	FMPA	TEC	D	150				
07/20/2000	11	FMPA	TEC	D	150				
07/20/2000	12	FMPA	TEC	D	150				
07/20/2000	13	FMPA	TEC	D	150				
07/20/2000	14	FMPA	TEC	D	150				
07/20/2000	15	FMPA	TEC	D	150				
07/20/2000	16	FMPA	TEC	D	150				
07/20/2000	17	FMPA	TEC	D	150				
07/20/2000	18	FMPA	TEC	D	150				
07/20/2000	19	FMPA	TEC	D	150				
07/20/2000	20	FMPA	TEC	D	150				
07/20/2000	21	FMPA	TEC	D	150				
07/20/2000	22	FMPA	TEC	D	150				
07/20/2000	23	FMPA	TEC	D	150				
07/20/2000	24	FMPA	TEC	D	150				
07/21/2000	1	FMPA	TEC	D	150				
07/21/2000	2	FMPA	TEC	D	150				
07/21/2000	3	FMPA	TEC	D	150				
07/21/2000	4	FMPA	TEC	D	150				
07/21/2000	5	FMPA	TEC	D	150				
07/21/2000	6	FMPA	TEC	D	150				
07/21/2000	7	FMPA	TEC	D	150				
07/21/2000	8	FMPA	TEC	D	150				
07/21/2000	9	FMPA	TEC	D	150				
07/21/2000	10	FMPA	TEC	D	150				
07/21/2000	11	FMPA	TEC	D	150				
07/21/2000	12	FMPA	TEC	D	150				
07/21/2000	13	FMPA	TEC	D	150				
07/21/2000	14	FMPA	TEC	D	150				
07/21/2000	15	FMPA	TEC	D	150				
07/21/2000	16	FMPA	TEC	D	150				
07/21/2000	17	FMPA	TEC	D	150				
07/21/2000	18	FMPA	TEC	D	150				
07/21/2000	19	FMPA	TEC	D	150				
07/21/2000	20	FMPA	TEC	D	150				

SCHEDULE A6 JULY 2000
DETAIL OF FMPA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/21/2000	21	FMPA	TEC	D	150	[redacted]			
07/21/2000	22	FMPA	TEC	D	150				
07/21/2000	23	FMPA	TEC	D	150				
07/21/2000	24	FMPA	TEC	D	150				
07/22/2000	1	FMPA	TEC	D	150				
07/22/2000	2	FMPA	TEC	D	150				
07/22/2000	3	FMPA	TEC	D	40				
07/22/2000	4	FMPA	TEC	D	40				
07/22/2000	5	FMPA	TEC	D	150				
07/22/2000	6	FMPA	TEC	D	150				
07/22/2000	7	FMPA	TEC	D	150				
07/22/2000	8	FMPA	TEC	D	150				
07/22/2000	9	FMPA	TEC	D	150				
07/22/2000	10	FMPA	TEC	D	150				
07/22/2000	11	FMPA	TEC	D	150				
07/22/2000	12	FMPA	TEC	D	150				
07/22/2000	13	FMPA	TEC	D	150				
07/22/2000	14	FMPA	TEC	D	150				
07/22/2000	15	FMPA	TEC	D	150				
07/22/2000	16	FMPA	TEC	D	150				
07/22/2000	17	FMPA	TEC	D	150				
07/22/2000	18	FMPA	TEC	D	150				
07/22/2000	19	FMPA	TEC	D	150				
07/22/2000	20	FMPA	TEC	D	150				
07/22/2000	21	FMPA	TEC	D	150				
07/22/2000	22	FMPA	TEC	D	150				
07/22/2000	23	FMPA	TEC	D	150				
07/22/2000	24	FMPA	TEC	D	150				
07/23/2000	1	FMPA	TEC	D	150				
07/23/2000	2	FMPA	TEC	D	150				
07/23/2000	3	FMPA	TEC	D	150				
07/23/2000	4	FMPA	TEC	D	150				
07/23/2000	5	FMPA	TEC	D	150				
07/23/2000	6	FMPA	TEC	D	150				
07/23/2000	7	FMPA	TEC	D	150				
07/23/2000	8	FMPA	TEC	D	150				
07/23/2000	9	FMPA	TEC	D	150				
07/23/2000	10	FMPA	TEC	D	150				
07/23/2000	11	FMPA	TEC	D	150				
07/23/2000	12	FMPA	TEC	D	150				
07/23/2000	13	FMPA	TEC	D	150				
07/23/2000	14	FMPA	TEC	D	150				
07/23/2000	15	FMPA	TEC	D	150				
07/23/2000	16	FMPA	TEC	D	150				
07/23/2000	17	FMPA	TEC	D	150				
07/23/2000	18	FMPA	TEC	D	150				
07/23/2000	19	FMPA	TEC	D	150				
07/23/2000	20	FMPA	TEC	D	150				
07/23/2000	21	FMPA	TEC	D	150				
07/23/2000	22	FMPA	TEC	D	150				
07/23/2000	23	FMPA	TEC	D	150				
07/23/2000	24	FMPA	TEC	D	150				
07/24/2000	1	FMPA	TEC	D	150				
07/24/2000	2	FMPA	TEC	D	150				

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DETAIL OF FMPA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/24/2000	3	FMPA	TEC	D	150	[redacted]			
07/24/2000	4	FMPA	TEC	D	150				
07/24/2000	5	FMPA	TEC	D	150				
07/24/2000	6	FMPA	TEC	D	150				
07/24/2000	7	FMPA	TEC	D	150				
07/24/2000	8	FMPA	TEC	D	150				
07/24/2000	9	FMPA	TEC	D	150				
07/24/2000	10	FMPA	TEC	D	150				
07/24/2000	11	FMPA	TEC	D	150				
07/24/2000	12	FMPA	TEC	D	150				
07/24/2000	13	FMPA	TEC	D	150				
07/24/2000	14	FMPA	TEC	D	150				
07/24/2000	15	FMPA	TEC	D	150				
07/24/2000	16	FMPA	TEC	D	150				
07/24/2000	17	FMPA	TEC	D	150				
07/24/2000	18	FMPA	TEC	D	150				
07/24/2000	19	FMPA	TEC	D	150				
07/24/2000	20	FMPA	TEC	D	150				
07/24/2000	21	FMPA	TEC	D	150				
07/24/2000	22	FMPA	TEC	D	150				
07/24/2000	23	FMPA	TEC	D	150				
07/24/2000	24	FMPA	TEC	D	150				
07/25/2000	1	FMPA	TEC	D	65				
07/25/2000	6	FMPA	TEC	D	40				
07/25/2000	7	FMPA	TEC	D	130				
07/25/2000	8	FMPA	TEC	D	150				
07/25/2000	9	FMPA	TEC	D	150				
07/25/2000	10	FMPA	TEC	D	150				
07/25/2000	11	FMPA	TEC	D	150				
07/25/2000	12	FMPA	TEC	D	150				
07/25/2000	13	FMPA	TEC	D	150				
07/25/2000	14	FMPA	TEC	D	150				
07/25/2000	15	FMPA	TEC	D	150				
07/25/2000	16	FMPA	TEC	D	150				
07/25/2000	17	FMPA	TEC	D	150				
07/25/2000	18	FMPA	TEC	D	150				
07/25/2000	19	FMPA	TEC	D	150				
07/25/2000	20	FMPA	TEC	D	150				
07/25/2000	21	FMPA	TEC	D	150				
07/25/2000	22	FMPA	TEC	D	150				
07/25/2000	23	FMPA	TEC	D	150				
07/25/2000	24	FMPA	TEC	D	150				
07/26/2000	1	FMPA	TEC	D	90				
07/26/2000	2	FMPA	TEC	D	65				
07/26/2000	8	FMPA	TEC	D	150				
07/26/2000	9	FMPA	TEC	D	150				
07/26/2000	10	FMPA	TEC	D	150				
07/26/2000	11	FMPA	TEC	D	150				
07/26/2000	12	FMPA	TEC	D	150				
07/26/2000	13	FMPA	TEC	D	150				
07/26/2000	14	FMPA	TEC	D	150				
07/26/2000	15	FMPA	TEC	D	150				
07/26/2000	16	FMPA	TEC	D	150				
07/26/2000	17	FMPA	TEC	D	150				

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SCHEDULE A6 JULY 2000
DETAIL OF FMPA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/26/2000	18	FMPA	TEC	D	150	[redacted]			
07/26/2000	19	FMPA	TEC	D	150				
07/26/2000	20	FMPA	TEC	D	150				
07/26/2000	21	FMPA	TEC	D	150				
07/26/2000	22	FMPA	TEC	D	150				
07/26/2000	23	FMPA	TEC	D	150				
07/26/2000	24	FMPA	TEC	D	150				
07/27/2000	1	FMPA	TEC	D	90				
07/27/2000	6	FMPA	TEC	D	40				
07/27/2000	7	FMPA	TEC	D	150				
07/27/2000	8	FMPA	TEC	D	150				
07/27/2000	9	FMPA	TEC	D	150				
07/27/2000	10	FMPA	TEC	D	150				
07/27/2000	11	FMPA	TEC	D	150				
07/27/2000	12	FMPA	TEC	D	150				
07/27/2000	13	FMPA	TEC	D	150				
07/27/2000	14	FMPA	TEC	D	150				
07/27/2000	15	FMPA	TEC	D	150				
07/27/2000	16	FMPA	TEC	D	150				
07/27/2000	17	FMPA	TEC	D	150				
07/27/2000	18	FMPA	TEC	D	150				
07/27/2000	19	FMPA	TEC	D	150				
07/27/2000	20	FMPA	TEC	D	150				
07/27/2000	21	FMPA	TEC	D	150				
07/27/2000	22	FMPA	TEC	D	150				
07/27/2000	23	FMPA	TEC	D	150				
07/27/2000	24	FMPA	TEC	D	150				
07/28/2000	7	FMPA	TEC	D	90				
07/28/2000	8	FMPA	TEC	D	150				
07/28/2000	9	FMPA	TEC	D	150				
07/28/2000	10	FMPA	TEC	D	150				
07/28/2000	11	FMPA	TEC	D	150				
07/28/2000	12	FMPA	TEC	D	150				
07/28/2000	13	FMPA	TEC	D	150				
07/28/2000	14	FMPA	TEC	D	150				
07/28/2000	15	FMPA	TEC	D	150				
07/28/2000	16	FMPA	TEC	D	150				
07/28/2000	17	FMPA	TEC	D	150				
07/28/2000	18	FMPA	TEC	D	150				
07/28/2000	19	FMPA	TEC	D	150				
07/28/2000	20	FMPA	TEC	D	150				
07/28/2000	21	FMPA	TEC	D	150				
07/28/2000	22	FMPA	TEC	D	150				
07/28/2000	23	FMPA	TEC	D	150				
07/28/2000	24	FMPA	TEC	D	150				
07/29/2000	1	FMPA	TEC	D	150				
07/29/2000	2	FMPA	TEC	D	150				
07/29/2000	3	FMPA	TEC	D	150				
07/29/2000	4	FMPA	TEC	D	150				
07/29/2000	5	FMPA	TEC	D	150				
07/29/2000	6	FMPA	TEC	D	150				
07/29/2000	7	FMPA	TEC	D	150				
07/29/2000	8	FMPA	TEC	D	150				
07/29/2000	9	FMPA	TEC	D	150				

SCHEDULE A6 JULY 2000
DETAIL OF FMPA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/29/2000	10	FMPA	TEC	D	150	[redacted]			
07/29/2000	11	FMPA	TEC	D	150				
07/29/2000	12	FMPA	TEC	D	150				
07/29/2000	13	FMPA	TEC	D	150				
07/29/2000	14	FMPA	TEC	D	150				
07/29/2000	15	FMPA	TEC	D	150				
07/29/2000	16	FMPA	TEC	D	150				
07/29/2000	17	FMPA	TEC	D	150				
07/29/2000	18	FMPA	TEC	D	150				
07/29/2000	19	FMPA	TEC	D	150				
07/29/2000	20	FMPA	TEC	D	150				
07/29/2000	21	FMPA	TEC	D	150				
07/29/2000	22	FMPA	TEC	D	150				
07/29/2000	23	FMPA	TEC	D	150				
07/29/2000	24	FMPA	TEC	D	150				
07/30/2000	1	FMPA	TEC	D	150				
07/30/2000	2	FMPA	TEC	D	150				
07/30/2000	3	FMPA	TEC	D	150				
07/30/2000	4	FMPA	TEC	D	150				
07/30/2000	5	FMPA	TEC	D	40				
07/30/2000	6	FMPA	TEC	D	40				
07/30/2000	7	FMPA	TEC	D	40				
07/30/2000	8	FMPA	TEC	D	150				
07/30/2000	9	FMPA	TEC	D	150				
07/30/2000	10	FMPA	TEC	D	150				
07/30/2000	11	FMPA	TEC	D	150				
07/30/2000	12	FMPA	TEC	D	150				
07/30/2000	13	FMPA	TEC	D	150				
07/30/2000	14	FMPA	TEC	D	150				
07/30/2000	15	FMPA	TEC	D	150				
07/30/2000	16	FMPA	TEC	D	150				
07/30/2000	17	FMPA	TEC	D	150				
07/30/2000	18	FMPA	TEC	D	150				
07/30/2000	19	FMPA	TEC	D	150				
07/30/2000	20	FMPA	TEC	D	150				
07/30/2000	21	FMPA	TEC	D	150				
07/30/2000	22	FMPA	TEC	D	150				
07/30/2000	23	FMPA	TEC	D	150				
07/30/2000	24	FMPA	TEC	D	150				
07/31/2000	1	FMPA	TEC	D	150				
07/31/2000	2	FMPA	TEC	D	150				
07/31/2000	3	FMPA	TEC	D	40				
07/31/2000	4	FMPA	TEC	D	40				
07/31/2000	5	FMPA	TEC	D	40				
07/31/2000	6	FMPA	TEC	D	150				
07/31/2000	7	FMPA	TEC	D	150				
07/31/2000	8	FMPA	TEC	D	150				
07/31/2000	9	FMPA	TEC	D	150				
07/31/2000	10	FMPA	TEC	D	150				
07/31/2000	11	FMPA	TEC	D	150				
07/31/2000	12	FMPA	TEC	D	150				
07/31/2000	13	FMPA	TEC	D	150				
07/31/2000	14	FMPA	TEC	D	150				
07/31/2000	15	FMPA	TEC	D	150				

SCHEDULE A6 JULY 2000
DETAIL OF FMPA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/31/2000	16	FMPA	TEC	D	150	[redacted]			
07/31/2000	17	FMPA	TEC	D	150				
07/31/2000	18	FMPA	TEC	D	150				
07/31/2000	19	FMPA	TEC	D	150				
07/31/2000	20	FMPA	TEC	D	150				
07/31/2000	21	FMPA	TEC	D	150				
07/31/2000	22	FMPA	TEC	D	150				
07/31/2000	23	FMPA	TEC	D	150				
07/31/2000	24	FMPA	TEC	D	150				

SCHEDULE A6 JULY 2000
DETAIL OF FMPA

	A6	DETAIL	VARIANCE	EXPLANATION
MWH	102,055	102,055	0	
FUEL	$1,934,627.04	$2,002,285.25	$67,658.21	Detail includes SO_2 that is not reported in the A schedules
SO_2	$0.00	($67,658.21)	($67,658.21)	Total SO_2 Hourly detail is not available.
TOTAL	**$1,934,627.04**	**$1,934,627.04**	**$0.00**	

SCHEDULE A6 JULY 2000
DETAIL OF FLORIDA POWER CORP.

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/04/2000	15	FPC	TEC	MA	50	[redacted]			
07/05/2000	12	FPC	TEC	MA	40				
07/05/2000	15	FPC	TEC	MA	65				
07/05/2000	16	FPC	TEC	MA	50				
07/05/2000	17	FPC	TEC	MA	63				
07/05/2000	18	FPC	TEC	MA	77				
07/05/2000	19	FPC	TEC	MA	50				
07/05/2000	20	FPC	TEC	MA	50				
07/06/2000	20	FPC	TEC	MA	61				
07/06/2000	21	FPC	TEC	MA	81				
07/06/2000	22	FPC	TEC	MA	101				
07/07/2000	11	FPC	TEC	MA	75				
07/08/2000	17	FPC	TEC	MA	50				
07/08/2000	18	FPC	TEC	MA	75				
07/08/2000	19	FPC	TEC	MA	50				
07/08/2000	20	FPC	TEC	MA	65				
07/08/2000	21	FPC	TEC	MA	50				
07/08/2000	22	FPC	TEC	MA	100				
07/10/2000	10	FPC	TEC	MA	50				
07/10/2000	11	FPC	TEC	MA	140				
07/10/2000	16	FPC	TEC	MA	85				
07/10/2000	17	FPC	TEC	MA	83				
07/10/2000	18	FPC	TEC	MA	83				
07/10/2000	19	FPC	TEC	MA	100				
07/10/2000	20	FPC	TEC	MA	95				
07/10/2000	21	FPC	TEC	MA	100				
07/10/2000	22	FPC	TEC	MA	83				
07/11/2000	2	FPC	TEC	MA	150				
07/11/2000	9	FPC	TEC	MA	200				
07/11/2000	10	FPC	TEC	MA	100				
07/15/2000	13	FPC	TEC	MA	50				
07/15/2000	14	FPC	TEC	MA	50				
07/22/2000	16	FPC	TEC	MA	75				

SCHEDULE A6 JULY 2000
DETAIL OF FLORIDA POWER CORP.

	A6	DETAIL	VARIANCE	EXPLANATION
MWH	2,597	2,597	0	
FUEL	$159,512.63	$163,569.50	$4,056.87	Detail includes transmission
TRANSMISSION	$0.00	($4,056.87)	($4,056.87)	Total cost of transmission through Tampa Electric's system
TOTAL	**$159,512.63**	**$159,512.63**	**$0.00**	

SCHEDULE A6 JULY 2000
DETAIL OF FLORIDA POWER & LIGHT

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/01/2000	19	FPL	TEC	MA	60	[redacted]			
07/02/2000	10	FPL	TEC	MA	85				
07/02/2000	11	FPL	TEC	MA	125				
07/03/2000	8	FPL	TEC	MA	100				
07/03/2000	9	FPL	TEC	MA	150				
07/03/2000	10	FPL	TEC	MA	150				
07/04/2000	8	FPL	TEC	MA	50				
07/04/2000	9	FPL	TEC	MA	100				
07/04/2000	15	FPL	TEC	MA	50				
07/04/2000	20	FPL	TEC	MA	30				
07/04/2000	21	FPL	TEC	MA	180				
07/04/2000	23	FPL	TEC	MA	140				
07/04/2000	24	FPL	TEC	MA	165				
07/05/2000	1	FPL	TEC	MA	300				
07/05/2000	7	FPL	TEC	MA	100				
07/05/2000	8	FPL	TEC	MA	200				
07/05/2000	9	FPL	TEC	MA	380				
07/05/2000	10	FPL	TEC	MA	475				
07/05/2000	11	FPL	TEC	MA	100				
07/06/2000	8	FPL	TEC	MA	100				
07/06/2000	9	FPL	TEC	MA	275				
07/06/2000	10	FPL	TEC	MA	175				
07/06/2000	16	FPL	TEC	MA	25				
07/06/2000	21	FPL	TEC	MA	100				
07/09/2000	10	FPL	TEC	MA	100				
07/10/2000	8	FPL	TEC	MA	100				
07/10/2000	9	FPL	TEC	MA	250				
07/10/2000	10	FPL	TEC	MA	265				
07/11/2000	3	FPL	TEC	MA	100				
07/11/2000	8	FPL	TEC	MA	200				
07/11/2000	9	FPL	TEC	MA	200				
07/11/2000	10	FPL	TEC	MA	100				
07/13/2000	15	FPL	TEC	MA	98				
07/15/2000	9	FPL	TEC	MA	60				
07/15/2000	13	FPL	TEC	MA	166				
07/15/2000	14	FPL	TEC	MA	160				
07/15/2000	15	FPL	TEC	MA	260				
07/15/2000	16	FPL	TEC	MA	360				
07/15/2000	17	FPL	TEC	MA	360				
07/15/2000	18	FPL	TEC	MA	360				
07/15/2000	19	FPL	TEC	MA	300				
07/15/2000	20	FPL	TEC	MA	300				
07/15/2000	21	FPL	TEC	MA	400				
07/15/2000	22	FPL	TEC	MA	400				
07/15/2000	23	FPL	TEC	MA	275				
07/15/2000	24	FPL	TEC	MA	375				
07/16/2000	1	FPL	TEC	MA	400				
07/16/2000	2	FPL	TEC	MA	400				
07/16/2000	3	FPL	TEC	MA	400				
07/16/2000	4	FPL	TEC	MA	100				
07/16/2000	5	FPL	TEC	MA	100				
07/16/2000	6	FPL	TEC	MA	100				
07/16/2000	9	FPL	TEC	MA	200				
07/16/2000	10	FPL	TEC	MA	300				
07/16/2000	11	FPL	TEC	MA	225				

SCHEDULE A6 JULY 2000
DETAIL OF FLORIDA POWER & LIGHT

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/22/2000	8	FPL	TEC	MA	200	[redacted]			
07/22/2000	9	FPL	TEC	MA	200				
07/22/2000	10	FPL	TEC	MA	125				
07/22/2000	18	FPL	TEC	MA	25				
07/23/2000	9	FPL	TEC	MA	200				
07/23/2000	17	FPL	TEC	MA	100				
07/23/2000	18	FPL	TEC	MA	100				
07/23/2000	21	FPL	TEC	MA	50				
07/23/2000	22	FPL	TEC	MA	300				
07/23/2000	23	FPL	TEC	MA	300				
07/23/2000	24	FPL	TEC	MA	140				
07/24/2000	15	FPL	TEC	MA	100				
07/24/2000	16	FPL	TEC	MA	100				
07/24/2000	17	FPL	TEC	MA	100				
07/24/2000	18	FPL	TEC	MA	100				
07/24/2000	19	FPL	TEC	MA	100				
07/24/2000	20	FPL	TEC	MA	179				
07/29/2000	9	FPL	TEC	MA	100				
07/31/2000	20	FPL	TEC	MA	220				

SCHEDULE A6 JULY 2000
DETAIL OF FLORIDA POWER & LIGHT

	A6	DETAIL	VARIANCE	EXPLANATION
MWH	13,768	13,768	0	
FUEL	$447,403.66	$468,691.00	$21,287.34	Detail includes transmission
TRANSMISSION	$0.00	(521,287.34)	($21,287.34)	Total cost of transmission through Tampa Electric's system
TOTAL	**$447,403.66**	**$447,403.66**	**$0.00**	

SCHEDULE A6 JULY 2000
DETAIL OF CITY OF LAKELAND

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/09/2000	1	PLK	TEC	MA	100	[redacted]			
07/09/2000	2	PLK	TEC	MA	150				
07/09/2000	3	PLK	TEC	MA	50				
07/31/2000	8	PLK	TEC	MA	100				
07/31/2000	9	PLK	TEC	MA	100				

SCHEDULE A6 JULY 2000
DETAIL OF CITY OF LAKELAND

	A6	DETAIL	VARIANCE	EXPLANATION
MWH	500	500	0	
FUEL	$12,542.52	$13,300.00	$757.48	Detail includes transmission
TRANSMISSION	$0.00	($757.48)	($757.48)	Total cost of transmission through Tampa Electric's system
TOTAL	**$12,542.52**	**$12,542.52**	($0.00)	

SCHEDULE A6 JULY 2000
DETAIL OF ORLANDO UTIL. COMM.

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/06/2000	16	POU	TEC	MA	38	[redacted]			
07/07/2000	7	POU	TEC	MA	50				
07/07/2000	8	POU	TEC	MA	50				
07/07/2000	9	POU	TEC	MA	100				

SCHEDULE A6 JULY 2000
DETAIL OF ORLANDO UTIL. COMM.

	A6	DETAIL	VARIANCE	EXPLANATION
MWH	238	238	0	
FUEL	$11,882.94	$12,350.00	$467.06	Detail includes transmission
TRANSMISSION	$0.00	($467.06)	($467.06)	Total cost of transmission through Tampa Electric's system
TOTAL	**$11,882.94**	**$11,882.94**	($0.00)	

SCHEDULE A6 JULY 2000
DETAIL OF CITY OF NEW SMYRNA BCH.

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/05/2000	16	NSB	TEC	MA	6	[redacted]			
07/05/2000	17	NSB	TEC	MA	6				
07/05/2000	18	NSB	TEC	MA	6				
07/05/2000	19	NSB	TEC	MA	6				
07/05/2000	20	NSB	TEC	MA	6				
07/05/2000	21	NSB	TEC	MA	6				
07/06/2000	14	NSB	TEC	MA	8				
07/06/2000	15	NSB	TEC	MA	8				
07/06/2000	16	NSB	TEC	MA	8				
07/06/2000	17	NSB	TEC	MA	8				
07/06/2000	18	NSB	TEC	MA	8				
07/06/2000	19	NSB	TEC	MA	8				
07/06/2000	20	NSB	TEC	MA	8				

SCHEDULE A6 JULY 2000
DETAIL OF CITY OF NEW SMYRNA BCH.

	A6	DETAIL	VARIANCE	EXPLANATION
MWH	92	92	0	
FUEL	$8,990.28	$9,128.00	$137.72	Detail includes transmission
TRANSMISSION	$0.00	($137.72)	($137.72)	Total cost of transmission through Tampa Electric's system
TOTAL	**$8,990.28**	**$8,990.28**	($0.00)	

SCHEDULE A6 JULY 2000
DETAIL OF CARGILL ALLIANT

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FUEL COST	TOTAL $ FOR TOTAL COST
07/05/2000	14:00	CARGILL	TEC	IMBALANCE	3				
07/05/2000	15:00	CARGILL	TEC	IMBALANCE	6				
07/05/2000	16:00	CARGILL	TEC	IMBALANCE	6				
07/05/2000	17:00	CARGILL	TEC	IMBALANCE	10				
07/05/2000	19:00	CARGILL	TEC	IMBALANCE	1				
07/05/2000	20:00	CARGILL	TEC	IMBALANCE	1				
07/05/2000	22:00	CARGILL	TEC	IMBALANCE	4				
07/06/2000	11:00	CARGILL	TEC	IMBALANCE	13				
07/06/2000	12:00	CARGILL	TEC	IMBALANCE	9				
07/06/2000	13:00	CARGILL	TEC	IMBALANCE	4				
07/06/2000	14:00	CARGILL	TEC	IMBALANCE	3				
07/06/2000	15:00	CARGILL	TEC	IMBALANCE	1				
07/06/2000	16:00	CARGILL	TEC	IMBALANCE	3				
07/06/2000	17:00	CARGILL	TEC	IMBALANCE	2				
07/06/2000	19:00	CARGILL	TEC	IMBALANCE	3				
07/06/2000	20:00	CARGILL	TEC	IMBALANCE	2				
07/06/2000	21:00	CARGILL	TEC	IMBALANCE	2				
07/06/2000	22:00	CARGILL	TEC	IMBALANCE	6				
07/06/2000	23:00	CARGILL	TEC	IMBALANCE	7				
07/07/2000	21:00	CARGILL	TEC	IMBALANCE	1				
07/10/2000	14:00	CARGILL	TEC	IMBALANCE	1				
07/10/2000	15:00	CARGILL	TEC	IMBALANCE	1				
07/10/2000	21:00	CARGILL	TEC	IMBALANCE	2				
07/11/2000	13:00	CARGILL	TEC	IMBALANCE	2				
07/11/2000	14:00	CARGILL	TEC	IMBALANCE	13				
07/11/2000	15:00	CARGILL	TEC	IMBALANCE	13				
07/11/2000	18:00	CARGILL	TEC	IMBALANCE	1				
07/11/2000	19:00	CARGILL	TEC	IMBALANCE	3				
07/11/2000	20:00	CARGILL	TEC	IMBALANCE	5				
07/11/2000	21:00	CARGILL	TEC	IMBALANCE	9				
07/12/2000	12:00	CARGILL	TEC	IMBALANCE	5				
07/12/2000	13:00	CARGILL	TEC	IMBALANCE	7				
07/12/2000	14:00	CARGILL	TEC	IMBALANCE	6				
07/12/2000	15:00	CARGILL	TEC	IMBALANCE	1				
07/12/2000	16:00	CARGILL	TEC	IMBALANCE	1				
07/12/2000	17:00	CARGILL	TEC	IMBALANCE	2				
07/12/2000	18:00	CARGILL	TEC	IMBALANCE	5				
07/12/2000	19:00	CARGILL	TEC	IMBALANCE	2				
07/12/2000	20:00	CARGILL	TEC	IMBALANCE	3				
07/12/2000	21:00	CARGILL	TEC	IMBALANCE	2				
07/13/2000	16:00	CARGILL	TEC	IMBALANCE	6				
07/13/2000	17:00	CARGILL	TEC	IMBALANCE	7				
07/13/2000	18:00	CARGILL	TEC	IMBALANCE	2				
07/17/2000	18:00	CARGILL	TEC	IMBALANCE	1				
07/17/2000	20:00	CARGILL	TEC	IMBALANCE	1				
07/17/2000	21:00	CARGILL	TEC	IMBALANCE	1				
07/18/2000	14:00	CARGILL	TEC	IMBALANCE	1				
07/18/2000	15:00	CARGILL	TEC	IMBALANCE	1				
07/18/2000	17:00	CARGILL	TEC	IMBALANCE	1				
07/20/2000	18:00	CARGILL	TEC	IMBALANCE	1				
07/20/2000	19:00	CARGILL	TEC	IMBALANCE	3				
07/20/2000	20:00	CARGILL	TEC	IMBALANCE	4				
07/20/2000	21:00	CARGILL	TEC	IMBALANCE	4				

SCHEDULE A6 JULY 2000
DETAIL OF CARGILL ALLIANT

	A6	DETAIL	VARIANCE	EXPLANATION
MWH	204	204	0	
FUEL	$14,194.66	$14,194.66	$0.00	
TOTAL	**$14,194.66**	**$14,194.66**	**$0.00**	

SCHEDULE A6 JULY 2000
DETAIL OF CITY OF HOMESTEAD

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH FUEL ADJUSTMENT	CENTS/KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL $ FOR TOTAL COST
07/06/2000	17	HST	TEC	MA	10	[redacted]			

SCHEDULE A6 JULY 2000
DETAIL OF CITY OF HOMESTEAD

	A6	DETAIL	VARIANCE	EXPLANATION
MWH	10	10	0	
FUEL	$1,735.03	$1,750.00	$14.97	Detail includes transmission
TRANSMISSION	$0.00	($14.97)	($14.97)	Total cost of transmission through Tampa Electric's system
TOTAL	**$1,735.03**	**$1,735.03**	**$0.00**	

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150. Provide a detailed listing of each transaction reported in TECO's Schedule A7 for the month of July 2000. Please identify the beginning and ending time of each transaction listed.

A. See attached.

SCHEDULE A7 JULY 2000
DETAIL OF HARDEE - NATIVE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/01/2000	11	TEC	HPP	D	104	[redacted]	[redacted]
07/01/2000	12	TEC	HPP	D	163		
07/01/2000	13	TEC	HPP	D	269		
07/01/2000	14	TEC	HPP	D	241		
07/01/2000	15	TEC	HPP	D	268		
07/01/2000	16	TEC	HPP	D	269		
07/01/2000	17	TEC	HPP	D	221		
07/01/2000	18	TEC	HPP	D	124		
07/01/2000	19	TEC	HPP	D	121		
07/01/2000	20	TEC	HPP	D	121		
07/01/2000	21	TEC	HPP	D	80		
07/02/2000	11	TEC	HPP	D	1		
07/02/2000	12	TEC	HPP	D	138		
07/02/2000	13	TEC	HPP	D	269		
07/02/2000	14	TEC	HPP	D	269		
07/02/2000	15	TEC	HPP	D	337		
07/02/2000	16	TEC	HPP	D	339		
07/02/2000	17	TEC	HPP	D	318		
07/02/2000	18	TEC	HPP	D	329		
07/02/2000	19	TEC	HPP	D	355		
07/02/2000	20	TEC	HPP	D	287		
07/02/2000	21	TEC	HPP	D	288		
07/02/2000	22	TEC	HPP	D	289		
07/02/2000	23	TEC	HPP	D	230		
07/02/2000	24	TEC	HPP	D	210		
07/03/2000	1	TEC	HPP	D	120		
07/03/2000	11	TEC	HPP	D	79		
07/03/2000	12	TEC	HPP	D	120		
07/03/2000	13	TEC	HPP	D	209		
07/03/2000	14	TEC	HPP	D	209		
07/03/2000	15	TEC	HPP	D	238		
07/03/2000	16	TEC	HPP	D	355		
07/03/2000	17	TEC	HPP	D	356		
07/03/2000	18	TEC	HPP	D	355		
07/03/2000	19	TEC	HPP	D	356		
07/03/2000	20	TEC	HPP	D	357		
07/03/2000	21	TEC	HPP	D	360		
07/03/2000	22	TEC	HPP	D	358		
07/03/2000	23	TEC	HPP	D	318		
07/03/2000	24	TEC	HPP	D	215		
07/04/2000	1	TEC	HPP	D	215		
07/04/2000	12	TEC	HPP	D	99		
07/04/2000	13	TEC	HPP	D	285		
07/04/2000	14	TEC	HPP	D	286		
07/04/2000	15	TEC	HPP	D	286		
07/04/2000	16	TEC	HPP	D	284		
07/04/2000	17	TEC	HPP	D	285		
07/04/2000	18	TEC	HPP	D	286		
07/04/2000	19	TEC	HPP	D	288		
07/04/2000	20	TEC	HPP	D	126		
07/05/2000	13	TEC	HPP	D	70		
07/05/2000	14	TEC	HPP	D	210		
07/05/2000	15	TEC	HPP	D	283		
07/05/2000	16	TEC	HPP	D	332		

SCHEDULE A7 JULY 2000
DETAIL OF HARDEE - NATIVE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/05/2000	17	TEC	HPP	D	344	[redacted]	[redacted]
07/05/2000	18	TEC	HPP	D	338		
07/05/2000	19	TEC	HPP	D	345		
07/05/2000	20	TEC	HPP	D	346		
07/05/2000	21	TEC	HPP	D	291		
07/05/2000	22	TEC	HPP	D	279		
07/05/2000	23	TEC	HPP	D	214		
07/05/2000	24	TEC	HPP	D	214		
07/06/2000	1	TEC	HPP	D	214		
07/06/2000	12	TEC	HPP	D	139		
07/06/2000	13	TEC	HPP	D	267		
07/06/2000	14	TEC	HPP	D	353		
07/06/2000	15	TEC	HPP	D	352		
07/06/2000	16	TEC	HPP	D	353		
07/06/2000	17	TEC	HPP	D	352		
07/06/2000	18	TEC	HPP	D	354		
07/06/2000	19	TEC	HPP	D	354		
07/06/2000	20	TEC	HPP	D	354		
07/06/2000	21	TEC	HPP	D	313		
07/06/2000	22	TEC	HPP	D	271		
07/06/2000	23	TEC	HPP	D	192		
07/06/2000	24	TEC	HPP	D	214		
07/07/2000	10	TEC	HPP	D	80		
07/07/2000	11	TEC	HPP	D	120		
07/07/2000	12	TEC	HPP	D	120		
07/07/2000	13	TEC	HPP	D	240		
07/07/2000	14	TEC	HPP	D	355		
07/07/2000	15	TEC	HPP	D	356		
07/07/2000	16	TEC	HPP	D	355		
07/07/2000	17	TEC	HPP	D	356		
07/07/2000	18	TEC	HPP	D	356		
07/07/2000	19	TEC	HPP	D	356		
07/07/2000	20	TEC	HPP	D	357		
07/07/2000	21	TEC	HPP	D	287		
07/07/2000	22	TEC	HPP	D	239		
07/07/2000	23	TEC	HPP	D	210		
07/07/2000	24	TEC	HPP	D	210		
07/08/2000	1	TEC	HPP	D	210		
07/08/2000	11	TEC	HPP	D	221		
07/08/2000	12	TEC	HPP	D	356		
07/08/2000	13	TEC	HPP	D	357		
07/08/2000	14	TEC	HPP	D	291		
07/08/2000	15	TEC	HPP	D	267		
07/08/2000	16	TEC	HPP	D	215		
07/08/2000	17	TEC	HPP	D	120		
07/08/2000	18	TEC	HPP	D	120		
07/08/2000	19	TEC	HPP	D	120		
07/09/2000	11	TEC	HPP	D	80		
07/09/2000	12	TEC	HPP	D	172		
07/09/2000	13	TEC	HPP	D	358		
07/09/2000	14	TEC	HPP	D	361		
07/09/2000	15	TEC	HPP	D	366		
07/09/2000	16	TEC	HPP	D	365		
07/09/2000	17	TEC	HPP	D	366		

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DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/09/2000	18	TEC	HPP	D	365	[redacted]	[redacted]
07/09/2000	19	TEC	HPP	D	366		
07/09/2000	20	TEC	HPP	D	356		
07/09/2000	21	TEC	HPP	D	223		
07/09/2000	22	TEC	HPP	D	210		
07/09/2000	23	TEC	HPP	D	210		
07/10/2000	12	TEC	HPP	D	19		
07/10/2000	13	TEC	HPP	D	195		
07/10/2000	14	TEC	HPP	D	209		
07/10/2000	15	TEC	HPP	D	280		
07/10/2000	16	TEC	HPP	D	350		
07/10/2000	17	TEC	HPP	D	350		
07/10/2000	18	TEC	HPP	D	350		
07/10/2000	19	TEC	HPP	D	355		
07/10/2000	20	TEC	HPP	D	336		
07/10/2000	21	TEC	HPP	D	206		
07/10/2000	22	TEC	HPP	D	134		
07/10/2000	23	TEC	HPP	D	210		
07/11/2000	11	TEC	HPP	D	120		
07/11/2000	12	TEC	HPP	D	248		
07/11/2000	13	TEC	HPP	D	356		
07/11/2000	14	TEC	HPP	D	356		
07/11/2000	15	TEC	HPP	D	355		
07/11/2000	16	TEC	HPP	D	355		
07/11/2000	17	TEC	HPP	D	354		
07/11/2000	18	TEC	HPP	D	354		
07/11/2000	19	TEC	HPP	D	354		
07/11/2000	20	TEC	HPP	D	356		
07/11/2000	21	TEC	HPP	D	358		
07/11/2000	22	TEC	HPP	D	357		
07/11/2000	23	TEC	HPP	D	358		
07/11/2000	24	TEC	HPP	D	358		
07/12/2000	1	TEC	HPP	D	304		
07/12/2000	2	TEC	HPP	D	120		
07/12/2000	9	TEC	HPP	D	120		
07/12/2000	10	TEC	HPP	D	214		
07/12/2000	11	TEC	HPP	D	317		
07/12/2000	12	TEC	HPP	D	364		
07/12/2000	13	TEC	HPP	D	364		
07/12/2000	14	TEC	HPP	D	363		
07/12/2000	15	TEC	HPP	D	363		
07/12/2000	16	TEC	HPP	D	363		
07/12/2000	17	TEC	HPP	D	363		
07/12/2000	18	TEC	HPP	D	363		
07/12/2000	19	TEC	HPP	D	364		
07/12/2000	20	TEC	HPP	D	364		
07/12/2000	21	TEC	HPP	D	365		
07/12/2000	22	TEC	HPP	D	365		
07/12/2000	23	TEC	HPP	D	248		
07/12/2000	24	TEC	HPP	D	210		
07/13/2000	1	TEC	HPP	D	210		
07/13/2000	2	TEC	HPP	D	210		
07/13/2000	3	TEC	HPP	D	210		
07/13/2000	4	TEC	HPP	D	150		

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DETAIL OF HARDEE - NATIVE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/13/2000	5	TEC	HPP	D	200	[redacted]	[redacted]
07/13/2000	6	TEC	HPP	D	120		
07/13/2000	7	TEC	HPP	D	120		
07/13/2000	8	TEC	HPP	D	120		
07/13/2000	9	TEC	HPP	D	146		
07/13/2000	10	TEC	HPP	D	214		
07/13/2000	11	TEC	HPP	D	361		
07/13/2000	12	TEC	HPP	D	360		
07/13/2000	13	TEC	HPP	D	360		
07/13/2000	14	TEC	HPP	D	308		
07/13/2000	15	TEC	HPP	D	359		
07/13/2000	16	TEC	HPP	D	314		
07/13/2000	17	TEC	HPP	D	364		
07/13/2000	18	TEC	HPP	D	364		
07/13/2000	19	TEC	HPP	D	365		
07/13/2000	20	TEC	HPP	D	364		
07/13/2000	21	TEC	HPP	D	365		
07/13/2000	22	TEC	HPP	D	365		
07/13/2000	23	TEC	HPP	D	367		
07/13/2000	24	TEC	HPP	D	219		
07/14/2000	1	TEC	HPP	D	210		
07/14/2000	2	TEC	HPP	D	210		
07/14/2000	3	TEC	HPP	D	150		
07/14/2000	4	TEC	HPP	D	150		
07/14/2000	5	TEC	HPP	D	150		
07/14/2000	6	TEC	HPP	D	210		
07/14/2000	7	TEC	HPP	D	210		
07/14/2000	8	TEC	HPP	D	210		
07/14/2000	9	TEC	HPP	D	210		
07/14/2000	10	TEC	HPP	D	281		
07/14/2000	11	TEC	HPP	D	287		
07/14/2000	12	TEC	HPP	D	358		
07/14/2000	13	TEC	HPP	D	357		
07/14/2000	14	TEC	HPP	D	356		
07/14/2000	15	TEC	HPP	D	357		
07/14/2000	16	TEC	HPP	D	358		
07/14/2000	17	TEC	HPP	D	356		
07/14/2000	18	TEC	HPP	D	360		
07/14/2000	19	TEC	HPP	D	289		
07/14/2000	20	TEC	HPP	D	290		
07/14/2000	21	TEC	HPP	D	289		
07/14/2000	22	TEC	HPP	D	290		
07/14/2000	23	TEC	HPP	D	268		
07/14/2000	24	TEC	HPP	D	210		
07/15/2000	1	TEC	HPP	D	210		
07/15/2000	2	TEC	HPP	D	70		
07/15/2000	10	TEC	HPP	D	80		
07/15/2000	11	TEC	HPP	D	125		
07/15/2000	12	TEC	HPP	D	130		
07/15/2000	13	TEC	HPP	D	125		
07/15/2000	14	TEC	HPP	D	125		
07/15/2000	15	TEC	HPP	D	125		
07/15/2000	16	TEC	HPP	D	125		
07/15/2000	17	TEC	HPP	D	125		

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DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/15/2000	18	TEC	HPP	D	125	[redacted]	[redacted]
07/16/2000	13	TEC	HPP	D	80		
07/16/2000	14	TEC	HPP	D	210		
07/16/2000	15	TEC	HPP	D	257		
07/16/2000	16	TEC	HPP	D	355		
07/16/2000	17	TEC	HPP	D	356		
07/16/2000	18	TEC	HPP	D	355		
07/16/2000	19	TEC	HPP	D	356		
07/16/2000	20	TEC	HPP	D	357		
07/16/2000	21	TEC	HPP	D	287		
07/16/2000	22	TEC	HPP	D	289		
07/16/2000	23	TEC	HPP	D	289		
07/16/2000	24	TEC	HPP	D	289		
07/17/2000	1	TEC	HPP	D	253		
07/17/2000	2	TEC	HPP	D	210		
07/17/2000	8	TEC	HPP	D	80		
07/17/2000	9	TEC	HPP	D	124		
07/17/2000	10	TEC	HPP	D	356		
07/17/2000	11	TEC	HPP	D	353		
07/17/2000	12	TEC	HPP	D	357		
07/17/2000	13	TEC	HPP	D	356		
07/17/2000	14	TEC	HPP	D	355		
07/17/2000	15	TEC	HPP	D	356		
07/17/2000	16	TEC	HPP	D	356		
07/17/2000	17	TEC	HPP	D	354		
07/17/2000	18	TEC	HPP	D	356		
07/17/2000	19	TEC	HPP	D	356		
07/17/2000	20	TEC	HPP	D	357		
07/17/2000	21	TEC	HPP	D	357		
07/17/2000	22	TEC	HPP	D	359		
07/17/2000	23	TEC	HPP	D	359		
07/17/2000	24	TEC	HPP	D	355		
07/18/2000	1	TEC	HPP	D	211		
07/18/2000	9	TEC	HPP	D	120		
07/18/2000	10	TEC	HPP	D	210		
07/18/2000	11	TEC	HPP	D	263		
07/18/2000	12	TEC	HPP	D	357		
07/18/2000	13	TEC	HPP	D	356		
07/18/2000	14	TEC	HPP	D	357		
07/18/2000	15	TEC	HPP	D	356		
07/18/2000	16	TEC	HPP	D	355		
07/18/2000	17	TEC	HPP	D	356		
07/18/2000	18	TEC	HPP	D	356		
07/18/2000	19	TEC	HPP	D	357		
07/18/2000	20	TEC	HPP	D	357		
07/18/2000	21	TEC	HPP	D	358		
07/18/2000	22	TEC	HPP	D	287		
07/18/2000	23	TEC	HPP	D	289		
07/18/2000	24	TEC	HPP	D	289		
07/19/2000	1	TEC	HPP	D	241		
07/19/2000	8	TEC	HPP	D	103		
07/19/2000	9	TEC	HPP	D	258		
07/19/2000	10	TEC	HPP	D	327		
07/19/2000	11	TEC	HPP	D	327		

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DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/19/2000	12	TEC	HPP	D	327		
07/19/2000	13	TEC	HPP	D	325		
07/19/2000	14	TEC	HPP	D	316		
07/19/2000	15	TEC	HPP	D	315		
07/19/2000	16	TEC	HPP	D	315		
07/19/2000	17	TEC	HPP	D	316		
07/19/2000	18	TEC	HPP	D	316		
07/19/2000	19	TEC	HPP	D	317		
07/19/2000	20	TEC	HPP	D	317		
07/19/2000	21	TEC	HPP	D	317		
07/19/2000	22	TEC	HPP	D	319		
07/19/2000	23	TEC	HPP	D	317		
07/19/2000	24	TEC	HPP	D	254		
07/20/2000	1	TEC	HPP	D	188		
07/20/2000	2	TEC	HPP	D	175		
07/20/2000	8	TEC	HPP	D	111		
07/20/2000	9	TEC	HPP	D	257		
07/20/2000	10	TEC	HPP	D	248		
07/20/2000	11	TEC	HPP	D	76		
07/20/2000	12	TEC	HPP	D	76		
07/20/2000	13	TEC	HPP	D	76		
07/20/2000	14	TEC	HPP	D	76		
07/20/2000	15	TEC	HPP	D	75		
07/20/2000	16	TEC	HPP	D	74		
07/20/2000	17	TEC	HPP	D	74		
07/20/2000	18	TEC	HPP	D	75		
07/20/2000	19	TEC	HPP	D	76		
07/20/2000	20	TEC	HPP	D	76		
07/20/2000	21	TEC	HPP	D	219		
07/20/2000	22	TEC	HPP	D	219		
07/20/2000	23	TEC	HPP	D	288		
07/20/2000	24	TEC	HPP	D	238		
07/21/2000	1	TEC	HPP	D	210		
07/21/2000	11	TEC	HPP	D	163		
07/21/2000	12	TEC	HPP	D	357		
07/21/2000	13	TEC	HPP	D	355		
07/21/2000	14	TEC	HPP	D	356		
07/21/2000	15	TEC	HPP	D	356		
07/21/2000	16	TEC	HPP	D	356		
07/21/2000	17	TEC	HPP	D	344		
07/21/2000	18	TEC	HPP	D	301		
07/21/2000	19	TEC	HPP	D	247		
07/21/2000	20	TEC	HPP	D	121		
07/22/2000	13	TEC	HPP	D	70		
07/22/2000	14	TEC	HPP	D	125		
07/22/2000	15	TEC	HPP	D	210		
07/22/2000	16	TEC	HPP	D	210		
07/22/2000	17	TEC	HPP	D	210		
07/22/2000	18	TEC	HPP	D	210		
07/22/2000	19	TEC	HPP	D	210		
07/22/2000	20	TEC	HPP	D	190		
07/22/2000	21	TEC	HPP	D	170		
07/22/2000	22	TEC	HPP	D	214		
07/22/2000	23	TEC	HPP	D	149		

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DETAIL OF HARDEE - NATIVE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/22/2000	24	TEC	HPP	D	214	[redacted]	[redacted]
07/23/2000	11	TEC	HPP	D	235		
07/23/2000	12	TEC	HPP	D	292		
07/23/2000	13	TEC	HPP	D	293		
07/23/2000	14	TEC	HPP	D	295		
07/23/2000	15	TEC	HPP	D	293		
07/23/2000	16	TEC	HPP	D	218		
07/23/2000	17	TEC	HPP	D	215		
07/23/2000	18	TEC	HPP	D	215		
07/23/2000	19	TEC	HPP	D	129		
07/24/2000	11	TEC	HPP	D	120		
07/24/2000	12	TEC	HPP	D	225		
07/24/2000	13	TEC	HPP	D	154		
07/24/2000	14	TEC	HPP	D	125		
07/24/2000	15	TEC	HPP	D	125		
07/24/2000	16	TEC	HPP	D	225		
07/24/2000	17	TEC	HPP	D	225		
07/24/2000	18	TEC	HPP	D	225		
07/24/2000	19	TEC	HPP	D	225		
07/24/2000	20	TEC	HPP	D	121		
07/24/2000	21	TEC	HPP	D	215		
07/24/2000	22	TEC	HPP	D	215		
07/24/2000	23	TEC	HPP	D	215		
07/24/2000	24	TEC	HPP	D	215		
07/25/2000	1	TEC	HPP	D	215		
07/25/2000	2	TEC	HPP	D	134		
07/25/2000	9	TEC	HPP	D	80		
07/25/2000	10	TEC	HPP	D	365		
07/25/2000	11	TEC	HPP	D	378		
07/25/2000	12	TEC	HPP	D	376		
07/25/2000	13	TEC	HPP	D	377		
07/25/2000	14	TEC	HPP	D	378		
07/25/2000	15	TEC	HPP	D	380		
07/25/2000	16	TEC	HPP	D	380		
07/25/2000	17	TEC	HPP	D	380		
07/25/2000	18	TEC	HPP	D	379		
07/25/2000	19	TEC	HPP	D	380		
07/25/2000	20	TEC	HPP	D	379		
07/25/2000	21	TEC	HPP	D	368		
07/25/2000	22	TEC	HPP	D	300		
07/26/2000	12	TEC	HPP	D	220		
07/26/2000	13	TEC	HPP	D	322		
07/26/2000	14	TEC	HPP	D	358		
07/26/2000	15	TEC	HPP	D	351		
07/26/2000	16	TEC	HPP	D	360		
07/26/2000	17	TEC	HPP	D	362		
07/26/2000	18	TEC	HPP	D	363		
07/26/2000	19	TEC	HPP	D	362		
07/26/2000	20	TEC	HPP	D	294		
07/26/2000	21	TEC	HPP	D	281		
07/26/2000	22	TEC	HPP	D	279		
07/26/2000	23	TEC	HPP	D	224		
07/26/2000	24	TEC	HPP	D	215		
07/27/2000	10	TEC	HPP	D	40		

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DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/27/2000	11	TEC	HPP	D	74		
07/27/2000	12	TEC	HPP	D	357		
07/27/2000	13	TEC	HPP	D	356		
07/27/2000	14	TEC	HPP	D	355		
07/27/2000	15	TEC	HPP	D	355		
07/27/2000	16	TEC	HPP	D	356		
07/27/2000	17	TEC	HPP	D	355		
07/27/2000	18	TEC	HPP	D	355		
07/27/2000	19	TEC	HPP	D	355		
07/27/2000	20	TEC	HPP	D	356		
07/27/2000	21	TEC	HPP	D	359		
07/27/2000	22	TEC	HPP	D	359		
07/27/2000	23	TEC	HPP	D	349		
07/27/2000	24	TEC	HPP	D	280		
07/28/2000	1	TEC	HPP	D	150		
07/28/2000	10	TEC	HPP	D	340		
07/28/2000	11	TEC	HPP	D	364		
07/28/2000	12	TEC	HPP	D	364		
07/28/2000	13	TEC	HPP	D	364		
07/28/2000	14	TEC	HPP	D	363		
07/28/2000	15	TEC	HPP	D	363		
07/28/2000	16	TEC	HPP	D	363		
07/28/2000	17	TEC	HPP	D	362		
07/28/2000	18	TEC	HPP	D	362		
07/28/2000	19	TEC	HPP	D	362		
07/28/2000	20	TEC	HPP	D	363		
07/28/2000	21	TEC	HPP	D	364		
07/28/2000	22	TEC	HPP	D	365		
07/28/2000	23	TEC	HPP	D	366		
07/28/2000	24	TEC	HPP	D	336		
07/29/2000	1	TEC	HPP	D	210		
07/29/2000	10	TEC	HPP	D	80		
07/29/2000	11	TEC	HPP	D	218		
07/29/2000	12	TEC	HPP	D	364		
07/29/2000	13	TEC	HPP	D	363		
07/29/2000	14	TEC	HPP	D	363		
07/29/2000	15	TEC	HPP	D	362		
07/29/2000	16	TEC	HPP	D	363		
07/29/2000	17	TEC	HPP	D	364		
07/29/2000	18	TEC	HPP	D	364		
07/29/2000	19	TEC	HPP	D	364		
07/29/2000	20	TEC	HPP	D	365		
07/29/2000	21	TEC	HPP	D	369		
07/29/2000	22	TEC	HPP	D	291		
07/29/2000	23	TEC	HPP	D	31		
07/30/2000	12	TEC	HPP	D	14		
07/30/2000	13	TEC	HPP	D	75		
07/30/2000	14	TEC	HPP	D	77		
07/30/2000	15	TEC	HPP	D	80		
07/30/2000	16	TEC	HPP	D	80		
07/30/2000	17	TEC	HPP	D	79		
07/30/2000	18	TEC	HPP	D	79		
07/30/2000	19	TEC	HPP	D	79		
07/30/2000	20	TEC	HPP	D	19		

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DETAIL OF HARDEE - NATIVE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/31/2000	12	TEC	HPP	D	20	[redacted]	[redacted]
07/31/2000	13	TEC	HPP	D	76		
07/31/2000	14	TEC	HPP	D	75		
07/31/2000	15	TEC	HPP	D	74		
07/31/2000	16	TEC	HPP	D	75		
07/31/2000	17	TEC	HPP	D	74		
07/31/2000	18	TEC	HPP	D	177		
07/31/2000	19	TEC	HPP	D	357		
07/31/2000	20	TEC	HPP	D	287		
07/31/2000	21	TEC	HPP	D	289		
07/31/2000	22	TEC	HPP	D	289		
07/31/2000	23	TEC	HPP	D	290		
07/31/2000	24	TEC	HPP	D	291		

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DETAIL OF HARDEE - NATIVE

	A7	DETAIL	VARIANCE	EXPLANATION
MWH	116,390	116,777	387	
INADVERTENT	0	(387)	(387)	Total monthly inadventent for Hardee schedules is not included in detail.
TOTAL MWH	**116,390**	**116,390**	**0**	
FUEL	$6,038,289.74	$6,487,253.97	$448,964.23	
INADVERTENT	$0.00	($21,498.82)	($21,498.82)	Total monthly inadventent for Hardee schedules is not included in detail.
ADJUSTMENT	$427,465.39	$0.00	($427,465.39)	Monthly billing adjustment made in August 2000
TOTAL $	$6,465,755.13	$6,465,755.15	$0.02	

SCHEDULE A7 JULY 2000
DETAIL OF HARDEE - OTHERS

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWh	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/05/2000	16	FPC	TEH	MA	22	[redacted]	[redacted]
07/05/2000	17	FPC	TEH	MA	10		
07/05/2000	18	FPC	TEH	MA	16		
07/05/2000	19	FPC	TEH	MA	9		
07/06/2000	20	FPC	TEH	MA	16		
07/06/2000	22	FPL	TEH	MA	21		
07/10/2000	12	FPC	TEH	MA	61		
07/10/2000	16	FPC	TEH	MA	15		
07/10/2000	17	FPC	TEH	MA	18		
07/10/2000	18	FPC	TEH	MA	18		
07/10/2000	21	FPC	TEH	MA	80		
07/15/2000	14	FPC	TEH	MA	88		
07/15/2000	15	FPL	TEH	MA	88		
07/15/2000	16	FPL	TEH	MA	88		
07/15/2000	17	FPL	TEH	MA	88		

SCHEDULE A7 JULY 2000
DETAIL OF HARDEE - OTHERS

	A7	DETAIL	VARIANCE	EXPLANATION
MWH	638	638	0	
FUEL	$23,592.49	$23,592.49	$0.00	
O&M	$0.00	$0.00	$0.00	
TOTAL	**$23,592.49**	**$23,592.49**	**$0.00**	

SCHEDULE A7 JULY 2000
DETAIL OF FLORIDA POWER CORP.

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/12/00	12	TEC	FPC	JAH	37	0	37	[redacted]	
07/12/00	13	TEC	FPC	JAH	35	35	0		
07/14/00	14	TEC	FPC	JAH	25	0	25		
07/14/00	16	TEC	FPC	JAH	150	0	150		
07/14/00	17	TEC	FPC	JAH	75	0	75		
07/20/00	20	TEC	FPC	JAH	50	50	0		
07/27/00	15	TEC	FPC	JAH	50	50	0		
07/30/00	15	TEC	FPC	JAH	160	160	0		
07/31/00	16	TEC	FPC	JAB1	20	20	0		
07/31/00	17	TEC	FPC	JAH	70	70	0		
07/31/00	18	TEC	FPC	JAB1	70	70	0		
07/08/00	1	TEC	FPC	JCH	100	0	100	[redacted]	
07/08/00	2	TEC	FPC	JCH	200	0	200		
07/08/00	3	TEC	FPC	JCH	100	0	100		
07/12/00	4	TEC	FPC	JCH	50	0	50		
07/12/00	5	TEC	FPC	JCH	50	0	50		
07/12/00	6	TEC	FPC	JCH	50	0	50		
07/12/00	7	TEC	FPC	JCH	50	0	50		
07/12/00	8	TEC	FPC	JCH	75	0	75		
07/12/00	9	TEC	FPC	JCH	100	0	100		
07/12/00	10	TEC	FPC	JCH	100	0	100		
07/12/00	12	TEC	FPC	JCH	63	0	63		
07/14/00	3	TEC	FPC	JCH	75	0	75		
07/14/00	14	TEC	FPC	JCH	45	0	45		
07/14/00	22	TEC	FPC	JCH	140	0	140		
07/14/00	23	TEC	FPC	JCH	185	0	185		
07/14/00	24	TEC	FPC	JCH	65	0	65		
07/15/00	2	TEC	FPC	JCH	100	0	100		
07/15/00	3	TEC	FPC	JCH	50	0	50		
07/15/00	4	TEC	FPC	JCH	50	0	50		
07/17/00	1	TEC	FPC	JCH	150	0	150		
07/17/00	2	TEC	FPC	JCH	150	0	150		
07/17/00	3	TEC	FPC	JCH	200	0	200		
07/17/00	4	TEC	FPC	JCH	200	0	200		
07/17/00	5	TEC	FPC	JCH	200	0	200		
07/17/00	6	TEC	FPC	JCH	100	0	100		
07/19/00	3	TEC	FPC	JCH	200	0	200		
07/19/00	4	TEC	FPC	JCH	300	0	300		
07/19/00	5	TEC	FPC	JCH	125	0	125		
07/19/00	6	TEC	FPC	JCH	50	0	50		
07/19/00	7	TEC	FPC	JCH	100	0	100		
07/20/00	2	TEC	FPC	JCH	75	0	75		
07/20/00	3	TEC	FPC	JCH	140	0	140		
07/20/00	4	TEC	FPC	JCH	140	0	140		
07/20/00	5	TEC	FPC	JCH	50	0	50		
07/20/00	6	TEC	FPC	JCH	100	0	100		
07/21/00	1	TEC	FPC	JCH	50	0	50		
07/21/00	2	TEC	FPC	JCH	150	0	150		
07/21/00	3	TEC	FPC	JCH	150	0	150		
07/21/00	4	TEC	FPC	JCH	100	0	100		
07/25/00	19	TEC	FPC	JCH	100	0	100		
07/25/00	20	TEC	FPC	JCH	150	0	150		
07/25/00	21	TEC	FPC	JCH	50	0	50		

SCHEDULE A7 JULY 2000
DETAIL OF FLORIDA POWER CORP.

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/25/00	22	TEC	FPC	JCH	150	0	150	[redacted]	
07/25/00	23	TEC	FPC	JCH	200	0	200		
07/25/00	24	TEC	FPC	JCH	250	0	250		
07/26/00	1	TEC	FPC	JCH	50	0	50		
07/26/00	23	TEC	FPC	JCH	125	0	125		
07/27/00	1	TEC	FPC	JCH	125	0	125		
07/27/00	14	TEC	FPC	JCH	100	0	100		
07/28/00	2	TEC	FPC	JCH	42	0	42		
07/28/00	3	TEC	FPC	JCH	75	0	75		
07/29/00	1	TEC	FPC	JCB	100	0	100		
07/29/00	2	TEC	FPC	JCB	100	0	100		
07/29/00	3	TEC	FPC	JCB	100	0	100		
07/29/00	4	TEC	FPC	JCB	100	0	100		
07/29/00	5	TEC	FPC	JCB	100	0	100		
07/29/00	6	TEC	FPC	JCB	100	0	100		
07/29/00	7	TEC	FPC	JCB	100	0	100		
07/29/00	11	TEC	FPC	JCH	100	0	100		
07/30/00	20	TEC	FPC	JCH	50	0	50		
07/30/00	21	TEC	FPC	JCH	150	0	150		
07/30/00	22	TEC	FPC	JCH	100	0	100		
07/30/00	23	TEC	FPC	JCH	100	0	100		
07/30/00	24	TEC	FPC	JCH	100	0	100		
07/31/00	11	TEC	FPC	JCH	150	0	150		
07/31/00	12	TEC	FPC	JCH	75	0	75		
07/31/00	13	TEC	FPC	JCH	250	0	250		
07/31/00	14	TEC	FPC	JCH	25	0	25		
07/31/00	15	TEC	FPC	JCB	100	0	100		
07/31/00	15	TEC	FPC	JCH	100	0	100		
07/31/00	16	TEC	FPC	JCB	100	0	100		
07/31/00	16	TEC	FPC	JCB1	80	0	80		
07/31/00	16	TEC	FPC	JCH	50	0	50		
07/31/00	17	TEC	FPC	JCB	100	0	100		
07/31/00	17	TEC	FPC	JCB1	100	0	100		
07/31/00	17	TEC	FPC	JCH	30	0	30		
07/31/00	18	TEC	FPC	JCB	100	0	100		
07/31/00	18	TEC	FPC	JCB1	30	0	30		
07/31/00	19	TEC	FPC	JCB	100	0	100		
07/31/00	19	TEC	FPC	JCB1	100	0	100		
07/31/00	20	TEC	FPC	JCB	100	0	100		
07/31/00	20	TEC	FPC	JCB1	100	0	100		
07/31/00	21	TEC	FPC	JCB	100	0	100		
07/31/00	21	TEC	FPC	JCB1	100	0	100		

SCHEDULE A7 JULY 2000
DETAIL OF FLORIDA POWER CORP.

	A7	DETAIL	VARIANCE	EXPLANATION
MWH - JA	742	742	0	
MWH - JC	8,985	8,985	0	
FUEL - JA	$33,065.00	$33,065.00	$0.00	
FUEL - JC	$417,772.00	$417,772.00	$0.00	
TRANSMISSION	$0.00	$0.00	$0.00	
ADJUSTMENT	$0.00	$0.00	$0.00	
TOTAL	**$450,837.00**	**$450,837.00**	**$0.00**	

SCHEDULE A7 JULY 2000
DETAIL OF FLORIDA POWER & LIGHT

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/12/2000	12	TEC	FPL	JAH	50	50	0	[redacted]	
07/12/2000	14	TEC	FPL	JAH	60	60	0		
07/12/2000	15	TEC	FPL	JAH	37	37	0		
07/13/2000	22	TEC	FPL	JAH	315	76	239		
07/14/2000	12	TEC	FPL	JAH	36	0	36		
07/14/2000	13	TEC	FPL	JAH	100	81	19		
07/17/2000	13	TEC	FPL	JAH	160	160	0		
07/17/2000	14	TEC	FPL	JAH	300	200	100		
07/17/2000	15	TEC	FPL	JAH	300	55	245		
07/17/2000	16	TEC	FPL	JAH	250	14	236		
07/17/2000	17	TEC	FPL	JAH	175	15	160		
07/17/2000	18	TEC	FPL	JAH	89	0	89		
07/17/2000	19	TEC	FPL	JAH	164	104	60		
07/17/2000	20	TEC	FPL	JAH	125	125	0		
07/19/2000	14	TEC	FPL	JAH	75	62	13		
07/19/2000	15	TEC	FPL	JAH	50	27	23		
07/19/2000	16	TEC	FPL	JAH	13	0	13		
07/20/2000	12	TEC	FPL	JAH	15	0	15		
07/21/2000	12	TEC	FPL	JAH	48	48	0		
07/21/2000	14	TEC	FPL	JAH	100	29	71		
07/25/2000	15	TEC	FPL	JAH	69	69	0		
07/25/2000	16	TEC	FPL	JAH	76	9	67		
07/25/2000	17	TEC	FPL	JAH	19	19	0		
07/27/2000	20	TEC	FPL	JAH	50	0	50		
07/27/2000	21	TEC	FPL	JAH	184	184	0		
07/27/2000	22	TEC	FPL	JAH	34	34	0		
07/30/2000	16	TEC	FPL	JAH	87	87	0		
07/03/2000	17	TEC	FPL	JCH	40	0	40	[redacted]	
07/03/2000	19	TEC	FPL	JCH	75	0	75		
07/03/2000	21	TEC	FPL	JCH	75	0	75		
07/06/2000	1	TEC	FPL	JCH	100	0	100		
07/06/2000	2	TEC	FPL	JCH	100	0	100		
07/08/2000	10	TEC	FPL	JCH	100	0	100		
07/08/2000	11	TEC	FPL	JCH	100	0	100		
07/08/2000	12	TEC	FPL	JCH	100	0	100		
07/09/2000	14	TEC	FPL	JCH	100	0	100		
07/09/2000	17	TEC	FPL	JCH	75	0	75		
07/09/2000	18	TEC	FPL	JCH	150	0	150		
07/09/2000	19	TEC	FPL	JCH	150	0	150		
07/11/2000	23	TEC	FPL	JCH	200	0	200		
07/11/2000	23	TEC	FPL	JCH1	100	0	100		
07/11/2000	24	TEC	FPL	JCH	300	0	300		
07/12/2000	1	TEC	FPL	JCH	200	0	200		
07/12/2000	10	TEC	FPL	JCH	200	0	200		
07/12/2000	11	TEC	FPL	JCH	200	0	200		
07/12/2000	22	TEC	FPL	JCH	200	0	200		
07/12/2000	23	TEC	FPL	JCH	200	0	200		
07/12/2000	24	TEC	FPL	JCH	200	0	200		
07/13/2000	1	TEC	FPL	JCH	200	0	200		
07/13/2000	2	TEC	FPL	JCH	200	0	200		
07/13/2000	3	TEC	FPL	JCH	200	0	200		
07/13/2000	4	TEC	FPL	JCH	100	0	100		
07/13/2000	22	TEC	FPL	JCH	35	0	35		

SCHEDULE A7 JULY 2000
DETAIL OF FLORIDA POWER & LIGHT

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/13/2000	23	TEC	FPL	JCH	350	0	350	[redacted]	[redacted]
07/13/2000	24	TEC	FPL	JCH	250	0	250		
07/14/2000	1	TEC	FPL	JCH	200	0	200		
07/14/2000	10	TEC	FPL	JCH	225	0	225		
07/14/2000	11	TEC	FPL	JCH	325	0	325		
07/14/2000	12	TEC	FPL	JCH	114	0	114		
07/16/2000	23	TEC	FPL	JCH	150	0	150		
07/16/2000	24	TEC	FPL	JCH	100	0	100		
07/17/2000	11	TEC	FPL	JCH	200	0	200		
07/17/2000	18	TEC	FPL	JCH	11	0	11		
07/17/2000	19	TEC	FPL	JCH	86	0	86		
07/17/2000	21	TEC	FPL	JCH	100	0	100		
07/17/2000	24	TEC	FPL	JCH	150	0	150		
07/18/2000	1	TEC	FPL	JCH	100	0	100		
07/18/2000	2	TEC	FPL	JCH	100	0	100		
07/18/2000	3	TEC	FPL	JCH	25	0	25		
07/18/2000	4	TEC	FPL	JCH	75	0	75		
07/18/2000	5	TEC	FPL	JCH	50	0	50		
07/18/2000	8	TEC	FPL	JCH	100	0	100		
07/18/2000	9	TEC	FPL	JCH	100	0	100		
07/18/2000	10	TEC	FPL	JCH	100	0	100		
07/18/2000	21	TEC	FPL	JCH	100	0	100		
07/18/2000	22	TEC	FPL	JCH	150	0	150		
07/18/2000	23	TEC	FPL	JCH	50	0	50		
07/18/2000	24	TEC	FPL	JCH	150	0	150		
07/18/2000	24	TEC	FPL	JCH1	150	0	150		
07/19/2000	1	TEC	FPL	JCH	300	0	300		
07/19/2000	2	TEC	FPL	JCH	150	0	150		
07/19/2000	24	TEC	FPL	JCH	200	0	200		
07/20/2000	1	TEC	FPL	JCH	200	0	200		
07/20/2000	2	TEC	FPL	JCH	100	0	100		
07/20/2000	11	TEC	FPL	JCH	100	0	100		
07/20/2000	12	TEC	FPL	JCH	35	0	35		
07/20/2000	23	TEC	FPL	JCH	150	0	150		
07/20/2000	24	TEC	FPL	JCH	200	0	200		
07/21/2000	1	TEC	FPL	JCH	150	0	150		
07/21/2000	2	TEC	FPL	JCH	100	0	100		
07/21/2000	10	TEC	FPL	JCH	100	0	100		
07/21/2000	11	TEC	FPL	JCH	100	0	100		
07/21/2000	11	TEC	FPL	JCH1	100	0	100		
07/21/2000	12	TEC	FPL	JCH	2	0	2		
07/21/2000	13	TEC	FPL	JCH	15	0	15		
07/23/2000	12	TEC	FPL	JCH	125	0	125		
07/23/2000	13	TEC	FPL	JCH	140	0	140		
07/23/2000	14	TEC	FPL	JCH	100	0	100		
07/25/2000	4	TEC	FPL	JCH	200	0	200		
07/25/2000	5	TEC	FPL	JCH	50	0	50		
07/25/2000	15	TEC	FPL	JCH	31	0	31		
07/25/2000	16	TEC	FPL	JCH	24	0	24		
07/25/2000	17	TEC	FPL	JCH	81	0	81		
07/26/2000	22	TEC	FPL	JCH	100	0	100		
07/27/2000	21	TEC	FPL	JCH	16	0	16		
07/27/2000	22	TEC	FPL	JCH	166	0	166		
07/27/2000	23	TEC	FPL	JCH	350	0	350		

SCHEDULE A7 JULY 2000
DETAIL OF FLORIDA POWER & LIGHT

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/27/2000	24	TEC	FPL	JCH	150	0	150	[redacted]	[redacted]
07/28/2000	1	TEC	FPL	JCH	100	0	100		
07/28/2000	2	TEC	FPL	JCH	25	0	25		
07/28/2000	3	TEC	FPL	JCH	50	0	50		
07/28/2000	11	TEC	FPL	JCH	300	0	300		
07/28/2000	12	TEC	FPL	JCH	300	0	300		
07/30/2000	11	TEC	FPL	JCH	100	0	100		
07/30/2000	12	TEC	FPL	JCH	250	0	250		
07/30/2000	13	TEC	FPL	JCH	250	0	250		
07/30/2000	14	TEC	FPL	JCH	250	0	250		
07/30/2000	16	TEC	FPL	JCH	63	0	63		
07/30/2000	17	TEC	FPL	JCH	75	0	75		
07/30/2000	18	TEC	FPL	JCH	50	0	50		
07/30/2000	19	TEC	FPL	JCH	50	0	50		
07/31/2000	12	TEC	FPL	JCH	75	0	75		
07/31/2000	22	TEC	FPL	JCH	50	0	50		

SCHEDULE A7 JULY 2000
DETAIL OF FLORIDA POWER & LIGHT

	A7	DETAIL	VARIANCE	EXPLANATION
MWH - JA	2,981	2,981	0	
MWH - JC	12,734	12,734	0	
FUEL - JA	$154,768.35	$154,768.35	$0.00	
FUEL - JC	$698,481.00	$698,481.00	$0.00	
TRANSMISSION	$0.00	$0.00	$0.00	
ADJUSTMENT	$0.00	$0.00	$0.00	
TOTAL	$853,249.35	$853,249.35	$0.00	

SCHEDULE A7 JULY 2000
DETAIL OF CITY OF LAKELAND

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/13/2000	18	TEC	LAKELAND	JAH	165	0	165	[redacted]	
07/13/2000	19	TEC	LAKELAND	JAH	200	0	200		
07/13/2000	20	TEC	LAKELAND	JAH	290	0	290		
07/13/2000	21	TEC	LAKELAND	JAH	350	79	271		
07/14/2000	10	TEC	LAKELAND	JAH	67	67	0		
07/14/2000	11	TEC	LAKELAND	JAH	217	89	128		
07/14/2000	12	TEC	LAKELAND	JAB	100	85	15		
07/14/2000	13	TEC	LAKELAND	JAB	100	0	100		
07/14/2000	14	TEC	LAKELAND	JAB	100	0	100		
07/14/2000	15	TEC	LAKELAND	JAB	100	0	100		
07/14/2000	15	TEC	LAKELAND	JAH	70	0	70		
07/14/2000	16	TEC	LAKELAND	JAB	100	0	100		
07/14/2000	16	TEC	LAKELAND	JAH	15	0	15		
07/14/2000	17	TEC	LAKELAND	JAB	100	0	100		
07/14/2000	17	TEC	LAKELAND	JAH	40	0	40		
07/17/2000	16	TEC	LAKELAND	JAH	150	150	0		
07/17/2000	17	TEC	LAKELAND	JAH	150	150	0		
07/17/2000	18	TEC	LAKELAND	JAH	150	150	0		
07/18/2000	15	TEC	LAKELAND	JAH	50	50	0		
07/18/2000	16	TEC	LAKELAND	JAH	100	100	0		
07/18/2000	17	TEC	LAKELAND	JAH	150	150	0		
07/18/2000	18	TEC	LAKELAND	JAH	150	86	64		
07/18/2000	19	TEC	LAKELAND	JAH	122	122	0		
07/19/2000	13	TEC	LAKELAND	JAH	100	42	58		
07/19/2000	14	TEC	LAKELAND	JAH	75	0	75		
07/19/2000	16	TEC	LAKELAND	JAH1	75	75	0		
07/19/2000	17	TEC	LAKELAND	JAH	75	38	37		
07/19/2000	18	TEC	LAKELAND	JAH	100	25	75		
07/19/2000	19	TEC	LAKELAND	JAH	100	100	0		
07/19/2000	20	TEC	LAKELAND	JAH	128	40	88		
07/20/2000	11	TEC	LAKELAND	JAH	200	184	16		
07/20/2000	12	TEC	LAKELAND	JAH	220	166	54		
07/20/2000	13	TEC	LAKELAND	JAH	200	166	34		
07/20/2000	14	TEC	LAKELAND	JAH	200	132	68		
07/20/2000	15	TEC	LAKELAND	JAH	125	22	103		
07/20/2000	16	TEC	LAKELAND	JAH	150	5	145		
07/20/2000	17	TEC	LAKELAND	JAH	150	3	147		
07/20/2000	18	TEC	LAKELAND	JAH	150	46	104		
07/20/2000	19	TEC	LAKELAND	JAH	150	99	51		
07/20/2000	20	TEC	LAKELAND	JAH	150	66	84		
07/21/2000	13	TEC	LAKELAND	JAH	200	50	150		
07/21/2000	15	TEC	LAKELAND	JAH	62	22	40		
07/25/2000	14	TEC	LAKELAND	JAH	89	89	0		
07/25/2000	15	TEC	LAKELAND	JAH	150	150	0		
07/25/2000	16	TEC	LAKELAND	JAH	200	200	0		
07/25/2000	17	TEC	LAKELAND	JAH	150	150	0		
07/27/2000	14	TEC	LAKELAND	JAH	96	96	0		
07/27/2000	15	TEC	LAKELAND	JAH	244	92	152		
07/27/2000	16	TEC	LAKELAND	JAB	250	119	131		
07/27/2000	16	TEC	LAKELAND	JAH	50	50	0		
07/27/2000	17	TEC	LAKELAND	JAB	250	174	76		
07/27/2000	17	TEC	LAKELAND	JAH	100	0	100		
07/27/2000	18	TEC	LAKELAND	JAB	200	0	200		
07/27/2000	18	TEC	LAKELAND	JAH	200	189	11		

SCHEDULE A7 JULY 2000
DETAIL OF CITY OF LAKELAND

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/27/2000	19	TEC	LAKELAND	JAH	400	203	197	[redacted]	
07/27/2000	20	TEC	LAKELAND	JAH	250	206	44		
07/28/2000	12	TEC	LAKELAND	JAB	100	100	0		
07/28/2000	12	TEC	LAKELAND	JAH	32	32	0		
07/28/2000	13	TEC	LAKELAND	JAB	100	100	0		
07/28/2000	14	TEC	LAKELAND	JAB	100	100	0		
07/28/2000	14	TEC	LAKELAND	JAH	50	0	50		
07/28/2000	15	TEC	LAKELAND	JAB	100	100	0		
07/28/2000	15	TEC	LAKELAND	JAH	100	0	100		
07/28/2000	16	TEC	LAKELAND	JAB	100	100	0		
07/28/2000	16	TEC	LAKELAND	JAH	50	50	0		
07/28/2000	17	TEC	LAKELAND	JAB	100	32	68		
07/28/2000	17	TEC	LAKELAND	JAH	85	85	0		
07/28/2000	18	TEC	LAKELAND	JAB	100	100	0		
07/28/2000	19	TEC	LAKELAND	JAB	100	100	0		
07/30/2000	13	TEC	LAKELAND	JAB	30	30	0		
07/30/2000	14	TEC	LAKELAND	JAB	200	200	0		
07/30/2000	15	TEC	LAKELAND	JAB	152	152	0		
07/30/2000	16	TEC	LAKELAND	JAB	200	200	0		
07/30/2000	17	TEC	LAKELAND	JAB	137	137	0		
07/31/2000	15	TEC	LAKELAND	JAH	69	69	0		
07/31/2000	16	TEC	LAKELAND	JAH	50	50	0		
07/09/2000	16	TEC	LAKELAND	JCH	125	0	125	[redacted]	
07/09/2000	17	TEC	LAKELAND	JCH	125	0	125		
07/13/2000	18	TEC	LAKELAND	JCH	35	0	35		
07/13/2000	20	TEC	LAKELAND	JCH	10	0	10		
07/14/2000	8	TEC	LAKELAND	JCH	200	0	200		
07/14/2000	9	TEC	LAKELAND	JCH	300	0	300		
07/14/2000	10	TEC	LAKELAND	JCH	283	0	283		
07/14/2000	11	TEC	LAKELAND	JCH	133	0	133		
07/14/2000	12	TEC	LAKELAND	JCH	110	0	110		
07/14/2000	13	TEC	LAKELAND	JCH	100	0	100		
07/14/2000	14	TEC	LAKELAND	JCH	100	0	100		
07/14/2000	15	TEC	LAKELAND	JCH	130	0	130		
07/14/2000	16	TEC	LAKELAND	JCH	85	0	85		
07/14/2000	17	TEC	LAKELAND	JCH	110	0	110		
07/14/2000	18	TEC	LAKELAND	JCB	100	0	100		
07/14/2000	18	TEC	LAKELAND	JCH	150	0	150		
07/14/2000	19	TEC	LAKELAND	JCB	100	0	100		
07/14/2000	19	TEC	LAKELAND	JCH	120	0	120		
07/14/2000	20	TEC	LAKELAND	JCH	175	0	175		
07/14/2000	21	TEC	LAKELAND	JCH	300	0	300		
07/18/2000	19	TEC	LAKELAND	JCH	28	0	28		
07/18/2000	20	TEC	LAKELAND	JCH	150	0	150		
07/19/2000	12	TEC	LAKELAND	JCH	150	0	150		
07/19/2000	13	TEC	LAKELAND	JCH	50	0	50		
07/19/2000	20	TEC	LAKELAND	JCH	22	0	22		
07/19/2000	21	TEC	LAKELAND	JCH	113	0	113		
07/19/2000	22	TEC	LAKELAND	JCH	100	0	100		
07/19/2000	23	TEC	LAKELAND	JCH	100	0	100		
07/19/2000	24	TEC	LAKELAND	JCH	200	0	200		
07/20/2000	1	TEC	LAKELAND	JCH	100	0	100		
07/20/2000	10	TEC	LAKELAND	JCH	130	0	130		

SCHEDULE A7 JULY 2000
DETAIL OF CITY OF LAKELAND

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/20/2000	21	TEC	LAKELAND	JCH	170	0	170	[redacted]	
07/20/2000	22	TEC	LAKELAND	JCH	75	0	75		
07/21/2000	12	TEC	LAKELAND	JCH	100	0	100		
07/25/2000	12	TEC	LAKELAND	JCH	75	0	75		
07/25/2000	13	TEC	LAKELAND	JCH	200	0	200		
07/25/2000	14	TEC	LAKELAND	JCH	161	0	161		
07/25/2000	18	TEC	LAKELAND	JCH	250	0	250		
07/25/2000	19	TEC	LAKELAND	JCH	150	0	150		
07/26/2000	15	TEC	LAKELAND	JCH	200	0	200		
07/26/2000	16	TEC	LAKELAND	JCH1	67	0	67		
07/26/2000	17	TEC	LAKELAND	JCH1	50	0	50		
07/26/2000	21	TEC	LAKELAND	JCH	17	0	17		
07/26/2000	22	TEC	LAKELAND	JCH	50	0	50		
07/27/2000	12	TEC	LAKELAND	JCH	75	0	75		
07/27/2000	13	TEC	LAKELAND	JCH	150	0	150		
07/27/2000	14	TEC	LAKELAND	JCH	4	0	4		
07/27/2000	15	TEC	LAKELAND	JCH	6	0	6		
07/27/2000	24	TEC	LAKELAND	JCH	150	0	150		
07/28/2000	1	TEC	LAKELAND	JCH	100	0	100		
07/28/2000	12	TEC	LAKELAND	JCH	18	0	18		
07/28/2000	13	TEC	LAKELAND	JCH	50	0	50		
07/29/2000	12	TEC	LAKELAND	JCH	150	0	150		
07/29/2000	13	TEC	LAKELAND	JCB	200	0	200		
07/29/2000	14	TEC	LAKELAND	JCB	200	0	200		
07/29/2000	14	TEC	LAKELAND	JCH	20	0	20		
07/29/2000	15	TEC	LAKELAND	JCB	200	0	200		
07/29/2000	16	TEC	LAKELAND	JCB	200	0	200		
07/29/2000	17	TEC	LAKELAND	JCB	200	0	200		
07/29/2000	18	TEC	LAKELAND	JCB	200	0	200		
07/29/2000	19	TEC	LAKELAND	JCB	200	0	200		
07/29/2000	20	TEC	LAKELAND	JCB	200	0	200		
07/30/2000	13	TEC	LAKELAND	JCB	170	0	170		
07/30/2000	15	TEC	LAKELAND	JCB	48	0	48		
07/30/2000	17	TEC	LAKELAND	JCB	63	0	63		
07/30/2000	18	TEC	LAKELAND	JCB	200	0	200		
07/30/2000	19	TEC	LAKELAND	JCB	200	0	200		
07/30/2000	20	TEC	LAKELAND	JCB	200	0	200		
07/31/2000	12	TEC	LAKELAND	JCH	50	0	50		
07/31/2000	13	TEC	LAKELAND	JCH	50	0	50		
07/31/2000	14	TEC	LAKELAND	JCH	100	0	100		
07/31/2000	15	TEC	LAKELAND	JCH	31	0	31		

SCHEDULE A7 JULY 2000
DETAIL OF CITY OF LAKELAND

	A7	DETAIL	VARIANCE	EXPLANATION
MWH - JA	10,230	10,230	0	
MWH - JC	8,934	8,934	0	
FUEL - JA	$901,318.51	$901,318.63	$0.12	Rounding
FUEL - JC	$641,117.50	$641,117.50	$0.00	
TRANSMISSION	$0.00	$0.00	$0.00	
ADJUSTMENT	$0.00	$0.00	$0.00	
TOTAL	**$1,542,436.01**	**$1,542,436.13**	**$0.12**	**Rounding**

SCHEDULE A7 JULY 2000
DETAIL OF ORLANDO

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/14/2000	13	TEC	ORLANDO	JAB	100	0	100	[redacted]	
07/14/2000	14	TEC	ORLANDO	JAB	150	77	73		
07/14/2000	15	TEC	ORLANDO	JAB	100	72	28		
07/14/2000	16	TEC	ORLANDO	JAB	150	71	79		
07/14/2000	17	TEC	ORLANDO	JAB	150	73	77		
07/14/2000	18	TEC	ORLANDO	JAB	137	80	57		
07/14/2000	19	TEC	ORLANDO	JAB	82	72	10		
07/17/2000	13	TEC	ORLANDO	JAH	145	38	107		
07/17/2000	14	TEC	ORLANDO	JAH	39	0	39		
07/17/2000	15	TEC	ORLANDO	JAH	124	124	0		
07/17/2000	20	TEC	ORLANDO	JAH	54	4	50		
07/19/2000	12	TEC	ORLANDO	JAB	39	39	0		
07/19/2000	13	TEC	ORLANDO	JAB	100	100	0		
07/19/2000	14	TEC	ORLANDO	JAB	100	100	0		
07/19/2000	15	TEC	ORLANDO	JAB	100	100	0		
07/19/2000	16	TEC	ORLANDO	JAB	100	97	3		
07/19/2000	17	TEC	ORLANDO	JAB	100	0	100		
07/19/2000	18	TEC	ORLANDO	JAB	100	0	100		
07/19/2000	19	TEC	ORLANDO	JAB	18	7	11		
07/19/2000	20	TEC	ORLANDO	JAB	100	100	0		
07/20/2000	11	TEC	ORLANDO	JAB	45	0	45		
07/20/2000	12	TEC	ORLANDO	JAB	100	0	100		
07/20/2000	13	TEC	ORLANDO	JAB	127	0	127		
07/20/2000	14	TEC	ORLANDO	JAB	171	0	171		
07/20/2000	15	TEC	ORLANDO	JAB	200	0	200		
07/20/2000	16	TEC	ORLANDO	JAB	200	0	200		
07/20/2000	17	TEC	ORLANDO	JAB	200	0	200		
07/20/2000	18	TEC	ORLANDO	JAB	140	0	140		
07/20/2000	19	TEC	ORLANDO	JAB	90	0	90		
07/20/2000	20	TEC	ORLANDO	JAB	15	0	15		
07/20/2000	21	TEC	ORLANDO	JAB	3	3	0		
07/21/2000	11	TEC	ORLANDO	JAB	20	20	0		
07/21/2000	12	TEC	ORLANDO	JAB	100	100	0		
07/21/2000	13	TEC	ORLANDO	JAB	99	99	0		
07/21/2000	14	TEC	ORLANDO	JAB	100	100	0		
07/21/2000	15	TEC	ORLANDO	JAB	100	100	0		
07/21/2000	16	TEC	ORLANDO	JAB	100	100	0		
07/21/2000	17	TEC	ORLANDO	JAB	3	3	0		
07/03/2000	13	TEC	ORLANDO	JCB	100	0	100	[redacted]	
07/03/2000	14	TEC	ORLANDO	JCB	100	0	100		
07/03/2000	15	TEC	ORLANDO	JCB	100	0	100		
07/03/2000	16	TEC	ORLANDO	JCB	100	0	100		
07/03/2000	17	TEC	ORLANDO	JCB	100	0	100		
07/03/2000	18	TEC	ORLANDO	JCH	125	0	125		
07/03/2000	19	TEC	ORLANDO	JCH	50	0	50		
07/03/2000	20	TEC	ORLANDO	JCH	100	0	100		
07/03/2000	21	TEC	ORLANDO	JCH	125	0	125		
07/03/2000	22	TEC	ORLANDO	JCH	100	0	100		
07/03/2000	23	TEC	ORLANDO	JCH	100	0	100		
07/13/2000	10	TEC	ORLANDO	JCH	200	0	200		
07/13/2000	11	TEC	ORLANDO	JCH	100	0	100		
07/13/2000	12	TEC	ORLANDO	JCH	50	0	50		
07/14/2000	13	TEC	ORLANDO	JCB	50	0	50		

SCHEDULE A7 JULY 2000
DETAIL OF ORLANDO

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/14/2000	15	TEC	ORLANDO	JCB	50	0	50	[redacted]	
07/14/2000	18	TEC	ORLANDO	JCB	13	0	13		
07/14/2000	19	TEC	ORLANDO	JCB	68	0	68		
07/14/2000	20	TEC	ORLANDO	JCB	150	0	150		
07/15/2000	11	TEC	ORLANDO	JCB	250	0	250		
07/15/2000	12	TEC	ORLANDO	JCB	250	0	250		
07/15/2000	13	TEC	ORLANDO	JCB	250	0	250		
07/15/2000	14	TEC	ORLANDO	JCB	250	0	250		
07/15/2000	15	TEC	ORLANDO	JCB	250	0	250		
07/15/2000	16	TEC	ORLANDO	JCB	250	0	250		
07/15/2000	17	TEC	ORLANDO	JCB	250	0	250		
07/15/2000	18	TEC	ORLANDO	JCB	250	0	250		
07/15/2000	19	TEC	ORLANDO	JCB	250	0	250		
07/15/2000	20	TEC	ORLANDO	JCB	250	0	250		
07/15/2000	21	TEC	ORLANDO	JCB	250	0	250		
07/15/2000	22	TEC	ORLANDO	JCB	250	0	250		
07/16/2000	11	TEC	ORLANDO	JCB	250	0	250		
07/16/2000	12	TEC	ORLANDO	JCB	250	0	250		
07/16/2000	13	TEC	ORLANDO	JCB	250	0	250		
07/16/2000	14	TEC	ORLANDO	JCB	250	0	250		
07/16/2000	15	TEC	ORLANDO	JCB	250	0	250		
07/16/2000	16	TEC	ORLANDO	JCB	250	0	250		
07/16/2000	17	TEC	ORLANDO	JCB	250	0	250		
07/16/2000	18	TEC	ORLANDO	JCB	250	0	250		
07/16/2000	19	TEC	ORLANDO	JCB	250	0	250		
07/16/2000	20	TEC	ORLANDO	JCB	250	0	250		
07/16/2000	21	TEC	ORLANDO	JCB	250	0	250		
07/16/2000	22	TEC	ORLANDO	JCB	250	0	250		
07/17/2000	12	TEC	ORLANDO	JCH	75	0	75		
07/17/2000	13	TEC	ORLANDO	JCH	55	0	55		
07/17/2000	14	TEC	ORLANDO	JCH	36	0	36		
07/17/2000	15	TEC	ORLANDO	JCH	26	0	26		
07/17/2000	20	TEC	ORLANDO	JCH	96	0	96		
07/18/2000	19	TEC	ORLANDO	JCH	50	0	50		
07/19/2000	11	TEC	ORLANDO	JCB	100	0	100		
07/19/2000	12	TEC	ORLANDO	JCB	61	0	61		
07/19/2000	19	TEC	ORLANDO	JCB	82	0	82		
07/19/2000	21	TEC	ORLANDO	JCB	100	0	100		
07/19/2000	22	TEC	ORLANDO	JCB	100	0	100		
07/20/2000	8	TEC	ORLANDO	JCB	100	0	100		
07/20/2000	9	TEC	ORLANDO	JCB	100	0	100		
07/20/2000	10	TEC	ORLANDO	JCB	100	0	100		
07/20/2000	11	TEC	ORLANDO	JCB	55	0	55		
07/20/2000	13	TEC	ORLANDO	JCB	73	0	73		
07/20/2000	14	TEC	ORLANDO	JCB	29	0	29		
07/20/2000	18	TEC	ORLANDO	JCB	60	0	60		
07/20/2000	19	TEC	ORLANDO	JCB	110	0	110		
07/20/2000	20	TEC	ORLANDO	JCB	185	0	185		
07/20/2000	21	TEC	ORLANDO	JCB	197	0	197		
07/20/2000	22	TEC	ORLANDO	JCB	100	0	100		
07/20/2000	23	TEC	ORLANDO	JCB	100	0	100		
07/21/2000	8	TEC	ORLANDO	JCB	100	0	100		
07/21/2000	9	TEC	ORLANDO	JCB	100	0	100		
07/21/2000	10	TEC	ORLANDO	JCB	100	0	100		

SCHEDULE A7 JULY 2000
DETAIL OF ORLANDO

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/21/2000	11	TEC	ORLANDO	JCB	80	0	80	[redacted]	
07/21/2000	13	TEC	ORLANDO	JCB	1	0	1		
07/21/2000	17	TEC	ORLANDO	JCB	97	0	97		
07/21/2000	18	TEC	ORLANDO	JCB	100	0	100		
07/21/2000	19	TEC	ORLANDO	JCB	100	0	100		
07/21/2000	20	TEC	ORLANDO	JCB	100	0	100		
07/21/2000	21	TEC	ORLANDO	JCB	100	0	100		
07/21/2000	22	TEC	ORLANDO	JCB	100	0	100		
07/21/2000	23	TEC	ORLANDO	JCB	100	0	100		
07/22/2000	8	TEC	ORLANDO	JCB	100	0	100		
07/22/2000	9	TEC	ORLANDO	JCB	100	0	100		
07/22/2000	10	TEC	ORLANDO	JCB	100	0	100		
07/22/2000	11	TEC	ORLANDO	JCB	100	0	100		
07/22/2000	12	TEC	ORLANDO	JCB	100	0	100		
07/22/2000	13	TEC	ORLANDO	JCB	100	0	100		
07/22/2000	14	TEC	ORLANDO	JCB	100	0	100		
07/22/2000	15	TEC	ORLANDO	JCB	100	0	100		
07/22/2000	16	TEC	ORLANDO	JCB	100	0	100		
07/22/2000	17	TEC	ORLANDO	JCB	100	0	100		
07/22/2000	18	TEC	ORLANDO	JCB	100	0	100		
07/22/2000	19	TEC	ORLANDO	JCB	100	0	100		
07/22/2000	20	TEC	ORLANDO	JCB	100	0	100		
07/22/2000	21	TEC	ORLANDO	JCB	100	0	100		
07/22/2000	22	TEC	ORLANDO	JCB	100	0	100		
07/22/2000	23	TEC	ORLANDO	JCB	100	0	100		
07/23/2000	8	TEC	ORLANDO	JCB	100	0	100		
07/23/2000	9	TEC	ORLANDO	JCB	100	0	100		
07/23/2000	10	TEC	ORLANDO	JCB	100	0	100		
07/23/2000	11	TEC	ORLANDO	JCB	100	0	100		
07/23/2000	12	TEC	ORLANDO	JCB	100	0	100		
07/23/2000	13	TEC	ORLANDO	JCB	100	0	100		
07/23/2000	14	TEC	ORLANDO	JCB	100	0	100		
07/23/2000	15	TEC	ORLANDO	JCB	100	0	100		
07/23/2000	16	TEC	ORLANDO	JCB	100	0	100		
07/23/2000	17	TEC	ORLANDO	JCB	100	0	100		
07/23/2000	18	TEC	ORLANDO	JCB	100	0	100		
07/23/2000	19	TEC	ORLANDO	JCB	100	0	100		
07/23/2000	20	TEC	ORLANDO	JCB	100	0	100		
07/23/2000	21	TEC	ORLANDO	JCB	100	0	100		
07/23/2000	22	TEC	ORLANDO	JCB	100	0	100		
07/23/2000	23	TEC	ORLANDO	JCB	100	0	100		
07/24/2000	8	TEC	ORLANDO	JCB	100	0	100		
07/24/2000	9	TEC	ORLANDO	JCB	100	0	100		
07/24/2000	10	TEC	ORLANDO	JCB	100	0	100		
07/24/2000	11	TEC	ORLANDO	JCB	100	0	100		
07/24/2000	12	TEC	ORLANDO	JCB	100	0	100		
07/24/2000	13	TEC	ORLANDO	JCB	100	0	100		
07/24/2000	14	TEC	ORLANDO	JCB	100	0	100		
07/24/2000	15	TEC	ORLANDO	JCB	100	0	100		
07/24/2000	16	TEC	ORLANDO	JCB	100	0	100		
07/24/2000	17	TEC	ORLANDO	JCB	100	0	100		
07/24/2000	18	TEC	ORLANDO	JCB	100	0	100		
07/24/2000	19	TEC	ORLANDO	JCB	100	0	100		
07/24/2000	20	TEC	ORLANDO	JCB	100	0	100		

SCHEDULE A7 JULY 2000
DETAIL OF ORLANDO

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/24/2000	21	TEC	ORLANDO	JCB	100	0	100	[redacted]	
07/24/2000	22	TEC	ORLANDO	JCB	100	0	100		
07/24/2000	23	TEC	ORLANDO	JCB	100	0	100		

SCHEDULE A7 JULY 2000
DETAIL OF ORLANDO

	A7	DETAIL	VARIANCE	EXPLANATION
MWH - JA	3,801	3,801	0	
MWH - JC	15,649	15,649	0	
FUEL - JA	$236,202.88	$236,202.88	($0.01)	Rounding
FUEL - JC	$1,395,097.50	$1,395,097.50	$0.00	
TRANSMISSION	$0.00	$0.00	$0.00	
ADJUSTMENT	$0.00	$0.00	$0.00	
TOTAL	**$1,631,300.38**	**$1,631,300.38**	**($0.01)**	**Rounding**

SCHEDULE A7 JULY 2000
DETAIL OF ENTERGY MARKETING

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/03/2000	12	TEC	ENTERGY	JCB	68	0	68	[redacted]	
07/03/2000	13	TEC	ENTERGY	JCB	69	0	69		
07/03/2000	14	TEC	ENTERGY	JCB	68	0	68		
07/03/2000	15	TEC	ENTERGY	JCB	68	0	68		

SCHEDULE A7 JULY 2000
DETAIL OF ENTERGY MARKETING

	A7	DETAIL	VARIANCE	EXPLANATION
MWH - JA	0	0	0	
MWH - JC	273	273	0	
FUEL - JA	$0.00	$0.00	$0.00	
FUEL - JC	$17,236.00	$17,236.00	$0.00	
TRANSMISSION	$0.00	$0.00	$0.00	
ADJUSTMENT	$0.00	$0.00	$0.00	
TOTAL	**$17,236.00**	**$17,236.00**	**$0.00**	

SCHEDULE A7 JULY 2000
DETAIL OF THE ENERGY AUTHORITY

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/12/2000	13	TEC	ENERGY AUTHORITY	JAH	49	3	46	[redacted]	
07/12/2000	13	TEC	ENERGY AUTHORITY	JAH2	3	0	3		
07/12/2000	14	TEC	ENERGY AUTHORITY	JAH	3	3	0		
07/12/2000	15	TEC	ENERGY AUTHORITY	JAH	10	37	(27)		
07/12/2000	15	TEC	ENERGY AUTHORITY	JAH2	68	0	68		
07/12/2000	16	TEC	ENERGY AUTHORITY	JAH	49	0	49		
07/12/2000	16	TEC	ENERGY AUTHORITY	JAH2	69	65	4		
07/12/2000	16	TEC	ENERGY AUTHORITY	JAH3	98	0	98		
07/12/2000	17	TEC	ENERGY AUTHORITY	JAH	49	0	49		
07/12/2000	17	TEC	ENERGY AUTHORITY	JAH2	69	0	69		
07/12/2000	17	TEC	ENERGY AUTHORITY	JAH3	98	63	35		
07/12/2000	18	TEC	ENERGY AUTHORITY	JAH	49	0	49		
07/12/2000	18	TEC	ENERGY AUTHORITY	JAH2	49	0	49		
07/12/2000	18	TEC	ENERGY AUTHORITY	JAH3	98	63	35		
07/12/2000	19	TEC	ENERGY AUTHORITY	JAH	49	0	49		
07/12/2000	19	TEC	ENERGY AUTHORITY	JAH2	49	0	49		
07/12/2000	19	TEC	ENERGY AUTHORITY	JAH3	98	63	35		
07/12/2000	20	TEC	ENERGY AUTHORITY	JAH	34	0	34		
07/12/2000	20	TEC	ENERGY AUTHORITY	JAH2	49	0	49		
07/12/2000	20	TEC	ENERGY AUTHORITY	JAH3	147	62	85		
07/12/2000	21	TEC	ENERGY AUTHORITY	JAH3	84	59	25		
07/13/2000	13	TEC	ENERGY AUTHORITY	JAB	56	56	0		
07/13/2000	14	TEC	ENERGY AUTHORITY	JAB	56	56	0		
07/13/2000	16	TEC	ENERGY AUTHORITY	JAB	95	83	12		
07/13/2000	18	TEC	ENERGY AUTHORITY	JAB	98	74	24		
07/13/2000	19	TEC	ENERGY AUTHORITY	JAB	98	72	26		
07/13/2000	20	TEC	ENERGY AUTHORITY	JAB	97	72	25		
07/14/2000	12	TEC	ENERGY AUTHORITY	JAB	25	0	25		
07/14/2000	14	TEC	ENERGY AUTHORITY	JAB	25	0	25		
07/14/2000	14	TEC	ENERGY AUTHORITY	JAB1	50	0	50		
07/14/2000	15	TEC	ENERGY AUTHORITY	JAB	25	0	25		
07/14/2000	15	TEC	ENERGY AUTHORITY	JAB1	50	0	50		
07/14/2000	16	TEC	ENERGY AUTHORITY	JAB	25	0	25		
07/14/2000	16	TEC	ENERGY AUTHORITY	JAB1	50	0	50		
07/14/2000	17	TEC	ENERGY AUTHORITY	JAB	25	0	25		
07/14/2000	17	TEC	ENERGY AUTHORITY	JAB1	50	0	50		
07/17/2000	16	TEC	ENERGY AUTHORITY	JAH2	22	0	22		
07/17/2000	17	TEC	ENERGY AUTHORITY	JAH2	57	0	57		
07/17/2000	18	TEC	ENERGY AUTHORITY	JAH2	98	38	60		
07/17/2000	19	TEC	ENERGY AUTHORITY	JAH2	98	98	0		
07/17/2000	20	TEC	ENERGY AUTHORITY	JAH2	73	73	0		
07/18/2000	15	TEC	ENERGY AUTHORITY	JAB	98	98	0		
07/18/2000	15	TEC	ENERGY AUTHORITY	JAB1	15	15	0		
07/18/2000	16	TEC	ENERGY AUTHORITY	JAB	63	63	0		
07/18/2000	16	TEC	ENERGY AUTHORITY	JAB1	97	21	76		
07/18/2000	17	TEC	ENERGY AUTHORITY	JAB1	98	27	71		
07/18/2000	18	TEC	ENERGY AUTHORITY	JAB1	98	98	0		
07/19/2000	15	TEC	ENERGY AUTHORITY	JAH	50	50	0		
07/20/2000	18	TEC	ENERGY AUTHORITY	JAB	49	0	49		
07/20/2000	19	TEC	ENERGY AUTHORITY	JAB	49	48	1		
07/20/2000	20	TEC	ENERGY AUTHORITY	JAB	49	48	1		
07/20/2000	21	TEC	ENERGY AUTHORITY	JAB	49	48	1		
07/21/2000	14	TEC	ENERGY AUTHORITY	JAH	16	0	16		
07/21/2000	15	TEC	ENERGY AUTHORITY	JAH	25	0	25		
07/28/2000	13	TEC	ENERGY AUTHORITY	JAB	25	25	0		
07/28/2000	13	TEC	ENERGY AUTHORITY	JAB1	47	15	32		
07/28/2000	13	TEC	ENERGY AUTHORITY	JAB2	98	98	0		
07/28/2000	14	TEC	ENERGY AUTHORITY	JAB	25	25	0		

SCHEDULE A7 JULY 2000
DETAIL OF THE ENERGY AUTHORITY

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/28/2000	14	TEC	ENERGY AUTHORITY	JAB1	47	0	47	[redacted]	
07/28/2000	14	TEC	ENERGY AUTHORITY	JAB2	98	96	2		
07/28/2000	15	TEC	ENERGY AUTHORITY	JAB	25	25	0		
07/28/2000	15	TEC	ENERGY AUTHORITY	JAB1	47	0	47		
07/28/2000	15	TEC	ENERGY AUTHORITY	JAB2	97	86	11		
07/28/2000	15	TEC	ENERGY AUTHORITY	JAH	98	0	98		
07/28/2000	16	TEC	ENERGY AUTHORITY	JAB	25	25	0		
07/28/2000	16	TEC	ENERGY AUTHORITY	JAB1	47	0	47		
07/28/2000	16	TEC	ENERGY AUTHORITY	JAB2	98	4	94		
07/28/2000	16	TEC	ENERGY AUTHORITY	JAH	29	29	0		
07/28/2000	17	TEC	ENERGY AUTHORITY	JAB	25	25	0		
07/28/2000	17	TEC	ENERGY AUTHORITY	JAB1	47	0	47		
07/28/2000	17	TEC	ENERGY AUTHORITY	JAB2	98	0	98		
07/28/2000	17	TEC	ENERGY AUTHORITY	JAH	36	36	0		
07/28/2000	18	TEC	ENERGY AUTHORITY	JAB	25	25	0		
07/28/2000	18	TEC	ENERGY AUTHORITY	JAB1	47	0	47		
07/28/2000	18	TEC	ENERGY AUTHORITY	JAB2	98	86	12		
07/28/2000	19	TEC	ENERGY AUTHORITY	JAB	5	5	0		
07/28/2000	19	TEC	ENERGY AUTHORITY	JAB1	47	24	23		
07/28/2000	19	TEC	ENERGY AUTHORITY	JAB2	98	98	0		
07/30/2000	14	TEC	ENERGY AUTHORITY	JAH	25	25	0		
07/03/2000	13	TEC	ENERGY AUTHORITY	JCB	47	0	47	[redacted]	
07/03/2000	14	TEC	ENERGY AUTHORITY	JCB	49	0	49		
07/03/2000	15	TEC	ENERGY AUTHORITY	JCB	49	0	49		
07/03/2000	16	TEC	ENERGY AUTHORITY	JCB	49	0	49		
07/03/2000	16	TEC	ENERGY AUTHORITY	JCH	59	0	59		
07/03/2000	17	TEC	ENERGY AUTHORITY	JCB	49	0	49		
07/03/2000	17	TEC	ENERGY AUTHORITY	JCH	59	0	59		
07/09/2000	21	TEC	ENERGY AUTHORITY	JCH	73	0	73		
07/09/2000	22	TEC	ENERGY AUTHORITY	JCH	73	0	73		
07/12/2000	10	TEC	ENERGY AUTHORITY	JCH	98	0	98		
07/12/2000	11	TEC	ENERGY AUTHORITY	JCH	98	0	98		
07/12/2000	13	TEC	ENERGY AUTHORITY	JCH1	25	0	25		
07/12/2000	13	TEC	ENERGY AUTHORITY	JCH2	36	0	36		
07/12/2000	14	TEC	ENERGY AUTHORITY	JCH	46	0	46		
07/12/2000	14	TEC	ENERGY AUTHORITY	JCH2	40	0	40		
07/12/2000	15	TEC	ENERGY AUTHORITY	JCH	15	0	15		
07/12/2000	20	TEC	ENERGY AUTHORITY	JCH	15	0	15		
07/12/2000	21	TEC	ENERGY AUTHORITY	JCH3	63	0	63		
07/13/2000	13	TEC	ENERGY AUTHORITY	JCB	42	0	42		
07/13/2000	14	TEC	ENERGY AUTHORITY	JCB	42	0	42		
07/13/2000	15	TEC	ENERGY AUTHORITY	JCB	97	0	97		
07/13/2000	16	TEC	ENERGY AUTHORITY	JCB	3	0	3		
07/13/2000	17	TEC	ENERGY AUTHORITY	JCB	98	0	98		
07/14/2000	8	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/14/2000	13	TEC	ENERGY AUTHORITY	JCB	25	0	25		
07/14/2000	13	TEC	ENERGY AUTHORITY	JCB1	50	0	50		
07/14/2000	13	TEC	ENERGY AUTHORITY	JCH	20	0	20		
07/14/2000	14	TEC	ENERGY AUTHORITY	JCH1	49	0	49		
07/14/2000	17	TEC	ENERGY AUTHORITY	JCH	25	0	25		
07/14/2000	18	TEC	ENERGY AUTHORITY	JCB	25	0	25		
07/14/2000	18	TEC	ENERGY AUTHORITY	JCB1	50	0	50		
07/14/2000	18	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/14/2000	19	TEC	ENERGY AUTHORITY	JCB	25	0	25		
07/14/2000	19	TEC	ENERGY AUTHORITY	JCB1	50	0	50		
07/14/2000	19	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/14/2000	20	TEC	ENERGY AUTHORITY	JCB1	50	0	50		

SCHEDULE A7 JULY 2000
DETAIL OF THE ENERGY AUTHORITY

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/17/2000	11	TEC	ENERGY AUTHORITY	JCH	49	0	49	[redacted]	
07/17/2000	12	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/17/2000	12	TEC	ENERGY AUTHORITY	JCH1	49	0	49		
07/17/2000	13	TEC	ENERGY AUTHORITY	JCH	39	0	39		
07/17/2000	14	TEC	ENERGY AUTHORITY	JCH	30	0	30		
07/17/2000	15	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/17/2000	16	TEC	ENERGY AUTHORITY	JCH	29	0	29		
07/17/2000	16	TEC	ENERGY AUTHORITY	JCH2	46	0	46		
07/17/2000	17	TEC	ENERGY AUTHORITY	JCH	10	0	10		
07/17/2000	17	TEC	ENERGY AUTHORITY	JCH2	41	0	41		
07/18/2000	1	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/18/2000	2	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/18/2000	3	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/18/2000	4	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/18/2000	5	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/18/2000	5	TEC	ENERGY AUTHORITY	JCH1	49	0	49		
07/18/2000	6	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/18/2000	6	TEC	ENERGY AUTHORITY	JCH1	49	0	49		
07/18/2000	14	TEC	ENERGY AUTHORITY	JCB	98	0	98		
07/18/2000	14	TEC	ENERGY AUTHORITY	JCB1	98	0	98		
07/18/2000	15	TEC	ENERGY AUTHORITY	JCB1	83	0	83		
07/18/2000	15	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/18/2000	19	TEC	ENERGY AUTHORITY	JCB1	98	0	98		
07/18/2000	20	TEC	ENERGY AUTHORITY	JCB1	98	0	98		
07/19/2000	2	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/19/2000	5	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/19/2000	6	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/20/2000	22	TEC	ENERGY AUTHORITY	JCB	49	0	49		
07/21/2000	10	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/21/2000	11	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/21/2000	12	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/21/2000	12	TEC	ENERGY AUTHORITY	JCH1	49	0	49		
07/21/2000	13	TEC	ENERGY AUTHORITY	JCH	49	0	49		
07/21/2000	14	TEC	ENERGY AUTHORITY	JCH	33	0	33		
07/28/2000	19	TEC	ENERGY AUTHORITY	JCB	20	0	20		
07/28/2000	20	TEC	ENERGY AUTHORITY	JCB	25	0	25		
07/28/2000	20	TEC	ENERGY AUTHORITY	JCB1	47	0	47		
07/28/2000	20	TEC	ENERGY AUTHORITY	JCB2	97	0	97		
07/30/2000	14	TEC	ENERGY AUTHORITY	JCH	15	0	15		
07/30/2000	15	TEC	ENERGY AUTHORITY	JCH	40	0	40		

SCHEDULE A7 JULY 2000
DETAIL OF THE ENERGY AUTHORITY

	A7	DETAIL	VARIANCE	EXPLANATION
MWH - JA	4,553	4,557	4	JC reclassified as JA
MWH - JC	3,770	3,766	-4	JC reclassified as JA
FUEL - JA	$280,897.22	$274,386.73	($6,510.49)	
FUEL - JC	$346,487.32	$341,291.00	($5,196.32)	
TRANSMISSION	$0.00	$11,634.80	$11,634.80	
ADJUSTMENT	$0.00	$0.00	$0.00	
TOTAL	**$627,384.54**	**$627,312.54**	**($72.00)**	

SCHEDULE A7 JULY 2000
DETAIL OF RELIANT

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/19/2000	17	TEC	RELIANT	JAH	15	15	0	[redacted]	
07/19/2000	18	TEC	RELIANT	JAH	15	15	0		
07/26/2000	22	TEC	RELIANT	JCH	75	0	75	[redacted]	

SCHEDULE A7 JULY 2000
DETAIL OF RELIANT

	A7	DETAIL	VARIANCE	EXPLANATION
MWH - JA	30	30	0	
MWH - JC	75	75	0	
FUEL - JA	$0.00	$0.00	$0.00	
FUEL - JC	$3,750.00	$3,750.00	$0.00	
TRANSMISSION	$0.00	$0.00	$0.00	
ADJUSTMENT	$0.00	$0.00	$0.00	
TOTAL	$3,750.00	$3,750.00	$0.00	

SCHEDULE A7 JULY 2000
DETAIL OF REEDY CREEK

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/21/2000	15	TEC	REEDY CREEK	JAH	6	0	6	[redacted]	
07/14/2000	22	TEC	REEDY CREEK	JCH	10	0	10	[redacted]	
07/14/2000	23	TEC	REEDY CREEK	JCH	15	0	15		
07/14/2000	24	TEC	REEDY CREEK	JCH	35	0	35		
07/21/2000	13	TEC	REEDY CREEK	JCH	10	0	10		
07/21/2000	14	TEC	REEDY CREEK	JCH	10	0	10		
07/21/2000	15	TEC	REEDY CREEK	JCH	4	0	4		

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SCHEDULE A7 JULY 2000
DETAIL OF REEDY CREEK

	A7	MARY'S	VARIANCE	EXPLANATION
MWH - JA	6	6	0	
MWH - JC	84	84	0	
FUEL - JA	$372.00	$372.00	$0.00	
FUEL - JC	$3,458.00	$3,458.00	$0.00	
TRANSMISSION	$0.00	$0.00	$0.00	
ADJUSTMENT	$0.00	$0.00	$0.00	
TOTAL	$3,830.00	$3,830.00	$0.00	

SCHEDULE A7 JULY 2000
DETAIL OF TALLAHASSEE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/12/2000	12	TEC	TALLAHASSEE	JAB	49	34	15		
07/12/2000	13	TEC	TALLAHASSEE	JAB	49	49	0		
07/12/2000	14	TEC	TALLAHASSEE	JAB	49	16	33		
07/12/2000	15	TEC	TALLAHASSEE	JAB	49	0	49		
07/12/2000	16	TEC	TALLAHASSEE	JAB	4	0	4		
07/12/2000	17	TEC	TALLAHASSEE	JAB	4	0	4		
07/12/2000	18	TEC	TALLAHASSEE	JAB	24	0	24		
07/12/2000	19	TEC	TALLAHASSEE	JAB	24	0	24		
07/20/2000	12	TEC	TALLAHASSEE	JAB	29	0	29		
07/20/2000	13	TEC	TALLAHASSEE	JAB	8	0	8		
07/20/2000	17	TEC	TALLAHASSEE	JAB	30	0	30		
07/20/2000	18	TEC	TALLAHASSEE	JAB	29	0	29		
07/20/2000	19	TEC	TALLAHASSEE	JAB	30	0	30		
07/20/2000	20	TEC	TALLAHASSEE	JAH	29	0	29		
07/21/2000	11	TEC	TALLAHASSEE	JAB	49	49	0		
07/21/2000	12	TEC	TALLAHASSEE	JAB	49	49	0		
07/21/2000	13	TEC	TALLAHASSEE	JAB	49	49	0		
07/21/2000	14	TEC	TALLAHASSEE	JAB	49	49	0		
07/21/2000	15	TEC	TALLAHASSEE	JAB	49	49	0		
07/21/2000	16	TEC	TALLAHASSEE	JAB	50	50	0		
07/21/2000	17	TEC	TALLAHASSEE	JAB	49	49	0		
07/28/2000	16	TEC	TALLAHASSEE	JAH	29	0	29		
07/28/2000	17	TEC	TALLAHASSEE	JAH	30	30	0		
07/08/2000	13	TEC	TALLAHASSEE	JCB	49	0	49		
07/08/2000	14	TEC	TALLAHASSEE	JCB	49	0	49		
07/08/2000	15	TEC	TALLAHASSEE	JCB	49	0	49		
07/08/2000	16	TEC	TALLAHASSEE	JCB	49	0	49		
07/08/2000	17	TEC	TALLAHASSEE	JCB	49	0	49		
07/08/2000	18	TEC	TALLAHASSEE	JCB	49	0	49		
07/08/2000	19	TEC	TALLAHASSEE	JCB	50	0	50		
07/08/2000	20	TEC	TALLAHASSEE	JCB	49	0	49		
07/12/2000	16	TEC	TALLAHASSEE	JCB	45	0	45		
07/12/2000	17	TEC	TALLAHASSEE	JCB	45	0	45		
07/12/2000	18	TEC	TALLAHASSEE	JCB	26	0	26		
07/12/2000	19	TEC	TALLAHASSEE	JCB	25	0	25		
07/13/2000	12	TEC	TALLAHASSEE	JCB	49	0	49		
07/13/2000	13	TEC	TALLAHASSEE	JCB	49	0	49		
07/13/2000	14	TEC	TALLAHASSEE	JCB	49	0	49		
07/14/2000	22	TEC	TALLAHASSEE	JCH	49	0	49		
07/14/2000	23	TEC	TALLAHASSEE	JCH	98	0	98		
07/16/2000	13	TEC	TALLAHASSEE	JCH	49	0	49		
07/20/2000	21	TEC	TALLAHASSEE	JCH	30	0	30		
07/21/2000	10	TEC	TALLAHASSEE	JCB	49	0	49		
07/21/2000	18	TEC	TALLAHASSEE	JCB	49	0	49		
07/21/2000	19	TEC	TALLAHASSEE	JCB	49	0	49		
07/21/2000	20	TEC	TALLAHASSEE	JCB	49	0	49		
07/21/2000	21	TEC	TALLAHASSEE	JCB	49	0	49		
07/22/2000	12	TEC	TALLAHASSEE	JCB	49	0	49		
07/22/2000	13	TEC	TALLAHASSEE	JCB	49	0	49		
07/22/2000	14	TEC	TALLAHASSEE	JCB	49	0	49		
07/22/2000	15	TEC	TALLAHASSEE	JCB	49	0	49		
07/22/2000	16	TEC	TALLAHASSEE	JCB	49	0	49		
07/22/2000	17	TEC	TALLAHASSEE	JCB	49	0	49		
07/22/2000	18	TEC	TALLAHASSEE	JCB	50	0	50		
07/22/2000	19	TEC	TALLAHASSEE	JCB	49	0	49		
07/23/2000	12	TEC	TALLAHASSEE	JCB	49	0	49		
07/23/2000	13	TEC	TALLAHASSEE	JCB	49	0	49		

SCHEDULE A7 JULY 2000
DETAIL OF TALLAHASSEE

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/23/2000	13	TEC	TALLAHASSEE	JCH	49	0	49	[redacted]	[redacted]
07/23/2000	14	TEC	TALLAHASSEE	JCB	49	0	49		
07/23/2000	15	TEC	TALLAHASSEE	JCB	49	0	49		
07/23/2000	16	TEC	TALLAHASSEE	JCB	49	0	49		
07/23/2000	17	TEC	TALLAHASSEE	JCB	49	0	49		
07/23/2000	18	TEC	TALLAHASSEE	JCB	50	0	50		
07/23/2000	19	TEC	TALLAHASSEE	JCB	49	0	49		
07/23/2000	21	TEC	TALLAHASSEE	JCH	49	0	49		
07/23/2000	22	TEC	TALLAHASSEE	JCH	98	0	98		
07/23/2000	23	TEC	TALLAHASSEE	JCH	98	0	98		
07/24/2000	3	TEC	TALLAHASSEE	JCB	49	0	49		
07/24/2000	4	TEC	TALLAHASSEE	JCB	49	0	49		
07/24/2000	5	TEC	TALLAHASSEE	JCB	49	0	49		
07/24/2000	6	TEC	TALLAHASSEE	JCB	49	0	49		
07/24/2000	7	TEC	TALLAHASSEE	JCB	49	0	49		
07/24/2000	8	TEC	TALLAHASSEE	JCB	49	0	49		
07/26/2000	1	TEC	TALLAHASSEE	JCH	49	0	49		
07/26/2000	2	TEC	TALLAHASSEE	JCH	49	0	49		
07/26/2000	3	TEC	TALLAHASSEE	JCH	98	0	98		
07/26/2000	4	TEC	TALLAHASSEE	JCH	98	0	98		
07/26/2000	5	TEC	TALLAHASSEE	JCH	99	0	99		
07/26/2000	6	TEC	TALLAHASSEE	JCH	98	0	98		
07/26/2000	7	TEC	TALLAHASSEE	JCH	98	0	98		
07/26/2000	8	TEC	TALLAHASSEE	JCH	98	0	98		
07/26/2000	9	TEC	TALLAHASSEE	JCH	98	0	98		
07/26/2000	10	TEC	TALLAHASSEE	JCH	74	0	74		
07/29/2000	13	TEC	TALLAHASSEE	JCH	49	0	49		
07/29/2000	14	TEC	TALLAHASSEE	JCH	30	0	30		

SCHEDULE A7 JULY 2000
DETAIL OF TALLAHASSEE

	A7	DETAIL	VARIANCE	EXPLANATION
MWH - JA	810	810	0	
MWH - JC	3,464	3,464	0	
FUEL - JA	$51,102.53	$50,121.85	($980.68)	
FUEL - JC	$237,853.74	$234,225.00	($3,628.74)	
TRANSMISSION	$0.00	$4,609.42	$4,609.42	
ADJUSTMENTS	$0.00	$0.00	$0.00	
TOTAL	**$288,956.27**	**$288,956.27**	**$0.00**	

SCHEDULE A7 JULY 2000
DETAIL OF AQUILA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/19/2000	18	TEC	AQUILA	JAB	30	0	30	[redacted]	
07/19/2000	19	TEC	AQUILA	JAB	30	30	0		
07/19/2000	20	TEC	AQUILA	JAB	30	30	0		
07/27/2000	20	TEC	AQUILA	JAB	14	0	14		
07/28/2000	16	TEC	AQUILA	JAB	49	0	49		
07/28/2000	17	TEC	AQUILA	JAB	25	0	25		
07/28/2000	18	TEC	AQUILA	JAB	27	0	27		
07/16/2000	17	TEC	AQUILA	JCH	49	0	49	[redacted]	
07/19/2000	21	TEC	AQUILA	JCB	30	0	30		
07/26/2000	12	TEC	AQUILA	JCB	45	0	45		
07/26/2000	13	TEC	AQUILA	JCB	45	0	45		
07/26/2000	14	TEC	AQUILA	JCB	45	0	45		
07/26/2000	15	TEC	AQUILA	JCB	46	0	46		
07/26/2000	16	TEC	AQUILA	JCB	45	0	45		
07/26/2000	17	TEC	AQUILA	JCB	45	0	45		
07/26/2000	18	TEC	AQUILA	JCB	45	0	45		
07/26/2000	19	TEC	AQUILA	JCB	45	0	45		
07/27/2000	13	TEC	AQUILA	JCB	49	0	49		
07/27/2000	14	TEC	AQUILA	JCB	49	0	49		
07/27/2000	15	TEC	AQUILA	JCB	49	0	49		
07/27/2000	16	TEC	AQUILA	JCB	49	0	49		
07/27/2000	17	TEC	AQUILA	JCB	49	0	49		
07/27/2000	18	TEC	AQUILA	JCB	49	0	49		
07/27/2000	19	TEC	AQUILA	JCB	50	0	50		
07/27/2000	20	TEC	AQUILA	JCB	35	0	35		
07/28/2000	13	TEC	AQUILA	JCB	49	0	49		
07/28/2000	14	TEC	AQUILA	JCB	49	0	49		
07/28/2000	15	TEC	AQUILA	JCB	49	0	49		
07/28/2000	17	TEC	AQUILA	JCB	24	0	24		
07/28/2000	18	TEC	AQUILA	JCB	22	0	22		
07/28/2000	19	TEC	AQUILA	JCB	50	0	50		
07/28/2000	20	TEC	AQUILA	JCB	49	0	49		
07/31/2000	13	TEC	AQUILA	JCH	49	0	49		
07/31/2000	14	TEC	AQUILA	JCB	49	0	49		
07/31/2000	15	TEC	AQUILA	JCB	49	0	49		
07/31/2000	16	TEC	AQUILA	JCB	50	0	50		
07/31/2000	17	TEC	AQUILA	JCB	50	0	50		
07/31/2000	18	TEC	AQUILA	JCB	50	0	50		
07/31/2000	19	TEC	AQUILA	JCB	50	0	50		
07/31/2000	20	TEC	AQUILA	JCB	50	0	50		

SCHEDULE A7 JULY 2000
DETAIL OF AQUILA

	A7	DETAIL	VARIANCE	EXPLANATION
MWH - JA	205	205	0	
MWH - JC	1,508	1,508	0	
FUEL - JA	$13,190.74	$13,150.00	($40.74)	
FUEL - JC	$108,803.87	$107,020.00	($1,783.87)	
TRANSMISSION	$0.00	$1,824.61	$1,824.61	
ADJUSTMENTS	$0.00	$0.00	$0.00	
TOTAL	$121,994.61	$121,994.61	$0.00	

SCHEDULE A7 JULY 2000
DETAIL OF MORGAN STANLEY

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/13/2000	12	TEC	MORGAN STANLEY	JAB	48	48	0	[redacted]	
07/13/2000	18	TEC	MORGAN STANLEY	JAB	49	0	49		
07/13/2000	19	TEC	MORGAN STANLEY	JAB	49	0	49		
07/21/2000	14	TEC	MORGAN STANLEY	JAB	49	0	49		
07/21/2000	15	TEC	MORGAN STANLEY	JAB	49	0	49		
07/21/2000	16	TEC	MORGAN STANLEY	JAB	2	2	0		
07/28/2000	13	TEC	MORGAN STANLEY	JAB	10	0	10		
07/28/2000	14	TEC	MORGAN STANLEY	JAB	95	0	95		
07/28/2000	15	TEC	MORGAN STANLEY	JAB	27	0	27		
07/28/2000	16	TEC	MORGAN STANLEY	JAB	98	0	98		
07/28/2000	17	TEC	MORGAN STANLEY	JAB	98	0	98		
07/28/2000	18	TEC	MORGAN STANLEY	JAB	98	0	98		
07/13/2000	12	TEC	MORGAN STANLEY	JCB	1	0	1	[redacted]	
07/13/2000	13	TEC	MORGAN STANLEY	JCB	49	0	49		
07/13/2000	14	TEC	MORGAN STANLEY	JCB	49	0	49		
07/13/2000	15	TEC	MORGAN STANLEY	JCB	49	0	49		
07/13/2000	16	TEC	MORGAN STANLEY	JCB	49	0	49		
07/13/2000	17	TEC	MORGAN STANLEY	JCB	48	0	48		
07/21/2000	8	TEC	MORGAN STANLEY	JCB	49	0	49		
07/21/2000	9	TEC	MORGAN STANLEY	JCB	49	0	49		
07/21/2000	10	TEC	MORGAN STANLEY	JCB	49	0	49		
07/21/2000	11	TEC	MORGAN STANLEY	JCB	49	0	49		
07/21/2000	12	TEC	MORGAN STANLEY	JCB	49	0	49		
07/21/2000	13	TEC	MORGAN STANLEY	JCB	48	0	48		
07/21/2000	16	TEC	MORGAN STANLEY	JCB	47	0	47		
07/21/2000	17	TEC	MORGAN STANLEY	JCB	49	0	49		
07/21/2000	18	TEC	MORGAN STANLEY	JCB	49	0	49		
07/21/2000	19	TEC	MORGAN STANLEY	JCB	49	0	49		
07/21/2000	20	TEC	MORGAN STANLEY	JCB	49	0	49		
07/21/2000	21	TEC	MORGAN STANLEY	JCB	49	0	49		
07/21/2000	22	TEC	MORGAN STANLEY	JCB	49	0	49		
07/21/2000	23	TEC	MORGAN STANLEY	JCB	48	0	48		
07/22/2000	12	TEC	MORGAN STANLEY	JCB	49	0	49		
07/22/2000	13	TEC	MORGAN STANLEY	JCB	49	0	49		
07/22/2000	14	TEC	MORGAN STANLEY	JCB	49	0	49		
07/22/2000	15	TEC	MORGAN STANLEY	JCB	49	0	49		
07/22/2000	16	TEC	MORGAN STANLEY	JCB	49	0	49		
07/22/2000	17	TEC	MORGAN STANLEY	JCB	48	0	48		
07/22/2000	18	TEC	MORGAN STANLEY	JCB	49	0	49		
07/22/2000	19	TEC	MORGAN STANLEY	JCB	49	0	49		
07/23/2000	12	TEC	MORGAN STANLEY	JCB	49	0	49		
07/23/2000	13	TEC	MORGAN STANLEY	JCB	49	0	49		
07/23/2000	14	TEC	MORGAN STANLEY	JCB	49	0	49		
07/23/2000	15	TEC	MORGAN STANLEY	JCB	49	0	49		
07/23/2000	16	TEC	MORGAN STANLEY	JCB	49	0	49		
07/23/2000	17	TEC	MORGAN STANLEY	JCB	48	0	48		
07/23/2000	18	TEC	MORGAN STANLEY	JCB	49	0	49		
07/23/2000	19	TEC	MORGAN STANLEY	JCB	49	0	49		
07/28/2000	13	TEC	MORGAN STANLEY	JCB	88	0	88		
07/28/2000	14	TEC	MORGAN STANLEY	JCB	3	0	3		
07/28/2000	15	TEC	MORGAN STANLEY	JCB	70	0	70		
07/28/2000	19	TEC	MORGAN STANLEY	JCB	98	0	98		
07/28/2000	20	TEC	MORGAN STANLEY	JCB	97	0	97		
07/28/2000	21	TEC	MORGAN STANLEY	JCB	98	0	98		

SCHEDULE A7 JULY 2000
DETAIL OF MORGAN STANLEY

	A7	DETAIL	VARIANCE	EXPLANATION
MWH - JA	670	672	2	JC reclassified as JA
MWH - JC	2,165	2,163	-2	JC reclassified as JA
FUEL - JA	$61,534.26	$57,050.00	($4,484.26)	
FUEL - JC	$214,200.26	$211,060.00	($3,140.26)	
TRANSMISSION	$0.00	$9,334.52	$9,334.52	
ADJUSTMENTS	$0.00	$0.00	$0.00	
TOTAL	**$275,734.52**	**$277,444.52**	**$1,710.00**	

SCHEDULE A7 JULY 2000
DETAIL OF CARGILL FERTILIZER

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/19/2000	16	TEC	CARGILL FERTILIZER	EAB	3	3	0	[redacted]	
07/19/2000	17	TEC	CARGILL FERTILIZER	EAB	16	0	16		
07/19/2000	18	TEC	CARGILL FERTILIZER	EAB	9	0	9		
07/20/2000	14	TEC	CARGILL FERTILIZER	EAB	8	0	8		
07/20/2000	15	TEC	CARGILL FERTILIZER	EAB	13	0	13		
07/20/2000	16	TEC	CARGILL FERTILIZER	EAB	6	0	6		
07/20/2000	17	TEC	CARGILL FERTILIZER	EAB	5	0	5		
07/20/2000	18	TEC	CARGILL FERTILIZER	EAB	3	0	3		
07/21/2000	13	TEC	CARGILL FERTILIZER	EAB	11	11	0		
07/21/2000	14	TEC	CARGILL FERTILIZER	EAB	13	13	0		
07/21/2000	15	TEC	CARGILL FERTILIZER	EAB	13	13	0		
07/21/2000	16	TEC	CARGILL FERTILIZER	EAB	15	15	0		
07/21/2000	17	TEC	CARGILL FERTILIZER	EAB	13	13	0		
07/21/2000	18	TEC	CARGILL FERTILIZER	EAB	11	11	0		
07/21/2000	19	TEC	CARGILL FERTILIZER	EAB	15	15	0		
07/14/2000	12	TEC	CARGILL FERTILIZER	JAB	20	0	20	[redacted]	
07/14/2000	13	TEC	CARGILL FERTILIZER	JCB	24	0	24	[redacted]	
07/14/2000	14	TEC	CARGILL FERTILIZER	JCB	24	0	24		
07/14/2000	15	TEC	CARGILL FERTILIZER	JCB	25	0	25		
07/14/2000	16	TEC	CARGILL FERTILIZER	JCB	25	0	25		
07/14/2000	17	TEC	CARGILL FERTILIZER	JCB	25	0	25		
07/14/2000	18	TEC	CARGILL FERTILIZER	JCB	25	0	25		
07/14/2000	19	TEC	CARGILL FERTILIZER	JCB	25	0	25		
07/14/2000	20	TEC	CARGILL FERTILIZER	JCB	25	0	25		
07/14/2000	21	TEC	CARGILL FERTILIZER	JCB	25	0	25		

SCHEDULE A7 JULY 2000
DETAIL OF CARGILL FERTILIZER

	A7	DETAIL	VARIANCE	EXPLANATION
MWH - JA	174	174	0	
MWH - JC	223	223	0	
FUEL - JA	$13,100.00	$13,100.00	$0.00	
FUEL - JC	$20,070.00	$20,070.00	$0.00	
TRANSMISSION	$0.00	$0.00	$0.00	
ADJUSTMENTS	$0.00	$0.00	$0.00	
TOTAL	**$33,170.00**	**$33,170.00**	**$0.00**	

SCHEDULE A7 JULY 2000
DETAIL OF CORAL ENERGY

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	TOTAL MWH	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/31/2000	14	TEC	CORAL	JCB	40	0	40	[redacted]	
07/31/2000	15	TEC	CORAL	JCB	40	0	40		
07/31/2000	16	TEC	CORAL	JCB	40	0	40		
07/31/2000	17	TEC	CORAL	JCB	40	0	40		
07/31/2000	18	TEC	CORAL	JCB	41	0	41		
07/31/2000	19	TEC	CORAL	JCB	40	0	40		
07/31/2000	20	TEC	CORAL	JCB	40	0	40		

SCHEDULE A7 JULY 2000
DETAIL OF CORAL ENERGY

	A7	DETAIL	VARIANCE	EXPLANATION
MWH - JA	0	0	0	
MWH - JC	281	281	0	
FUEL - JA	$0.00	$0.00	$0.00	
FUEL - JC	$18,081.00	$18,081.00	$0.00	
TRANSMISSION	$0.00	$0.00	$0.00	
ADJUSTMENTS	$0.00	$0.00	$0.00	
TOTAL	$18,081.00	$18,081.00	$0.00	

SCHEDULE A7 JULY 2000
DETAIL OF FARMLAND HYDRO LP

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/03/2000	13	TEC	FARMLAND HYDRO LP	CG	2	[redacted]	[redacted]
07/03/2000	14	TEC	FARMLAND HYDRO LP	CG	1		
07/03/2000	15	TEC	FARMLAND HYDRO LP	CG	1		
07/03/2000	16	TEC	FARMLAND HYDRO LP	CG	1		
07/03/2000	17	TEC	FARMLAND HYDRO LP	CG	1		
07/03/2000	18	TEC	FARMLAND HYDRO LP	CG	1		
07/04/2000	13	TEC	FARMLAND HYDRO LP	CG	1		
07/04/2000	14	TEC	FARMLAND HYDRO LP	CG	1		
07/06/2000	18	TEC	FARMLAND HYDRO LP	CG	1		
07/07/2000	13	TEC	FARMLAND HYDRO LP	CG	4		
07/07/2000	14	TEC	FARMLAND HYDRO LP	CG	3		
07/07/2000	15	TEC	FARMLAND HYDRO LP	CG	2		
07/07/2000	16	TEC	FARMLAND HYDRO LP	CG	1		
07/07/2000	17	TEC	FARMLAND HYDRO LP	CG	2		
07/08/2000	16	TEC	FARMLAND HYDRO LP	CG	2		
07/08/2000	17	TEC	FARMLAND HYDRO LP	CG	2		
07/08/2000	18	TEC	FARMLAND HYDRO LP	CG	2		
07/08/2000	19	TEC	FARMLAND HYDRO LP	CG	2		
07/08/2000	20	TEC	FARMLAND HYDRO LP	CG	1		
07/09/2000	20	TEC	FARMLAND HYDRO LP	CG	1		
07/10/2000	13	TEC	FARMLAND HYDRO LP	CG	4		
07/10/2000	14	TEC	FARMLAND HYDRO LP	CG	4		
07/10/2000	15	TEC	FARMLAND HYDRO LP	CG	4		
07/10/2000	16	TEC	FARMLAND HYDRO LP	CG	3		
07/10/2000	17	TEC	FARMLAND HYDRO LP	CG	1		
07/10/2000	18	TEC	FARMLAND HYDRO LP	CG	1		
07/10/2000	19	TEC	FARMLAND HYDRO LP	CG	2		
07/10/2000	20	TEC	FARMLAND HYDRO LP	CG	2		
07/11/2000	13	TEC	FARMLAND HYDRO LP	CG	4		
07/11/2000	14	TEC	FARMLAND HYDRO LP	CG	2		
07/11/2000	15	TEC	FARMLAND HYDRO LP	CG	1		
07/11/2000	16	TEC	FARMLAND HYDRO LP	CG	1		
07/11/2000	17	TEC	FARMLAND HYDRO LP	CG	1		
07/11/2000	18	TEC	FARMLAND HYDRO LP	CG	2		
07/11/2000	19	TEC	FARMLAND HYDRO LP	CG	3		
07/11/2000	20	TEC	FARMLAND HYDRO LP	CG	3		
07/12/2000	13	TEC	FARMLAND HYDRO LP	CG	4		
07/12/2000	14	TEC	FARMLAND HYDRO LP	CG	4		
07/12/2000	15	TEC	FARMLAND HYDRO LP	CG	4		
07/12/2000	16	TEC	FARMLAND HYDRO LP	CG	4		
07/12/2000	17	TEC	FARMLAND HYDRO LP	CG	4		
07/12/2000	18	TEC	FARMLAND HYDRO LP	CG	3		
07/12/2000	19	TEC	FARMLAND HYDRO LP	CG	3		
07/12/2000	20	TEC	FARMLAND HYDRO LP	CG	4		
07/13/2000	15	TEC	FARMLAND HYDRO LP	CG	2		
07/13/2000	16	TEC	FARMLAND HYDRO LP	CG	1		
07/13/2000	17	TEC	FARMLAND HYDRO LP	CG	2		
07/13/2000	19	TEC	FARMLAND HYDRO LP	CG	2		
07/13/2000	20	TEC	FARMLAND HYDRO LP	CG	2		
07/14/2000	13	TEC	FARMLAND HYDRO LP	CG	3		
07/14/2000	14	TEC	FARMLAND HYDRO LP	CG	3		
07/14/2000	15	TEC	FARMLAND HYDRO LP	CG	2		
07/14/2000	16	TEC	FARMLAND HYDRO LP	CG	1		
07/14/2000	17	TEC	FARMLAND HYDRO LP	CG	1		

SCHEDULE A7 JULY 2000
DETAIL OF FARMLAND HYDRO LP

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/14/2000	18	TEC	FARMLAND HYDRO LP	CG	1	[redacted]	[redacted]
07/14/2000	19	TEC	FARMLAND HYDRO LP	CG	1		
07/14/2000	20	TEC	FARMLAND HYDRO LP	CG	1		
07/15/2000	16	TEC	FARMLAND HYDRO LP	CG	2		
07/15/2000	17	TEC	FARMLAND HYDRO LP	CG	3		
07/15/2000	18	TEC	FARMLAND HYDRO LP	CG	3		
07/15/2000	19	TEC	FARMLAND HYDRO LP	CG	3		
07/15/2000	20	TEC	FARMLAND HYDRO LP	CG	3		
07/17/2000	13	TEC	FARMLAND HYDRO LP	CG	4		
07/17/2000	14	TEC	FARMLAND HYDRO LP	CG	4		
07/17/2000	15	TEC	FARMLAND HYDRO LP	CG	3		
07/17/2000	16	TEC	FARMLAND HYDRO LP	CG	3		
07/17/2000	17	TEC	FARMLAND HYDRO LP	CG	1		
07/18/2000	14	TEC	FARMLAND HYDRO LP	CG	1		
07/18/2000	15	TEC	FARMLAND HYDRO LP	CG	4		
07/18/2000	16	TEC	FARMLAND HYDRO LP	CG	4		
07/18/2000	17	TEC	FARMLAND HYDRO LP	CG	4		
07/18/2000	18	TEC	FARMLAND HYDRO LP	CG	4		
07/18/2000	19	TEC	FARMLAND HYDRO LP	CG	4		
07/18/2000	20	TEC	FARMLAND HYDRO LP	CG	4		
07/19/2000	13	TEC	FARMLAND HYDRO LP	CG	4		
07/19/2000	14	TEC	FARMLAND HYDRO LP	CG	4		
07/19/2000	15	TEC	FARMLAND HYDRO LP	CG	3		
07/19/2000	16	TEC	FARMLAND HYDRO LP	CG	2		
07/19/2000	17	TEC	FARMLAND HYDRO LP	CG	2		
07/19/2000	18	TEC	FARMLAND HYDRO LP	CG	2		
07/19/2000	19	TEC	FARMLAND HYDRO LP	CG	4		
07/19/2000	20	TEC	FARMLAND HYDRO LP	CG	3		
07/20/2000	14	TEC	FARMLAND HYDRO LP	CG	3		
07/20/2000	15	TEC	FARMLAND HYDRO LP	CG	3		
07/20/2000	16	TEC	FARMLAND HYDRO LP	CG	1		
07/20/2000	17	TEC	FARMLAND HYDRO LP	CG	1		
07/20/2000	18	TEC	FARMLAND HYDRO LP	CG	1		
07/20/2000	19	TEC	FARMLAND HYDRO LP	CG	1		
07/21/2000	14	TEC	FARMLAND HYDRO LP	CG	1		
07/21/2000	15	TEC	FARMLAND HYDRO LP	CG	3		
07/21/2000	16	TEC	FARMLAND HYDRO LP	CG	1		
07/21/2000	17	TEC	FARMLAND HYDRO LP	CG	3		
07/21/2000	18	TEC	FARMLAND HYDRO LP	CG	3		
07/22/2000	13	TEC	FARMLAND HYDRO LP	CG	1		
07/22/2000	14	TEC	FARMLAND HYDRO LP	CG	1		
07/22/2000	15	TEC	FARMLAND HYDRO LP	CG	1		
07/22/2000	16	TEC	FARMLAND HYDRO LP	CG	1		
07/23/2000	13	TEC	FARMLAND HYDRO LP	CG	1		
07/23/2000	14	TEC	FARMLAND HYDRO LP	CG	1		
07/23/2000	15	TEC	FARMLAND HYDRO LP	CG	1		
07/26/2000	16	TEC	FARMLAND HYDRO LP	CG	1		
07/26/2000	17	TEC	FARMLAND HYDRO LP	CG	1		
07/26/2000	18	TEC	FARMLAND HYDRO LP	CG	1		
07/26/2000	19	TEC	FARMLAND HYDRO LP	CG	2		
07/26/2000	20	TEC	FARMLAND HYDRO LP	CG	1		
07/27/2000	17	TEC	FARMLAND HYDRO LP	CG	1		
07/27/2000	18	TEC	FARMLAND HYDRO LP	CG	4		
07/27/2000	19	TEC	FARMLAND HYDRO LP	CG	3		

SCHEDULE A7 JULY 2000
DETAIL OF FARMLAND HYDRO LP

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/27/2000	20	TEC	FARMLAND HYDRO LP	CG	3	[redacted]	
07/28/2000	13	TEC	FARMLAND HYDRO LP	CG	4		
07/28/2000	14	TEC	FARMLAND HYDRO LP	CG	4		
07/28/2000	15	TEC	FARMLAND HYDRO LP	CG	4		
07/28/2000	16	TEC	FARMLAND HYDRO LP	CG	3		
07/28/2000	17	TEC	FARMLAND HYDRO LP	CG	1		
07/29/2000	13	TEC	FARMLAND HYDRO LP	CG	4		
07/29/2000	14	TEC	FARMLAND HYDRO LP	CG	4		
07/29/2000	15	TEC	FARMLAND HYDRO LP	CG	4		
07/29/2000	16	TEC	FARMLAND HYDRO LP	CG	3		
07/29/2000	17	TEC	FARMLAND HYDRO LP	CG	1		
07/30/2000	13	TEC	FARMLAND HYDRO LP	CG	3		
07/30/2000	14	TEC	FARMLAND HYDRO LP	CG	3		
07/30/2000	15	TEC	FARMLAND HYDRO LP	CG	3		
07/30/2000	16	TEC	FARMLAND HYDRO LP	CG	3		
07/30/2000	17	TEC	FARMLAND HYDRO LP	CG	3		
07/30/2000	18	TEC	FARMLAND HYDRO LP	CG	3		
07/30/2000	19	TEC	FARMLAND HYDRO LP	CG	3		
07/30/2000	20	TEC	FARMLAND HYDRO LP	CG	1		
07/31/2000	20	TEC	FARMLAND HYDRO LP	CG	4		

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SCHEDULE A7 JULY 2000
DETAIL OF FARMLAND HYDRO LP

	A7	DETAIL	VARIANCE	EXPLANATION
MWH - JA	0	0	0	
MWH - JC	302	303	1	
FUEL - JA	$0.00	$0.00	$0.00	
FUEL - JC	$10,556.80	$10,605.00	$48.20	
TOTAL	**$10,556.80**	**$10,605.00**	**$48.20**	

SCHEDULE A7 JULY 2000
DETAIL OF RINGHAVER

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/06/2000	16:00	TEC	RINGHAVER	JC	1.5	[redacted]	[redacted]
	17:00	TEC	RINGHAVER	JC	10.0		
	18:00	TEC	RINGHAVER	JC	10.0		
	19:00	TEC	RINGHAVER	JC	1.5		
07/17/2000	14:00	TEC	RINGHAVER	JC	1.5		
	15:00	TEC	RINGHAVER	JC	19.0		
	16:00	TEC	RINGHAVER	JC	19.0		
	17:00	TEC	RINGHAVER	JC	18.0		
	18:00	TEC	RINGHAVER	JC	12.0		
	19:00	TEC	RINGHAVER	JC	1.5		
07/19/2000	14:00	TEC	RINGHAVER	JC	1.5		
	15:00	TEC	RINGHAVER	JC	16.0		
	16:00	TEC	RINGHAVER	JC	19.0		
	17:00	TEC	RINGHAVER	JC	17.0		
	18:00	TEC	RINGHAVER	JC	1.0		
	19:00	TEC	RINGHAVER	JC	1.5		
07/20/2000	13:00	TEC	RINGHAVER	JC	9.0		
	14:00	TEC	RINGHAVER	JC	16.0		
	15:00	TEC	RINGHAVER	JC	16.0		
	16:00	TEC	RINGHAVER	JC	16.0		
	17:00	TEC	RINGHAVER	JC	14.0		
	18:00	TEC	RINGHAVER	JC	14.0		
	19:00	TEC	RINGHAVER	JC	14.0		
	20:00	TEC	RINGHAVER	JC	8.0		
	21:00	TEC	RINGHAVER	JC	1.0		

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SCHEDULE A7 JULY 2000
DETAIL OF RINGHAVER

	A7	DETAIL	VARIANCE	EXPLANATION
			0	
MWH - JC	258	258	0	
FUEL	$21,710.79	$21,710.79	$0.00	
TOTAL	**$21,710.79**	**$21,710.79**	**$0.00**	

SCHEDULE A7 JULY 2000
DETAIL OF OKEELANTA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/01/2000	8	TEC	OKEELANTA	D	54	[redacted]	
07/01/2000	9	TEC	OKEELANTA	D	54		
07/01/2000	10	TEC	OKEELANTA	D	53		
07/01/2000	11	TEC	OKEELANTA	D	54		
07/01/2000	12	TEC	OKEELANTA	D	54		
07/01/2000	13	TEC	OKEELANTA	D	54		
07/01/2000	14	TEC	OKEELANTA	D	54		
07/01/2000	15	TEC	OKEELANTA	D	53		
07/01/2000	16	TEC	OKEELANTA	D	54		
07/01/2000	17	TEC	OKEELANTA	D	54		
07/01/2000	18	TEC	OKEELANTA	D	54		
07/01/2000	19	TEC	OKEELANTA	D	54		
07/01/2000	20	TEC	OKEELANTA	D	53		
07/01/2000	21	TEC	OKEELANTA	D	54		
07/01/2000	22	TEC	OKEELANTA	D	54		
07/01/2000	23	TEC	OKEELANTA	D	54		
07/02/2000	8	TEC	OKEELANTA	D	54		
07/02/2000	9	TEC	OKEELANTA	D	54		
07/02/2000	10	TEC	OKEELANTA	D	52		
07/02/2000	11	TEC	OKEELANTA	D	49		
07/02/2000	12	TEC	OKEELANTA	D	54		
07/02/2000	13	TEC	OKEELANTA	D	54		
07/02/2000	14	TEC	OKEELANTA	D	54		
07/02/2000	15	TEC	OKEELANTA	D	53		
07/02/2000	16	TEC	OKEELANTA	D	54		
07/02/2000	17	TEC	OKEELANTA	D	54		
07/02/2000	18	TEC	OKEELANTA	D	54		
07/02/2000	19	TEC	OKEELANTA	D	54		
07/02/2000	20	TEC	OKEELANTA	D	53		
07/02/2000	21	TEC	OKEELANTA	D	54		
07/02/2000	22	TEC	OKEELANTA	D	54		
07/02/2000	23	TEC	OKEELANTA	D	54		
07/03/2000	8	TEC	OKEELANTA	D	54		
07/03/2000	9	TEC	OKEELANTA	D	54		
07/03/2000	10	TEC	OKEELANTA	D	53		
07/03/2000	11	TEC	OKEELANTA	D	54		
07/03/2000	12	TEC	OKEELANTA	D	54		
07/03/2000	13	TEC	OKEELANTA	D	54		
07/03/2000	14	TEC	OKEELANTA	D	54		
07/03/2000	15	TEC	OKEELANTA	D	53		
07/03/2000	16	TEC	OKEELANTA	D	54		
07/03/2000	17	TEC	OKEELANTA	D	54		
07/03/2000	18	TEC	OKEELANTA	D	54		
07/03/2000	19	TEC	OKEELANTA	D	54		
07/03/2000	20	TEC	OKEELANTA	D	54		
07/03/2000	21	TEC	OKEELANTA	D	53		
07/03/2000	22	TEC	OKEELANTA	D	54		
07/03/2000	23	TEC	OKEELANTA	D	54		
07/04/2000	8	TEC	OKEELANTA	D	54		
07/04/2000	9	TEC	OKEELANTA	D	54		
07/04/2000	10	TEC	OKEELANTA	D	53		
07/04/2000	11	TEC	OKEELANTA	D	54		
07/04/2000	12	TEC	OKEELANTA	D	54		
07/04/2000	13	TEC	OKEELANTA	D	54		

SCHEDULE A7 JULY 2000
DETAIL OF OKEELANTA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/04/2000	14	TEC	OKEELANTA	D	54		
07/04/2000	15	TEC	OKEELANTA	D	53		
07/04/2000	16	TEC	OKEELANTA	D	54		
07/04/2000	17	TEC	OKEELANTA	D	54		
07/04/2000	18	TEC	OKEELANTA	D	54		
07/04/2000	19	TEC	OKEELANTA	D	54		
07/04/2000	20	TEC	OKEELANTA	D	53		
07/04/2000	21	TEC	OKEELANTA	D	54		
07/04/2000	22	TEC	OKEELANTA	D	54		
07/04/2000	23	TEC	OKEELANTA	D	54		
07/05/2000	8	TEC	OKEELANTA	D	54		
07/05/2000	9	TEC	OKEELANTA	D	54		
07/05/2000	10	TEC	OKEELANTA	D	53		
07/05/2000	11	TEC	OKEELANTA	D	54		
07/05/2000	12	TEC	OKEELANTA	D	54		
07/05/2000	13	TEC	OKEELANTA	D	54		
07/05/2000	14	TEC	OKEELANTA	D	54		
07/05/2000	15	TEC	OKEELANTA	D	53		
07/05/2000	16	TEC	OKEELANTA	D	54		
07/05/2000	17	TEC	OKEELANTA	D	54		
07/05/2000	18	TEC	OKEELANTA	D	54		
07/05/2000	19	TEC	OKEELANTA	D	54		
07/05/2000	20	TEC	OKEELANTA	D	53		
07/05/2000	21	TEC	OKEELANTA	D	54		
07/05/2000	22	TEC	OKEELANTA	D	54		
07/05/2000	23	TEC	OKEELANTA	D	54		
07/06/2000	8	TEC	OKEELANTA	D	54		
07/06/2000	9	TEC	OKEELANTA	D	54		
07/06/2000	10	TEC	OKEELANTA	D	53		
07/06/2000	11	TEC	OKEELANTA	D	54		
07/06/2000	12	TEC	OKEELANTA	D	54		
07/06/2000	13	TEC	OKEELANTA	D	54		
07/06/2000	14	TEC	OKEELANTA	D	54		
07/06/2000	15	TEC	OKEELANTA	D	53		
07/06/2000	16	TEC	OKEELANTA	D	54		
07/06/2000	17	TEC	OKEELANTA	D	54		
07/06/2000	18	TEC	OKEELANTA	D	54		
07/06/2000	19	TEC	OKEELANTA	D	54		
07/06/2000	20	TEC	OKEELANTA	D	53		
07/06/2000	21	TEC	OKEELANTA	D	54		
07/06/2000	22	TEC	OKEELANTA	D	54		
07/06/2000	23	TEC	OKEELANTA	D	54		
07/07/2000	8	TEC	OKEELANTA	D	54		
07/07/2000	9	TEC	OKEELANTA	D	54		
07/07/2000	10	TEC	OKEELANTA	D	53		
07/07/2000	11	TEC	OKEELANTA	D	25		
07/07/2000	12	TEC	OKEELANTA	D	6		
07/07/2000	13	TEC	OKEELANTA	D	14		
07/07/2000	15	TEC	OKEELANTA	D	54		
07/07/2000	16	TEC	OKEELANTA	D	54		
07/07/2000	17	TEC	OKEELANTA	D	54		
07/07/2000	18	TEC	OKEELANTA	D	54		
07/07/2000	19	TEC	OKEELANTA	D	53		
07/07/2000	20	TEC	OKEELANTA	D	54		

SCHEDULE A7 JULY 2000
DETAIL OF OKEELANTA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/07/2000	21	TEC	OKEELANTA	D	54	[redacted]	
07/07/2000	22	TEC	OKEELANTA	D	54		
07/07/2000	23	TEC	OKEELANTA	D	54		
07/08/2000	8	TEC	OKEELANTA	D	54		
07/08/2000	9	TEC	OKEELANTA	D	54		
07/08/2000	10	TEC	OKEELANTA	D	53		
07/08/2000	11	TEC	OKEELANTA	D	54		
07/08/2000	12	TEC	OKEELANTA	D	54		
07/08/2000	13	TEC	OKEELANTA	D	54		
07/08/2000	14	TEC	OKEELANTA	D	54		
07/08/2000	15	TEC	OKEELANTA	D	53		
07/08/2000	16	TEC	OKEELANTA	D	54		
07/08/2000	17	TEC	OKEELANTA	D	54		
07/08/2000	18	TEC	OKEELANTA	D	44		
07/08/2000	19	TEC	OKEELANTA	D	15		
07/08/2000	23	TEC	OKEELANTA	D	14		
07/09/2000	8	TEC	OKEELANTA	D	15		
07/09/2000	9	TEC	OKEELANTA	D	14		
07/09/2000	10	TEC	OKEELANTA	D	15		
07/09/2000	11	TEC	OKEELANTA	D	15		
07/09/2000	12	TEC	OKEELANTA	D	14		
07/09/2000	13	TEC	OKEELANTA	D	15		
07/09/2000	14	TEC	OKEELANTA	D	15		
07/09/2000	15	TEC	OKEELANTA	D	14		
07/09/2000	16	TEC	OKEELANTA	D	15		
07/09/2000	17	TEC	OKEELANTA	D	15		
07/09/2000	18	TEC	OKEELANTA	D	14		
07/09/2000	19	TEC	OKEELANTA	D	15		
07/09/2000	20	TEC	OKEELANTA	D	15		
07/09/2000	21	TEC	OKEELANTA	D	14		
07/09/2000	22	TEC	OKEELANTA	D	15		
07/09/2000	23	TEC	OKEELANTA	D	15		
07/10/2000	8	TEC	OKEELANTA	D	54		
07/10/2000	9	TEC	OKEELANTA	D	54		
07/10/2000	10	TEC	OKEELANTA	D	53		
07/10/2000	11	TEC	OKEELANTA	D	54		
07/10/2000	12	TEC	OKEELANTA	D	54		
07/10/2000	13	TEC	OKEELANTA	D	54		
07/10/2000	14	TEC	OKEELANTA	D	54		
07/10/2000	15	TEC	OKEELANTA	D	53		
07/10/2000	16	TEC	OKEELANTA	D	54		
07/10/2000	17	TEC	OKEELANTA	D	54		
07/10/2000	18	TEC	OKEELANTA	D	54		
07/10/2000	19	TEC	OKEELANTA	D	54		
07/10/2000	20	TEC	OKEELANTA	D	53		
07/10/2000	21	TEC	OKEELANTA	D	54		
07/10/2000	22	TEC	OKEELANTA	D	54		
07/10/2000	23	TEC	OKEELANTA	D	54		
07/11/2000	8	TEC	OKEELANTA	D	54		
07/11/2000	9	TEC	OKEELANTA	D	54		
07/11/2000	10	TEC	OKEELANTA	D	53		
07/11/2000	11	TEC	OKEELANTA	D	54		
07/11/2000	12	TEC	OKEELANTA	D	54		
07/11/2000	13	TEC	OKEELANTA	D	54		

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SCHEDULE A7 JULY 2000
DETAIL OF OKEELANTA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/11/2000	14	TEC	OKEELANTA	D	49		
07/11/2000	15	TEC	OKEELANTA	D	44		
07/11/2000	16	TEC	OKEELANTA	D	53		
07/11/2000	17	TEC	OKEELANTA	D	54		
07/11/2000	18	TEC	OKEELANTA	D	49		
07/11/2000	19	TEC	OKEELANTA	D	49		
07/11/2000	20	TEC	OKEELANTA	D	49		
07/11/2000	21	TEC	OKEELANTA	D	49		
07/11/2000	22	TEC	OKEELANTA	D	49		
07/11/2000	23	TEC	OKEELANTA	D	49		
07/12/2000	8	TEC	OKEELANTA	D	54		
07/12/2000	9	TEC	OKEELANTA	D	54		
07/12/2000	10	TEC	OKEELANTA	D	53		
07/12/2000	11	TEC	OKEELANTA	D	54		
07/12/2000	12	TEC	OKEELANTA	D	54		
07/12/2000	13	TEC	OKEELANTA	D	54		
07/12/2000	14	TEC	OKEELANTA	D	49		
07/12/2000	15	TEC	OKEELANTA	D	44		
07/12/2000	16	TEC	OKEELANTA	D	53		
07/12/2000	17	TEC	OKEELANTA	D	54		
07/12/2000	18	TEC	OKEELANTA	D	49		
07/12/2000	19	TEC	OKEELANTA	D	44		
07/12/2000	20	TEC	OKEELANTA	D	44		
07/12/2000	21	TEC	OKEELANTA	D	44		
07/12/2000	22	TEC	OKEELANTA	D	44		
07/12/2000	23	TEC	OKEELANTA	D	44		
07/13/2000	8	TEC	OKEELANTA	D	12		
07/13/2000	9	TEC	OKEELANTA	D	14		
07/13/2000	10	TEC	OKEELANTA	D	15		
07/13/2000	11	TEC	OKEELANTA	D	12		
07/13/2000	13	TEC	OKEELANTA	D	8		
07/13/2000	15	TEC	OKEELANTA	D	7		
07/13/2000	16	TEC	OKEELANTA	D	10		
07/13/2000	17	TEC	OKEELANTA	D	10		
07/13/2000	18	TEC	OKEELANTA	D	10		
07/13/2000	19	TEC	OKEELANTA	D	54		
07/13/2000	20	TEC	OKEELANTA	D	53		
07/13/2000	21	TEC	OKEELANTA	D	54		
07/13/2000	22	TEC	OKEELANTA	D	54		
07/13/2000	23	TEC	OKEELANTA	D	54		
07/14/2000	8	TEC	OKEELANTA	D	54		
07/14/2000	9	TEC	OKEELANTA	D	54		
07/14/2000	10	TEC	OKEELANTA	D	53		
07/14/2000	11	TEC	OKEELANTA	D	54		
07/14/2000	12	TEC	OKEELANTA	D	54		
07/14/2000	13	TEC	OKEELANTA	D	54		
07/14/2000	14	TEC	OKEELANTA	D	54		
07/14/2000	15	TEC	OKEELANTA	D	53		
07/14/2000	16	TEC	OKEELANTA	D	54		
07/14/2000	17	TEC	OKEELANTA	D	54		
07/14/2000	18	TEC	OKEELANTA	D	54		
07/14/2000	19	TEC	OKEELANTA	D	54		
07/14/2000	20	TEC	OKEELANTA	D	53		
07/14/2000	21	TEC	OKEELANTA	D	54		

SCHEDULE A7 JULY 2000
DETAIL OF OKEELANTA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/14/2000	22	TEC	OKEELANTA	D	54	[redacted]	[redacted]
07/14/2000	23	TEC	OKEELANTA	D	54		
07/15/2000	8	TEC	OKEELANTA	D	54		
07/15/2000	9	TEC	OKEELANTA	D	54		
07/15/2000	10	TEC	OKEELANTA	D	53		
07/15/2000	11	TEC	OKEELANTA	D	54		
07/15/2000	12	TEC	OKEELANTA	D	54		
07/15/2000	13	TEC	OKEELANTA	D	54		
07/15/2000	14	TEC	OKEELANTA	D	54		
07/15/2000	15	TEC	OKEELANTA	D	53		
07/15/2000	16	TEC	OKEELANTA	D	54		
07/15/2000	17	TEC	OKEELANTA	D	54		
07/15/2000	18	TEC	OKEELANTA	D	54		
07/15/2000	19	TEC	OKEELANTA	D	54		
07/15/2000	20	TEC	OKEELANTA	D	53		
07/15/2000	21	TEC	OKEELANTA	D	54		
07/15/2000	22	TEC	OKEELANTA	D	54		
07/15/2000	23	TEC	OKEELANTA	D	54		
07/16/2000	8	TEC	OKEELANTA	D	54		
07/16/2000	9	TEC	OKEELANTA	D	54		
07/16/2000	10	TEC	OKEELANTA	D	53		
07/16/2000	11	TEC	OKEELANTA	D	54		
07/16/2000	12	TEC	OKEELANTA	D	54		
07/16/2000	13	TEC	OKEELANTA	D	54		
07/16/2000	14	TEC	OKEELANTA	D	54		
07/16/2000	15	TEC	OKEELANTA	D	53		
07/16/2000	16	TEC	OKEELANTA	D	54		
07/16/2000	17	TEC	OKEELANTA	D	54		
07/16/2000	18	TEC	OKEELANTA	D	54		
07/16/2000	19	TEC	OKEELANTA	D	54		
07/16/2000	20	TEC	OKEELANTA	D	53		
07/16/2000	21	TEC	OKEELANTA	D	54		
07/16/2000	22	TEC	OKEELANTA	D	54		
07/16/2000	23	TEC	OKEELANTA	D	54		
07/17/2000	8	TEC	OKEELANTA	D	54		
07/17/2000	9	TEC	OKEELANTA	D	54		
07/17/2000	10	TEC	OKEELANTA	D	53		
07/17/2000	11	TEC	OKEELANTA	D	54		
07/17/2000	12	TEC	OKEELANTA	D	54		
07/17/2000	13	TEC	OKEELANTA	D	54		
07/17/2000	14	TEC	OKEELANTA	D	49		
07/17/2000	15	TEC	OKEELANTA	D	44		
07/17/2000	16	TEC	OKEELANTA	D	53		
07/17/2000	17	TEC	OKEELANTA	D	54		
07/17/2000	18	TEC	OKEELANTA	D	54		
07/17/2000	19	TEC	OKEELANTA	D	54		
07/17/2000	20	TEC	OKEELANTA	D	53		
07/17/2000	21	TEC	OKEELANTA	D	54		
07/17/2000	22	TEC	OKEELANTA	D	54		
07/17/2000	23	TEC	OKEELANTA	D	54		
07/18/2000	8	TEC	OKEELANTA	D	15		
07/18/2000	9	TEC	OKEELANTA	D	14		
07/18/2000	10	TEC	OKEELANTA	D	15		
07/18/2000	11	TEC	OKEELANTA	D	15		

SCHEDULE A7 JULY 2000
DETAIL OF OKEELANTA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/18/2000	12	TEC	OKEELANTA	D	14	[redacted]	[redacted]
07/18/2000	13	TEC	OKEELANTA	D	15		
07/18/2000	14	TEC	OKEELANTA	D	15		
07/18/2000	15	TEC	OKEELANTA	D	14		
07/18/2000	16	TEC	OKEELANTA	D	15		
07/18/2000	17	TEC	OKEELANTA	D	34		
07/18/2000	18	TEC	OKEELANTA	D	20		
07/18/2000	19	TEC	OKEELANTA	D	49		
07/18/2000	20	TEC	OKEELANTA	D	35		
07/18/2000	21	TEC	OKEELANTA	D	37		
07/18/2000	22	TEC	OKEELANTA	D	29		
07/18/2000	23	TEC	OKEELANTA	D	40		
07/19/2000	8	TEC	OKEELANTA	D	5		
07/19/2000	16	TEC	OKEELANTA	D	54		
07/19/2000	17	TEC	OKEELANTA	D	53		
07/19/2000	18	TEC	OKEELANTA	D	54		
07/19/2000	19	TEC	OKEELANTA	D	54		
07/19/2000	20	TEC	OKEELANTA	D	54		
07/19/2000	21	TEC	OKEELANTA	D	54		
07/19/2000	22	TEC	OKEELANTA	D	53		
07/19/2000	23	TEC	OKEELANTA	D	54		
07/20/2000	8	TEC	OKEELANTA	D	54		
07/20/2000	9	TEC	OKEELANTA	D	54		
07/20/2000	10	TEC	OKEELANTA	D	53		
07/20/2000	11	TEC	OKEELANTA	D	54		
07/20/2000	12	TEC	OKEELANTA	D	54		
07/20/2000	13	TEC	OKEELANTA	D	54		
07/20/2000	14	TEC	OKEELANTA	D	54		
07/20/2000	15	TEC	OKEELANTA	D	53		
07/20/2000	16	TEC	OKEELANTA	D	54		
07/20/2000	17	TEC	OKEELANTA	D	54		
07/20/2000	18	TEC	OKEELANTA	D	54		
07/20/2000	19	TEC	OKEELANTA	D	54		
07/20/2000	20	TEC	OKEELANTA	D	53		
07/20/2000	21	TEC	OKEELANTA	D	54		
07/20/2000	22	TEC	OKEELANTA	D	54		
07/20/2000	23	TEC	OKEELANTA	D	54		
07/21/2000	8	TEC	OKEELANTA	D	54		
07/21/2000	9	TEC	OKEELANTA	D	44		
07/21/2000	11	TEC	OKEELANTA	D	54		
07/21/2000	12	TEC	OKEELANTA	D	53		
07/21/2000	13	TEC	OKEELANTA	D	54		
07/21/2000	14	TEC	OKEELANTA	D	54		
07/21/2000	15	TEC	OKEELANTA	D	54		
07/21/2000	16	TEC	OKEELANTA	D	54		
07/21/2000	17	TEC	OKEELANTA	D	39		
07/21/2000	18	TEC	OKEELANTA	D	54		
07/21/2000	19	TEC	OKEELANTA	D	53		
07/21/2000	20	TEC	OKEELANTA	D	54		
07/21/2000	21	TEC	OKEELANTA	D	54		
07/21/2000	23	TEC	OKEELANTA	D	29		
07/22/2000	8	TEC	OKEELANTA	D	54		
07/22/2000	9	TEC	OKEELANTA	D	54		
07/22/2000	10	TEC	OKEELANTA	D	53		

SCHEDULE A7 JULY 2000
DETAIL OF OKEELANTA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/22/2000	11	TEC	OKEELANTA	D	54		
07/22/2000	12	TEC	OKEELANTA	D	54		
07/22/2000	13	TEC	OKEELANTA	D	54		
07/22/2000	14	TEC	OKEELANTA	D	54		
07/22/2000	15	TEC	OKEELANTA	D	53		
07/22/2000	16	TEC	OKEELANTA	D	54		
07/22/2000	17	TEC	OKEELANTA	D	54		
07/22/2000	18	TEC	OKEELANTA	D	54		
07/22/2000	19	TEC	OKEELANTA	D	54		
07/22/2000	20	TEC	OKEELANTA	D	53		
07/22/2000	21	TEC	OKEELANTA	D	54		
07/22/2000	22	TEC	OKEELANTA	D	54		
07/22/2000	23	TEC	OKEELANTA	D	54		
07/23/2000	8	TEC	OKEELANTA	D	54		
07/23/2000	9	TEC	OKEELANTA	D	54		
07/23/2000	10	TEC	OKEELANTA	D	53		
07/23/2000	11	TEC	OKEELANTA	D	54		
07/23/2000	12	TEC	OKEELANTA	D	54		
07/23/2000	13	TEC	OKEELANTA	D	54		
07/23/2000	14	TEC	OKEELANTA	D	54		
07/23/2000	15	TEC	OKEELANTA	D	53		
07/23/2000	16	TEC	OKEELANTA	D	54		
07/23/2000	17	TEC	OKEELANTA	D	54		
07/23/2000	18	TEC	OKEELANTA	D	49		
07/23/2000	19	TEC	OKEELANTA	D	49		
07/23/2000	21	TEC	OKEELANTA	D	54		
07/23/2000	22	TEC	OKEELANTA	D	53		
07/23/2000	23	TEC	OKEELANTA	D	54		
07/24/2000	8	TEC	OKEELANTA	D	54		
07/24/2000	9	TEC	OKEELANTA	D	54		
07/24/2000	10	TEC	OKEELANTA	D	53		
07/24/2000	11	TEC	OKEELANTA	D	54		
07/24/2000	12	TEC	OKEELANTA	D	54		
07/24/2000	13	TEC	OKEELANTA	D	54		
07/24/2000	14	TEC	OKEELANTA	D	54		
07/24/2000	15	TEC	OKEELANTA	D	53		
07/24/2000	16	TEC	OKEELANTA	D	54		
07/24/2000	17	TEC	OKEELANTA	D	54		
07/24/2000	18	TEC	OKEELANTA	D	54		
07/24/2000	19	TEC	OKEELANTA	D	54		
07/24/2000	20	TEC	OKEELANTA	D	29		
07/24/2000	21	TEC	OKEELANTA	D	29		
07/24/2000	22	TEC	OKEELANTA	D	54		
07/24/2000	23	TEC	OKEELANTA	D	54		
07/25/2000	8	TEC	OKEELANTA	D	54		
07/25/2000	9	TEC	OKEELANTA	D	54		
07/25/2000	10	TEC	OKEELANTA	D	53		
07/25/2000	11	TEC	OKEELANTA	D	54		
07/25/2000	12	TEC	OKEELANTA	D	54		
07/25/2000	13	TEC	OKEELANTA	D	54		
07/25/2000	14	TEC	OKEELANTA	D	54		
07/25/2000	15	TEC	OKEELANTA	D	53		
07/25/2000	16	TEC	OKEELANTA	D	54		
07/25/2000	17	TEC	OKEELANTA	D	54		

SCHEDULE A7 JULY 2000
DETAIL OF OKEELANTA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/25/2000	18	TEC	OKEELANTA	D	54	[redacted]	[redacted]
07/25/2000	19	TEC	OKEELANTA	D	54		
07/25/2000	20	TEC	OKEELANTA	D	53		
07/25/2000	21	TEC	OKEELANTA	D	54		
07/25/2000	22	TEC	OKEELANTA	D	54		
07/25/2000	23	TEC	OKEELANTA	D	54		
07/26/2000	8	TEC	OKEELANTA	D	54		
07/26/2000	9	TEC	OKEELANTA	D	54		
07/26/2000	10	TEC	OKEELANTA	D	53		
07/26/2000	11	TEC	OKEELANTA	D	54		
07/26/2000	12	TEC	OKEELANTA	D	54		
07/26/2000	13	TEC	OKEELANTA	D	54		
07/26/2000	14	TEC	OKEELANTA	D	54		
07/26/2000	15	TEC	OKEELANTA	D	53		
07/26/2000	16	TEC	OKEELANTA	D	54		
07/26/2000	17	TEC	OKEELANTA	D	54		
07/26/2000	18	TEC	OKEELANTA	D	54		
07/26/2000	19	TEC	OKEELANTA	D	54		
07/26/2000	20	TEC	OKEELANTA	D	53		
07/26/2000	21	TEC	OKEELANTA	D	54		
07/26/2000	22	TEC	OKEELANTA	D	54		
07/26/2000	23	TEC	OKEELANTA	D	54		
07/27/2000	8	TEC	OKEELANTA	D	54		
07/27/2000	9	TEC	OKEELANTA	D	54		
07/27/2000	10	TEC	OKEELANTA	D	53		
07/27/2000	11	TEC	OKEELANTA	D	54		
07/27/2000	12	TEC	OKEELANTA	D	54		
07/27/2000	13	TEC	OKEELANTA	D	54		
07/27/2000	14	TEC	OKEELANTA	D	54		
07/27/2000	15	TEC	OKEELANTA	D	53		
07/27/2000	16	TEC	OKEELANTA	D	54		
07/27/2000	17	TEC	OKEELANTA	D	54		
07/27/2000	18	TEC	OKEELANTA	D	54		
07/27/2000	19	TEC	OKEELANTA	D	54		
07/27/2000	20	TEC	OKEELANTA	D	53		
07/27/2000	21	TEC	OKEELANTA	D	54		
07/27/2000	22	TEC	OKEELANTA	D	54		
07/27/2000	23	TEC	OKEELANTA	D	54		
07/28/2000	8	TEC	OKEELANTA	D	54		
07/28/2000	9	TEC	OKEELANTA	D	54		
07/28/2000	10	TEC	OKEELANTA	D	53		
07/28/2000	11	TEC	OKEELANTA	D	54		
07/28/2000	12	TEC	OKEELANTA	D	54		
07/28/2000	13	TEC	OKEELANTA	D	54		
07/28/2000	14	TEC	OKEELANTA	D	54		
07/28/2000	15	TEC	OKEELANTA	D	53		
07/28/2000	16	TEC	OKEELANTA	D	54		
07/28/2000	17	TEC	OKEELANTA	D	54		
07/28/2000	18	TEC	OKEELANTA	D	54		
07/28/2000	19	TEC	OKEELANTA	D	54		
07/28/2000	20	TEC	OKEELANTA	D	53		
07/28/2000	21	TEC	OKEELANTA	D	54		
07/28/2000	22	TEC	OKEELANTA	D	54		
07/28/2000	23	TEC	OKEELANTA	D	54		

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SCHEDULE A7 JULY 2000
DETAIL OF OKEELANTA

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/29/2000	8	TEC	OKEELANTA	D	54		
07/29/2000	9	TEC	OKEELANTA	D	54		
07/29/2000	10	TEC	OKEELANTA	D	53		
07/29/2000	11	TEC	OKEELANTA	D	54		
07/29/2000	12	TEC	OKEELANTA	D	54		
07/29/2000	13	TEC	OKEELANTA	D	54		
07/29/2000	14	TEC	OKEELANTA	D	54		
07/29/2000	15	TEC	OKEELANTA	D	53		
07/29/2000	16	TEC	OKEELANTA	D	54		
07/29/2000	17	TEC	OKEELANTA	D	54		
07/29/2000	18	TEC	OKEELANTA	D	54		
07/29/2000	19	TEC	OKEELANTA	D	54		
07/29/2000	20	TEC	OKEELANTA	D	53		
07/29/2000	21	TEC	OKEELANTA	D	54		
07/29/2000	22	TEC	OKEELANTA	D	54		
07/29/2000	23	TEC	OKEELANTA	D	54		
07/30/2000	8	TEC	OKEELANTA	D	54		
07/30/2000	9	TEC	OKEELANTA	D	54		
07/30/2000	10	TEC	OKEELANTA	D	53		
07/30/2000	11	TEC	OKEELANTA	D	54		
07/30/2000	12	TEC	OKEELANTA	D	54		
07/30/2000	13	TEC	OKEELANTA	D	54		
07/30/2000	14	TEC	OKEELANTA	D	54		
07/30/2000	15	TEC	OKEELANTA	D	53		
07/30/2000	16	TEC	OKEELANTA	D	54		
07/30/2000	17	TEC	OKEELANTA	D	54		
07/30/2000	18	TEC	OKEELANTA	D	34		
07/30/2000	19	TEC	OKEELANTA	D	54		
07/30/2000	20	TEC	OKEELANTA	D	54		
07/30/2000	21	TEC	OKEELANTA	D	54		
07/30/2000	22	TEC	OKEELANTA	D	53		
07/30/2000	23	TEC	OKEELANTA	D	54		
07/31/2000	8	TEC	OKEELANTA	D	54		
07/31/2000	9	TEC	OKEELANTA	D	54		
07/31/2000	10	TEC	OKEELANTA	D	53		
07/31/2000	11	TEC	OKEELANTA	D	54		
07/31/2000	12	TEC	OKEELANTA	D	54		
07/31/2000	13	TEC	OKEELANTA	D	54		
07/31/2000	14	TEC	OKEELANTA	D	54		
07/31/2000	15	TEC	OKEELANTA	D	53		
07/31/2000	16	TEC	OKEELANTA	D	54		
07/31/2000	17	TEC	OKEELANTA	D	54		
07/31/2000	18	TEC	OKEELANTA	D	54		
07/31/2000	19	TEC	OKEELANTA	D	54		
07/31/2000	20	TEC	OKEELANTA	D	53		
07/31/2000	21	TEC	OKEELANTA	D	54		
07/31/2000	22	TEC	OKEELANTA	D	54		
07/31/2000	23	TEC	OKEELANTA	D	54		

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SCHEDULE A7 JULY 2000
DETAIL OF OKEELANTA

	A7	DETAIL	VARIANCE	EXPLANATION
MWH - D	23,816	23,816	0	
FUEL - D	$1,306,311.60	$1,246,361.60	($59,950.00)	
TRANSMISSION	$0.00	$59,950.00	$59,950.00	
ADJUSTMENTS	$0.00	$0.00	$0.00	
TOTAL	**$1,306,311.60**	**$1,306,311.60**	**$0.00**	

SCHEDULE A7 JULY 2000
DETAIL OF AUBURNDALE POWER PARTNER

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/03/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12	[redacted]	
07/03/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/03/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/03/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/03/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/03/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/03/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/03/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/03/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/03/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/03/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/03/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/03/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/03/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/03/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/03/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/04/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/04/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/04/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/04/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/04/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/04/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/04/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/04/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/04/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/04/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/04/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/04/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/04/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/04/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/04/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/04/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/05/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/05/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/05/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/05/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/05/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/05/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/05/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/05/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/05/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/05/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/05/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/05/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/05/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/05/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/05/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/05/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/06/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/06/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/06/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/06/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/06/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/06/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/06/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/06/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/06/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/06/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		

SCHEDULE A7 JULY 2000
DETAIL OF AUBURNDALE POWER PARTNER

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/06/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12	[redacted]	
07/06/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/06/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/06/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/06/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/06/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/07/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/07/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/07/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/07/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/07/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/07/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/07/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/07/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/07/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/07/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/07/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/07/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/07/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/07/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/07/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/07/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/10/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/10/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/10/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/10/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/10/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/10/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/10/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/10/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/10/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/10/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/10/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/10/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/10/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/10/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/10/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/10/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/11/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/11/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/11/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/11/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/11/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/11/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/11/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/11/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/11/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/11/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/11/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/11/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/11/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/11/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/11/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/11/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/12/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/12/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/12/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/12/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		

SCHEDULE A7 JULY 2000
DETAIL OF AUBURNDALE POWER PARTNER

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/12/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12	[redacted]	
07/12/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/12/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/12/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/12/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/12/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/12/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/12/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/12/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/12/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/12/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/12/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/13/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/13/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/13/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/13/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/13/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/13/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/13/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/13/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/13/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/13/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/13/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/13/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/13/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/13/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/13/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/13/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/14/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/14/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/14/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/14/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/14/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/14/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/14/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/14/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/14/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/14/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/14/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/14/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/14/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/14/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/14/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/14/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/17/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/17/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/17/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/17/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/17/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/17/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/17/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/17/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/17/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/17/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/17/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/17/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/17/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/17/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		

SCHEDULE A7 JULY 2000
DETAIL OF AUBURNDALE POWER PARTNER

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/17/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12	[redacted]	[redacted]
07/17/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/18/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/18/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/18/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/18/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/18/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/18/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/18/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/18/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/18/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/18/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/18/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/18/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/18/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/18/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/18/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/18/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/19/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/19/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/19/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/19/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/19/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/19/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/19/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/19/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/19/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/19/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/19/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/19/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/19/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/19/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/19/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/19/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/20/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/20/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/20/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/20/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/20/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/20/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/20/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/20/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/20/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/20/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/20/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/20/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/20/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/20/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/20/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/20/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/21/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/21/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/21/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/21/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/21/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/21/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/21/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/21/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		

SCHEDULE A7 JULY 2000
DETAIL OF AUBURNDALE POWER PARTNER

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/21/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12	[redacted]	
07/21/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/21/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/21/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/21/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/21/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/21/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/21/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/24/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/24/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/24/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/24/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/24/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/24/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/24/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/24/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/24/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/24/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/24/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/24/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/24/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/24/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/24/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/24/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/25/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/25/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/25/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/25/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/25/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/25/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/25/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/25/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/25/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/25/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/25/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/25/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/25/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/25/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/25/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/25/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/26/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/26/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/26/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/26/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/26/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/26/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/26/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/26/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/26/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/26/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/26/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/26/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/26/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/26/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/26/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/26/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/27/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/27/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		

SCHEDULE A7 JULY 2000
DETAIL OF AUBURNDALE POWER PARTNER

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/27/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12	[redacted]	
07/27/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/27/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/27/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/27/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/27/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/27/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/27/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/27/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/27/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/27/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/27/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/27/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/27/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/28/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/28/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/28/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/28/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/28/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/28/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/28/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/28/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/28/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/28/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/28/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/28/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/28/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/28/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/28/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/28/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/31/2000	8	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/31/2000	9	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/31/2000	10	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/31/2000	11	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/31/2000	12	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/31/2000	13	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/31/2000	14	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/31/2000	15	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/31/2000	16	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/31/2000	17	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/31/2000	18	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/31/2000	19	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/31/2000	20	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/31/2000	21	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/31/2000	22	TEC	AUBURNDALE POWER PARTNERS	CG	12		
07/31/2000	23	TEC	AUBURNDALE POWER PARTNERS	CG	12		

SCHEDULE A7 JULY 2000
DETAIL OF AUBURNDALE POWER PARTNER

	A7	DETAIL	VARIANCE	EXPLANATION
MWH - D	4,029	4,032	3	
FUEL - D	$105,769.91	$105,840.00	$70.09	
O&M	$0.00	$0.00	$0.00	
TOTAL	$105,769.91	$105,840.00	$70.09	

SCHEDULE A7 JULY 2000
DETAIL OF FLORIDA POWER & LIGHT STEAM A

DATE	HOUR ENDING	BUYER	SELLER	SCHEDULE	MWH	CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT
07/20/2000	16	TEC	FPL	A	25	[redacted]	

SCHEDULE A7 JULY 2000
DETAIL OF FLORIDA POWER & LIGHT STEAM A

	A7	DETAIL	VARIANCE	EXPLANATION
MWH - A	25	25	0	
FUEL	$2,886.00	$2,886.00	$0.00	
O&M	$0.00	$0.00	$0.00	
TOTAL	$2,886.00	$2,886.00	$0.00	

155. Please provide a description of the service schedules under which TECO makes sales and purchases. For each service schedule, include the interchange service type, a brief description of the schedule, typical usage, and parameters under which the sale or purchase is made.

A. The following are the service schedules under which Tampa Electric makes sales and purchases on the wholesale market.

Emergency Interchange Service: Interchange Service Type A
Interchange Service Schedule A was established to facilitate the sale and purchase of cost-based capacity and energy, which are surplus to the needs of the selling utility, during a specified period of time, after the purchasing utility has experienced a forced outage of a generating resource.

A utility typically purchases Schedule A Service during periods when it lacks sufficient generating capacity and energy to serve its load due to

1) the unexpected loss of a generating resource or an entitlement to a generating resource or a restriction on the operation of such a resource; or
2) unanticipated high loads.

The length of time that Schedule A Service is available to a purchasing utility is a maximum of seventy-two hours, except for Florida Power and Light Company, which has a maximum term of twenty-four hours. Schedule A sales are non-firm and are served immediately after the selling utility serves its firm native load and firm wholesale power sale commitments.

Scheduled/Short-Term Firm Interchange Service: Interchange Service Type B
Interchange Service Schedule B was established to facilitate the sale and purchase of cost-based capacity and energy, which are surplus to the needs of the selling utility, during a period of time after the purchasing utility has experienced a forced outage of a generating resource, and the length of time that service is available under Schedule A has expired.

A utility typically purchases Schedule B Service during periods when it lacks sufficient generating capacity or energy or desires to purchase additional capacity or energy to

1) serve its load due to the unexpected loss of a generating resource or an entitlement to a generating resource or a restriction on the operation of such a resource, and the length of time that service is available under Schedule A has expired;
2) serve existing off-system power sales commitments (if service to such customers cannot be suspended per contract provisions), and the length of time that service is available under Schedule A has expired;

3) serve its load and existing off-system power sales commitments during a planned or scheduled maintenance outage or an extended forced outage;
4) provide for additional operating and/or installed reserves;
5) serve unanticipated high loads.

The length of time that Schedule B service is available to a purchasing utility is a maximum of twelve months. Schedule B sales are non-firm and are served immediately after the selling utility serves its firm native load and firm wholesale power sale commitments. The day prior to the beginning of the transaction and each day thereafter, the purchasing utility provides the selling utility a schedule of the amount of capacity and energy it expects to purchase under Schedule B during each hour of the following day.

Economy Energy Interchange Service: Interchange Service Type C
Interchange Service Schedule C was established to facilitate the sale and purchase of cost-based excess energy on an hourly basis.

Schedule C energy sold is surplus, at the time, to the needs of the selling utility and economically usable on the system of the purchasing utility. "Economy energy" transactions are hourly, "split-the-savings" sales or purchases of non-firm energy. An "economy energy" sale or purchase is a transaction under which a seller with available excess energy sells such energy on a non-firm basis to a buyer at a transaction price that is greater than the seller's sell quote and less than the buyer's buy quote. Buy and sell quotes are cost-based and the transaction price is the mid-point between those quotes. Interchange Service Schedule C became dormant when the Energy Broker Network, Inc. (EBN) was discontinued August 22, 2000. Effective August 1, 2001, Tampa Electric terminated all of its Interchange Service Schedules C pursuant to a Federal Energy Regulatory Commission filing.

Long-Term Interchange Service: Interchange Service Type D
Service typically available under Schedule D is firm, cost-based, long-term capacity or energy which is surplus, at the time, to the needs of the selling utility and which is economically usable on the system of the purchasing utility.

A letter of commitment for Schedule D service defines details such as how the purchasing utility will be served with respect to the selling utility's existing power sale commitments and the components of the capacity and energy charges. The length of Schedule D transactions is normally one year or more. Letters of commitment must be filed with, and accepted by, the FERC prior to the commencement of Schedule D service. Effective August 1, 2001, Tampa Electric terminated all but one of its Interchange Service Schedules D pursuant to a Federal Energy Regulatory Commission filing.

Backup/Reserve Interchange Service: Interchange Service Type G
Service typically available under Schedule G is considered to be a "first call" on cost-based, firm capacity or energy which is surplus, at the time, to the needs of the selling utility and which is economically usable on the system of the purchasing utility.

When utilities execute a letter of commitment under Service Schedule G, the selling utility assumes an obligation to sell backup or reserve interchange service to the purchasing utility upon request. The purchasing utility pays a reservation charge that entitles the purchasing utility to request energy in the amount of its reservation during any hour during the term of the letter of commitment. Effective August 1, 2001, Tampa Electric terminated all of its Interchange Service Schedules G pursuant to a Federal Energy Regulatory Commission filing.

Negotiated Interchange Service: Interchange Service Type J
Service typically available under Schedule J is cost-based capacity or energy, which is normally non-firm and which is surplus, at the time, to the needs of the selling utility.

A letter of commitment for Schedule J service defines details such as how the purchasing utility will be served with respect to the selling utility's existing power sale commitments and the components of the capacity and energy charges. Effective August 1, 2001, Tampa Electric terminated all but two of its Interchange Service Schedule J letters of commitment pursuant to a Federal Energy Regulatory Commission filing. The two remain in effect to afford other utilities the opportunity to use this Schedule to make sales to Tampa Electric.

Extended Economy Interchange Service: Interchange Service Type X
Service available under Schedule X is cost-based, non-firm, extended economy energy. The energy sold is surplus, at the time, to the needs of the selling utility and economically usable on the system of the purchasing utility.

Schedule X transactions are essentially extended Schedule C transactions that allow utilities with higher cost generating resources to realize savings by not running those resources by purchasing energy from another utility with lower cost generating resources. The utilities with lower cost generating resources realize revenues by more fully utilizing those resources and selling available energy. Schedule X Service transactions are non-firm, as-available and voluntary. Schedule X sales have a greater priority than Schedule C sales.

Schedule X service is priced similarly to Schedule C, on a split-the-savings basis between the two utilities involved in a transaction. The length of time that Schedule X service is available is more than one hour but not more than seven days.

Effective August 1, 2001, Tampa Electric terminated all of its Interchange Service Schedules X pursuant to a Federal Energy Regulatory Commission filing.

Market-Based Sales Tariff (MA/MB)
Tampa Electric's Market-Based Sales Tariff became effective on April 1, 1999 and provides for sales of wholesale electric capacity or energy at market-based rates.

Transactions designated "MA" are sales that are made from Tampa Electric's resources, and "MB" transactions are re-sales that are made from outside resources. Tampa Electric may provide capacity or energy in varying amounts, at varying levels of firmness or priorities of service, and in accordance with varying delivery schedules. Tampa Electric provides service under the Market-Based Sales Tariff, and the Customer takes service under the tariff when Tampa Electric and the customer mutually agree on the rates, terms and conditions of a transaction. The customer and Tampa Electric must execute a Service Agreement. Tampa Electric files the executed Service Agreement with the FERC no later than 30 days following the date on which service commences.

Requirements Service Tariff (AR-1)
Tampa Electric's all requirements ("AR") tariff provides cost-based full requirements ("FR") and partial requirements ("PR") service to qualified customers.

When a utility that does not own or have entitlements to generating resources purchases FR service, it commits to purchase all of its electric service requirements from the selling utility for a specified period of time, usually in excess of five years. FR service is load-following electric service, and the purchasing utility is invoiced according to the amount of capacity and energy delivered during the billing month or period. When a utility that does own or have entitlements to generating resources purchases PR service, it commits to purchase a portion of its electric service requirements from the selling utility for a specified period of time, usually in excess of five years. The particular terms and conditions associated with FR and PR service are documented in "service agreements". A service agreement is executed by the parties and linked to the tariff. Any specific terms and conditions associated with the service are described within the service agreement. Once a requirements service tariff is accepted by the FERC, it becomes available to any qualified applicant that requests service.

Requirements service tariffs contain general terms and conditions, including provisions that define how and which types of services may be requested and the charges associated with the service. Tampa Electric's AR-1 tariff is cost-based. The non-fuel rates for service under the tariff represent the composite cost of the generating assets (which also serve firm retail customers) when the tariff is made effective by the FERC. The fuel rates for service under the tariff reflect the actual cost of fuel and purchased power and include fuel adjustment factors.

In addition to the service schedules and tariffs described above, Tampa Electric has also bought and sold capacity and energy under stand-alone contracts.

156. For the period 1999 through 2001, list all days in which TECO bought power from and sold power to an affiliate on the same day. For each such day, please identify:

A) the name of the entity;

B) the Schedule under which the power purchase was made;

C) the Schedule under which the power sale was made:

D) the dollars per megawatt hour paid by TECO for the power purchased;

E) the dollars per megawatt hour received by TECO for the power sold;

F) the date each contract was entered into; and,

G) the term (length/period) of each contract.

A. A separated sale to TECO Power Services (TPS) for Seminole Electric Cooperative from Big Bend Unit 4 occurred contemporaneously with the Hardee contract purchase from TPS. The two transactions are not related. One is a purchase to serve native load, and the other is an approved unit-based separated sale. The costs associated with the separated sale are not borne by retail ratepayers.

A) See attached.

B) See attached.

C) See attached.

D) See attached.

E) See attached.

F) See attached.

G) See attached.

A.

	TAMPA ELECTRIC BUYING FROM TPS			TAMPA ELECTRIC SELLING TO TPS		
DATE	BUYER	B. SCHEDULE TYPE	D. ENERGY CHARGE	BUYER	C. SCHEDULE TYPE	E. ENERGY CHARGE
01/04/1999	TEC	D	30.62	SEC	BB4	28.33
01/05/1999	TEC	D	30.62	SEC	BB4	28.33
01/06/1999	TEC	D	30.62	SEC	BB4	28.33
01/07/1999	TEC	D	30.62	SEC	BB4	28.33
01/10/1999	TEC	D	30.62	SEC	BB4	28.33
01/11/1999	TEC	D	30.62	SEC	BB4	28.33
02/14/1999	TEC	D	20.43	SEC	BB4	27.46
02/15/1999	TEC	D	20.43	SEC	BB4	27.46
02/16/1999	TEC	D	20.43	SEC	BB4	27.46
02/22/1999	TEC	D	20.43	SEC	BB4	27.46
02/23/1999	TEC	D	20.43	SEC	BB4	27.46
02/24/1999	TEC	D	20.43	SEC	BB4	27.46
02/25/1999	TEC	D	20.43	SEC	BB4	27.46
03/25/1999	TEC	D	17.46	SEC	BB4	26.54
03/29/1999	TEC	D	17.46	SEC	BB4	26.54
04/01/1999	TEC	D	22.98	SEC	BB4	27.08
04/02/1999	TEC	D	22.98	SEC	BB4	27.08
04/03/1999	TEC	D	22.98	SEC	BB4	27.08
04/04/1999	TEC	D	22.98	SEC	BB4	27.08
04/05/1999	TEC	D	22.98	SEC	BB4	27.08
04/06/1999	TEC	D	22.98	SEC	BB4	27.08
04/08/1999	TEC	D	22.98	SEC	BB4	27.08
04/09/1999	TEC	D	22.98	SEC	BB4	27.08
04/10/1999	TEC	D	22.98	SEC	BB4	27.08
04/12/1999	TEC	D	22.98	SEC	BB4	27.08
04/14/1999	TEC	D	22.98	SEC	BB4	27.08
04/24/1999	TEC	D	22.98	SEC	BB4	27.08
04/25/1999	TEC	D	22.98	SEC	BB4	27.08
04/26/1999	TEC	D	22.98	SEC	BB4	27.08
04/27/1999	TEC	D	22.98	SEC	BB4	27.08
04/28/1999	TEC	D	22.98	SEC	BB4	27.08
04/29/1999	TEC	D	22.98	SEC	BB4	27.08
05/04/1999	TEC	D	25.80	SEC	BB4	28.16
05/05/1999	TEC	D	25.80	SEC	BB4	28.16
05/06/1999	TEC	D	25.80	SEC	BB4	28.16
05/07/1999	TEC	D	25.80	SEC	BB4	28.16
05/08/1999	TEC	D	25.80	SEC	BB4	28.16
05/09/1999	TEC	D	25.80	SEC	BB4	28.16
05/10/1999	TEC	D	25.80	SEC	BB4	28.16
05/11/1999	TEC	D	25.80	SEC	BB4	28.16
05/12/1999	TEC	D	25.80	SEC	BB4	28.16
05/13/1999	TEC	D	25.80	SEC	BB4	28.16
05/14/1999	TEC	D	25.80	SEC	BB4	28.16

A.

	TAMPA ELECTRIC BUYING FROM TPS			TAMPA ELECTRIC SELLING TO TPS		
		B.	D.		C.	E.
DATE	BUYER	SCHEDULE TYPE	ENERGY CHARGE	BUYER	SCHEDULE TYPE	ENERGY CHARGE
05/15/1999	TEC	D	25.80	SEC	BB4	28.16
05/16/1999	TEC	D	25.80	SEC	BB4	28.16
05/17/1999	TEC	D	25.80	SEC	BB4	28.16
05/18/1999	TEC	D	25.80	SEC	BB4	28.16
05/19/1999	TEC	D	25.80	SEC	BB4	28.16
05/20/1999	TEC	D	25.80	SEC	BB4	28.16
05/21/1999	TEC	D	25.80	SEC	BB4	28.16
05/22/1999	TEC	D	25.80	SEC	BB4	28.16
05/23/1999	TEC	D	25.80	SEC	BB4	28.16
05/24/1999	TEC	D	25.80	SEC	BB4	28.16
05/25/1999	TEC	D	25.80	SEC	BB4	28.16
05/26/1999	TEC	D	25.80	SEC	BB4	28.16
05/27/1999	TEC	D	25.80	SEC	BB4	28.16
05/28/1999	TEC	D	25.80	SEC	BB4	28.16
05/29/1999	TEC	D	25.80	SEC	BB4	28.16
05/30/1999	TEC	D	25.80	SEC	BB4	28.16
05/31/1999	TEC	D	25.80	SEC	BB4	28.16
06/01/1999	TEC	D	29.27	SEC	BB4	27.32
06/02/1999	TEC	D	29.27	SEC	BB4	27.32
06/03/1999	TEC	D	29.27	SEC	BB4	27.32
06/04/1999	TEC	D	29.27	SEC	BB4	27.32
06/05/1999	TEC	D	29.27	SEC	BB4	27.32
06/06/1999	TEC	D	29.27	SEC	BB4	27.32
06/07/1999	TEC	D	29.27	SEC	BB4	27.32
06/08/1999	TEC	D	29.27	SEC	BB4	27.32
06/09/1999	TEC	D	29.27	SEC	BB4	27.32
06/10/1999	TEC	D	29.27	SEC	BB4	27.32
06/11/1999	TEC	D	29.27	SEC	BB4	27.32
06/12/1999	TEC	D	29.27	SEC	BB4	27.32
06/13/1999	TEC	D	29.27	SEC	BB4	27.32
06/14/1999	TEC	D	29.27	SEC	BB4	27.32
06/15/1999	TEC	D	29.27	SEC	BB4	27.32
06/16/1999	TEC	D	29.27	SEC	BB4	27.32
06/19/1999	TEC	D	29.27	SEC	BB4	27.32
06/20/1999	TEC	D	29.27	SEC	BB4	27.32
06/22/1999	TEC	D	29.27	SEC	BB4	27.32
06/23/1999	TEC	D	29.27	SEC	BB4	27.32
06/24/1999	TEC	D	29.27	SEC	BB4	27.32
06/25/1999	TEC	D	29.27	SEC	BB4	27.32
06/26/1999	TEC	D	29.27	SEC	BB4	27.32
06/27/1999	TEC	D	29.27	SEC	BB4	27.32
06/28/1999	TEC	D	29.27	SEC	BB4	27.32
06/29/1999	TEC	D	29.27	SEC	BB4	27.32

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	TAMPA ELECTRIC BUYING FROM TPS			TAMPA ELECTRIC SELLING TO TPS		
		B.	D.		C.	E.
DATE	BUYER	SCHEDULE TYPE	ENERGY CHARGE	BUYER	SCHEDULE TYPE	ENERGY CHARGE
06/30/1999	TEC	D	29.27	SEC	BB4	27.32
07/01/1999	TEC	D	29.68	SEC	BB4	28.80
07/02/1999	TEC	D	29.68	SEC	BB4	28.80
07/03/1999	TEC	D	29.68	SEC	BB4	28.80
07/04/1999	TEC	D	29.68	SEC	BB4	28.80
07/05/1999	TEC	D	29.68	SEC	BB4	28.80
07/06/1999	TEC	D	29.68	SEC	BB4	28.80
07/07/1999	TEC	D	29.68	SEC	BB4	28.80
07/08/1999	TEC	D	29.68	SEC	BB4	28.80
07/09/1999	TEC	D	29.68	SEC	BB4	28.80
07/10/1999	TEC	D	29.68	SEC	BB4	28.80
07/11/1999	TEC	D	29.68	SEC	BB4	28.80
07/12/1999	TEC	D	29.68	SEC	BB4	28.80
07/13/1999	TEC	D	29.68	SEC	BB4	28.80
07/14/1999	TEC	D	29.68	SEC	BB4	28.80
07/15/1999	TEC	D	29.68	SEC	BB4	28.80
07/16/1999	TEC	D	29.68	SEC	BB4	28.80
07/17/1999	TEC	D	29.68	SEC	BB4	28.80
07/18/1999	TEC	D	29.68	SEC	BB4	28.80
07/19/1999	TEC	D	29.68	SEC	BB4	28.80
07/20/1999	TEC	D	29.68	SEC	BB4	28.80
07/21/1999	TEC	D	29.68	SEC	BB4	28.80
07/22/1999	TEC	D	29.68	SEC	BB4	28.80
07/23/1999	TEC	D	29.68	SEC	BB4	28.80
07/24/1999	TEC	D	29.68	SEC	BB4	28.80
07/25/1999	TEC	D	29.68	SEC	BB4	28.80
07/26/1999	TEC	D	29.68	SEC	BB4	28.80
07/27/1999	TEC	D	29.68	SEC	BB4	28.80
07/28/1999	TEC	D	29.68	SEC	BB4	28.80
07/29/1999	TEC	D	29.68	SEC	BB4	28.80
07/30/1999	TEC	D	29.68	SEC	BB4	28.80
07/31/1999	TEC	D	29.68	SEC	BB4	28.80
08/01/1999	TEC	D	32.83	SEC	BB4	31.68
08/02/1999	TEC	D	32.83	SEC	BB4	31.68
08/03/1999	TEC	D	32.83	SEC	BB4	31.68
08/04/1999	TEC	D	32.83	SEC	BB4	31.68
08/05/1999	TEC	D	32.83	SEC	BB4	31.68
08/06/1999	TEC	D	32.83	SEC	BB4	31.68
08/09/1999	TEC	D	32.83	SEC	BB4	31.68
08/10/1999	TEC	D	32.83	SEC	BB4	31.68
08/11/1999	TEC	D	32.83	SEC	BB4	31.68
08/12/1999	TEC	D	32.83	SEC	BB4	31.68
08/13/1999	TEC	D	32.83	SEC	BB4	31.68

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	TAMPA ELECTRIC BUYING FROM TPS			TAMPA ELECTRIC SELLING TO TPS		
		B.	D.		C.	E.
DATE	BUYER	SCHEDULE TYPE	ENERGY CHARGE	BUYER	SCHEDULE TYPE	ENERGY CHARGE
08/14/1999	TEC	D	32.83	SEC	BB4	31.68
08/15/1999	TEC	D	32.83	SEC	BB4	31.68
08/16/1999	TEC	D	32.83	SEC	BB4	31.68
08/17/1999	TEC	D	32.83	SEC	BB4	31.68
08/18/1999	TEC	D	32.83	SEC	BB4	31.68
08/19/1999	TEC	D	32.83	SEC	BB4	31.68
08/20/1999	TEC	D	32.83	SEC	BB4	31.68
08/23/1999	TEC	D	32.83	SEC	BB4	31.68
08/24/1999	TEC	D	32.83	SEC	BB4	31.68
08/25/1999	TEC	D	32.83	SEC	BB4	31.68
08/26/1999	TEC	D	32.83	SEC	BB4	31.68
08/27/1999	TEC	D	32.83	SEC	BB4	31.68
08/28/1999	TEC	D	32.83	SEC	BB4	31.68
08/29/1999	TEC	D	32.83	SEC	BB4	31.68
08/30/1999	TEC	D	32.83	SEC	BB4	31.68
08/31/1999	TEC	D	32.83	SEC	BB4	31.68
09/01/1999	TEC	D	31.16	SEC	BB4	31.04
09/02/1999	TEC	D	31.16	SEC	BB4	31.04
09/03/1999	TEC	D	31.16	SEC	BB4	31.04
09/05/1999	TEC	D	31.16	SEC	BB4	31.04
09/07/1999	TEC	D	31.16	SEC	BB4	31.04
09/08/1999	TEC	D	31.16	SEC	BB4	31.04
09/09/1999	TEC	D	31.16	SEC	BB4	31.04
09/10/1999	TEC	D	31.16	SEC	BB4	31.04
09/11/1999	TEC	D	31.16	SEC	BB4	31.04
09/12/1999	TEC	D	31.16	SEC	BB4	31.04
09/13/1999	TEC	D	31.16	SEC	BB4	31.04
09/14/1999	TEC	D	31.16	SEC	BB4	31.04
09/16/1999	TEC	D	31.16	SEC	BB4	31.04
09/17/1999	TEC	D	31.16	SEC	BB4	31.04
09/21/1999	TEC	D	31.16	SEC	BB4	31.04
09/22/1999	TEC	D	31.16	SEC	BB4	31.04
09/24/1999	TEC	D	31.16	SEC	BB4	31.04
09/25/1999	TEC	D	31.16	SEC	BB4	31.04
09/27/1999	TEC	D	31.16	SEC	BB4	31.04
09/28/1999	TEC	D	31.16	SEC	BB4	31.04
09/29/1999	TEC	D	31.16	SEC	BB4	31.04
09/30/1999	TEC	D	31.16	SEC	BB4	31.04
10/01/1999	TEC	D	34.63	SEC	BB4	30.19
10/02/1999	TEC	D	34.63	SEC	BB4	30.19
10/03/1999	TEC	D	34.63	SEC	BB4	30.19
10/04/1999	TEC	D	34.63	SEC	BB4	30.19
10/06/1999	TEC	D	34.63	SEC	BB4	30.19

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	TAMPA ELECTRIC BUYING FROM TPS			TAMPA ELECTRIC SELLING TO TPS		
DATE	BUYER	B. SCHEDULE TYPE	D. ENERGY CHARGE	BUYER	C. SCHEDULE TYPE	E. ENERGY CHARGE
10/07/1999	TEC	D	34.63	SEC	BB4	30.19
10/08/1999	TEC	D	34.63	SEC	BB4	30.19
10/09/1999	TEC	D	34.63	SEC	BB4	30.19
10/10/1999	TEC	D	34.63	SEC	BB4	30.19
10/11/1999	TEC	D	34.63	SEC	BB4	30.19
10/12/1999	TEC	D	34.63	SEC	BB4	30.19
10/13/1999	TEC	D	34.63	SEC	BB4	30.19
10/15/1999	TEC	D	34.63	SEC	BB4	30.19
10/20/1999	TEC	D	34.63	SEC	BB4	30.19
10/21/1999	TEC	D	34.63	SEC	BB4	30.19
10/22/1999	TEC	D	34.63	SEC	BB4	30.19
10/27/1999	TEC	D	34.63	SEC	BB4	30.19
01/14/2000	TEC	D	35.22	SEC	BB4	31.40
01/15/2000	TEC	D	35.22	SEC	BB4	31.40
01/16/2000	TEC	D	35.22	SEC	BB4	31.40
01/17/2000	TEC	D	35.22	SEC	BB4	31.40
01/18/2000	TEC	D	35.22	SEC	BB4	31.40
01/21/2000	TEC	D	35.22	SEC	BB4	31.40
01/25/2000	TEC	D	35.22	SEC	BB4	31.40
01/26/2000	TEC	D	35.22	SEC	BB4	31.40
01/27/2000	TEC	D	35.22	SEC	BB4	31.40
01/28/2000	TEC	D	35.22	SEC	BB4	31.40
01/31/2000	TEC	D	35.22	SEC	BB4	31.40
02/01/2000	TEC	D	38.05	SEC	BB4	31.21
02/02/2000	TEC	D	38.05	SEC	BB4	31.21
02/03/2000	TEC	D	38.05	SEC	BB4	31.21
02/04/2000	TEC	D	38.05	SEC	BB4	31.21
02/05/2000	TEC	D	38.05	SEC	BB4	31.21
02/06/2000	TEC	D	38.05	SEC	BB4	31.21
02/07/2000	TEC	D	38.05	SEC	BB4	31.21
02/08/2000	TEC	D	38.05	SEC	BB4	31.21
02/09/2000	TEC	D	38.05	SEC	BB4	31.21
02/10/2000	TEC	D	38.05	SEC	BB4	31.21
02/11/2000	TEC	D	38.05	SEC	BB4	31.21
02/16/2000	TEC	D	38.05	SEC	BB4	31.21
02/22/2000	TEC	D	38.05	SEC	BB4	31.21
03/15/2000	TEC	D	37.01	SEC	BB4	30.94
03/16/2000	TEC	D	37.01	SEC	BB4	30.94
03/18/2000	TEC	D	37.01	SEC	BB4	30.94
03/20/2000	TEC	D	37.01	SEC	BB4	30.94
03/21/2000	TEC	D	37.01	SEC	BB4	30.94
03/22/2000	TEC	D	37.01	SEC	BB4	30.94
03/23/2000	TEC	D	37.01	SEC	BB4	30.94

A.

	TAMPA ELECTRIC BUYING FROM TPS			TAMPA ELECTRIC SELLING TO TPS		
		B.	D.		C.	E.
DATE	BUYER	SCHEDULE TYPE	ENERGY CHARGE	BUYER	SCHEDULE TYPE	ENERGY CHARGE
03/24/2000	TEC	D	37.01	SEC	BB4	30.94
03/25/2000	TEC	D	37.01	SEC	BB4	30.94
03/30/2000	TEC	D	37.01	SEC	BB4	30.94
03/31/2000	TEC	D	37.01	SEC	BB4	30.94
04/01/2000	TEC	D	36.46	SEC	BB4	31.16
04/02/2000	TEC	D	36.46	SEC	BB4	31.16
04/03/2000	TEC	D	36.46	SEC	BB4	31.16
04/13/2000	TEC	D	36.46	SEC	BB4	31.16
04/15/2000	TEC	D	36.46	SEC	BB4	31.16
04/16/2000	TEC	D	36.46	SEC	BB4	31.16
04/17/2000	TEC	D	36.46	SEC	BB4	31.16
04/18/2000	TEC	D	36.46	SEC	BB4	31.16
04/19/2000	TEC	D	36.46	SEC	BB4	31.16
04/20/2000	TEC	D	36.46	SEC	BB4	31.16
04/21/2000	TEC	D	36.46	SEC	BB4	31.16
04/23/2000	TEC	D	36.46	SEC	BB4	31.16
04/24/2000	TEC	D	36.46	SEC	BB4	31.16
04/25/2000	TEC	D	36.46	SEC	BB4	31.16
04/26/2000	TEC	D	36.46	SEC	BB4	31.16
04/27/2000	TEC	D	36.46	SEC	BB4	31.16
04/29/2000	TEC	D	36.46	SEC	BB4	31.16
04/30/2000	TEC	D	36.46	SEC	BB4	31.16
05/01/2000	TEC	D	44.74	SEC	BB4	31.23
05/02/2000	TEC	D	44.74	SEC	BB4	31.23
05/03/2000	TEC	D	44.74	SEC	BB4	31.23
05/04/2000	TEC	D	44.74	SEC	BB4	31.23
05/05/2000	TEC	D	44.74	SEC	BB4	31.23
05/06/2000	TEC	D	44.74	SEC	BB4	31.23
05/08/2000	TEC	D	44.74	SEC	BB4	31.23
05/09/2000	TEC	D	44.74	SEC	BB4	31.23
05/10/2000	TEC	D	44.74	SEC	BB4	31.23
05/11/2000	TEC	D	44.74	SEC	BB4	31.23
05/12/2000	TEC	D	44.74	SEC	BB4	31.23
05/13/2000	TEC	D	44.74	SEC	BB4	31.23
05/14/2000	TEC	D	44.74	SEC	BB4	31.23
05/15/2000	TEC	D	44.74	SEC	BB4	31.23
05/16/2000	TEC	D	44.74	SEC	BB4	31.23
05/17/2000	TEC	D	44.74	SEC	BB4	31.23
05/18/2000	TEC	D	44.74	SEC	BB4	31.23
05/19/2000	TEC	D	44.74	SEC	BB4	31.23
05/20/2000	TEC	D	44.74	SEC	BB4	31.23
05/21/2000	TEC	D	44.74	SEC	BB4	31.23
05/22/2000	TEC	D	44.74	SEC	BB4	31.23

A.

	TAMPA ELECTRIC BUYING FROM TPS			TAMPA ELECTRIC SELLING TO TPS		
DATE	BUYER	B. SCHEDULE TYPE	D. ENERGY CHARGE	BUYER	C. SCHEDULE TYPE	E. ENERGY CHARGE
05/23/2000	TEC	D	44.74	SEC	BB4	31.23
05/24/2000	TEC	D	44.74	SEC	BB4	31.23
05/25/2000	TEC	D	44.74	SEC	BB4	31.23
05/26/2000	TEC	D	44.74	SEC	BB4	31.23
05/27/2000	TEC	D	44.74	SEC	BB4	31.23
05/28/2000	TEC	D	44.74	SEC	BB4	31.23
05/29/2000	TEC	D	44.74	SEC	BB4	31.23
05/30/2000	TEC	D	44.74	SEC	BB4	31.23
05/31/2000	TEC	D	44.74	SEC	BB4	31.23
06/01/2000	TEC	D	52.71	SEC	BB4	32.31
06/02/2000	TEC	D	52.71	SEC	BB4	32.31
06/03/2000	TEC	D	52.71	SEC	BB4	32.31
06/04/2000	TEC	D	52.71	SEC	BB4	32.31
06/05/2000	TEC	D	52.71	SEC	BB4	32.31
06/06/2000	TEC	D	52.71	SEC	BB4	32.31
06/07/2000	TEC	D	52.71	SEC	BB4	32.31
06/08/2000	TEC	D	52.71	SEC	BB4	32.31
06/09/2000	TEC	D	52.71	SEC	BB4	32.31
06/10/2000	TEC	D	52.71	SEC	BB4	32.31
06/11/2000	TEC	D	52.71	SEC	BB4	32.31
06/12/2000	TEC	D	52.71	SEC	BB4	32.31
06/13/2000	TEC	D	52.71	SEC	BB4	32.31
06/14/2000	TEC	D	52.71	SEC	BB4	32.31
06/15/2000	TEC	D	52.71	SEC	BB4	32.31
06/16/2000	TEC	D	52.71	SEC	BB4	32.31
06/20/2000	TEC	D	52.71	SEC	BB4	32.31
06/21/2000	TEC	D	52.71	SEC	BB4	32.31
06/23/2000	TEC	D	52.71	SEC	BB4	32.31
06/24/2000	TEC	D	52.71	SEC	BB4	32.31
06/25/2000	TEC	D	52.71	SEC	BB4	32.31
06/26/2000	TEC	D	52.71	SEC	BB4	32.31
06/27/2000	TEC	D	52.71	SEC	BB4	32.31
06/28/2000	TEC	D	52.71	SEC	BB4	32.31
06/29/2000	TEC	D	52.71	SEC	BB4	32.31
06/30/2000	TEC	D	52.71	SEC	BB4	32.31
07/01/2000	TEC	D	55.73	SEC	BB4	32.20
07/02/2000	TEC	D	55.73	SEC	BB4	32.20
07/03/2000	TEC	D	55.73	SEC	BB4	32.20
07/04/2000	TEC	D	55.73	SEC	BB4	32.20
07/05/2000	TEC	D	55.73	SEC	BB4	32.20
07/06/2000	TEC	D	55.73	SEC	BB4	32.20
07/07/2000	TEC	D	55.73	SEC	BB4	32.20
07/08/2000	TEC	D	55.73	SEC	BB4	32.20

A.

	TAMPA ELECTRIC BUYING FROM TPS			TAMPA ELECTRIC SELLING TO TPS		
DATE	BUYER	B. SCHEDULE TYPE	D. ENERGY CHARGE	BUYER	C. SCHEDULE TYPE	E. ENERGY CHARGE
07/09/2000	TEC	D	55.73	SEC	BB4	32.20
07/10/2000	TEC	D	55.73	SEC	BB4	32.20
07/11/2000	TEC	D	55.73	SEC	BB4	32.20
07/12/2000	TEC	D	55.73	SEC	BB4	32.20
07/13/2000	TEC	D	55.73	SEC	BB4	32.20
07/14/2000	TEC	D	55.73	SEC	BB4	32.20
07/15/2000	TEC	D	55.73	SEC	BB4	32.20
07/16/2000	TEC	D	55.73	SEC	BB4	32.20
07/17/2000	TEC	D	55.73	SEC	BB4	32.20
07/18/2000	TEC	D	55.73	SEC	BB4	32.20
07/19/2000	TEC	D	55.73	SEC	BB4	32.20
07/20/2000	TEC	D	55.73	SEC	BB4	32.20
07/21/2000	TEC	D	55.73	SEC	BB4	32.20
07/22/2000	TEC	D	55.73	SEC	BB4	32.20
07/23/2000	TEC	D	55.73	SEC	BB4	32.20
07/24/2000	TEC	D	55.73	SEC	BB4	32.20
07/25/2000	TEC	D	55.73	SEC	BB4	32.20
07/26/2000	TEC	D	55.73	SEC	BB4	32.20
07/27/2000	TEC	D	55.73	SEC	BB4	32.20
07/28/2000	TEC	D	55.73	SEC	BB4	32.20
07/29/2000	TEC	D	55.73	SEC	BB4	32.20
07/31/2000	TEC	D	55.73	SEC	BB4	32.20
08/01/2000	TEC	D	50.67	SEC	BB4	33.53
08/02/2000	TEC	D	50.67	SEC	BB4	33.53
08/03/2000	TEC	D	50.67	SEC	BB4	33.53
08/04/2000	TEC	D	50.67	SEC	BB4	33.53
08/07/2000	TEC	D	50.67	SEC	BB4	33.53
08/08/2000	TEC	D	50.67	SEC	BB4	33.53
08/09/2000	TEC	D	50.67	SEC	BB4	33.53
08/10/2000	TEC	D	50.67	SEC	BB4	33.53
08/11/2000	TEC	D	50.67	SEC	BB4	33.53
08/12/2000	TEC	D	50.67	SEC	BB4	33.53
08/13/2000	TEC	D	50.67	SEC	BB4	33.53
08/14/2000	TEC	D	50.67	SEC	BB4	33.53
08/15/2000	TEC	D	50.67	SEC	BB4	33.53
08/16/2000	TEC	D	50.67	SEC	BB4	33.53
08/17/2000	TEC	D	50.67	SEC	BB4	33.53
08/18/2000	TEC	D	50.67	SEC	BB4	33.53
08/20/2000	TEC	D	50.67	SEC	BB4	33.53
08/21/2000	TEC	D	50.67	SEC	BB4	33.53
08/22/2000	TEC	D	50.67	SEC	BB4	33.53
08/23/2000	TEC	D	50.67	SEC	BB4	33.53
08/24/2000	TEC	D	50.67	SEC	BB4	33.53

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	TAMPA ELECTRIC BUYING FROM TPS			TAMPA ELECTRIC SELLING TO TPS		
		B.	D.		C.	E.
DATE	BUYER	SCHEDULE TYPE	ENERGY CHARGE	BUYER	SCHEDULE TYPE	ENERGY CHARGE
08/25/2000	TEC	D	50.67	SEC	BB4	33.53
08/26/2000	TEC	D	50.67	SEC	BB4	33.53
08/27/2000	TEC	D	50.67	SEC	BB4	33.53
08/28/2000	TEC	D	50.67	SEC	BB4	33.53
08/29/2000	TEC	D	50.67	SEC	BB4	33.53
08/30/2000	TEC	D	50.67	SEC	BB4	33.53
08/31/2000	TEC	D	50.67	SEC	BB4	33.53
09/01/2000	TEC	D	63.27	SEC	BB4	31.94
09/02/2000	TEC	D	63.27	SEC	BB4	31.94
09/03/2000	TEC	D	63.27	SEC	BB4	31.94
09/04/2000	TEC	D	63.27	SEC	BB4	31.94
09/05/2000	TEC	D	63.27	SEC	BB4	31.94
09/06/2000	TEC	D	63.27	SEC	BB4	31.94
09/07/2000	TEC	D	63.27	SEC	BB4	31.94
09/08/2000	TEC	D	63.27	SEC	BB4	31.94
09/09/2000	TEC	D	63.27	SEC	BB4	31.94
09/10/2000	TEC	D	63.27	SEC	BB4	31.94
09/11/2000	TEC	D	63.27	SEC	BB4	31.94
09/12/2000	TEC	D	63.27	SEC	BB4	31.94
09/13/2000	TEC	D	63.27	SEC	BB4	31.94
09/14/2000	TEC	D	63.27	SEC	BB4	31.94
09/15/2000	TEC	D	63.27	SEC	BB4	31.94
09/16/2000	TEC	D	63.27	SEC	BB4	31.94
09/18/2000	TEC	D	63.27	SEC	BB4	31.94
09/19/2000	TEC	D	63.27	SEC	BB4	31.94
09/20/2000	TEC	D	63.27	SEC	BB4	31.94
09/21/2000	TEC	D	63.27	SEC	BB4	31.94
09/24/2000	TEC	D	63.27	SEC	BB4	31.94
09/25/2000	TEC	D	63.27	SEC	BB4	31.94
09/26/2000	TEC	D	63.27	SEC	BB4	31.94
09/27/2000	TEC	D	63.27	SEC	BB4	31.94
09/28/2000	TEC	D	63.27	SEC	BB4	31.94
09/29/2000	TEC	D	63.27	SEC	BB4	31.94
09/30/2000	TEC	D	63.27	SEC	BB4	31.94
10/02/2000	TEC	D	67.88	SEC	BB4	30.55
10/03/2000	TEC	D	67.88	SEC	BB4	30.55
10/04/2000	TEC	D	67.88	SEC	BB4	30.55
10/05/2000	TEC	D	67.88	SEC	BB4	30.55
10/06/2000	TEC	D	67.88	SEC	BB4	30.55
10/07/2000	TEC	D	67.88	SEC	BB4	30.55
10/08/2000	TEC	D	67.88	SEC	BB4	30.55
10/10/2000	TEC	D	67.88	SEC	BB4	30.55
10/11/2000	TEC	D	67.88	SEC	BB4	30.55

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	TAMPA ELECTRIC BUYING FROM TPS			TAMPA ELECTRIC SELLING TO TPS		
		B.	D.		C.	E.
DATE	BUYER	SCHEDULE TYPE	ENERGY CHARGE	BUYER	SCHEDULE TYPE	ENERGY CHARGE
10/12/2000	TEC	D	67.88	SEC	BB4	30.55
10/13/2000	TEC	D	67.88	SEC	BB4	30.55
10/14/2000	TEC	D	67.88	SEC	BB4	30.55
10/16/2000	TEC	D	67.88	SEC	BB4	30.55
10/17/2000	TEC	D	67.88	SEC	BB4	30.55
10/18/2000	TEC	D	67.88	SEC	BB4	30.55
10/19/2000	TEC	D	67.88	SEC	BB4	30.55
10/20/2000	TEC	D	67.88	SEC	BB4	30.55
10/22/2000	TEC	D	67.88	SEC	BB4	30.55
10/23/2000	TEC	D	67.88	SEC	BB4	30.55
10/24/2000	TEC	D	67.88	SEC	BB4	30.55
10/25/2000	TEC	D	67.88	SEC	BB4	30.55
10/26/2000	TEC	D	67.88	SEC	BB4	30.55
10/27/2000	TEC	D	67.88	SEC	BB4	30.55
10/29/2000	TEC	D	67.88	SEC	BB4	30.55
10/30/2000	TEC	D	67.88	SEC	BB4	30.55
11/04/2000	TEC	D	60.33	SEC	BB4	30.49
11/05/2000	TEC	D	60.33	SEC	BB4	30.49
11/06/2000	TEC	D	60.33	SEC	BB4	30.49
11/07/2000	TEC	D	60.33	SEC	BB4	30.49
11/08/2000	TEC	D	60.33	SEC	BB4	30.49
11/09/2000	TEC	D	60.33	SEC	BB4	30.49
11/10/2000	TEC	D	60.33	SEC	BB4	30.49
11/11/2000	TEC	D	60.33	SEC	BB4	30.49
11/12/2000	TEC	D	60.33	SEC	BB4	30.49
11/13/2000	TEC	D	60.33	SEC	BB4	30.49
11/14/2000	TEC	D	60.33	SEC	BB4	30.49
11/15/2000	TEC	D	60.33	SEC	BB4	30.49
11/16/2000	TEC	D	60.33	SEC	BB4	30.49
11/17/2000	TEC	D	60.33	SEC	BB4	30.49
11/18/2000	TEC	D	60.33	SEC	BB4	30.49
11/19/2000	TEC	D	60.33	SEC	BB4	30.49
11/20/2000	TEC	D	60.33	SEC	BB4	30.49
11/21/2000	TEC	D	60.33	SEC	BB4	30.49
11/22/2000	TEC	D	60.33	SEC	BB4	30.49
11/23/2000	TEC	D	60.33	SEC	BB4	30.49
11/25/2000	TEC	D	60.33	SEC	BB4	30.49
11/27/2000	TEC	D	60.33	SEC	BB4	30.49
12/20/2000	TEC	D	78.94	SEC	BB4	29.82
12/21/2000	TEC	D	78.94	SEC	BB4	29.82
12/23/2000	TEC	D	78.94	SEC	BB4	29.82
12/30/2000	TEC	D	78.94	SEC	BB4	29.82
12/31/2000	TEC	D	78.94	SEC	BB4	29.82

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	TAMPA ELECTRIC BUYING FROM TPS			TAMPA ELECTRIC SELLING TO TPS		
DATE	BUYER	B. SCHEDULE TYPE	D. ENERGY CHARGE	BUYER	C. SCHEDULE TYPE	E. ENERGY CHARGE
01/01/2001	TEC	D	105.45	SEC	BB4	29.88
01/02/2001	TEC	D	105.45	SEC	BB4	29.88
01/03/2001	TEC	D	105.45	SEC	BB4	29.88
01/04/2001	TEC	D	105.45	SEC	BB4	29.88
01/05/2001	TEC	D	105.45	SEC	BB4	29.88
01/07/2001	TEC	D	105.45	SEC	BB4	29.88
01/09/2001	TEC	D	105.45	SEC	BB4	29.88
01/10/2001	TEC	D	105.45	SEC	BB4	29.88
01/11/2001	TEC	D	105.45	SEC	BB4	29.88
01/13/2001	TEC	D	105.45	SEC	BB4	29.88
01/14/2001	TEC	D	105.45	SEC	BB4	29.88
01/15/2001	TEC	D	105.45	SEC	BB4	29.88
01/16/2001	TEC	D	105.45	SEC	BB4	29.88
01/17/2001	TEC	D	105.45	SEC	BB4	29.88
01/18/2001	TEC	D	105.45	SEC	BB4	29.88
01/19/2001	TEC	D	105.45	SEC	BB4	29.88
01/21/2001	TEC	D	105.45	SEC	BB4	29.88
01/22/2001	TEC	D	105.45	SEC	BB4	29.88
01/23/2001	TEC	D	105.45	SEC	BB4	29.88
01/24/2001	TEC	D	105.45	SEC	BB4	29.88
01/25/2001	TEC	D	105.45	SEC	BB4	29.88
01/26/2001	TEC	D	105.45	SEC	BB4	29.88
01/27/2001	TEC	D	105.45	SEC	BB4	29.88
01/28/2001	TEC	D	105.45	SEC	BB4	29.88
01/29/2001	TEC	D	105.45	SEC	BB4	29.88
01/30/2001	TEC	D	105.45	SEC	BB4	29.88
01/31/2001	TEC	D	105.45	SEC	BB4	29.88
02/01/2001	TEC	D	61.84	SEC	BB4	30.21
02/02/2001	TEC	D	61.84	SEC	BB4	30.21
02/03/2001	TEC	D	61.84	SEC	BB4	30.21
02/04/2001	TEC	D	61.84	SEC	BB4	30.21
02/05/2001	TEC	D	61.84	SEC	BB4	30.21
02/06/2001	TEC	D	61.84	SEC	BB4	30.21
02/07/2001	TEC	D	61.84	SEC	BB4	30.21
02/15/2001	TEC	D	61.84	SEC	BB4	30.21
02/16/2001	TEC	D	61.84	SEC	BB4	30.21
02/17/2001	TEC	D	61.84	SEC	BB4	30.21
02/18/2001	TEC	D	61.84	SEC	BB4	30.21
02/19/2001	TEC	D	61.84	SEC	BB4	30.21
02/20/2001	TEC	D	61.84	SEC	BB4	30.21
02/21/2001	TEC	D	61.84	SEC	BB4	30.21
02/22/2001	TEC	D	61.84	SEC	BB4	30.21
02/23/2001	TEC	D	61.84	SEC	BB4	30.21

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	TAMPA ELECTRIC BUYING FROM TPS			TAMPA ELECTRIC SELLING TO TPS		
DATE	BUYER	B. SCHEDULE TYPE	D. ENERGY CHARGE	BUYER	C. SCHEDULE TYPE	E. ENERGY CHARGE
02/24/2001	TEC	D	61.84	SEC	BB4	30.21
02/25/2001	TEC	D	61.84	SEC	BB4	30.21
02/26/2001	TEC	D	61.84	SEC	BB4	30.21
02/27/2001	TEC	D	61.84	SEC	BB4	30.21
02/28/2001	TEC	D	61.84	SEC	BB4	30.21
03/01/2001	TEC	D	55.27	SEC	BB4	31.22
03/02/2001	TEC	D	55.27	SEC	BB4	31.22
03/03/2001	TEC	D	55.27	SEC	BB4	31.22
03/04/2001	TEC	D	55.27	SEC	BB4	31.22
03/05/2001	TEC	D	55.27	SEC	BB4	31.22
03/06/2001	TEC	D	55.27	SEC	BB4	31.22
03/07/2001	TEC	D	55.27	SEC	BB4	31.22
03/08/2001	TEC	D	55.27	SEC	BB4	31.22
03/09/2001	TEC	D	55.27	SEC	BB4	31.22
03/10/2001	TEC	D	55.27	SEC	BB4	31.22
03/11/2001	TEC	D	55.27	SEC	BB4	31.22
03/13/2001	TEC	D	55.27	SEC	BB4	31.22
03/14/2001	TEC	D	55.27	SEC	BB4	31.22
03/15/2001	TEC	D	55.27	SEC	BB4	31.22
03/16/2001	TEC	D	55.27	SEC	BB4	31.22
03/17/2001	TEC	D	55.27	SEC	BB4	31.22
03/18/2001	TEC	D	55.27	SEC	BB4	31.22
03/19/2001	TEC	D	55.27	SEC	BB4	31.22
03/20/2001	TEC	D	55.27	SEC	BB4	31.22
03/21/2001	TEC	D	55.27	SEC	BB4	31.22
03/22/2001	TEC	D	55.27	SEC	BB4	31.22
03/23/2001	TEC	D	55.27	SEC	BB4	31.22
03/25/2001	TEC	D	55.27	SEC	BB4	31.22
03/26/2001	TEC	D	55.27	SEC	BB4	31.22
03/27/2001	TEC	D	55.27	SEC	BB4	31.22
03/28/2001	TEC	D	55.27	SEC	BB4	31.22
03/29/2001	TEC	D	55.27	SEC	BB4	31.22
03/30/2001	TEC	D	55.27	SEC	BB4	31.22
03/31/2001	TEC	D	55.27	SEC	BB4	31.22
04/01/2001	TEC	D	61.59	SEC	BB4	30.01
04/02/2001	TEC	D	61.59	SEC	BB4	30.01
04/03/2001	TEC	D	61.59	SEC	BB4	30.01
04/04/2001	TEC	D	61.59	SEC	BB4	30.01
04/05/2001	TEC	D	61.59	SEC	BB4	30.01
04/06/2001	TEC	D	61.59	SEC	BB4	30.01
04/07/2001	TEC	D	61.59	SEC	BB4	30.01
04/08/2001	TEC	D	61.59	SEC	BB4	30.01
04/09/2001	TEC	D	61.59	SEC	BB4	30.01

A.

	TAMPA ELECTRIC BUYING FROM TPS			TAMPA ELECTRIC SELLING TO TPS		
		B.	D.		C.	E.
DATE	BUYER	SCHEDULE TYPE	ENERGY CHARGE	BUYER	SCHEDULE TYPE	ENERGY CHARGE
04/10/2001	TEC	D	61.59	SEC	BB4	30.01
04/11/2001	TEC	D	61.59	SEC	BB4	30.01
04/12/2001	TEC	D	61.59	SEC	BB4	30.01
04/13/2001	TEC	D	61.59	SEC	BB4	30.01
04/14/2001	TEC	D	61.59	SEC	BB4	30.01
04/15/2001	TEC	D	61.59	SEC	BB4	30.01
04/16/2001	TEC	D	61.59	SEC	BB4	30.01
04/17/2001	TEC	D	61.59	SEC	BB4	30.01
04/18/2001	TEC	D	61.59	SEC	BB4	30.01
04/19/2001	TEC	D	61.59	SEC	BB4	30.01
04/20/2001	TEC	D	61.59	SEC	BB4	30.01
04/21/2001	TEC	D	61.59	SEC	BB4	30.01
04/22/2001	TEC	D	61.59	SEC	BB4	30.01
04/23/2001	TEC	D	61.59	SEC	BB4	30.01
04/24/2001	TEC	D	61.59	SEC	BB4	30.01
04/25/2001	TEC	D	61.59	SEC	BB4	30.01
04/26/2001	TEC	D	61.59	SEC	BB4	30.01
04/27/2001	TEC	D	61.59	SEC	BB4	30.01
04/28/2001	TEC	D	61.59	SEC	BB4	30.01
05/01/2001	TEC	D	38.20	SEC	BB4	34.70
06/02/2001	TEC	D	38.64	SEC	BB4	31.59
06/04/2001	TEC	D	38.64	SEC	BB4	31.59
06/05/2001	TEC	D	38.64	SEC	BB4	31.59
06/06/2001	TEC	D	38.64	SEC	BB4	31.59
06/07/2001	TEC	D	38.64	SEC	BB4	31.59
06/08/2001	TEC	D	38.64	SEC	BB4	31.59
06/09/2001	TEC	D	38.64	SEC	BB4	31.59
06/10/2001	TEC	D	38.64	SEC	BB4	31.59
06/11/2001	TEC	D	38.64	SEC	BB4	31.59
06/12/2001	TEC	D	38.64	SEC	BB4	31.59
06/13/2001	TEC	D	38.64	SEC	BB4	31.59
06/14/2001	TEC	D	38.64	SEC	BB4	31.59
06/15/2001	TEC	D	38.64	SEC	BB4	31.59
06/16/2001	TEC	D	38.64	SEC	BB4	31.59
06/17/2001	TEC	D	38.64	SEC	BB4	31.59
06/18/2001	TEC	D	38.64	SEC	BB4	31.59
06/19/2001	TEC	D	38.64	SEC	BB4	31.59
06/20/2001	TEC	D	38.64	SEC	BB4	31.59
06/21/2001	TEC	D	38.64	SEC	BB4	31.59
06/24/2001	TEC	D	38.64	SEC	BB4	31.59
06/25/2001	TEC	D	38.64	SEC	BB4	31.59
06/26/2001	TEC	D	38.64	SEC	BB4	31.59
06/27/2001	TEC	D	38.64	SEC	BB4	31.59

A.

	TAMPA ELECTRIC BUYING FROM TPS			TAMPA ELECTRIC SELLING TO TPS		
DATE	BUYER	B. SCHEDULE TYPE	D. ENERGY CHARGE	BUYER	C. SCHEDULE TYPE	E. ENERGY CHARGE
06/29/2001	TEC	D	38.64	SEC	BB4	31.59
06/30/2001	TEC	D	38.64	SEC	BB4	31.59
07/01/2001	TEC	D	27.57	SEC	BB4	29.02
07/02/2001	TEC	D	27.57	SEC	BB4	29.02
07/03/2001	TEC	D	27.57	SEC	BB4	29.02
07/05/2001	TEC	D	27.57	SEC	BB4	29.02
07/06/2001	TEC	D	27.57	SEC	BB4	29.02
07/07/2001	TEC	D	27.57	SEC	BB4	29.02
07/08/2001	TEC	D	27.57	SEC	BB4	29.02
07/09/2001	TEC	D	27.57	SEC	BB4	29.02
07/10/2001	TEC	D	27.57	SEC	BB4	29.02
07/12/2001	TEC	D	27.57	SEC	BB4	29.02
07/13/2001	TEC	D	27.57	SEC	BB4	29.02
07/14/2001	TEC	D	27.57	SEC	BB4	29.02
07/15/2001	TEC	D	27.57	SEC	BB4	29.02
07/16/2001	TEC	D	27.57	SEC	BB4	29.02
07/17/2001	TEC	D	27.57	SEC	BB4	29.02
07/18/2001	TEC	D	27.57	SEC	BB4	29.02
07/19/2001	TEC	D	27.57	SEC	BB4	29.02
07/20/2001	TEC	D	27.57	SEC	BB4	29.02
07/21/2001	TEC	D	27.57	SEC	BB4	29.02
07/22/2001	TEC	D	27.57	SEC	BB4	29.02
07/24/2001	TEC	D	27.57	SEC	BB4	29.02
07/25/2001	TEC	D	27.57	SEC	BB4	29.02
07/26/2001	TEC	D	27.57	SEC	BB4	29.02
07/27/2001	TEC	D	27.57	SEC	BB4	29.02
07/28/2001	TEC	D	27.57	SEC	BB4	29.02
07/30/2001	TEC	D	27.57	SEC	BB4	29.02
08/01/2001	TEC	D	32.42	SEC	BB4	31.43
08/02/2001	TEC	D	32.42	SEC	BB4	31.43
08/04/2001	TEC	D	32.42	SEC	BB4	31.43
08/05/2001	TEC	D	32.42	SEC	BB4	31.43
08/06/2001	TEC	D	32.42	SEC	BB4	31.43
08/07/2001	TEC	D	32.42	SEC	BB4	31.43
08/08/2001	TEC	D	32.42	SEC	BB4	31.43
08/09/2001	TEC	D	32.42	SEC	BB4	31.43
08/10/2001	TEC	D	32.42	SEC	BB4	31.43
08/16/2001	TEC	D	32.42	SEC	BB4	31.43
08/17/2001	TEC	D	32.42	SEC	BB4	31.43
08/18/2001	TEC	D	32.42	SEC	BB4	31.43
08/19/2001	TEC	D	32.42	SEC	BB4	31.43
08/20/2001	TEC	D	32.42	SEC	BB4	31.43
08/21/2001	TEC	D	32.42	SEC	BB4	31.43

A.

	TAMPA ELECTRIC BUYING FROM TPS			TAMPA ELECTRIC SELLING TO TPS		
		B.	D.		C.	E.
DATE	BUYER	SCHEDULE TYPE	ENERGY CHARGE	BUYER	SCHEDULE TYPE	ENERGY CHARGE
08/22/2001	TEC	D	32.42	SEC	BB4	31.43
08/23/2001	TEC	D	32.42	SEC	BB4	31.43
08/24/2001	TEC	D	32.42	SEC	BB4	31.43
08/25/2001	TEC	D	32.42	SEC	BB4	31.43
08/26/2001	TEC	D	32.42	SEC	BB4	31.43
08/27/2001	TEC	D	32.42	SEC	BB4	31.43
08/28/2001	TEC	D	32.42	SEC	BB4	31.43
08/29/2001	TEC	D	32.42	SEC	BB4	31.43
08/30/2001	TEC	D	32.42	SEC	BB4	31.43
08/31/2001	TEC	D	32.42	SEC	BB4	31.43
09/01/2001	TEC	D	28.95	SEC	BB4	33.26
09/02/2001	TEC	D	28.95	SEC	BB4	33.26
09/03/2001	TEC	D	28.95	SEC	BB4	33.26
09/04/2001	TEC	D	28.95	SEC	BB4	33.26
09/05/2001	TEC	D	28.95	SEC	BB4	33.26
09/06/2001	TEC	D	28.95	SEC	BB4	33.26
09/07/2001	TEC	D	28.95	SEC	BB4	33.26
09/08/2001	TEC	D	28.95	SEC	BB4	33.26
09/09/2001	TEC	D	28.95	SEC	BB4	33.26
09/10/2001	TEC	D	28.95	SEC	BB4	33.26
09/11/2001	TEC	D	28.95	SEC	BB4	33.26
09/12/2001	TEC	D	28.95	SEC	BB4	33.26
09/16/2001	TEC	D	28.95	SEC	BB4	33.26
09/17/2001	TEC	D	28.95	SEC	BB4	33.26
09/18/2001	TEC	D	28.95	SEC	BB4	33.26
09/19/2001	TEC	D	28.95	SEC	BB4	33.26
09/20/2001	TEC	D	28.95	SEC	BB4	33.26
09/21/2001	TEC	D	28.95	SEC	BB4	33.26
09/22/2001	TEC	D	28.95	SEC	BB4	33.26

F. 07/27/1989 — 07/27/1989

G. 01/01/1993 - 12/31/2012 — 01/01/1993 - 12/31/2002

157. What capacity options were available to TECO at the time the most recent Hardee Power Project Sales Agreement was signed? How did TECO compare the Hardee Power Project Sales Agreement to other available options?

A. Tampa Electric solicited long term capacity and energy responses from three entities: Florida Power and Light, Florida Power Corporation and the City of Lakeland. Florida Power and Light and Florida Power Corporation responded with bids. The bids were compared to the option of purchasing capacity and energy from Hardee Power Station by Witness Mark D. Ward. Information regarding the bid solicitation and comparative analysis can be found in direct and rebuttal testimony of W. Lynn Brown and rebuttal testimony of Mark D. Ward in Docket 990001-EI.

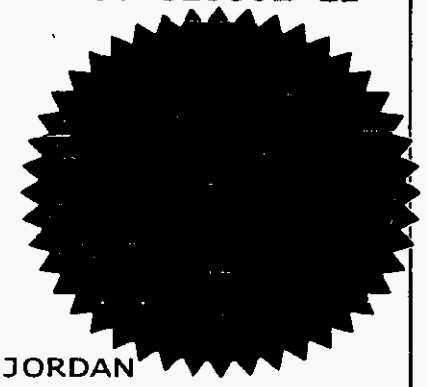
BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of

DOCKET NO. 010001-EI

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE AND GENERATING PERFORMANCE INCENTIVE FACTOR.

_____/



DEPOSITION OF:	J. DENISE JORDAN
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
DATE:	Thursday, October 25, 2001
TIME:	Commenced at 9:35 a.m. Concluded at 11:10 a.m.
LOCATION:	Gerald L. Gunter Building Room 362 2540 Shumard Oak Boulevard Tallahassee, Florida
REPORTED BY:	MARY ALLEN NEEL, RPR Notary Public, State of Florida at Large

ACCURATE STENOTYPE REPORTERS, INC.
100 SALEM COURT
TALLAHASSEE, FLORIDA 32301
(850) 878-2221

BUREAU OF REPORTING

RECEIVED 11-1-01

APPEARANCES:

JAMES D. BEASLEY, Ausley & McMullen, 217 South Calhoun Street, Tallahassee, Florida 32301, appearing on behalf of Tampa Electric Company.

JOHN MCWHIRTER, McWhirter Reeves Law Firm, P.O. Box 3350, Tampa, Florida 33601-3350, appearing on behalf of the Florida Industrial Power Users Group.

ROBERT VANDIVER, Deputy Public Counsel, Office of Public Counsel, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

WILLIAM COCHRAN KEATING, IV, Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0870, appearing on behalf of the Commission Staff.

ALSO PRESENT:

LESLIE J. PAUGH, Landers & Parsons, 310 West College Avenue, 32301, Tallahassee, Florida 32301, on behalf of Johnson Controls.

W. LYNN BROWN, Tampa Electric Company.

TODD BOHRMAN, MATTHEW BRINKLEY, ELISABETH DRAPER, ROLAND FLOYD, JUDY HARLOW, PETER LESTER, and WILLIAM MCNULTY, Commission Staff.

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S T I P U L A T I O N S

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure; that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing is not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

PROCEEDINGS

Thereupon,

J. DENISE JORDAN

the witness herein, having been first duly sworn on oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. KEATING:

Q Good morning, Ms. Jordan.

A Good morning.

Q For the record, could you provide your name and business address?

A J. Denise Jordan, 702 North Franklin Street, Tampa, Florida 33602.

Q Is it correct that you are employed in TECO's Regulatory Affairs Department?

A That's correct.

Q And you've been employed there since April 2000?

A Correct.

Q In your position there, is it correct that you are responsible for preparing and coordinating TECO's filings in the fuel docket?

A Correct.

Q If you were asked a question about a decision that was made relevant to the fuel docket as

far as Tampa Electric is concerned since April 2000, would you be able to address those questions?

A I should be able to, yes.

Q Do you have any knowledge of TECO's fuel-related activities prior to April 2000?

A In some instances.

Q Prior to joining the Regulatory Affairs Department in April 2000, were you employed by TECO?

A No, I was not.

Q And if I asked a question about why TECO is seeking recovery of a particular expense through the fuel clause, you would be the appropriate witness to address that question to?

A In all likelihood, yes.

Q Okay. If you could turn -- do you have your direct testimony that was filed September 20th in this docket?

A Yes, I do.

Q If you could turn to pages 30 and 31. I believe that's Schedule E3 that's attached to your testimony. Was the data shown in Schedule E3 prepared by you or under your supervision?

A Yes.

Q And would that include the projected price by fuel type data?

A Yes. The schedule was prepared under my supervision.

Q Okay. If you could look at Schedule -- I believe it's Schedule E4 on the following pages, 42 to 43. Was the data shown on Schedule E4 prepared by you or under your supervision?

A Yes.

Q Okay. And I have the same questions with respect to E5, E6, E7, and E8.

A All E schedules were prepared under my supervision.

MR. KEATING: I just realized I got right into the questions without taking appearances this morning. And now that Mr. McWhirter is here --

MR. MCWHIRTER: You can do it now.

MR. KEATING: We're all here, and we can take appearances.

MR. MCWHIRTER: Despite my appearance.

MR. KEATING: I carefully blamed that on you somehow.

MR. BEASLEY: I'm Jim Beasley representing Tampa Electric Company.

MR. BROWN: Lynn Brown, a witness for Tampa Electric Company.

MR. McWHIRTER: John McWhirter representing the Florida Industrial Power Users Group.

MS. PAUGH: Leslie Paugh representing Johnson Controls, but we have not intervened in this docket as of this time.

MR. VANDIVER: I'm Rob Vandiver appearing on behalf of the Citizens of the State of Florida.

MR. KEATING: Cochran Keating appearing on behalf of the Commission Staff.

MR. BEASLEY: While we're at a lull, someone joined us on the phone. Is that you, Mark? Did we have an additional party join us on the telephone? No? Okay. I heard a beep.

BY MR. KEATING:

Q In your opinion, Ms. Jordan, what similarities exist between electric energy that TECO generates itself and electric energy that TECO purchases from another entity?

A What similarities? Could you repeat the question?

Q In your opinion, what are the similarities between electric energy that TECO generates itself and electrical energy that TECO purchases from another entity?

A The similarities would be I guess the creation via the power plants, the similarities in the type of fuel that's utilized to produce the product. But to some extent, there is probably more dissimilarities right now, because we are more heavily dependent on coal as opposed to the mix of the other IOUs, which may be potentially more of a gas, oil, that type.

Q Do you recall that on May 2, 2000, TECO filed a petition for a mid-course correction to its fuel and purchased power cost recovery factors?

A Yes.

Q What were the reasons that TECO provided at that time for the requested mid-course correction?

A The primary driver was an increase in our purchased power costs, which were being driven -- because what we were purchasing from the other utilities were from units that were gas and oil driven, and those prices were rising, so we were seeing a higher price on the market for purchased power.

Q Do you recall that on February 9th of this year, TECO filed a petition for a mid-course correction to it fuel and purchased power cost recovery factors?

A Yes.

Q To your recollection, was part of the reason for that mid-course correction that the projected under-recovery -- there would be a projected under-recovery primarily due to continued increases in natural gas and oil costs that had resulted in higher purchased power and generation costs?

A That is correct. I think in January of 2001, we had the coldest winter on record, and also gas prices were at an all-time high.

Q As a general proposition, when natural gas prices increase, do TECO's purchased power costs also increase?

A There's a direct correlation, yes.

Q So most of TECO's purchased power would come from natural-gas-fired generation?

A I can't say most of it. What I can say -- Witness Brown could probably give you a better breakdown, but what I can say is that as gas and oil prices are going up and we're in the market purchasing power on the spot market or day ahead, we are going to see the result of that in a higher price for purchased power.

Q If you could look at page 15 of your testimony that was filed September 20th, in lines 5

through 15, you provide a response to the question, "What is the appropriate rate of return on the unamortized balance of capital projects with an in-service date on or after January 1, 2002, that are expected to reduce long-term fuel costs?"

It's correct that Tampa Electric is not currently seeking recovery of any capital expenditures for projects with an in-service date on or after January 1, 2002?

A That is correct.

Q Do you believe that if TECO were seeking recovery of such amounts through the fuel clause, that recovery would be more certain through the fuel clause than through base rates?

A No. I would expect that with any type of recovery, whether through base rates or through the fuel clause, we would have to come before the Commission on a case-by-case basis and show justification that there would be a savings and net benefit to the ratepayers, so I don't see any more certainty in either place.

Q Absent a rate case, though, would recovery through the fuel clause be more immediate?

A It could potentially be more immediate, but I think you would have to meet the criteria to show

that it was beneficial in order to recover it.

Q Do you believe that expenses that qualify for recovery through the fuel adjustment clause are more certain to be recovered compared to expenses that would be recovered in base rates?

A No, I do not believe that there's more certainty.

Q What differences do you believe exist generally between recovery through the fuel cost recovery clause and recovery through base rates?

A For capital expenditures or in general?

Q In general.

A I guess probably the difference would be that in a base rate proceeding, you are putting up front your projected test period with your capital expenditures and O&M dollars and getting approval, whereas, probably, depending on the fuel cost, depending on the situation, you may actually put it in your projection and then go through an audit process and have it potentially disallowed. So there could be a timing as opposed to a front-end approval.

Q Would one difference also be that if you are under-recovering expenses that are recovered through the fuel clause, that under-recovery can be collected through the fuel clause true-up process,

whereas if you are underearning on recovery through base rates, you would have to -- some sort of rate proceeding would have to be instituted to collect that underearning?

A Personally, I think we're talking about two separate and different mechanisms here, and trying to compare them is a little bit unfair. But with regards to the fuel clause, I would say that, yes, you can recover that under-recovery, but there's also an evidentiary hearing that takes place, and you still have to be within the guidelines of the intent and the purpose of fuel clause.

As far as a base rate proceeding goes, yes, that's different criteria that you have to meet. But there is no more certainty, in my opinion, in one versus the other, because at some point you do have to come before the Commission and put forth your case and justify whatever the actions may be.

Q But you would agree that fuel clause proceedings are much more frequent than rate proceedings?

A And I think that was the intention of taking the fuel cost out of base rates, is due to the volatility and the nature, and to make the utility whole dollar for dollar in a nonprofit way.

Q In your opinion, should the rate of return for the unamortized balance of capital projects that are recovered through the fuel clause be different than the rate of return that the capital project would have earned if it was part of rate base?

A In my opinion, they would be pretty much one and the same, which would probably be the midpoint of the authorized range that the Commission has approved in a base rate proceeding. The asset is still being used. The only difference probably is that you've met the criteria that it's going to result in fuel savings to the ratepayers.

Q Do you believe that the Commission could authorize a utility to earn a rate of return on the unamortized balance of a capital project that's being recovered through the fuel clause other than the utility's authorized rate of return midpoint?

A I don't know if that's a legal question or not.

Q Maybe I can ask it differently. Regardless of the legality, do you see any technical impediments if the Commission were to take that course of action, were to approve a rate of return different than the rate of return midpoint that has been authorized for the company?

A I'm personally not aware of any technical difficulties, but I would point to the environmental clause, where we do have capital recovery, and there's definitely a policy set there. But I'm not aware of any technical impediments.

Q Do you believe that there's any maximum or minimum rate of return that the Commission could authorize a utility to recover on the unamortized balance of a capital project?

A I would assume they would look back to whatever the range was for the max and min, the maximum and the minimum.

Q What is TECO's policy with respect to interrupting non-firm retail customers in order to make non-firm sales, non-firm wholesale sales?

A Probably the appropriate witness is Witness Brown.

Q Do you know if TECO does have a policy with respect to that?

A We do not make non-firm non-separated sales at the expense of the interruptible customer.

Q Is it your understanding of that policy that a non-firm sale would be recalled in terms of a capacity shortfall?

A Yes.

Q I don't believe I have this with me, but I wanted to -- I guess not quote, but paraphrase some statements that were included in your testimony in Docket 010283, which was a hearing that was held on August 31st concerning treatment of gains on non-separated wholesale sales.

A Yes.

Q I believe you testified in that docket that TECO's interruptible customers receive approximately a 22% discount below the otherwise applicable firm service rate, even taking into account the additional cost of buy-through purchases. Do you still -- well, first let me ask, is that your understanding of what your testimony was?

A Yes, it was.

Q Do you still agree with that statement?

A Yes.

Q How did you calculate the 22% amount?

A Based on the rate, the otherwise applicable firm rate, taking the usage of all the other customers in the interruptible class. We have a rate comparison program that we can run, and we could put the customer hypothetically on the otherwise applicable rate and then adding in the optional provision cost and taking the difference.

Q In what time period was that analysis run, or over what time period?

A Subject to check, but I think it was 1998 through 2000.

Q Would that have been for the full calendar years for that period?

A Yes.

Q And which of the firm rate schedules was used in the comparison?

A I think it was the GSLD, the General Service Large Demand rate.

Q In your answer you said that as far as the term, it was subject to check, 1998 to 2000. Is that something you could confirm in a late-filed deposition exhibit?

A Yes.

Q And the GSLD rate schedule, is that something you were certain about?

A I will provide the years as well as the rate that was compared.

MR. KEATING: Okay. That would be Late-Filed Exhibit 1, time period and rate schedule used in analysis of discount to interruptible customers.

(Discussion of the record.)

MR. KEATING: And I guess one other piece of that that we would like to see is the actual calculations that compare the rates.

THE WITNESS: That's fine.

MR. KEATING: I don't know how I keep a straight face sometimes.

(Late-Filed Deposition Exhibit 1 was identified.)

BY MR. KEATING:

Q You also stated in your testimony that TECO's interruptible customers receive a minimum 99.5% electric service availability; is that correct?

A That's correct.

Q And is that still true to your knowledge?

A I have not updated it, but at the time that was correct.

Q How are non-firm retail customers impacted by TECO's non-separated wholesale sales?

A Interruptible customers are not impacted by non-separated wholesale sales. They benefit all retail customers. 100% of all the gains flow back until the utility reaches the threshold, so it is a benefit to all ratepayers. And we recall, as was stated earlier, in lieu of interrupting an interruptible customer, any non-firm non-separated

sales.

Q TECO would recall non-firm non-separated sales?

A Right.

Q Does TECO make any firm non-separated sales?

A That would probably be better answered by Witness Lynn Brown.

MR. KEATING: I think I have just a couple more questions, and I want to take just a minute.

(Short recess.)

MR. KEATING: I think that's all the questions I have. Thank you.

MR. VANDIVER: I have a very few questions.

CROSS EXAMINATION

BY MR. VANDIVER:

Q Good morning, Ms. Jordan.

A Good morning.

Q I'm shocked staff is finished.

Ms. Jordan, I believe you addressed hedging on pages 12 through 14 of your testimony.

A That's correct.

Q A total of a page and a half of testimony.

Would you agree with me that hedging is a

very important issue for ratepayers of this state?

A I would agree that it is an important issue that we should look at, yes.

Q Would Tampa Electric have any objection if the Commission were to defer consideration of the hedging issue and to workshop or to spin the hedging issue out into 2002 and take more testimony on this issue?

A That's not something that we've discussed, but I could understand the need to look into it further and to fully understand the impacts, rewards, and benefits of putting forth any type of hedging type strategy within the utility.

Q Would Tampa Electric support such a proposition?

A Yes.

Q Do you think it might be a good idea for the Commission to get more information, given that the other IOUs have filed very little testimony on this issue?

A Yes, it would probably be appropriate to get more information on that subject.

Q I would like to return for just a moment to your discussion with Mr. Keating concerning the discussion of the recovery of the assets through the

fuel clause. You were discussing the recovery through base rates versus the fuel clause.

A Yes.

Q And I think you said there was no more certainty when they were recovered through the fuel clause. Is it true that when Tampa Electric's rates are set in a rate case that Tampa Electric is given the opportunity to earn a fair rate of return?

A Correct.

Q And in that case, that rate of return is not guaranteed?

A Correct.

Q And therefore, the recovery of any given asset is not a dollar-for-dollar recovery in every case?

A That is correct. However, in order to get a capital expenditure through the fuel clause, you have to first show that it will result in that benefit. And that goes back to the '85 order, 14546. So from my perspective, the certainty is really whether or not you can even start to recover it through the fuel clause. And there is no certainty that you are going to get that unless you can prove that it does result in fuel cost savings.

Q Exactly. However, once that showing is

made and that showing is made in the fuel clause, that recovery is guaranteed, is it not?

A Yes, after that point.

Q After that point.

A Yes.

Q So that is a critical difference, is it not, that in the base rate case, you have the opportunity to earn a fair rate of return, and once that demonstration is made in the fuel clause, it's dollar for dollar guaranteed, is it not?

A That's correct.

Q Okay. I just wanted to clear up that point.

So Tampa Electric Company would have no objection to some sort of either spin-off proceeding in 2002 of the fuel clause or looking at the hedging issue in the 2002 fuel clause; is that correct?

A I don't think we would object to that.

MR. VANDIVER: Okay. Thank you very much. That's all I have.

CROSS EXAMINATION

BY MR. MCWHIRTER:

Q Ms. Jordan, in the schedules attached to your testimony, we're dealing not with actual fuel costs, but we're dealing with estimated fuel costs for

next year; is that correct?

MR. BEASLEY: Do you have a reference to a schedule, Mr. McWhirter?

MR. MCWHIRTER: I'm looking at Schedule E1, and with greater particularity, Schedule E3.

A That's correct.

Q And in order to come up with these numbers, I presume you rely upon some sources of information to forecast future fuel costs; is that correct?

A That's correct. We have a cross-functional team that is comprised of not just regulatory, but wholesale marketing and sales, resource planning, the fuels department, the accounting department, and we utilize a production costing model simulation.

Q And all of your forecasts are done, therefore, internally, and you don't rely on outside information such as NYMEX fuel cost futures or other projections?

A I would disagree with that. To say that we do it internally and don't rely on other forecasts would say that we're doing it in a bubble. I think the appropriate departments look out into the market to see what's going on, and that's their area of expertise.

Q And these departments report to you?

A No, they do not.

Q Are you the one that assimilates the numbers for E3?

A We are the one that prepares the schedule. Actually, what happens is, we have a process in place where all the information is put into our production costing model.

Q So people from different departments put in different --

A Correct.

Q -- pieces of information into a computer model, and the computer spits out the estimate?

A Yes.

Q Now, how frequently are these estimates revised?

A We do typically the fuel budget, you know, once a year, unless something in the marketplace is happening which would dictate that we go back and recalculate.

Q I see. And what date is that once-a-year look-see made?

A To coincide with the filings that we have to make.

Q And this filing, you filed it on September 20th?

A Yes.

Q What date did you do your look-see at the market?

A I think the model runs that were passed off to us were around September 4th.

Q Has anyone looked at the model again after September 11th to see what has happened to the fuel cost?

A Not -- no.

Q I noticed reading this mornings's Wall Street Journal for the futures price on --

MR. BEASLEY: Object to the form of the question.

MR. MCWHIRTER: You object to the form of the question? What is the nature of the objection?

MR. BEASLEY: The testimony regarding what you read in the Wall Street Journal.

MR. MCWHIRTER: I'm laying a foundation for the question.

MR. BEASLEY: That assumes facts not in evidence.

MR. MCWHIRTER: All right. Would you note the objection? Are you going to instruct your witness not to answer?

MR. BEASLEY: No, I'm not.

MR. MCWHIRTER: All right.

BY MR. MCWHIRTER:

Q This morning's Wall Street Journal, subject to check, Ms. Jordan, shows that in December and January, the anticipated futures cost for natural gas is in the range of $2.90. In your E3, you lay it out as $5.61 as an average for the year. In light of that very significant difference, is there any thought in your mind that your model should be upgraded or revisited?

A I'm not really the appropriate person to answer questions on the fuel forecasts. That would be Witness Joann Wehle.

Q Do I understand your answer to say that you would not be familiar with the specific details of any of the contracts that are involved in the transactions that underlie the estimates that are made in your exhibit?

A What you are -- if I understood you correctly, you are asking me to basically justify the forecasts that we have, compared to what you see in the Wall Street Journal. And what I am saying is that I cannot justify that, because I did not create that fuel forecast, and I don't have the details for that.

Q Who would be the person to trigger a re-examination of the fuel costs? Would that be you, or would that be Joann?

A Potentially, it could be either one of us. I mean, I could read something like you read and call her and say, "Does this impact our forecast?" Or she could me and say, "I think we need to relook at the forecast."

Q In the event that the fuel cost for natural gas, say, dropped 50% from your forecast, what action would you recommend the company take?

A Depending on whether or not we were in the market for natural gas as opposed to a contract -- there's a lot of variability there. I can't say that I would do one thing in particular. If we had most of our gas tied up in long-term contracts, there probably wouldn't be a lot I could do. If we were out on the spot market, I would have a discussion with Joann, and ultimately they would probably make the call from their department. They are the experts with regard to the fuel forecasts.

Q Do you have personal knowledge of specific contracts between Tampa Electric and fuel suppliers?

A I really don't, sir.

Q And who has that knowledge?

A Joann, the director of the fuels department.

Q So she's the auricle of fuel knowledge.

Is there a procedure in place that triggers an event for a modification of your fuel factor in light of significant changes in price as a company policy?

A Well, the major policy would be the plus or minus 10% as far as the under-recovery. Obviously, that would trigger us at any point, as we're looking and as our prices start -- our costs start to get out of alignment. And if it looks as if on just an overall basis we're going to be plus or minus 10%, that obviously would trigger us to go into detail and to research that.

Q Is there a company policy that calls for you to -- when prices change more than 10%, say they were reducing instead of going up, that you would automatically notify the Commission and take curative steps to change the fuel factor in mid course?

A The plus or minus 10% is not in relationship to the price of the commodity, if that's what you're asking. The plus or minus 10%, as you know, is in relationship to your total costs. So that's what would trigger it, not the price of the

commodity.

Q The total cost of fuel?

A Your total fuel expense.

Q So if the total fuel expense changed by more than 10%, would that trigger internal action if the price was going down as opposed to going up, as a company policy?

A The policy is plus or minus 10%. It doesn't trigger it just only up. It triggers it down as well, yes.

Q That's the Commission policy. I'm talking about the Tampa Electric policy.

A Well, we would abide by that policy.

Q You would immediately file a petition?

A (Nodding head affirmatively.)

Q I'm somewhat perplexed by what you say, that about 98% of the fuel burned by Tampa Electric Company generators comes from coal. Let's see. 93.33% you estimate next year. I'm looking at Schedule E3, page 2 of 2.

A Yes.

Q And about 4-1/2% comes from natural gas?

A Yes.

Q Is that fairly consistent with the ratio of coal to gas, or is the forthcoming year unusual?

A I'm sorry. Could you repeat the question?

Q I say is this ratio of fuel, the relative relationship between coal and gas, consistent from year to year because of the nature of your generating facilities, or does it change dramatically from year to year?

A It has not changed, but there is a little bit more gas.

Q In your last mid-course correction, one of the principal reasons given for the increase was a dramatic change in natural gas price. How could the change in natural gas price, which constitutes less than 5% of your total fuel costs, trigger a 10% change in your total fuel costs?

A Can I walk you through it?

Q Please.

A What you're looking at on the E3 schedule is Tampa Electric's generation mix. What you have to keep in mind is our total resource mix. So when you flip back to your E1 schedule that we talked about earlier that you had me look at -- that's probably the best place to look. You will see that there's another section, the purchased power, that total cost of 154 million. That is what is being impacted by the increase in the natural gas price, not so much Tampa

Electric's generation mix, but what we're going to the market to purchase.

Obviously, if we're purchasing from the market or from other utilities, they're not going to sell us their cheapest generation. They're going to keep that for their ratepayers. So we are paying for more expensive purchased power costs because the price of gas and oil was going up. So indirectly we're seeing that through the purchased power. So it's looking at the total picture, not just looking at the generation mix.

But keep in mind that coal has also increased for 2002 as well. So we also have an increase in our coal price from last year to this year, this coming year.

Q Let's look at line 6 of Schedule E1. It looks like you're going to buy 2.7 million megawatt-hours of electricity and pay $52.62 a megawatt-hour for the electricity; is that correct?

A Correct.

Q And that is because you buy power from other utilities. Do you have a fixed price on this power, or does that power fluctuate?

A The price fluctuates. And Witness Brown could probably answer questions on purchased power.

Q Do you know the things that cause the price to fluctuate, or would you prefer Mr. Brown to do that?

A I could live you a high level, but I would prefer Mr. Brown to --

Q Give me a highlight, and then we --

A Obviously, we just talked about one of the main things, which is gas, obviously, in the marketplace.

Q So if the price of natural gas went from 5.61 down to somewhere close to the $2 or $1.50, that would have a dramatic impact on your purchased power costs, wouldn't it?

A Yes.

Q And your testimony was that in the event there was an indication at some point in the year that your total fuel cost for the year was going to change by more than 10%, your company policy is immediately to bring that to the attention of the Commission and request a mid-course correction?

A That is the Commission's policy, and we do abide by the Commission's policy, yes.

Q The Commission requires you to do that, or --

A They require notification.

Q You would not petition; you would just notify the Commission?

A Well, we would follow the guidelines. And I'm sure we would ultimately petition, but we would definitely send a letter of notification as a first step.

Q And gas is most expensive in what season of the year?

A As a novice, I would say summer, but I'm not the caller. I guess it could be winter.

Q That might be better answered by Mr. Brown or Ms. Wehle?

A Yes.

Q Now, I notice that when you're selling electricity, you're going to sell three-quarters of a million megawatt-hours, and the price you're going to charge for that is $25.62 for sales under your schedule D, line 15, and the average cost before you factor in gains is $24.02. I calculated that average by deducting $3 million on line 18 from the 21 million on line 20 to get back to the fuel cost as opposed to the cost including the gains on the sales.

A I will have to take your word for your calculation.

Q Can you explain the rationale for the

disparity in which you sell electricity at $24 a megawatt-hour and buy it back, buy electricity at 52.62 a megawatt-hour?

A You have as to keep in mind, first of all, that especially the Schedule D separated sale is separated from the rate base. Retail customers are not responsible for any of the generating plant associated with that sale. These are cost-based, FERC-approved sales. They've been before the Commission. There were net benefits to ratepayers. And we are contractually obligated to the terms of those contracts, so at this point, you know, we cannot arbitrarily change or assign a different cost.

Q You can't assign a different cost to the customers under those contracts because of your contractual obligation.

A Right.

Q Can you as the regulatory czar of Tampa Electric direct me to the Commission requirement that forces you to charge your retail customers the higher price for purchased power instead of the lower price for your generated power?

A Well, the way you've stated it, let me rephrase and say that the Commission has addressed separated wholesale sales in prior proceedings, in

particular, as late as the '97 docket. That was Order No. PSC-97-0262-FOF-EI. The Commission said that as far as wholesale sales currently being made pursuant to existing contracts, they will not be affected by this policy of requiring retail markets for all prospective separable sales to be allocated at system average cost. So this is the order that I would direct you to look at that shows that at this point in time, separated sales are treated according to the terms of the contract per the order of the Commission.

Q That's the docket in which the Commission addressed benefits to retail customers and approved wholesale sales when there was a benefit to retail customers?

A Correct.

Q Can you identify the benefit to retail customers that occurs when you sell power at $24 a megawatt-hour and buy it back at -- buy replacement power at $52?

A The benefit is the fact that base rates do not reflect the costs that have been separated out for the generation plant and for the O&M expense. The A schedules only capture, obviously, fuel-related issues, but the other benefit is off-sheet, so to

speak. You don't see that. Their rates do not reflect the cost of that sale.

Q Do you perform the separation studies, or does someone else in your company --

A Someone else does.

Q Do you know the procedure that's used?

A Not in depth.

Q And who is that other person? Bill Ashcroft?

A Ashburn.

Q Ash what?

A Ashburn.

Q Ashburn. I'm sorry. Ashcroft is the attorney.

A I don't think he wants that job right now.

Q Bill Ashburn isn't trying to replace him. Okay.

Now, you have Schedule D jurisdictional sales. And Schedule D sales, as I understand it, are non-separated sales. It's Schedule D hyphen --

MR. BEASLEY: Were are you referring to?

MR. MCWHIRTER: I'm looking at line 13 on Schedule E-1.

A Yes.

Q Now, in those kind of sales, based on your

previous answer, retail customers don't get the benefit of having the generating plant removed from the rate base; is that correct?

A That's correct.

Q They still pay for that. And you're going to sell 72,000 megawatt-hours at a price of $14.68 under those contracts?

A That's correct. I think that is a unit power sale, and so the customer takes on the added risk as if the unit is not there. It is up to them to find replacement power for any planned or unplanned outage.

Q That price is cheaper than the price it costs you to produce power out of your own generators. Where does that power come from?

A That's an aggregate price. When you say cheaper than our price, you're looking at an aggregate number, whereas this is probably a particular unit.

Q What unit is it that you have that has a fuel cost of $14.68 a megawatt-hour?

A It's a coal unit.

Q What is it?

A It's the Big Bend coal unit.

Q Beg your pardon?

A Big Bend coal unit.

Q Big Bend 1, 2, 3, or 4?

A I think it's 4, sir, but that would be subject to check.

Q And your schedule, Schedule E4 shows the price for Big Bend 4 to be $12.37 -- I mean $23.70 a megawatt-hour, which is -- what? $9 higher than the sales price? Am I misreading something? Look at line 18.

A I see where you're referring. I would have to check.

Q What are Schedule J sales?

A Emergency, FERC Schedule A's.

Q J, I said.

A Yes.

Q Schedule A I thought was emergency.

A Well, that is JA. It would be a JA sale, emergency.

Q Looking at Schedule 7, page 2 of 7, you anticipate purchasing 151,000 megawatt-hours of Schedule J sales. Do you expect that many emergencies during the year?

A That is -- there's a JA emergency and a JC, which is optional provision.

Q What? JC?

A Yes.

Q I didn't understand what you said JC was.

A You were saying -- Schedule J is emergency and optional provision, so that it's clear, and the 151 is JC, which is optional provision.

Q So those are sales -- those are the purchases that you make for the benefit of your non-firm customers?

A Yes.

Q And you anticipate that that cost is going to be $71.61 per megawatt-hour during the forthcoming year?

A In total.

Q Average, you mean?

A Yes.

Q If you would rather Mr. Brown answer this question, let me know, but are you familiar with the concept of market-basked pricing and cost-based pricing as it pertains to the wholesale market?

A No.

Q When you purchase power, your purchased power is shown on Schedule E7, and it shows that you're going to have about a million, 1.1 million megawatt-hours of market-based purchased power. And you don't know what that means?

MR. BEASLEY: Which schedule are you

referring to?

MR. MCWHIRTER: I'm looking at the penultimate line on that page.

BY MR. MCWHIRTER:

Q You're paying $60 million for market-based power in the forthcoming year?

A Right. Are you asking me -- maybe I misunderstood your question.

Q I asked you if you knew what market-based power meant in the wholesale market, and you said no, and I was looking --

A I thought you meant in terms of actually participating in the market. I'm sorry. If you're just asking me in terms of market-based, that's whatever the market price is. You have the right to charge a fair market price for the product.

Q Now, you purchase power from Florida Power Corporation and Florida Power & Light from time to time?

A Yes.

Q And I understand they must sell their power at cost; is that correct?

A You're getting into an area that I don't know that much about it. I assume they probably have market-based authority, at least outside of the state,

if not in the state.

Q Are you buying your power outside or inside the state?

A Inside.

Q You don't personally get involved in finding out where the electricity comes from?

A Correct.

Q You're just the person that brings the information up to Tallahassee, and if it's not right, then --

A You've got a job to do.

Q Okay. I notice that you're going to charge the customers some $88 million this year for --

MR. BEASLEY: Where are you referring to?

MR. MCWHIRTER: I'm sorry. Strike that, strike that, strike that.

BY MR. MCWHIRTER:

Q You're going to charge the customer -- I'm looking at Schedule E1, line 34, and you're going to charge retail customers $3.3 million for the Peabody contract buy-out. Do you know what the terms and conditions of that buy-out are and how long it lasts?

A I don't know all the terms and conditions, but I think the buy-out lasts through 2003, the end of 2003. It terminates on December 31st. And I think it

has been in place since April of 1995.

Q So in 1995 --

A Is when that started.

Q -- Tampa Electric paid some money to Peabody to renegotiate the coal price?

A I think to buy out a long-term coal agreement.

Q To buy out a long-term agreement. And that long-term agreement ran through the year 2003?

A I'm sorry. It goes through 2004, December 31, 2004.

Q So you had a contract with Peabody to buy coal at a certain price from '95 through -- or some earlier date through 2004, and you bought it out in 1995?

A That's my understanding.

Q Do you know what the price on that contract was that you bought out?

A Say again?

Q Do you know what the price for coal was when the contract was bought out?

A No.

Q You don't know the price?

A No.

Q In line 33 on Schedule E1, you're charging

the customers $88.6 million for true-up. That is the amount of money that was involved in 2000 and 2001?

A Correct.

Q What was the total under-recovery for 2001?

A 65,543,259.

Q What?

A $65,543,259.

Q And the difference between 65 million and 88 million is?

A The final true-up for 2000.

Q So you have 2001 --

A You asked me what the under-recovery was for 2001. That's the 65 million. Then we've got the final true-up for 2000, which is 23,129,476.

Q So you add those together to come up with the 88 million?

A Correct.

Q And you really had -- what? A $45 million under-recovery, or 46 million in 2000, and you split the recovery in two years? Is that what the deal was?

A I'm sorry. Repeat that again.

Q Well, you were carrying 23 million into 2002 for an under-recovery in the year 2000; is that correct?

A Right.

Q And that amount is one-half of the under-recovery in 2000. Didn't you collect part of the 2000 under-recovery during 2001?

A Not in that period. Maybe I don't understand what you're asking me.

Q We've got December 31, 2000, and you had paid more for fuel costs than you had charged your retail customers; is that right?

A That's correct.

Q And was that amount 23 million, or was it some other amount?

A It was 23 million.

Q Twenty-three million was the total under-recovery for 2000?

A That's the final amount. We had -- keep in mind that when you set the factor for 2001, that's an actual estimated. So we estimated what we thought the under-recovery would be throughout the rest of 2000. And basically you have just a few months that are estimated, so when you do your final true-up in April, you're truing up just those additional months that are not included in the new factor for '01.

Q All right. Well, what was included in 2001 before you revised it?

A I didn't bring those numbers with me, sir.

Q Would you agree subject to check that it was something like 46 million under-recovery in 2000?

A No, I wouldn't agree to that. I think I'm missing something in what you're saying, because we do a reprojection and actual estimated that is folded into that factor.

Q I'm not trying to confuse you. I'm just -- my recollection of reading your petition was that you said when you had the mid-course correction that you underestimated the 2000 loss, and rather than trying to collect the entire amount in 2001, you would collect part of it in 2001 and another part of it in 2002. Do you have any recollection of that?

A Right. But now we're talking about different years. We were originally talking about 2000. If you're talking about 2001, yes, you are correct. We were anticipating that we were going to be under-recovered, and we agreed to collect 50% of it this year for that and flow that over, plus the 23 million final true-up, into 2002. And that's where you see that 55 million that we're going to collect for 2002.

Q So the 23 million was your total under-recovery in the year 2000?

A Correct.

Q You're sure?

A The final true-up was 23 million.

Q Well, that's what you put in your mid-course correction, but you had some true-up when you came in in November with your estimated shortfall.

If you don't know, Ms. Jordan, I don't want to antagonize you.

A No. I guess I'm just missing what you're saying. What I'm explaining to you is that, yes, the final true-up in 2000 was 23 million. When we reset for the mid-course, we did not ask recovery for that 23 million. We always said that we would collect it in 2002 as part of the normal process.

Q Okay. And are you telling me that that was the total under-recovery for the year 2000, 23 million, or was there some greater number?

A The final true-up for 2000 was 23 million.

Q I didn't ask you what final was. I asked you what the total was.

A Okay. That was the total under-recovery.

Q For the whole year 2000?

A Right.

Q So what happened was, when you got to 2001, you had a gigantic comparative under-recovery, is that right, 65 million compared to 23 million for the

preceding year?

A Prior to the mid-course, we were anticipating 86 million under-recovered, which included the 23 million. We came to the Commission and petitioned and requested that we be allowed to recover half of the 65 million, leaving the other 30 million and the 23 million still on the table for 2002. We would recover it over a 20-month period.

Q I got you.

And what is going to be your total estimated under-recovery this year?

A That's the 88 million.

Q Well, that includes 2000. I'm talking about -- the under-recovery for the current year is what? Sixty-five million?

A Right, right.

Q And it's still 65 million, even though you got a mid-course correction increasing the rate.

A Right.

Q And how does that 65 million compare to the estimate that you made in February when you started the mid-course correction?

A I don't have that with me.

Q Would you agree to file that as a late-filed exhibit?

A It's in the mid-course correction filing. Do you want me to produce that schedule for you again?

Q Yes.

A Okay.

MR. BEASLEY: Have you got a title for that, Mr. McWhirter?

MR. MCWHIRTER: Actual 2001 under-recovery, which would be the difference between your estimate in November of 2000 and your current estimate for 2001. It's the actual under-recovery for the year 2001.

MR. BEASLEY: You referred to a February 2001 estimate earlier in connection with the mid-course correction.

MR. MCWHIRTER: As I understand it, you made an estimate of what your 2001 fuel costs would be in September of 2000, and in February of 2001 you said that was wrong and it was going to be bigger. And I'm trying to find out whether that second estimate was accurate or whether that second estimate was still low and you had an even greater under-recovery than you anticipated you would have in February of 2001.

MR. BEASLEY: Can we go off the record?

MR. MCWHIRTER: Yes.

(Discussion off the record.)

MR. MCWHIRTER: In Docket 000001, Tampa Electric anticipated that its 2001 fuel cost would be a number, and I would like a late-filed exhibit that demonstrates the difference between that number and the current number for 2001.

MR. BEASLEY: To revisit that request, you want the November estimate compared to the 65 million?

MR. MCWHIRTER: NO. I want the November estimate for 2001 --

THE WITNESS: You want the September filing compared to the September filing, the September that we filed -- I mean the August filing.

MR. MCWHIRTER: You got it.

MR. BEASLEY: Okay. That will be Late-Filed Exhibit 2.

(Late-filed Deposition Exhibit 1 was identified.)

BY MR. MCWHIRTER:

Q I would like you to look at your Schedule 7 and look at the bottom group of numbers on page 2 of Schedule 7, which shows your anticipated January through December fuel costs, and in that you indicate

that you're going to buy power from HPP. What is HPP?

A Hardee Power Partners.

Q And that's under Schedule IPP. What is IPP?

A Independent power producer.

Q And you're going to buy a million dollars, or a million megawatt-hours plus at an average -- at a total cost of $46.19 a megawatt-hour.

A Where --

Q Okay. See the line that says through, January through December?

A Correct.

Q Look over in your total cost column on 8B. And that's $46.19 a megawatt-hour; is that correct? In Column 4 you're using megawatt-hours, and in Column 8 you're using kilowatt-hours. I'm just trying to make them comparable.

A Tell me again where you are. What column?

Q Column 8, sub B, Schedule 7, page 2 of 2. I see a $48 million number --

A I'm sorry. I was looking at the actual estimated filing. That's why.

MR. BEASLEY: Page 49.

THE WITNESS: Thank you.

MR. McWHIRTER: Page 49. That would have

been easier.

THE WITNESS: Yes.

BY MR. MCWHIRTER:

Q Okay. You're going pay Hardee Power Partners $46.19 for a total of $48 million you expect during the forthcoming year?

A Yes.

Q And that payment is based primarily on gas costs? Hardee Power burns natural gas? Do you know? If you don't know, just say, "I don't know."

A Yes, I don't know.

Q Now, if you'll look at Schedule E6 --

MR. BEASLEY: I think it would be helpful if you would --

MR. MCWHIRTER: Page 47.

MR. BEASLEY: Good. Thank you.

BY MR. MCWHIRTER:

Q Look down near the bottom, and you'll see HPP again. That's Hardee Power, and you're going to sell it 486,000 megawatt-hours; is that correct?

A Yes.

Q And the fuel cost on those sales is $25.62?

A Yes.

Q Now, is that one of the fuel costs that's locked in by merit of that 1997 order that you talked

about earlier?

A It's a separated contract, yes.

Q And Hardee Power, is that an affiliated company to Tampa Electric Company?

A Yes.

Q And you're fearful that Hardee Power is going to sue Tampa Electric if you seek to change that contract?

Strike that question. That's unfair.

Look under Column B on Schedule 7. And the price that you're going to receive for that power is not the fuel cost. It's a higher number. Can you tell me what the difference is between the fuel cost and the higher number?

MR. BEASLEY: Which number are you referring to?

MR. McWHIRTER: I'm referring to the $36.10 in Column 7B.

A Probably the O&M component, the variable O&M component, and potentially any gains, I guess.

Q It's not the gain on the sale. It's something else.

A It's probably the O&M and the gain.

Q Well, you've got gain down below, various gains, so it's not the gain on Hardee. That's --

A I would have to check. It may just be O&M there.

Q And is that O&M price flowed back to the retail consumer through the fuel clause?

A It's per the wholesale incentive guideline, so if we haven't passed a threshold -- oh, I'm sorry. On O&M, it's kept in other operating revenues.

Q So that money goes to the company and is not shared with the retail customers?

A Correct.

MR. MCWHIRTER: As Late-Filed Exhibit Number 2 --

MR. BEASLEY: Three.

MR. MCWHIRTER: I'm sorry. Yes. I apologize.

As Number 3, would you prepare a list of the different wholesale schedules by which you buy and sell power, such as A, JA, JC?

THE WITNESS: We provided that in numerous interrogatories to you already, sir.

MR. MCWHIRTER: Well, I would like to have it as an exhibit to this deposition.

MR. BEASLEY: Well, I think that would be duplicative.

MR. MCWHIRTER: Duplicative?

MR. BEASLEY: Yes. You already have it.

MR. McWHIRTER: Not duplicitous?

MR. BEASLEY: Duplicitous.

MR. McWHIRTER: Do you object to filing that exhibit?

MR. BEASLEY: Describe what you want.

MR. McWHIRTER: I would like to have a list of the various schedule classifications used by Tampa Electric Company in its wholesale transactions, such as Schedule A, Schedule B, Schedule D, and an identification of each one of these schedules.

MR. BEASLEY: We will either do that or file a late-filed exhibit telling you where you already have it.

MR. McWHIRTER: I prefer it to be an exhibit to this deposition. If you've already got it, it won't be too tough.

MR. BEASLEY: Mr. McWhirter, could we have Mr. Brown sponsor that exhibit?

MR. McWHIRTER: Sure.

MR. BEASLEY: So we'll withhold it from Ms. Jordan's deposition, and you can ask for it in Mr. Brown's.

MR. McWHIRTER: Okay.

BY MR. McWHIRTER:

Q Do you have know what syn fuel is, or would you prefer to have Ms. Wehle answer that?

A Ms. Wehle can.

MR. McWHIRTER: I didn't notice Ms. Wehle for deposition, but do you object if I ask her a few questions based on the ones Ms. Jordan thinks she would be a better person to answer?

MR. BEASLEY: Sure, as long as it's limited to those items.

BY MR. McWHIRTER:

Q Are you familiar with FERC Form 423?

A No.

Q Do you not familiar with it? You don't know anything about it?

A No.

MR. McWHIRTER: I tender the witness.

MR. BEASLEY: That's it? Okay.

CROSS EXAMINATION

BY MR. BEASLEY:

Q Mr. McWhirter characterized, I believe, your costing policy as assigning purchased power costs to retail customers, but not to wholesale customers. Is that a correct assessment?

A No, it's not. Wholesale customers, in

particular the separated sales, depending on the contract, if they are system average, the system average fuel costs include not only Tampa Electric's own generating fuel costs, but also the cost of purchased power.

Q And I think you indicated to me that your reference to the J schedules may have been somewhat needing correction?

A Yes. I think I have said the JA was the emergency, but the JA is optional provision in our designation internally, and the JC is the economy or emergency. I swapped them around. I'm sorry about that.

MR. BROWN: Economy.

THE WITNESS: Economy.

MR. McWHIRTER: That's going to be his schedule anyway, so you don't have to worry about it.

MR. BEASLEY: That's it.

(Deposition concluded at 11:10 a.m.)

CERTIFICATE OF ADMINISTERING OATH

STATE OF FLORIDA)
COUNTY OF LEON)

I, MARY ALLEN NEEL, Notary Public in and for the State of Florida at Large:

DO HEREBY CERTIFY that on the date and place indicated on the title page of the foregoing transcript, an oath was duly administered by me to the designated witness before testimony was taken.

WITNESS my hand and official seal this 27th day of October, 2001.

MARY ALLEN NEEL, RPR
100 Salem Court
Tallahassee, Florida 32301



CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, MARY ALLEN NEEL, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter transcribed under my supervision; and that the foregoing pages numbered 1 through 56 are a true and correct transcription of my stenographic notes.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, or relative or employee of such attorney or counsel, or financially interested in the action.

DATED THIS 27th day of October, 2001.

MARY ALLEN NEEL, RPR
100 Salem Court
Tallahassee, Florida 32301
(850) 878-2221

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor	))))	DOCKET NO. 010001-EI FILED: November 6, 2001

TAMPA ELECTRIC COMPANY'S

LATE-FILED DEPOSITION EXHIBITS (NOS. 1-2)

OF

J. DENISE JORDAN

Tampa Electric files this its Late-Filed Deposition Exhibits of Witness J. Denise Jordan (Nos.1-2), requested during her deposition held on October 25, 2001.

TAMPA ELECTRIC COMPANY
DOCKET NO. 010001-EI
DEPOSITION OF J. D. JORDAN
LATE-FILED DEPOSITION EXHIBITS
FILED: NOVEMBER 6, 2001

INDEX

LATE - FILED EXHIBIT	TITLE
1	Time Period and Rate Schedule Used in Analysis of Discount to Interruptible Customer
2	Difference Between 2001 Estimated and Actual Fuel Costs

1. Provide the time period and rate schedule used in determining the discount provided to interruptible customers in comparison to service under a firm rate schedule.

A. The attached tables show the savings the interruptible customers received in each year from 1996 to 2000, compared to the otherwise applicable firm rate. As stated in the pre-filed testimony of J. Denise Jordan, the interruptible customers received a 22% discount in calendar year 2000, as shown on page 2 of 6.

Calculation

The firm service total bill was determined by recalculating each interruptible account's bill using the otherwise applicable firm rate. If demand was greater than 999 KW, then the GSLD(T) rate was used; otherwise the GSD(T) rate was used.

The interruptible service total bill was determined by adding the interruptible rate bill and optional provision purchased power charges.

The bill amounts for customers with multiple accounts are shown in total.

The savings to customers is calculated by subtracting the interruptible service total bill from the firm service total bill.

TAMPA ELECTRIC COMPANY

Total Bill Comparison
Interruptible Service v. Firm Service
January - December 2000

(1)	(2)	(3)	(4)	(5)
	Total Bill by Rate Class		Savings [4]	
Customer [1]	Interruptible [2]	Firm [3]	$	%
1	$3,009,050.94	$3,899,027.21	$889,976.27	23%
2	$99,103.10	$226,958.38	$127,855.28	56%
3	$2,325,174.40	$2,663,420.49	$338,246.09	13%
4	$4,440,595.74	$7,741,339.45	$3,300,743.71	43%
5	$1,733,655.45	$2,566,776.36	$833,120.91	32%
6	$0.00	$0.00	$0.00	NA
7	$896,739.24	$1,018,832.78	$122,093.54	12%
8	$1,241,582.42	$1,393,220.58	$151,638.16	11%
9	$1,786,423.79	$2,837,068.03	$1,050,644.24	37%
10	$161,652.92	$205,318.27	$43,665.35	21%
11	$1,854,373.75	$2,299,967.59	$445,593.84	19%
12	$390,766.54	$437,506.47	$46,739.93	11%
13	$158,070.05	$226,109.58	$68,039.53	30%
14	$2,729,904.43	$2,894,397.62	$164,493.19	6%
15	$338,091.12	$375,545.05	$37,453.93	10%
16	$48,318,313.82	$60,852,825.00	$12,534,511.18	21%
17	$1,276,210.20	$1,463,716.38	$187,506.18	13%
18	$2,180,049.44	$2,411,815.49	$231,766.05	10%
19	$1,525,120.22	$1,753,194.72	$228,074.50	13%
20	$436,027.52	$564,473.77	$128,446.25	23%
21	$3,733,004.12	$4,588,407.78	$855,403.66	19%
22	$381,474.47	$457,869.48	$76,395.01	17%
23	$0.00	$0.00	$0.00	NA
24	$607,221.49	$821,907.77	$214,686.28	26%
25	$441,055.60	$504,014.47	$62,958.87	12%
26	$149,808.55	$280,487.04	$130,678.49	47%
27	$124,504.21	$144,869.47	$20,365.26	14%
28	$546,496.85	$744,058.27	$197,561.42	27%
29	$375,213.88	$409,165.99	$33,952.11	8%
30	$0.00	$0.00	$0.00	NA
31	$220,622.92	$296,014.37	$75,391.45	25%
32	$279,589.23	$525,707.82	$246,118.59	47%
33	$517,779.48	$583,637.89	$65,858.41	11%
34	$887,891.81	$1,027,812.83	$139,921.02	14%
35	$366,460.47	$426,098.31	$59,637.84	14%
36	$306,061.72	$349,031.66	$42,969.94	12%
TOTAL	**$83,838,089.89**	**$106,990,596.37**	**$23,152,506.48**	**22%**

[1] May include billing information for multiple accounts

[2] Includes charges for optional provision power purchases

[3] Based on GSLD(T) rate if demand > 999 kW and on GSD(T) rate if demand < or = 999 kW

[4] Savings ($) = Firm Rate Total Bill (Column 3) less Interruptible Rate Total Bill (Column 2)

TAMPA ELECTRIC COMPANY

Total Bill Comparison
Interruptible Service v. Firm Service
January - December 1999

(1)	(2)	(3)	(4)	(5)
	Total Bill by Rate Class		Savings [4]	
Customer [1]	Interruptible [2]	Firm [3]	$	%
1	$4,719,064.29	$5,889,394.35	$1,170,330.06	20%
2	$96,947.94	$221,349.34	$124,401.40	56%
3	$1,438,213.33	$1,620,045.68	$181,832.35	11%
4	$6,446,799.90	$9,770,674.72	$3,323,874.82	34%
5	$2,457,335.98	$3,479,449.29	$1,022,113.31	29%
6	$0.00	$0.00	$0.00	NA
7	$808,930.55	$914,897.98	$105,967.43	12%
8	$1,066,121.95	$1,204,186.04	$138,064.09	11%
9	$1,098,648.14	$2,102,701.96	$1,004,053.82	48%
10	$1,691,084.64	$2,082,891.56	$391,806.92	19%
11	$381,861.92	$420,703.14	$38,841.22	9%
12	$138,191.03	$209,663.51	$71,472.48	34%
13	$2,416,527.89	$2,637,565.49	$221,037.60	8%
14	$314,186.07	$336,822.80	$22,636.73	7%
15	$35,407,925.47	$44,443,219.32	$9,035,293.85	20%
16	$1,204,311.05	$1,460,452.04	$256,140.99	18%
17	$2,039,191.17	$2,282,511.13	$243,319.96	11%
18	$1,385,414.28	$1,612,190.23	$226,775.95	14%
19	$1,449,060.61	$1,630,023.64	$180,963.03	11%
20	$3,848,790.83	$4,766,063.87	$917,273.04	19%
21	$336,896.17	$425,358.50	$88,462.33	21%
22	$0.00	$0.00	$0.00	NA
23	$3,232,479.71	$3,663,739.63	$431,259.92	12%
24	$407,727.35	$461,137.49	$53,410.14	12%
25	$184,199.01	$317,596.86	$133,397.85	42%
26	$111,635.53	$139,496.47	$27,860.94	20%
27	$706,542.32	$864,606.79	$158,064.47	18%
28	$361,710.26	$394,506.04	$32,795.78	8%
29	$0.00	$0.00	$0.00	NA
30	$305,866.71	$415,119.07	$109,252.36	26%
31	$240,726.08	$455,342.24	$214,616.16	47%
32	$495,978.24	$558,305.97	$62,327.73	11%
33	$861,503.61	$1,000,798.24	$139,294.63	14%
34	$313,420.90	$420,898.13	$107,477.23	26%
35	$289,576.50	$345,648.62	$56,072.12	16%
TOTAL	**$76,256,869.43**	**$96,547,360.14**	**$20,290,490.71**	**21%**

[1] May include billing information for multiple accounts

[2] Includes charges for optional provision power purchases

[3] Based on GSLD(T) rate if demand > 999 kW and on GSD(T) rate if demand < or = 999 kW

[4] Savings ($) = Firm Rate Total Bill (Column 3) less Interruptible Rate Total Bill (Column 2)

TAMPA ELECTRIC COMPANY

Total Bill Comparison
Interruptible Service v. Firm Service
January - December 1998

(1)	(2)	(3)	(4)	(5)
	Total Bill by Rate Class		Savings [4]	
Customer [1]	Interruptible [2]	Firm [3]	$	%
1	$4,074,406.97	$5,684,848.76	$1,610,441.79	28%
2	$92,892.53	$206,717.60	$113,825.07	55%
3	$1,194,427.59	$1,579,022.04	$384,594.45	24%
4	$5,772,098.57	$9,892,587.51	$4,120,488.94	42%
5	$2,448,301.50	$3,767,106.04	$1,318,804.54	35%
6	$40,439.39	$51,804.36	$11,364.97	22%
7	$744,249.76	$942,545.60	$198,295.84	21%
8	$1,041,392.43	$1,357,883.36	$316,490.93	23%
9	$2,314,960.41	$3,666,864.93	$1,351,904.52	37%
10	$1,161,728.58	$1,775,365.74	$613,637.16	35%
11	$345,464.25	$434,686.62	$89,222.37	21%
12	$122,054.92	$201,834.04	$79,779.12	40%
13	$2,225,251.45	$2,788,884.21	$563,632.76	20%
14	$178,698.87	$215,527.95	$36,829.08	17%
15	$41,971,480.63	$60,671,921.83	$18,700,441.20	31%
16	$970,630.63	$1,262,242.22	$291,611.59	23%
17	$1,543,588.21	$1,971,449.68	$427,861.47	22%
18	$939,136.51	$1,249,106.61	$309,970.10	25%
19	$1,232,049.90	$1,570,896.37	$338,846.47	22%
20	$4,514,478.87	$5,805,992.43	$1,291,513.56	22%
21	$324,668.32	$472,405.55	$147,737.23	31%
22	$0.00	$0.00	$0.00	NA
23	$2,957,675.49	$3,792,338.55	$834,663.06	22%
24	$329,865.41	$433,085.91	$103,220.50	24%
25	$180,744.22	$350,280.15	$169,535.93	48%
26	$109,704.80	$151,083.86	$41,379.06	27%
27	$120,361.78	$173,872.89	$53,511.11	31%
28	$310,704.25	$392,965.52	$82,261.27	21%
29	$578,021.25	$804,683.10	$226,661.85	28%
30	$330,753.76	$476,324.09	$145,570.33	31%
31	$216,600.20	$486,650.30	$270,050.10	55%
32	$422,801.12	$540,433.98	$117,632.86	22%
33	$787,741.15	$1,061,543.55	$273,802.40	26%
34	$264,771.82	$381,632.67	$116,860.85	31%
35	$254,725.72	$336,180.65	$81,454.93	24%
TOTAL	**$80,116,871.26**	**$114,950,768.67**	**$34,833,897.41**	**30%**

[1] May include billing information for multiple accounts

[2] Includes charges for optional provision power purchases

[3] Based on GSLD(T) rate if demand > 999 kW and on GSD(T) rate if demand < or = 999 kW

[4] Savings ($) = Firm Rate Total Bill (Column 3) less Interruptible Rate Total Bill (Column 2)

TAMPA ELECTRIC COMPANY

Total Bill Comparison
Interruptible Service v. Firm Service
January - December 1997

(1)	(2)	(3)	(4)	(5)
	Total Bill by Rate Class		Savings [4]	
Customer [1]	Interruptible [2]	Firm [3]	$	%
1	$4,181,596.54	$6,025,311.82	$1,843,715.28	31%
2	$81,974.00	$201,689.79	$119,715.79	59%
3	$1,263,305.62	$1,701,916.14	$438,610.52	26%
4	$6,772,603.69	$10,950,154.26	$4,177,550.57	38%
5	$2,922,994.47	$4,407,037.98	$1,484,043.51	34%
6	$198,474.39	$245,557.07	$47,082.68	19%
7	$792,018.97	$994,622.30	$202,603.33	20%
8	$1,082,909.31	$1,413,332.25	$330,422.94	23%
9	$1,331,143.34	$2,389,721.75	$1,058,578.41	44%
10	$714,516.48	$1,154,023.15	$439,506.67	38%
11	$325,530.77	$419,155.49	$93,624.72	22%
12	$117,765.10	$196,235.59	$78,470.49	40%
13	$2,207,726.92	$2,822,564.91	$614,837.99	22%
14	$0.00	$0.00	$0.00	NA
15	$41,987,169.37	$61,718,961.03	$19,731,791.66	32%
16	$827,620.20	$1,105,858.03	$278,237.83	25%
17	$1,329,385.96	$1,915,228.57	$585,842.61	31%
18	$843,880.52	$1,150,623.41	$306,742.89	27%
19	$1,079,068.63	$1,406,948.33	$327,879.70	23%
20	$4,910,727.50	$6,431,908.90	$1,521,181.40	24%
21	$279,220.52	$419,450.49	$140,229.97	33%
22	$0.00	$0.00	$0.00	NA
23	$2,997,362.81	$3,909,357.72	$911,994.91	23%
24	$277,921.42	$372,898.14	$94,976.72	25%
25	$212,469.98	$411,074.19	$198,604.21	48%
26	$115,298.48	$158,972.87	$43,674.39	27%
27	$0.00	$0.00	$0.00	NA
28	$283,637.41	$366,602.79	$82,965.38	23%
29	$627,258.91	$901,511.46	$274,252.55	30%
30	$349,873.84	$507,794.94	$157,921.10	31%
31	$248,149.97	$538,674.72	$290,524.75	54%
32	$521,459.46	$653,614.28	$132,154.82	20%
33	$756,780.67	$1,040,469.22	$283,688.55	27%
34	$239,182.38	$354,972.04	$115,789.66	33%
35	$255,112.53	$337,984.87	$82,872.34	25%
TOTAL	**$80,134,140.16**	**$116,624,228.50**	**$36,490,088.34**	**31%**

[1] May include billing information for multiple accounts

[2] Includes charges for optional provision power purchases

[3] Based on GSLD(T) rate if demand > 999 kW and on GSD(T) rate if demand < or = 999 kW

[4] Savings ($) = Firm Rate Total Bill (Column 3) less Interruptible Rate Total Bill (Column 2)

TAMPA ELECTRIC COMPANY

Total Bill Comparison
Interruptible Service v. Firm Service
January - December 1996

(1)	(2)	(3)	(4)	(5)
	Total Bill by Rate Class		Savings [4]	
Customer [1]	Interruptible [2]	Firm [3]	$	%
1	$2,529,210.51	$3,793,488.89	$1,264,278.38	33%
2	$110,795.96	$233,632.63	$122,836.67	53%
3	$1,310,186.78	$1,794,673.81	$484,487.03	27%
4	$6,092,805.09	$10,240,956.34	$4,148,151.25	41%
5	$3,070,271.82	$4,648,219.23	$1,577,947.41	34%
6	$263,234.13	$326,869.38	$63,635.25	19%
7	$313,185.41	$409,375.09	$96,189.68	23%
8	$1,106,591.31	$1,436,419.10	$329,827.79	23%
9	$1,161,087.92	$2,229,856.63	$1,068,768.71	48%
10	$369,747.35	$671,847.73	$302,100.38	45%
11	$328,902.87	$424,123.70	$95,220.83	22%
12	$114,928.23	$189,895.22	$74,966.99	39%
13	$2,233,652.54	$2,898,509.63	$664,857.09	23%
14	$0.00	$0.00	$0.00	NA
15	$43,647,048.58	$64,465,028.16	$20,817,979.58	32%
16	$784,752.75	$1,067,997.29	$283,244.54	27%
17	$981,309.74	$1,214,046.37	$232,736.63	19%
18	$938,532.85	$1,275,425.64	$336,892.79	26%
19	$963,769.07	$1,263,831.48	$300,062.41	24%
20	$4,771,468.36	$6,344,517.74	$1,573,049.38	25%
21	$274,593.11	$425,303.12	$150,710.01	35%
22	$881,328.06	$1,444,839.83	$563,511.77	39%
23	$2,989,537.02	$3,922,911.98	$933,374.96	24%
24	$227,592.93	$307,491.63	$79,898.70	26%
25	$182,195.46	$382,384.36	$200,188.90	52%
26	$119,621.38	$179,104.67	$59,483.29	33%
27	$0.00	$0.00	$0.00	NA
28	$284,254.34	$377,967.24	$93,712.90	25%
29	$499,953.28	$749,606.97	$249,653.69	33%
30	$361,544.19	$521,704.04	$160,159.85	31%
31	$264,037.90	$565,070.26	$301,032.36	53%
32	$527,234.91	$668,696.38	$141,461.47	21%
33	$777,066.35	$1,072,326.63	$295,260.28	28%
34	$251,657.79	$362,202.79	$110,545.00	31%
35	$263,555.79	$359,878.26	$96,322.47	27%
TOTAL	**$78,995,653.78**	**$116,268,202.22**	**$37,272,548.44**	**32%**

[1] May include billing information for multiple accounts

[2] Includes charges for optional provision power purchases

[3] Based on GSLD(T) rate if demand > 999 kW and on GSD(T) rate if demand < or = 999 kW

[4] Savings ($) = Firm Rate Total Bill (Column 3) less Interruptible Rate Total Bill (Column 2)

2. Provide an exhibit that shows the 2001 under-recovery projected at the November 2000 hearing and the current 2001 under-recovery projection.

A. The attached tables include a summary of the 2001 under-recovery projections and details of the September 2000 projection filing and August 2001 actual / estimated filing.

Page 2 of 4 shows the original 2001 projection under-recovery amount. The total under-recovery to be collected in 2002--the amount of the final 2000 true-up plus the amount of the current 2001 estimated under-recovery--is also shown.

SUMMARY OF ORIGINAL 2001 PROJECTION ESTIMATED TRUE-UP AND 2001 ACTUAL / ESTIMATED TRUE-UP

		True-Up for the Period
1.	2001 PROJECTION FILING (September 21, 2000)	($1,944,174)
2.	2001 ACTUAL / ESTIMATED FILING (August 20, 2001)	($65,543,259)
3.	2000 FINAL TRUE-UP (April 2, 2001)	($23,129,476)
4.	TOTAL FUEL ADJUSTMENT TRUE-UP AMOUNTS TO BE COLLECTED IN 2002 (Sum of Lines 2 and 3)	($88,672,735)

CALCULATION OF ESTIMATED TRUE-UP
12 MONTHS ESTIMATED AS PER THE ORIGINAL PROJECTION FILED SEPT. 21, 2000
TAMPA ELECTRIC COMPANY
FOR THE PERIOD OF: JANUARY 2001 THRU DECEMBER 2001

	JAN-01	FEB-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TOTAL JAN.-DEC.
A 1. FUEL COST OF SYSTEM NET GENERATION	28,118,543	24,182,793	24,535,922	22,684,311	28,577,787	32,582,349	36,652,912	33,794,873	30,829,479	28,132,342	23,933,531	25,642,307	339,667,149
2. FUEL COST OF POWER SOLD *	1,997,664	1,613,332	1,041,492	684,100	1,321,500	3,291,700	5,128,500	2,467,600	1,007,400	792,600	428,200	410,700	20,184,788
3. FUEL COST OF PURCHASED POWER	1,859,300	2,588,100	5,254,300	7,651,300	4,894,900	9,257,800	9,342,700	11,534,300	5,485,900	2,724,400	2,468,800	999,300	64,061,100
3a. DEMAND & NON-FUEL COST OF PUR. PWR.	0	0	0	0	0	0	0	0	0	0	0	0	0
3b. ENERGY PAYMENTS TO QUALIFIED FACILITIES	625,400	648,800	736,100	781,000	860,800	858,100	961,700	955,500	916,100	905,600	738,000	659,200	9,646,300
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0	0	0	0	0	0	0	0	0	0
5. ADJUSTMENTS TO FUEL COST (FT. MEADE / WAUCHULA WHEELING)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(48,000)
5a. ADJUSTMENTS TO FUEL COST	0	0	0	0	0	0	0	0	0	0	0	0	0
6. TOTAL FUEL & NET POWER TRANSACTION (Sum of Lines A1 Through A5a) *INCLUDES ECONOMY SALES PROFITS (80%)	28,601,579	25,802,361	29,480,830	30,428,511	33,007,987	39,402,549	41,824,812	43,813,073	36,220,079	30,965,742	26,708,131	26,886,107	393,141,761
B 1. JURISDICTIONAL MWH SALES	1,379,357	1,246,664	1,223,356	1,255,480	1,376,129	1,581,312	1,649,962	1,638,301	1,680,299	1,502,760	1,292,809	1,287,642	17,114,071
2. NON-JURISDICTIONAL MWH SALES	28,266	20,438	35,076	33,063	39,207	64,705	66,700	69,838	45,929	37,540	31,373	23,142	495,277
3. TOTAL SALES (Lines B1 + B2)	1,407,623	1,267,102	1,258,432	1,288,543	1,415,336	1,646,017	1,716,662	1,708,139	1,726,228	1,540,300	1,324,182	1,310,784	17,609,348
4. JURISDIC. % OF TOTAL SALES (Line B1/B3)	0.9799193	0.9838703	0.9721272	0.9743408	0.9722985	0.9606900	0.9611455	0.9591146	0.9733934	0.9756281	0.9763076	0.9823449	-
C 1. JURISDICTIONAL FUEL RECOVERY REVENUE (Net of Revenue Taxes)	34,429,211	31,108,602	30,521,025	31,328,444	34,348,269	39,491,566	41,212,327	40,923,535	41,967,783	37,519,986	32,258,774	32,128,867	427,238,389
1a. ADJUSTMENTS TO FUEL REVENUE	0	0	0	0	0	0	0	0	0	0	0	0	0
2. TRUE-UP PROVISION	(3,560,110)	(3,560,110)	(3,560,110)	(3,560,110)	(3,560,110)	(3,560,110)	(3,560,110)	(3,560,110)	(3,560,110)	(3,560,110)	(3,560,110)	(3,560,111)	(42,721,321)
2a. INCENTIVE PROVISION	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,870	1,150,407
2b. OTHER	0	0	0	0	0	0	0	0	0	0	0	0	0
3. FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2b)	30,964,968	27,644,359	27,056,782	27,864,201	30,884,026	36,027,323	37,748,084	37,459,292	38,503,540	34,055,743	28,794,531	28,664,626	385,667,475
4. TOTAL FUEL & NET PWR. TRANS. (Line A6)	28,601,579	25,802,361	29,480,830	30,428,511	33,007,987	39,402,549	41,824,812	43,813,073	36,220,079	30,965,742	26,708,131	26,886,107	393,141,761
5. JURISDIC. TOTAL FUEL & NET PWR.TRANS. (Line A6 x Line B4)	28,027,239	25,386,177	28,659,117	29,647,740	32,093,616	37,853,635	40,199,730	42,021,758	35,256,386	30,211,048	26,075,351	26,411,430	381,843,227
5a. JURISDIC. LOSS MULTIPLIER	1.00067	1.00067	1.00067	1.00067	1.00067	1.00067	1.00067	1.00067	1.00067	1.00067	1.00067	1.00067	-
5b. LINE 5 X LINE 5a	28,046,017	25,403,186	28,678,319	29,667,604	32,115,119	37,878,997	40,226,664	42,049,913	35,280,008	30,231,289	26,092,821	26,429,126	382,099,063
5c. PEABODY COAL CONTRACT BUY-OUT AMORT.	345,594	343,063	340,532	338,002	335,471	332,940	330,409	327,878	325,347	322,816	320,285	317,754	3,980,091
5d. PEABODY JURISDICTIONALIZED (LINE 5c X LINE B4)	338,654	337,529	331,040	329,329	326,178	319,852	317,571	314,473	316,691	314,948	312,697	312,144	3,871,106
5e. FUEL CREDIT DIFFERENTIAL	0	0	0	0	0	0	0	0	0	0	0	0	0
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS. INCL. PEABODY & FUEL CREDIT DIFF.	28,384,671	25,740,715	29,009,359	29,996,933	32,441,297	38,198,849	40,544,235	42,364,386	35,596,699	30,546,237	26,405,518	26,741,270	385,970,169
7. OVER/(UNDER) RECOVERY	2,580,297	1,903,644	(1,952,577)	(2,132,732)	(1,557,271)	(2,171,526)	(2,796,151)	(4,905,094)	2,906,841	3,509,506	2,389,013	1,923,356	(302,694)
8. INTEREST PROVISION	(221,253)	(190,112)	(171,444)	(163,933)	(155,278)	(146,682)	(141,495)	(143,906)	(130,418)	(93,379)	(57,578)	(26,002)	(1,641,480)
9. TOTAL ESTIMATED TRUE-UP FOR THE PERIOD													(1,944,174)

PAGE 3 OF 4

FILED: 11/15/2000 COMPANY

CALCULATION OF ESTIMATED TRUE-UP
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2001 THROUGH DECEMBER 2001

SCHEDULE E1-B

		ACTUAL						ESTIMATED						
		Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TOTAL
A. 1.	Fuel Cost of System Net Generation	35,049,220	25,906,064	28,330,024	26,941,440	27,442,642	36,399,600	35,041,284	36,391,718	32,849,664	30,297,255	27,298,671	28,711,246	370,658,828
2.	Fuel Cost of Power Sold [1]	4,860,627	2,828,366	2,785,635	1,928,904	201,546	1,140,789	2,033,300	1,463,000	872,800	1,718,300	1,292,700	1,010,700	22,136,667
3.	Fuel Cost of Purchased Power	22,623,589	8,185,643	10,471,838	21,799,335	16,795,332	16,405,170	12,819,500	16,103,700	10,909,200	6,737,100	3,413,100	2,488,300	148,751,807
3a.	Demand and Non-Fuel Cost of Purchased Pwr	0	0	0	0	0	0	0	0	0	0	0	0	0
3b.	Payments to Qualifying Facilities	614,083	477,237	865,771	840,934	823,903	851,322	956,400	950,100	911,000	900,200	733,200	711,900	9,636,050
4.	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
5.	Adjustment to Fuel Cost (Ft. Meade/Wau. Wheeling)	(4,145)	(2,961)	(3,158)	(4,064)	(4,381)	(4,558)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(47,267)
5a	Adjustment to Fuel Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	**TOTAL FUEL & NET POWER TRANS.**	**53,422,120**	**31,737,617**	**36,878,840**	**47,648,741**	**44,855,950**	**52,510,745**	**46,779,884**	**51,978,518**	**43,793,064**	**36,212,255**	**30,148,271**	**30,896,746**	**506,862,751**
[1]	Includes Gains													
B 1.	Jurisdictional MWH Sales	1,604,027	1,292,892	1,209,453	1,232,701	1,303,234	1,580,541	1,649,041	1,626,561	1,675,400	1,498,370	1,294,124	1,286,997	17,253,340
2.	Non-Jurisdictional MWH Sales	59,200	43,339	68,623	71,754	76,402	69,941	84,557	84,910	79,709	57,487	43,408	39,316	778,646
3.	**TOTAL SALES (LINE B1+B2)**	**1,663,227**	**1,336,231**	**1,278,076**	**1,304,455**	**1,379,636**	**1,650,482**	**1,733,598**	**1,711,471**	**1,755,109**	**1,555,857**	**1,337,532**	**1,326,313**	**18,031,986**
4.	**Jurisdictional % of Total Sales**	**0.9644065**	**0.9675662**	**0.9463078**	**0.9449931**	**0.9446216**	**0.9576239**	**0.9512246**	**0.9503877**	**0.9545846**	**0.9630512**	**0.9675462**	**0.9703569**	-
C. 1.	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	39,749,385	32,021,651	29,884,053	34,416,247	36,519,851	44,240,442	42,908,569	45,835,998	47,208,010	42,203,613	36,426,773	36,226,917	467,641,509
1a.	Adjustment to Fuel Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
2.	True-up Provision	(3,560,110)	(3,560,110)	(3,560,110)	(3,426,463)	(3,426,463)	(3,426,463)	(3,426,463)	(3,426,463)	(3,426,463)	(3,426,463)	(3,426,463)	(3,426,461)	(41,518,495)
2a.	Incentive Provision	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,870	1,150,407
2b.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0
	FUEL REVENUE APPLICABLE TO PERIOD	**36,285,142**	**28,557,408**	**26,419,810**	**31,085,651**	**33,189,255**	**40,909,846**	**39,577,973**	**42,505,402**	**43,877,414**	**38,873,017**	**33,096,177**	**32,896,326**	**427,273,421**
4.	Total Fuel and Net Power Transactions (Line A6)	53,422,120	31,737,617	36,878,840	47,648,741	44,855,950	52,510,745	46,779,884	51,978,518	43,793,064	36,212,255	30,148,271	30,896,746	506,862,751
5.	Jurisd. Total Fuel and Net Power Transactions (Line A6*Line B4)	51,520,640	30,708,247	34,898,727	45,027,733	42,371,899	50,285,544	44,498,176	49,399,744	41,804,184	34,874,256	29,169,845	29,980,871	484,539,866
5a.	Jurisdictional Loss Multiplier	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	-
5b.	Jurisdictional Sales Adjusted for Line Losses	51,554,644	30,728,514	34,921,760	45,057,451	42,399,864	50,318,732	44,527,545	49,432,348	41,831,775	34,897,273	29,189,097	30,000,658	484,859,661
5c.	Peabody Coal Contract Buyout Amortization	345,594	343,063	340,532	338,002	335,471	332,940	330,409	327,878	325,347	322,816	320,285	317,754	3,980,091
5d.	Peabody Jurisdictionalized (Line 5c*Line B4)	333,293	331,936	322,248	319,410	316,693	316,831	314,293	311,611	310,571	310,888	309,891	308,335	3,808,200
6.	**JURISD. TOTAL FUEL AND NET POWER TRANSACTIONS INCLUDING PEABODY**	**51,887,937**	**31,060,450**	**35,244,008**	**45,376,861**	**42,716,757**	**50,637,583**	**44,841,838**	**49,743,959**	**42,142,346**	**35,208,161**	**29,498,988**	**30,308,993**	**488,667,861**
7.	Over/(Under) Recovery	(15,602,795)	(2,503,042)	(8,824,198)	(14,291,210)	(9,527,502)	(9,727,717)	(5,263,865)	(7,238,557)	1,735,068	3,664,856	3,597,189	2,587,333	(61,394,440)
8.	Interest Provision	(360,990)	(346,828)	(339,307)	(345,611)	(337,165)	(335,871)	(352,268)	(371,519)	(370,509)	(351,342)	(329,010)	(308,399)	(4,148,819)
9.	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD**													**(65,543,259)**

TAMPA ELECTRIC COMPANY
PAGE 4 OF 4

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and purchase power cost recovery clause and generating performance incentive factor.) DOCKET NO. 010001-EI

DEPOSITION OF: MARK HORNICK

TAKEN AT THE INSTANCE OF: FPSC

DATE: FRIDAY, OCTOBER 26, 2001

TIME: COMMENCED AT 11:45 A.M.
CONCLUDED AT 12:15 P.M.

PLACE: FPSC
2540 SHUMARD OAK BOULEVARD
ROOM 362
TALLAHASSEE, FLORIDA

REPORTED BY: NANCY S. METZKE, RPR, CCR

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BUREAU OF REPORTING

RECEIVED 11-2-01

APPEARANCES:

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* * * *

ALSO PRESENT:
Denise Jordan, TECO
Joann Wehle, TECO
Judy Harlow, FPSC Staff
Todd Bohrman, FPSC Staff
Sid Matlock, FPSC Staff
Bernie Windham, FPSC Staff

* * * *

I N D E X

NAME	PAGE NO.
MARK HORNICK	
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Whereupon,

MARK HORNICK

was called as a witness by the FPSC Staff and, after being first duly sworn, was examined and testified as follows:

EXAMINATION

BY MR. KEATING:

Q Good morning, Mr. Hornick.

A Good morning.

Q For the record, could you --

MR. KEATING: Well, before I forget again, let's just go ahead and take appearances for this deposition.

MR. BEASLEY: I'm Jim Beasley representing Tampa Electric Company.

MS. PAUGH: Leslie Paugh, Landers & Parsons, representing Johnson Controls. We have not intervened in this docket.

MR. VANDIVER: Rob Vandiver appearing on behalf of the citizens of the state of Florida.

MR. KEATING: And Cochran Keating on behalf of Commission staff.

Is there anyone on the phone to make an appearance on behalf of any of the parties?

(NO RESPONSE)

BY MR. KEATING (Continuing):

Q Okay. For the record, Mr. Hornick, could you state your full name and your business address?

A My name is Mark J. Hornick. My business address is 702 North Franklin Street, Tampa, Florida.

Q I just have a few questions for you this morning. And first, if you could, if you have your direct testimony that was filed September 20th in this docket.

A Uh-huh.

Q Referring to Page 9, at Lines 1 through 2 you state that environmental regulations have also reduced the allowable nitrogen oxide emissions from the company's generating units?

A Right.

Q Which units are impacted by the changed nitrogen oxide requirements?

A I'm trying to remember the specifics. There was an agreement. I believe Gannon -- this is -- I'm generally familiar with this. I'm not in the environmental department. But, you know, subject to check, I guess, Gannon 1 and 2, I don't believe, are in the mix. But the coal units at Gannon 3, 4, 5, and 6, and I believe all the Big Bend coal units are impacted by the reduction in NOx, allowable NOx.

Q Okay.

A I think that Gannon 1 and 2 were below the

capacity threshold.

Q You also state, reading further down in your answer in that section on Page 9, that TECO has been able to comply with those rules through some modifications to boilers and fuel-burning equipment.

A Yes.

Q Could you describe what those modifications are or were?

A Yeah, generally I can. At Gannon and Big Bend we've got slightly different equipment than is typical in the industry in that those are wet bottom boilers, meaning they tap slag in a molten state out the bottom of the boiler rather than have a dry ash that comes out the bottom. Gannon 3 and 4 are cyclone-fired units, Gannon 5 and 6 and Big Bend 1, 2, and 3, are wet bottom turbos. It's a design by Riley Stoker, and because of the nature of the wet-bottom, slag-tapping units and the fact that they are a bit unique, there's not a lot of developed low NOx burner technology that's applicable to those units. Tampa Electric has quite a knowledge of, particularly, the Riley turbo-fired boilers, and we've been able to make modifications to the burner equipment and the pulverizer fuel-handling equipment that better sizes the coal, stages the fuel and air in the boiler, and reduces the NOx due to, basically, improved conditions that in the combustion

system that lower NOx output.

Q I'm not an engineer, so I'll trust you on that.

A Yeah, it's --

Q And have those modifications been made already?

A Yes.

Q On all of the units?

A Yes.

Q Okay. Do you know when those were made?

A I couldn't quote specific dates to you. It was a series of efforts, projects, that we took over a period of time. It took some experimentation, if you will, to try a concept on a unit and verify that it did perform as expected and then roll that out to the subsequent units, again, probably subject to check, 1998, in that time frame. '97 to 2000 we made most of those modifications, but there was work that was -- preliminary work that was going on ahead of that. We did significant work on the pulverizer, classifiers on Big Bend 1 and 2 and Gannon 5 and 6 that, you know, were fairly significant projects and were quite beneficial.

Q Okay. Would you agree that in recent months there's been a high availability rate for Phillips Units 1 and 2?

A Yes.

Q Okay. And would you agree that the capacity

factors of those units have been in the 30 to 40 percent range?

A That seems correct. I couldn't quote the exact number, but they've been pretty high, yes.

Q And would you agree that the fuel cost for those units has been in the range of four to four and a half cents per kilowatt hour in those recent months?

A Fuel cost? It seems right. I know it in different terms. They burn residual oil, Number 6 oil. My recollection is it's been about five dollars a million BTU, and the heat rate of those units is in the low nine thousands, so that seems about right to me, those numbers for fuel cost.

Q Given those fuel costs and the high availability rates, why have Phillips 1 and 2 not been utilized more?

A Well, they actually have been utilized more than our expectations were for the year, quite a bit more. I think the -- I mean I'm responsible for the Phillips units as well as the units out at Polk Power Station. I think we're almost double the expected generation because of the economic dispatch of those units.

Q Okay.

A So I guess it depends on your perspective. We dispatch the system economically. And the units that the next increment of generation that's most cost effective is

the one that runs, so --

Q Okay. Would you agree, and I believe that this is a number that Staff has derived from TECO's A schedules and E schedules, would you agree that Polk Unit 2 has shown a high availability recently with a point seven cent per kilowatt hour fuel price, fuel cost?

A You know, Polk 2's availability has been good, although availability is not related to fuel cost.

Q Okay. I probably asked two questions in that.

MR. BEASLEY: Could I get you to restate that fuel cost?

MR. KEATING: Absolutely.

BY MR. KEATING (Continuing):

Q Did you agree that Polk Unit 2 has shown a high availability recently, has had a high availability recently?

A Yes, I would agree to that.

Q Okay. Would you agree that fuel cost for that unit has been point seven cents per kilowatt hour?

A Well, you have to really specify the time frame there. It burns natural gas primarily. It's a dual unit. And the price of natural gas has been volatile. It was -- I'm sure at one point it was probably at that range. Currently, gas prices are down, and that number, I think, is probably higher than the current value.

Q Okay. Would you agree that for July that it was point seven cents per kilowatt hour, subject to check?

A The heat rate on that unit is in the mid 11 thousands, and I'm trying to remember what the natural gas price was in the July time frame. It seems a little high to me, but subject to check, you know, it's not unreasonable. I don't know from first-hand. I could go back and calculate it.

Q Does it seem a little high?

A It seems high, but I wouldn't disagree, you know, necessarily. I don't know that it's wrong, but, you know --

MR. BEASLEY: If there is any discrepancy, he can provide you something in writing confirming what it was by his calculations.

BY MR. KEATING (Continuing):

Q I believe that, based on information provided by TECO in its schedules, that the capacity factor in January of 2001 for Polk Unit 2 was approximately 14 percent. Would you agree with that?

A You said capacity factor?

Q Yes.

A Yeah, I don't have it in my testimony, and that would be one I'd really have to verify. It's possible. January is typically a shoulder type of month where the

peaking units run on very cold days, and if the weather is mild, they're not in the economic dispatch, so they typically run harder in the summer. They'll peak in the morning. Come on very early in the morning and then be shut off, you know, mid morning or noon time, so they have fewer run hours. It makes sense to me that the capacity factor would be lower in January.

Q Has Polk Unit 2 been utilized more in 2001 than was originally anticipated?

A Yes, I believe it has.

Q Okay. Do you believe that that's been due to the economics of running it in terms of, you know, how it's dispatched?

A Well, the operation of the unit is based on -- my understanding of it is the demand of the system, you know, which is largely dependent on weather. And the units are dispatched in an economic fashion. There are economics models of the total cost of each unit, and as the next increment of load is required the folks at energy management dispatch the system on that basis.

Q What is the current status of the Hooker Point units?

A They're on a -- as we speak, I believe they're available on a 30-day notice. They're available to run, but they're not -- there's a little bit of work that's

required to start them up, basically.

Q Okay.

A They are available.

Q Would you agree, subject to check, that the capacity factors for Gannon units ranged from 33 to 49 percent in July of this year?

A Gannon station in total, 1 through 6, all of them?

Q Yes.

A In July? I'm trying to think what was happening on the system. Those are numbers I don't have on the tip of my tongue. That one I'm not really sure of.

Q Okay. I believe those are numbers that we've pulled from the TECO's A schedules.

A If it's in there, and I don't doubt it. I just don't have any personal knowledge of it.

Q Okay. Is it your understanding that the Gannon plants, that their utilization was -- strike that.

Were the Gannon plants utilized less than expected or less than anticipated in that July 2001 period?

A Gannon station, all the units in total?

Q Yes.

A I'm searching my brain for the budgeted generation for that month for that station. The capacity factor you asked me about earlier was a pretty low number.

If that's correct, I would expect the budget would have had a higher expectation for operating those units. I know we've had some difficulty in the summer over there with some issues that were addressed in my testimony.

Q What were the primary reasons that it would have been utilized less?

A In July of 2001, that particular month?

Q Yes.

A Wow. Well, one of the issues that we've had at Gannon is a -- and it's in my testimony, not to make too big a deal of it, but we have -- yeah, it's on Page 9 -- talked about the green-lipped mussel, really infestation, that we've had at Gannon. It's kind of funny sounding, but there's a nonindigenous clam type of organism that has come into Tampa Bay fairly recently, over the last couple of years, and for whatever reason -- we're working with several agencies to understand it -- they grow rapidly, and they foul the condensers, and it's -- I don't know if it's salinity or some other issue, but Gannon station in that area of the bay is a specifically -- they seem to target it, and we've got -- we use circulating water pumps to pull water through the condensers. And as these organisms have grown and developed shells, they block the tube sheet of the condensers. And we have had to go in and do extensive maintenance to remove that blockage to the point where

we're taking 50 gallons of shell off the face of this condenser in one evening, and then a couple of days later having to bring the unit down in load and do the same thing.

That's one issue that I'm aware of that has particularly impacted Gannon. We try to manage that and do those -- that required maintenance during non-peak hours and have been relatively successful in doing that, but that would lower the capacity factor on this station. The Gannon units are, you know, generally older on our system, and they do tend to require more maintenance and have more issues because of their age and other issues.

Q Okay. We'll try not to let this transcript get out to any of the terrorists who may find a new biological threat.

Typically, and I'm not sure if this is, you know, within your area, when Phillips is available for use, is TECO purchasing power?

A Probably you'll have to say it a little different way. When it's available for use -- It has a very high availability, so --

Q Okay.

A And I'm not sure I could answer the question about when it's operating are they purchasing power or not. It isn't in my area of typical knowledge.

Q Okay. When did the operation of scrubbers at Big Bend Units 1 and 2 begin?

A It was required as part of the Phase 2 Clean Air Act compliance, and my understanding is that had to be in place by January 1 of 2000. I believe the units -- the scrubber was placed in service prior to that to sort things out and get it started up.

Q Do you know when the operation began at each of those units?

A It has a common scrubber that serves both Units 1 and 2.

Q Okay.

A I don't know specifically. My recollection was, you know, within the quarter preceding the compliance date, but I would have to check that.

Q When was the compliance date again?

A January 1, 2000.

Q Okay.

MR. KEATING: Can we take just a minute off the record? I've just got a couple more questions.

MR. BEASLEY: Sure. Sure.

(DISCUSSION OFF THE RECORD)

BY MR. KEATING (Continuing):

Q Okay. I've just got a couple of questions to finish up.

Is it correct that flew gas desulfurization requires the use of some megawatt hours of electricity?

A Yes. That is correct. There are various pumps and motors that are consumers of electricity internal to the process.

Q Do you know how the number of megawatt hours that are attributable to flew gas desulfurization are determined?

A There are meters that meter, in some cases, kilowatts, in many cases, amps and volts on the system where you can calculate kilowatts that feed those specific pieces of equipment that are associated with the scrubber, the FGD equipment, and those are monitored and calculated.

MR. KEATING: If I could take one more minute.

(DISCUSSION OFF THE RECORD)

BY MR. KEATING (Continuing):

Q Okay. When TECO measures the performance of Big Bend Units 1 and 2, does it make an adjustment for the generation that's attributable to FGD?

A When you say measure the performance, what that would mean to me is to be the efficiency of the unit.

Q Yes.

A Possibly net heat rate, which would be the total BTUs going into the plant divided by the kilowatt hours, and we would do that on a net basis. We would take the

gross generation and subtract station service, as we call it, which is all the station internal consumption, and that would include the scrubber. In some cases, there are common loads within the plant that are not associated with a particular unit, such as maybe a fire pump that would service all the units and those loads -- those consumptions are, typically, allocated based on, you know, a methodology. It's a pretty small percentage. But, yes, all the internal consumption is accounted for, and scrubbers are a fairly significant consumer, so that's in the mix.

Q Okay. Do you believe that those adjustments are necessary to show the performance of the unit?

A Yeah. If you want to know on a net basis what the efficiency of the unit is, yes.

Q Okay.

MR. KEATING: That's all the questions I have. Thanks.

MR. BEASLEY: Thank you.

EXAMINATION

BY MR. VANDIVER:

Q Good morning, Mr. Hornick.

A Good morning.

Q On Pages 7 and 8 of your testimony, you referenced the 2000 consent decree of Tampa Electric

Company with the U.S. EPA and the Department of Justice.

A Yes, sir.

Q Where is Tampa Electric Company in compliance with that decree? Are you all on schedule, ahead of schedule, or behind schedule?

A To my knowledge, we are on schedule. I'm not aware of us being behind schedule in any area. I know there's a great deal of activity that's going on, and we may well be ahead in a normal type of way.

Q What planned mainte -- or what activities are scheduled for 2002 for compliance with that decree that you're aware of?

A Yeah, I'm trying to think of the activities that are involved. They're at two different stations, Gannon and Big Bend Station. Gannon, part of the consent decree was an agreement to repower the units at Gannon, and the station will now be known as Bay Side; and there are activities in 2002 that are required to make that conversion happen. There's construction going on now for the infrastructure in place for the new Bay Side units, heat recovery, steam generators, combustion turbine foundations, those type of things. There has got to be an interface or a time made between the new section of the plant, which is the Bay Side new construction, and the existing Gannon steam units and auxiliaries. So next year

there's going to be tie in, steam piping, that kind of thing that will have to be done in preparation. In large measure the construction can happen on a stand-alone basis. It's separated geographically on the site, even though the site is small, but there is tie-in work that will occur in 2002. My recollection is that's primarily on Gannon Units 5 and 6.

Q Will that necessitate taking them down?

A Yes. They will need to be off-line. My understanding is they're going to do that as much as possible with planned outages that would happen anyway. But there will be some additional work and I believe extension of outage time in order to accommodate those mods.

Q Do you know offhand what time of the year that's scheduled to take place?

A I don't know other than my general knowledge that large unit outages are typically scheduled in the shoulder months, in the spring and fall, low to medium periods, so we have the units available in the summer.

MR. VANDIVER: That's all the questions I have. Thank you, sir.

THE WITNESS: Sure.

MR. BEASLEY: That's all we have.

MR. KEATING: Thank you, Mr. Hornick.

(WHEREUPON, THE DEPOSITION WAS CONCLUDED)

* * * *

ERRATA SHEET

DOCKET NUMBER 010001-EI
MARK HORNICK
OCTOBER 26, 2001

STATE OF FLORIDA)
: CERTIFICATE OF OATH
COUNTY OF LEON)

I, the undersigned authority, certify that MARK HORNICK personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 27th day of October, 2001.

Nancy S. Metzke

NANCY S. METZKE
Notary Public - State of Florida

Nancy S. Metzke
MY COMMISSION # DD050811 EXPIRES
September 13, 2005
BONDED THRU TROY FAIN INSURANCE, INC.

CERTIFICATE OF DEPONENT

This is to certify that I, MARK HORNICK, have read the foregoing transcription of my testimony, Pages 1 through 20, given on October 26, 2001, in Docket Number 010001-EI, and find the same to be true and correct, with the exceptions, and/or corrections, if any, as shown on the Errata Sheet attached hereto.

_____

MARK HORNICK

Sworn to and subscribed before me this
day of 2001

NOTARY PUBLIC
State of
My Commission Expires:

REPORTER'S DEPOSITION CERTIFICATE

STATE OF FLORIDA)
COUNTY OF LEON)

I, NANCY S. METZKE, Certified Shorthand Reporter and Registered Professional Reporter, certify that I was authorized to and did stenographically report the deposition of MARK HORNICK; that a review of the transcript was requested; and that the transcript is a true and complete record of my stenographic notes.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 27th day of October, 2001.

Nancy S. Metzke

NANCY S. METZKE, RPR, CCR

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010001-EI EXHIBIT NO 5
COMPANY/
WITNESS: Brown
DATE: 11-20-01

Tampa Electric Company

Summary of Wholesale Sales Contracts
1998-2001

Line	Purchaser	Applicable Years	Maximum Contract Demand 1998	1999	2000	2001	Separated or Non-Separated	Level of Firmness	Units Used In Pricing
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Florida Municipal Power Agency	1998-2001	85	105	150	150	Separated 1998-1999 Non-Separated 2000-2001	Firm	Big Bend 2 and 3; Gannon 5 and 6
2	Florida Power Corporation	1998-2001	50	60	60	60	Separated	Firm	System Average
3	City of Fort Meade	1998	5	0	0	0	Separated	Firm	Big Bend 1,2,3,4
4	City of Fort Meade *	1998-2001	5	12	12	13	Separated	Firm	System Average
5	City of St. Cloud	1998-2001	10	15	15	15	Separated	Firm	System Average
6	City of Wauchula	1998	5	0	0	0	Separated	Firm	Big Bend 1,2,3,4
7	City of Wauchula *	1998-2001	8	15	15	15	Separated	Firm	System Average
8	Reedy Creek Improvement District	1998-1999	20	15	0	0	Separated	Firm	Big Bend 1,2,3,4
9	Reedy Creek Improvement District	1998	15	0	0	0	Non-Separated	Firm	Big Bend 1 and 3 Gannon 5 and 6
10	Reedy Creek Improvement District	1998-2001	75	75	75	75	Separated	Firm	System Average
11	TECO Power Services	1998-2001	145	145	145	145	Separated	Firm	Big Bend 4
12	TOTAL		423	442	472	473			

* These sales are load following.
Greatest actual demands are shown.

Sources: TECO Response to FIPUG's 1st Set of Interrogatories, Interrogatory No. 15, Pages 1-4.
TECO Response to FIPUG's 3rd Set of Interrogatories, Interrogatory No. 65, Pages 1-2; No. 66; No. 67, Page 1.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 6
COMPANY/ WITNESS. Collins
DATE: 11-29-01

Docket No. 010001-EI
Witness: Brian C. Collins
Exhibit ___ (BCC-1)
Page 1 of 2

TAMPA ELECTRIC COMPANY
DOCKET NO. 010001-EI
FIPUG'S 3rd SET OF INTERROGATORIES
INTERROGATORY NO. 67
PAGE 1 OF 1
FILED: SEPTEMBER 27, 2001

67. For each separated contract identified in TECo's response to the previous request, identify by each generating unit the amount in net MW separated from the retail rate base and used to cover the wholesale sale contract.

A. See the response to Interrogatory No. 64 for the MW separated from the retail rate base, by contract. As stated in the response the Interrogatory No. 64, Tampa Electric is neither required to nor able to separate sales by each generating unit. For those wholesale sales that are unit- or station-specific, however, the unit(s) and amount of MW committed to serve the sale are shown below.

Units and MW Committed to Unit- or Station-Sales

1998	
Reedy Creek D	Up to 20 MW from the Big Bend Station
New Smyrna D	Up to 12 MW January to May and up to 13 MW June to December from Big Bend Unit 2 and Big Bend Unit 3. During the months of June, July, August and September an additional 5 MW was supplied from the same units.
Wauchula D	Up to 5 MW from the Big Bend Station
Fort Meade D	Up to 5 MW from the Big Bend Station
FMPA D	Up to 85 MW in January and February, 25 MW in March and 15 MW in April, from Big Bend Unit 2, Big Bend Unit 3, Gannon Unit 5 and Gannon Unit 6 . Served entirely with purchase beginning May 1998.
Hardee Power Partners	Up to 145 MW from Big Bend Unit 4
1999	
Reedy Creek D	Up to 15 MW from the Big Bend Station
New Smyrna D	Up to 13 MW January to May and up to 14 MW June to December from Big Bend Unit 2 and Big Bend Unit 3. During the months of June, July, August and September an additional 5 MW was supplied from the same units.
FMPA D	Served entirely with purchase
Hardee Power Partners	Up to 145 MW from Big Bend Unit 4
2000	
New Smyrna D	Up to 14 MW from Big Bend Unit 2 and Big Bend Unit 3
Hardee Power Partners	Up to 145 MW from Big Bend Unit 4
2001	
Hardee Power Partners	Up to 145 MW from Big Bend Unit 4

NOTE: All PR sales and the Lakeland D contract are system sales.

Tampa Electric Company

Average Fuel Costs Charged to
Wholesale and Retail Customers

Line	Year	Wholesale Sales (¢/kWh)	Paid by Retail Customers (¢/kWh)
	(1)	(2)	(3)
1	1999	2.15	2.33
2	2000	2.17	2.83
3	2001E	2.47	3.07

Sources: TECO Schedule A-1, Period to Date, December 1999
TECO Schedule A-1, Period to Date, December 2000
J. Denise Jordan Testimony, Actual/Estimated True-up,
January 2001 through December 2001, Sch. E2 and E6

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JANUARY 1999

SCHEDULE A6
PAGE 1 OF 3

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (E)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (E)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:									
VARIOUS	SCON.	321,698.0	0.0	321,698.0	1.849	2.364	5,950,606.00	7,608,700.00	1,280,960.00
VARIOUS JURISDICTIONAL	SCH.-D	5,625.0	0.0	5,625.0	1.836	1.836	103,500.00	103,500.00	
VARIOUS SEPARATED	SCH.-D	20,364.0	0.0	20,364.0	1.781	2.034	366,400.00	412,000.00	
VARIOUS	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS SEPARATED	CONTRACT	16,100.0	0.0	16,100.0	2.488	3.365	400,400.00	606,800.00	
VARIOUS	SCH.-D	76,120.0	76,120.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS JURISDICTIONAL	SCH.-J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS	-	443,887.0	76,120.0	368,777.0	1.972	2.406	6,846,706.00	8,786,800.00	1,280,960.00
LESS TRANSMISSION COSTS	-						(16,000.00)		
LESS VARIABLE O & M COSTS	-						(883,200.00)		
PLUS 80% OF ECON. ENERGY SALES PROFIT	-						1,280,960.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL 80% OF ECON. ENERGY SALES PROFITS	-	443,887.0	76,120.0	368,777.0	2.086	2.406	7,688,260.00	8,786,800.00	1,280,960.00
ACTUAL:									
FLA. PWR. CORP.	ECON.-C	160.0	0.0	160.0	1.786	2.008	2,886.44	3,385.22	383.42
FLA. PWR. & LIGHT	ECON.-C	160.0	0.0	160.0	1.741	1.739	2,786.78	2,772.21	(10.83)
CITY OF LAKELAND	ECON.-C	944.0	0.0	944.0	1.680	1.648	15,868.80	15,883.47	(82.31)
FT. PIERCE UTIL. AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	12.0	0.0	12.0	1.772	2.048	212.64	245.76	26.46
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	148.0	0.0	148.0	1.726	2.348	2,555.17	3,283.17	694.00
CITY OF NEW SMYRNA BCH.	ECON.-C	8.0	0.0	8.0	1.976	4.166	158.08	326.04	147.97
ORLANDO UTIL. COMM.	ECON.-C	864.0	0.0	864.0	1.704	1.755	15,063.78	15,868.00	426.19
SEMINOLE ELECTRIC CO-OP	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF ST. CLOUD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
PMPA	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK	ECON.-C	3,691.0	0.0	3,691.0	1.843	1.821	68,174.38	68,575.16	5,120.62
SONAT	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY, INC.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENRGY, INC.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENN. VALLEY AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT SEPAR.	SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
PMPA SEPAR.	SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL. SEPAR.	SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA B SEPAR.	SCH.-D	8,982.0	0.0	8,982.0	1.755	1.904	156,866.60	170,417.27	
REEDY CREEK SEPAR.	SCH.-D	11,160.0	0.0	11,160.0	1.379	1.666	153,896.40	184,896.00	
WAUCHULA SEPAR.	SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE SEPAR.	SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD SEPAR.	SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTN SEP CONTRACT		9,312.0	0.0	9,312.0	2.192	2.824	204,116.84	262,970.86	
SEMINOLE ELECTRIC CO JURISD.	SCH.-D	4,837.0	0.0	4,837.1	1.600	1.600	72,432.41	72,432.41	
SEMINOLE ELECTRIC CO JURISD.	SCH.-D	788.0	0.0	788.0	1.539	1.539	11,832.16	11,832.16	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JANUARY 1999

SCHEDULE A6
PAGE 2 OF 3

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) ---cents/KWH--- (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. J	50.0	0.0	50.0	1.999	1.999	999.30	999.30	
CITY OF HOMESTEAD	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA B	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA		SCH. D	78,120.0	78,120.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PART. TO FLA. PWR. CORP.		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FLA. PWR.& LT.		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO REEDY CREEK		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO GAINESVILLE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO JACKSONVILLE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO KISSIMMEE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO NEW SMYRNA BCH.		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO ORLANDO		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO STARKE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FMPA		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO HOMESTEAD		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO SEMINOLE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FT. PIERCE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO TALLAHASSEE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO LAKELAND		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO LK. WORTH		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO KEY WEST		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO VERO BEACH		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO ENERGY AUTH		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FPC		SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP		SCH. G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE		SCH. G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JANUARY 1999

SCHEDULE A6
PAGE 3 OF 3

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (6)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ADJUSTMENTS TO PREV MONYR TYPE	SCHED.								
HARDEE POWER PARTN 12/98 SEPAR.	CONTRACT	(4,804.0)	0.0	(4,804.0)	2.591	3.235	(121,868.24)	(155,733.00)	
HARDEE POWER PARTN 12/98 SEPAR.	CONTRACT	4,804.0	0.0	4,804.0	2.139	2.834	102,757.56	135,884.00	
SUB-TOTAL ECONOMY POWER SALES		5,922.0	0.0	5,922.0	1.694	1.852	98,888.04	108,708.57	6,517.54
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.		20,112.0	0.0	20,112.0	1.545	1.708	310,705.68	355,115.37	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.		5,208.9	0.0	5,208.1	1.591	1.591	84,284.57	84,284.57	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.		50.0	0.0	50.0	1.598	1.598	598.2	598.2	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.		9,312.0	0.0	9,312.0	1.980	2.599	186,267.36	226,882.04	
SUB-TOTAL OTHER D POWER SALES		76,120.0	76,120.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.		0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS		116,622.9	76,120.9	40,692.1	1.671	1.932	679,894.30	785,866.65	6,517.54
LESS VARIABLE O & M COSTS							(8,668.74)		
LESS VARIABLE O & M COSTS - HARDEE							0.00		
LESS TRANSMISSION COSTS SCH. D (SEP.)							(16,792.03)		
PLUS 80% OF ECON. ENERGY SALES PROFITS	-						6,517.54		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS	-	116,622.9	76,120.9	40,692.1	1.621	1.932	660,730.00	785,866.65	6,517.54
CURRENT MONTH:									
DIFFERENCE	-	(325,075.0)	0.0	(325,084.9)	(0.478)	(0.478)	(7,008,880.00)	(8,910,513.18)	(1,384,442.46)
DIFFERENCE %	-	(73.2)	0.0	(88.9)	(22.7)	(19.7)	(91.40)	(91.10)	(99.5)
PERIOD TO DATE:									
ACTUAL	-	116,622.0	76,120.9	40,692.1	1.621	1.932	660,730.00	785,866.65	6,517.54
ESTIMATED	-	443,697.0	76,120.0	365,777.0	2.099	2.409	7,669,680.00	8,796,680.00	1,390,960.00
DIFFERENCE	-	(325,075.0)	0.0	(325,084.9)	(0.478)	(0.478)	(7,008,880.00)	(8,910,513.18)	(1,384,442.46)
DIFFERENCE %	-	(73.2)	0.0	(88.9)	(22.7)	(19.7)	(91.40)	(91.10)	(99.5)

* No Economy Sales to Hardee Power Partners for Others in the month of January 1999.

SCHEDULE A7

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH JANUARY 1999

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	¢/MWH (A) FUEL COST	¢/MWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	2,821.0	0.0	1,210.0	1,311.0	9.779	9.779	128,200.00
HARDEE POWER PARTNERS	IPP	7,636.0	0.0	0.0	7,636.0	5.078	5.078	388,000.00
PSCO	OTHER	54,095.0	54,095.0	0.0	0.0	0.000	0.000	0.00
FPC	OTHER	24,026.0	24,026.0	0.0	0.0	0.000	0.000	0.00
TOTAL	-	88,478.0	78,120.0	1,210.0	8,148.0	5.751	5.751	526,200.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	23,200.0	0.0	0.0	23,200.0	3.428	3.428	795,272.47
HARDEE PWR. PART.-OTHERS	IPP				0.0	0.000	0.000	
FLA. POWER CORP.	SCH.-Js				0.0	0.000	0.000	
FLA. POWER CORP.	SCH.-Js	12,852.0	0.0	0.0	12,852.0	1.906	1.906	244,906.80
FLA. POWER & LIGHT	SCH.-Js	392.0	0.0	278.4	113.6	7.092	7.092	8,044.73
FLA. POWER & LIGHT	SCH.-Js	4,921.0	0.0	0.0	4,921.0	3.282	3.282	161,515.60
CITY OF LAKELAND	SCH.-Js	132.0	0.0	132.0	0.0	0.000	0.000	0.00
CITY OF LAKELAND	SCH.-Js	168.0	0.0	0.0	168.0	3.366	3.366	5,656.00
ORLANDO	SCH.-Js	790.0	0.0	402.2	387.8	20.457	20.457	79,332.10
ORLANDO	SCH.-Js	1,569.0	0.0	0.0	1,569.0	2.936	2.936	46,762.00
KISSIMMEE ELEC. AUTH.	SCH.-Js				0.0	0.000	0.000	
KISSIMMEE ELEC. AUTH.	SCH.-Js				0.0	0.000	0.000	
THE ENERGY AUTH.	SCH.-Js	370.0	0.0	33.0	337.0	6.363	6.363	28,283.26
THE ENERGY AUTH.	SCH.-Js	71.0	0.0	0.0	71.0	3.014	3.014	2,138.76
REEDY CREEK	SCH.-Js				0.0	0.000	0.000	
PSCO	SCH.-Js				0.0	0.000	0.000	
PSCO	SCH.-Js	200.0	0.0	0.0	200.0	4.100	4.100	8,200.00
KOCH ENERGY TRAD.	SCH.-Js				0.0	0.000	0.000	
PSCO	OTHER	54,094.0	54,094.0	0.0	0.0	0.000	0.000	0.00
FPC	OTHER	24,028.0	24,028.0	0.0	0.0	0.000	0.000	0.00
KEY WEST	SCH.-Js	383.0	0.0	0.0	383.0	7.311	7.311	28,000.00
ADJUSTMENTS TO PRIOR MONTHS:								
HARDEE PWR. PART.-NATIVE Dec-98	IPP	(28,328.0)	0.0	0.0	(28,328.0)	3.147	3.147	(922,933.22)
HARDEE PWR. PART.-NATIVE Dec-98	IPP	28,328.0	0.0	0.0	28,328.0	4.024	4.024	1,140,082.09
TOTAL		123,182.0	78,123.0	845.6	44,193.4	3.766	3.766	1,663,944.16
CURRENT MONTH:								
DIFFERENCE	-	34,673.0	3.0	(364.4)	35,034.4	(1.985)	(1.985)	1,137,744.16
DIFFERENCE %	-	39.2	0.0	(30.1)	382.9	(34.5)	(34.5)	216.2
PERIOD TO DATE:								
ACTUAL	-	123,182.0	78,123.0	845.6	44,193.4	3.766	3.766	1,663,944.2
ESTIMATED	-	88,478.0	78,120.0	1,210.0	8,148.0	5.751	5.751	526,200.00
DIFFERENCE	-	34,673.0	3.0	(364.4)	36,034.4	(1.985)	(1.985)	1,137,744.16
DIFFERENCE %	-	39.2	0.0	(30.1)	382.9	(34.5)	(34.5)	216.2

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JULY 2000

SCHEDULE A6
PAGE 1 OF 3

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (6)*(A)	(8) TOTAL $ FOR TOTAL COST (6)*(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:									
VARIOUS	ECON.	94,400.0	0.0	94,400.0	4.100	7.575	2,704,000.00	4,000,100.00	1,744,000.00
VARIOUS JURISDICTIONAL	SCH -D	5,700.0	0.0	5,700.0	2.300	2.300	137,200.00	137,200.00	
VARIOUS SEPARATED	SCH -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS SEPARATED	CONTRACT	40,015.0	0.0	40,015.0	2.310	2.300	1,100,000.00	1,000,400.00	
PMPA	SCH -D	111,000.0	0.0	111,000.0	1.000	1.000	2,014,004.00	2,014,004.00	
VARIOUS JURISDICTIONAL	SCH -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS	-	231,700.0	0.0	231,700.0	2.004	3.730	6,011,704.00	8,000,304.00	1,744,000.00
LESS TRANSMISSION COSTS	-						0.00		
LESS VARIABLE O & M COSTS	-						(130,400.00)		
PLUS 80% OF ECON. ENERGY SALES PROF	-						1,744,000.00		
TOTAL EXCL. VARIABLE O & M COSTS AND EC	-								
80% OF ECON. ENERGY SALES PROFITS	-	231,700.0	0.0	231,700.0	2.300	3.730	7,021,304.00	8,000,304.00	1,744,000.00
ACTUAL:									
FLA. PWR. CORP.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF ST. CLOUD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
PMPA	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SONAT	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY, INC.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENERGY, INC.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENN. VALLEY AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	SEPAR. SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
PMPA	SEPAR. SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR. SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR. SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPAR. SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPAR. SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPAR. SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPAR. SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEP. CONTRACT	60,000.0	0.0	60,000.0	2.300	2.231	1,404,302.30	1,001,000.40	
SEMINOLE ELECTRIC CO-OP FIRE	JURISD. SCH.-D	3,343.0	310.0	3,222.4	2.342	2.342	75,700.40	75,700.40	
SEMINOLE ELECTRIC CO-OP HAR	JURISD. SCH.-D	953.0	0.0	953.0	2.176	2.176	20,741.03	20,741.03	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JULY 2000

SCHEDULE A6
PAGE 2 OF 3

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT ((5)*(6)(A))	(8) TOTAL $ FOR TOTAL COST ((5)*(6)(B))	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
[illegible] ELEC. UTIL.	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
AQUILLA	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
THE ENERGY AUTH.	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
MORGAN STANLEY	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
PMPA		SCH. O	102,000.0	0.0	102,000.0	1.866	1.866	1,904,827.84	1,904,827.84	
HARDEE POWER PART. TO FLA. PWR. CORP.		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR.& LT.		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO REEDY CREEK		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO GAINESVILLE		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO JACKSONVILLE		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO [illegible]		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO NEW SMYRNA BCH.		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ORLANDO		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO STARKE		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO PMPA		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO HOMESTEAD		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO SEMINOLE		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FT. PIERCE		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO TALLAHASSEE		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LAKELAND		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LK. WORTH		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KEY WEST		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO VERO BEACH		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ENERGY AUTHOR		SCON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PART. TO AQUILLA		SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PART. TO ORLANDO		SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PART. TO FLA. PWR. CORP.		SCH. -MB	263.0	0.0	263.0	6.316	6.316	16,419.20	16,419.20	
HARDEE POWER PART. TO FLA. PWR.& LT.		SCH. -MB	395.0	0.0	395.0	3.799	3.799	10,797.55	10,797.55	
SEMINOLE ELECTRIC CO-OP		SCH. -S	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE		SCH. -S	0.0	0.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JULY 2000

SCHEDULE A6
PAGE 5 OF 3

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (6)*(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)*(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -MB	2,897.0	0.0	2,897.0	6.142	6.142	169,812.65	169,812.65	
FLA. PWR. & LIGHT	JURISD.	SCH. -MB	13,700.0	0.0	13,700.0	3.269	3.269	447,488.66	447,488.66	
CITY OF LAKELAND	JURISD.	SCH. -MB	656.0	0.0	656.0	2.020	2.020	12,542.52	12,542.52	
ORLANDO UTIL. COMM.	JURISD.	SCH. -MB	236.0	0.0	236.0	4.668	4.668	11,022.04	11,022.04	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -MB	82.0	0.0	82.0	9.772	9.772	8,008.30	8,008.30	
CARGILL ALLIANT	JURISD.	SCH. -MB	204.0	0.0	204.0	6.966	6.966	14,104.66	14,104.66	
CITY OF HOMESTEAD	JURISD.	SCH. -MB	16.0	0.0	16.0	17.269	17.269	1,726.83	1,726.83	
ORLANDO UTIL. COMM.	JURISD.	STEAM-A	373.0	0.0	373.0	36.661	36.661	136,816.36	136,816.36	
ADJ. TO PREVIOUS MONTHS	MONYR TYP	SCHED.								
HARDEE POWER PARTNERS BS	000 SEPAR.	CONTRACT	(57,000.0)	0.0	(57,000.0)	2.396	3.139	(1,316,694.00)	(1,782,000.40)	
HARDEE POWER PARTNERS ACT	000 SEPAR.	CONTRACT	57,000.0	0.0	57,000.0	2.396	3.231	1,367,688.00	1,844,264.00	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			4,466.0	310.6	4,166.4	2.304	2.304	96,446.32	96,446.32	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.			80,666.0	0.0	80,666.0	2.402	3.333	1,936,166.00	2,822,701.98	
SUB-TOTAL OTHER D POWER SALES			102,666.0	0.0	102,666.0	1.966	1.966	1,994,627.84	1,994,627.84	
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE MB POWER SALES-JURISD.			18,047.0	0.0	18,047.0	3.798	3.798	685,476.76	685,476.76	
SUB-TOTAL OTHER POWER SALES			373.0	0.0	373.0	36.661	36.661	136,816.36	136,816.36	
TOTAL INCLUDING VARIABLE O & M COSTS			186,666.0	310.6	186,366.4	2.362	2.631	4,366,627.00	4,676,674.36	0.00
LESS VARIABLE O & M COSTS								0.00		
LESS VARIABLE O & M COSTS - HARDEE								0.00		
LESS TRANSMISSION COSTS SCH. D (SEP.)								0.00		
PLUS 80% OF ECON. ENERGY SALES PROFITS *								0.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-	186,666.0	310.6	186,366.4	2.362	2.631	4,366,627.00	4,676,674.36	0.00
CURRENT MONTH:										
DIFFERENCE		-	(46,666.0)	310.6	(46,366.6)	(0.697)	(1.167)	(3,291,666.00)	(3,707,266.66)	(1,744,902.00)
DIFFERENCE %		-	(19.9)	0.0	(20.0)	(26.5)	(28.6)	(42.9)	(43.7)	(100.0)
PERIOD TO DATE:										
ACTUAL		-	1,094,146.0	4,731.2	1,089,413.8	2.161	2.346	22,696,423.16	24,676,694.46	0.00
ESTIMATED		-	1,116,602.0	0.0	1,116,602.0	2.340	2.486	26,099,686.66	27,466,166.66	2,217,320.00
DIFFERENCE		-	(54,267.0)	4,731.2	(59,068.2)	(0.679)	(0.160)	(2,164,264.62)	(2,666,663.61)	(2,217,320.00)
DIFFERENCE %		-	(4.9)	0.0	(5.3)	(3.0)	(4.4)	(8.0)	(9.8)	(100.0)

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. BSC 60% OR $8,438.66 HAS BEEN EXCLUDED.

SCHEDULE A7

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH JULY 2000

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	57,825.0	0.0	27,675.0	29,950.0	16.059	16.059	4,808,700.00
HARDEE POWER PARTNERS	IPP	146,970.0	0.0	0.0	146,970.0	3.555	3.555	5,225,400.00
VARIOUS	OTHER	57,676.0	0.0	0.0	57,676.0	4.512	4.512	2,611,100.00
TOTAL	-	262,471.0	0.0	27,675.0	234,796.0	5.386	5.386	12,646,200.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	116,380.0	0.0	0.0	116,380.0	5.188	5.188	6,038,288.74
HARDEE PWR. PART.-OTHERS	IPP	636.0	0.0	0.0	636.0	3.698	3.698	23,882.48
FLA. POWER CORP.	SCH.-Js	742.0	0.0	455.0	287.0	11.521	11.521	33,068.00
FLA. POWER CORP.	SCH.-Jc	8,995.0	0.0	0.0	8,995.0	4.650	4.650	417,772.00
FLA. POWER & LIGHT	SCH.-Js	2,881.0	0.0	1,544.2	1,436.8	10.772	10.772	154,788.36
FLA. POWER & LIGHT	SCH.-Jc	12,734.0	0.0	0.0	12,734.0	5.486	5.486	698,481.80
CITY OF LAKELAND	SCH.-Js	10,230.0	0.0	6,018.2	4,211.8	21.400	21.400	901,316.51
CITY OF LAKELAND	SCH.-Jc	8,934.0	0.0	0.0	8,934.0	7.176	7.176	641,117.50
ORLANDO	SCH.-Js	3,801.0	0.0	1,678.0	2,122.0	11.131	11.131	236,202.86
ORLANDO	SCH.-Jc	15,849.0	0.0	0.0	15,849.0	8.915	8.915	1,395,097.50
ENTERGY MARKETING	SCH.-Jc	273.0	0.0	0.0	273.0	6.314	6.314	17,236.00
THE ENERGY AUTH.	SCH.-Js	4,553.0	0.0	2,306.9	2,246.1	12.506	12.506	280,897.22
THE ENERGY AUTH.	SCH.-Jc	3,770.0	0.0	0.0	3,770.0	9.191	9.191	346,487.32
RELIANT	SCH.-Js	30.0	0.0	30.0	0.0	0.000	0.000	0.00
RELIANT	SCH.-Jc	75.0	0.0	0.0	75.0	5.000	5.000	3,750.00
REEDY CREEK	SCH.-Js	6.0	0.0	0.0	6.0	6.200	6.200	372.00
REEDY CREEK	SCH.-Jc	84.0	0.0	0.0	84.0	4.117	4.117	3,458.00
TALLAHASSEE	SCH.-Js	810.0	0.0	472.4	337.6	15.137	15.137	51,102.83
TALLAHASSEE	SCH.-Jc	3,464.0	0.0	0.0	3,464.0	6.886	6.886	237,883.74
AQUILLA	SCH.-Js	205.0	0.0	60.0	145.0	9.087	9.087	13,180.74
AQUILLA	SCH.-Jc	1,806.0	0.0	0.0	1,806.0	7.215	7.215	108,803.87
MORGAN STANLEY	SCH.-Js	670.0	0.0	50.0	620.0	9.925	9.925	61,534.28
MORGAN STANLEY	SCH.-Jc	2,165.0	0.0	0.0	2,165.0	9.884	9.884	214,000.26
CARGILL FERTILIZER	SCH.-Js	174.0	0.0	94.0	80.0	16.375	16.375	13,100.00
CARGILL FERTILIZER	SCH.-Jc	223.0	0.0	0.0	223.0	9.000	9.000	20,070.00
CORAL ENERGY	SCH.-Jc	261.0	0.0	0.0	261.0	6.435	6.435	16,801.00
FARMLAND HYDRO LP	SCH.-Jc	302.0	0.0	0.0	302.0	3.486	3.486	10,528.80
RINGHAVER	SCH.-Jc	258.0	0.0	0.0	258.0	8.415	8.415	21,710.79
OKEELANTA	SCH.-O	23,816.0	0.0	0.0	23,816.0	5.485	5.485	1,306,311.80
AUBURNDALE POWER PARTNERS	SCH.-O	4,029.0	0.0	0.0	4,029.0	2.625	2.625	105,768.91
FLA. POWER & LIGHT	STEAM-A	25.0	0.0	0.0	25.0	11.544	11.544	2,886.00
ADJUSTMENTS TO PRIOR MONTHS:								
HARDEE PWR. PART.-NATIVE	Jun-00 IPP	(94,031.0)	0.0	0.0	(94,031.0)	5.116	5.116	(4,810,882.84)
HARDEE PWR. PART.-NATIVE	Jun-00 IPP	94,031.0	0.0	0.0	94,031.0	5.271	5.271	4,956,144.36
CARGILL FERTILIZER	Jan-00 SCH.-Jc	(33.0)	0.0	0.0	(33.0)	4.670	4.670	(1,541.16)
CARGILL FERTILIZER	Jan-00 SCH.-Jc	33.0	0.0	0.0	33.0	5.066	5.066	1,662.32
TOTAL		227,805.0	0.0	12,709.7	215,095.3	6.267	6.267	13,822,488.69
CURRENT MONTH:								
DIFFERENCE	-	(34,666.0)	0.0	(14,965.3)	(19,700.7)	-4.448	-4.448	876,288.69
DIFFERENCE %	-	(13.2)	0.0	(54.1)	(8.4)	(82.6)	(82.6)	6.9
PERIOD TO DATE:								
ACTUAL	-	1,193,966.00	0.00	131,847.50	1,062,107.5	4.804	4.804	51,028,880.21
ESTIMATED	-	847,802.0	0.0	104,673.0	743,129.0	4.791	4.791	35,600,300.0
DIFFERENCE	-	346,183.0	0.0	27,174.5	318,978.5	0.013	0.013	15,428,580.21
DIFFERENCE %	-	40.8	0.0	20.0	42.9	0.3	0.3	43.3

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: AUGUST 1999

SCHEDULE A6
PAGE 1 OF 3

(1) SOLD TO		(2) TYPE & SCHEDUL	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) (A) FUEL COST	(6) (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5*6*A)	(8) TOTAL $ FOR TOTAL COST (5*6*B)	(9) 65% GAIN N ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	5,316.0	0.0	5,316.0	1.948	2.302	103,566.00	122,395.00	10,000.00
VARIOUS	JURISDICTIONAL	SCH.-O	5,734.0	0.0	5,734.0	2.169	2.169	124,355.00	124,355.00	
VARIOUS	SEPARATED	SCH.-O	24,772.0	0.0	24,772.0	1.743	1.958	431,895.00	485,095.00	
VARIOUS		CONTRAC	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPARATED	CONTRAC	46,899.0	0.0	46,899.0	2.348	3.210	1,144,295.00	1,505,400.00	
VARIOUS		SCH.-O	78,139.0	78,139.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDICTIONAL	SCH.-J	5,951.0	0.0	5,951.0	2.384	2.384	141,899.00	141,899.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	166,807.0	78,139.0	88,807.0	2.143	2.706	1,941,200.00	2,409,209.00	10,000.00
LESS TRANSMISSION COSTS		-						(34,200.00)		
LESS VARIABLE O & M COSTS		-						(5,100.00)		
PLUS 65% OF ECON. ENERGY SALES PROFITS		-						10,000.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 65% OF ECON. ENERGY SALES PROFITS		-	166,807.0	78,139.0	88,807.0	2.127	2.706	1,930,900.00	2,409,209.00	10,000.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		ECON.-C	937.0	0.0	937.0	2.179	2.393	20,416.97	21,995.59	938.57
CITY OF LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		ECON.-C	135.0	0.0	135.0	2.316	2.988	3,126.72	3,942.48	661.62
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	88.0	0.0	88.0	2.404	3.000	1,304.45	2,230.88	675.52
CITY OF NEW SMYRNA BCH.		ECON.-C	12.0	0.0	12.0	2.410	2.997	288.19	468.86	143.73
ORLANDO UTIL. COMM.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENERGY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
OGLETHORPE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NOCH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENN. VALLEY AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	SEPAR.	SCH.-O	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPAR.	SCH.-O	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH.-O	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH.-O	13,265.0	0.0	13,265.0	1.702	1.870	224,754.59	247,743.66	
REEDY CREEK	SEPAR.	SCH.-O	8,265.0	0.0	8,265.0	1.871	1.995	138,157.36	164,172.25	
WAUCHULA	SEPAR.	SCH.-O	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPAR.	SCH.-O	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPAR.	SCH.-O	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEP. CONTRACT		47,807.0	0.0	47,807.0	2.220	2.800	1,060,567.40	1,388,600.00	
SEMINOLE ELECTRIC CO-OP PINCO	JURISD.	SCH.-O	6,166.0	1,000.0	4,250.2	(1.233)	(1.233)	(82,403.45)	(82,403.45)	
SEMINOLE ELECTRIC CO-OP HARDE	JURISD.	SCH.-O	523.0	0.0	523.0	1.511	1.511	9,479.69	9,479.69	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: AUGUST 1999

SCHEDULE A6
PAGE 2 OF 3

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) (A) FUEL COST	(6) (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT ((5)*(6)(A))	(8) TOTAL $ FOR TOTAL COST ((5)*(6)(B))	(9) 80% GAIN N ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. J	402.0	0.0	402.0	3.169	3.169	12,322.00	12,322.00	
FLA. PWR. & LIGHT	JURISD.	SCH. J	477.0	0.0	477.0	2.346	2.346	11,402.00	11,402.00	
CITY OF HOMESTEAD	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. J	468.0	0.0	468.0	3.741	3.741	14,063.35	14,063.35	
ORLANDO UTIL. COMM.	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. J	4,668.0	0.0	4,668.0	2.314	2.314	107,998.47	107,998.47	
WAUCHULA	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
THE ENERGY AUTHORITY	JURISD.	SCH. J	1,822.0	0.0	1,822.0	6.123	6.123	83,199.85	83,199.85	
PMPA		SCH. O	78,138.0	78,138.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PART. TO FLA. PWR. CORP.		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR.& LT.		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO REEDY CREEK		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO GAINESVILLE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO JACKSONVILLE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KISSIMMEE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO NEW SMYRNA BCH.		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ORLANDO		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO STARKE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO PMPA		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO HOMESTEAD		ECON.C	31.0	0.0	31.0	3.072	3.210	952.34	1,000.04	110.00
HARDEE POWER PART. TO SEMINOLE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FT. PIERCE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO TALLAHASSEE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LAKELAND		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LK. WORTH		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KEY WEST		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO VERO BEACH		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ENERGY AUTHORITY		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR. CORP.		SCH. J	35.0	0.0	35.0	2.691	2.691	933.91	933.91	
HARDEE POWER PART. TO FLA. PWR.& LT.		SCH. J	364.0	0.0	364.0	3.011	3.011	11,000.40	11,000.40	
SEMINOLE ELECTRIC CO-OP		SCH. G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE		SCH. G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: AUGUST 1999

SCHEDULE A6
PAGE 3 OF 3

(1) SOLD TO		(2) TYPE & SCHEDUL	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (6)(B)/(A)	(8) TOTAL $ FOR TOTAL COST (6)(B)/100	(9) 60% GAIN N ECONOMY ENERGY SALES
ADJUSTMENTS TO PREVIOUS MONT	MO/YR TYPE	SCHED.								
HARDEE POWER PARTNERS EST.	7/99 SEPAR.	CONTRAC	(40,200.0)	0.0	(40,200.0)	2.000	2.732	(1,023,026.40)	(1,344,302.80)	
HARDEE POWER PARTNERS ACT.	7/99 SEPAR.	CONTRAC	40,200.0	0.0	40,200.0	2.539	2.899	1,101,707.12	1,417,100.48	
FLA. PWR. CORP.	7/99	ECON.-C	(600.0)	0.0	(600.0)	2.896	3.810	(17,021.64)	(22,251.00)	(4,343.40)
FLA. PWR. CORP.	7/99	ECON.-C	574.0	0.0	574.0	3.166	4.001	17,021.64	23,251.00	4,343.40
THE ENERGY AUTHORITY	7/99 JURISD.	SCH. J	(200.0)	0.0	(200.0)	23.344	23.344	(66,110.02)	(66,110.02)	
THE ENERGY AUTHORITY	7/99 JURISD.	SCH. J	351.0	0.0	351.0	16.888	16.888	66,110.02	66,110.02	
AQUILA	7/99 JURISD.	SCH. J	(121.0)	0.0	(121.0)	16.539	16.539	(16,770.40)	(16,770.40)	
AQUILA	7/99 JURISD.	SCH. J	100.0	0.0	100.0	13.488	13.488	26,270.40	26,270.40	
CITY OF NEW SMYRNA BCH.	7/99 JURISD.	SCH. J	(4,535.0)	0.0	(4,535.0)	2.312	2.312	(104,794.82)	(104,794.82)	
CITY OF NEW SMYRNA BCH.	7/99 JURISD.	SCH. J	4,535.0	0.0	4,535.0	2.312	2.312	104,738.40	104,738.40	
SUB-TOTAL ECONOMY POWER SALES			1,136.0	0.0	1,136.0	2.291	2.544	26,191.57	28,946.89	2,211.22
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.			21,491.0	0.0	21,491.0	1.891	1.979	364,911.85	403,946.11	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			6,663.0	1,988.0	4,773.2	(0.889)	(0.889)	(42,932.70)	(42,932.70)	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.			8,138.0	0.0	8,138.0	3.279	3.279	266,804.70	266,804.70	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.			47,887.0	0.0	47,887.0	2.394	3.033	1,134,338.12	1,442,787.44	
SUB-TOTAL OTHER D POWER SALES			73,138.0	73,138.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS			163,127.0	80,829.8	83,667.2	2.000	2.536	1,730,000.00	2,000,193.16	2,211.22
LESS VARIABLE O & M COSTS								(2,302.02)		
LESS VARIABLE O & M COSTS - HARDEE								(4.34)		
LESS TRANSMISSION COSTS SCH. D (SEP.)								(10,000.00)		
PLUS 60% OF ECON. ENERGY SALES PROFITS -								2,211.22		
TOTAL EXCL. VARIABLE O & M COSTS AND EXCL. 60% OF ECON. ENERGY SALES PROFITS -			163,127.0	80,829.8	83,667.2	2.071	2.536	1,730,000.12	2,000,193.16	2,211.22
CURRENT MONTH:										
DIFFERENCE	-		(5,500.0)	1,988.8	(7,488.8)	(0.000)	(0.179)	(266,033.88)	(361,006.84)	(16,588.78)
DIFFERENCE %	-		(3.3)	2.4	(8.2)	(2.8)	(6.6)	(10.7)	(14.3)	(88.2)
PERIOD TO DATE:										
ACTUAL	-		1,847,388.8	618,178.7	429,178.3	1.887	2.336	8,168,173.02	9,982,488.81	43,318.30*
ESTIMATED	-		2,827,488.8	612,388.8	1,415,848.8	2.288	2.618	31,848,448.88	37,048,888.88	4,438,848.88
DIFFERENCE	-		(980,848.8)	5,818.7	(986,887.7)	(0.371)	(0.282)	(23,848,288.38)	(27,883,138.88)	(4,387,228.88)
DIFFERENCE %	-		(48.3)	1.8	(88.7)	(18.4)	(11.2)	(74.8)	(73.1)	(88.8)

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. SEC 60% OR $2,814.38 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH AUGUST 1999

SCHEDULE A7

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (8) = (7A)
ESTIMATED:								
VARIOUS	SMER.	28,325.0	0.0	16,300.0	12,027.0	3.770	3.770	1,264,100.00
HARDEE POWER PARTNERS	IPP	71,131.0	0.0	0.0	71,131.0	2.904	2.904	2,066,400.00
PSCO	OTHER	54,066.0	54,066.0	0.0	0.0	0.000	0.000	0.00
FPC	OTHER	24,025.0	24,025.0	0.0	0.0	0.000	0.000	0.00
TOTAL		177,976.0	78,126.0	16,300.0	84,068.0	3.001	3.001	3,330,500.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	122,363.0	0.0	0.0	122,363.0	3.290	3.290	4,026,662.02
HARDEE PWR. PART.-OTHERS	IPP	461.0	0.0	0.0	461.0	2.436	2.436	10,062.71
FLA. POWER CORP.	SCH.-JU	4,300.0	0.0	1,842.1	2,448.0	10.000	10.000	269,000.20
FLA. POWER CORP.	SCH.-JU	20,463.0	0.0	0.0	20,463.0	2.928	2.928	599,026.30
FLA. POWER & LIGHT	SCH.-JU	9,000.0	0.0	2,075.3	7,423.7	9.346	9.346	696,346.61
FLA. POWER & LIGHT	SCH.-JU	13,300.0	0.0	0.0	13,300.0	4.106	4.106	546,026.70
CITY OF LAKELAND	SCH.-JU	16,000.0	0.0	11,301.2	5,000.0	13.700	13.700	700,720.24
CITY OF LAKELAND	SCH.-JU	10,303.0	0.0	0.0	10,303.0	5.002	5.002	001,011.00
ORLANDO	SCH.-JU	1,070.0	0.0	1,001.0	69.0	12.440	12.440	0,003.00
ORLANDO	SCH.-JU	2,707.0	0.0	0.0	2,707.0	4.575	4.575	120,000.00
OKEELANTA	SCH.-JU	2,040.0	0.0	300.4	2,007.0	4.000	4.000	120,000.70
OKEELANTA	SCH.-JU	300.0	0.0	0.0	300.0	4.000	4.000	10,100.00
THE ENERGY AUTH.	SCH.-JU	14,000.0	0.0	12,007.0	1,002.1	10.033	10.033	340,030.07
THE ENERGY AUTH.	SCH.-JU	1,041.0	0.0	0.0	1,041.0	0.002	0.002	127,300.30
REEDY CREEK	SCH.-JU	334.0	0.0	130.5	197.5	5.710	5.710	11,270.42
REEDY CREEK	SCH.-JU	003.0	0.0	0.0	003.0	4.300	4.300	20,721.00
AQUILLA	SCH.-JU	3,304.0	0.0	1,000.4	1,040.0	0.304	0.304	104,010.40
AQUILLA	SCH.-JU	222.0	0.0	0.0	222.0	3.200	3.200	7,102.02
TALLAHASSEE	SCH.-JU	3,013.0	0.0	2,400.5	1,470.5	10.201	10.201	101,004.10
TALLAHASSEE	SCH.-JU	1,000.0	0.0	0.0	1,000.0	0.420	0.420	100,000.02
MORGAN STANLEY	SCH.-JU	13,324.0	0.0	4,000.0	0,720.2	0.740	0.740	000,023.03
MORGAN STANLEY	SCH.-JU	1,700.0	0.0	0.0	1,700.0	0.021	0.021	140,121.12
KOCH	SCH.-JU	7,204.0	0.0	0,700.0	004.0	23.004	23.004	110,000.04
KOCH	SCH.-JU	2,300.0	0.0	0.0	2,300.0	0.404	0.404	102,201.10
FARMLAND HYDRO LP	SCH.-JU	000.0	0.0	0.0	000.0	3.000	3.000	34,000.00
AUBURNDALE POWER PARTNERS	SCH.-JU	4,000.0	0.0	0.0	4,000.0	2.700	2.700	112,720.00
PSCO	OTHER	54,000.0	54,000.0	0.0	0.0	0.000	0.000	0.00
FPC	OTHER	24,025.0	24,025.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS:								
HARDEE PWR. PART.-NATIV	7/99	IPP	(00,334.0)	0.0	0.0	(00,334.0)	3.202	3.202	(3,227,302.70)
HARDEE PWR. PART.-NATIV	7/99	IPP	100,110.0	0.0	0.0	100,110.0	2.000	2.000	3,230,017.22
FLA. POWER & LIGHT	7/99	STEAM-A	(700.0)	0.0	(24.0)	(722.0)	7.047	7.047	(00,001.30)
FLA. POWER & LIGHT	7/99	STEAM-A	700.0	0.0	24.0	722.0	110.130	110.130	001,200.70
JACKSONVILLE ELEC. AUTH.	7/99	STEAM-A	(400.0)	0.0	(2.0)	(307.4)	0.000	0.000	(20,020.07)
JACKSONVILLE ELEC. AUTH.	7/99	STEAM-A	400.0	0.0	2.0	307.4	132.071	132.071	024,001.40
FLA. POWER & LIGHT	7/99	SCH.-JU	(13,002.0)	0.0	0.0	(13,002.0)	3.020	3.020	(004,102.00)
FLA. POWER & LIGHT	7/99	SCH.-JU	13,002.0	0.0	0.0	13,002.0	4.000	4.000	002,073.01
THE ENERGY AUTH.	7/99	SCH.-JU	(4,010.0)	0.0	(4,340.0)	(300.4)	10.112	10.112	(40,240.00)
THE ENERGY AUTH.	7/99	SCH.-JU	4,010.0	0.0	4,340.0	300.4	10.340	10.340	01,030.12
THE ENERGY AUTH.	7/99	SCH.-JU	(300.0)	0.0	0.0	(300.0)	0.020	0.020	(33,100.70)
THE ENERGY AUTH.	7/99	SCH.-JU	300.0	0.0	0.0	300.0	0.040	0.040	33,202.00
TALLAHASSEE	7/99	SCH.-JU	(2,230.0)	0.0	(1,420.0)	(004.0)	10.270	10.270	(130,000.00)
TALLAHASSEE	7/99	SCH.-JU	2,230.0	0.0	1,420.0	004.0	10.140	10.140	120,047.00
TALLAHASSEE	7/99	SCH.-JU	(000.0)	0.0	0.0	(000.0)	4.000	4.000	(44,070.30)
TALLAHASSEE	7/99	SCH.-JU	000.0	0.0	0.0	000.0	4.020	4.020	44,401.00
AQUILLA	7/99	SCH.-JU	(2,002.0)	0.0	0.0	(2,002.0)	3.773	3.773	(07,700.37)
AQUILLA	7/99	SCH.-JU	2,002.0	0.0	0.0	2,002.0	3.710	3.710	00,310.30
OKEELANTA	7/99	SCH.-JU	(300.0)	0.0	0.0	(300.0)	24.022	24.022	(00,002.12)
OKEELANTA	7/99	SCH.-JU	300.0	0.0	0.0	300.0	4.070	4.070	10,102.12
AUBURNDALE PWR. PARTN	7/99	SCH.-JU	(4,300.0)	0.0	0.0	(4,300.0)	4.144	4.144	(102,100.00)
AUBURNDALE PWR. PARTN	7/99	SCH.-JU	4,224.0	0.0	0.0	4,224.0	3.010	3.010	101,100.00
CUTRALE CITRUS	7/99	SCH.-JU	(20.0)	0.0	0.0	(20.0)	32.000	32.000	(0,000.00)
CUTRALE CITRUS	7/99	SCH.-JU	20.0	0.0	0.0	20.0	30.000	30.000	0,000.00
TOTAL			300,037.0	70,120.0	40,000.0	220,007.4	0.003	0.003	11,302,740.70
CURRENT MONTH:									
DIFFERENCE		-	173,301.0	0.0	30,011.0	142,040.4	0.017	0.017	0,023,240.70
DIFFERENCE %		-	07.0	0.0	100.2	100.0	141.0	141.0	241.0
PERIOD TO DATE:									
ACTUAL		-	1,072,040.00	012,200.00	140,020.20	1,214,700.0	3.701	3.701	44,007,000.00
ESTIMATED		-	1,004,277.0	012,300.0	00,402.0	410,404.0	3.000	3.000	14,000,000.0
DIFFERENCE		-	000,000.0	(102.0)	00,400.2	700,300.0	0.002	0.002	20,001,000.00
DIFFERENCE %		-	02.0	0.0	100.4	102.4	2.0	2.0	100.0

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: DECEMBER 1999

SCHEDULE A6
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(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT ($)(6)(A)	(8) TOTAL $ FOR TOTAL COST ($)(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:									
VARIOUS	ECON.	74,589.0	0.0	74,589.0	1.846	2.264	1,377,200.00	1,688,600.00	248,360.00
VARIOUS JURISDICTIONAL	SCH. -D	6,675.0	0.0	6,675.0	1.681	1.681	112,400.00	112,400.00	
VARIOUS SEPARATED	SCH. -D	21,060.0	0.0	21,060.0	1.778	2.063	374,300.00	432,100.00	
VARIOUS	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS SEPARATED	CONTRACT	16,700.0	0.0	16,700.0	2.336	3.200	390,000.00	534,400.00	
VARIOUS	SCH. -D	96,400.0	96,400.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS JURISDICTIONAL	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS	-	213,414.0	96,400.0	118,014.0	1.910	2.346	2,253,700.00	2,767,800.00	248,360.00
LESS TRANSMISSION COSTS	-						(18,100.00)		
LESS VARIABLE O & M COSTS	-						(126,300.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS	-						248,360.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS	-	213,414.0	96,400.0	118,014.0	1.997	2.346	2,366,660.00	2,767,800.00	248,360.00
ACTUAL:									
FLA. PWR. CORP.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF ST. CLOUD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
PMPA	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SONAT	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY, INC.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENRGY, INC.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENN. VALLEY AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
PMPA SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL. SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH. SEPAR.	SCH. -D	9,666.0	0.0	9,666.0	1.666	1.903	161,270.98	183,982.03	
REEDY CREEK SEPAR.	SCH. -D	7,860.0	0.0	7,860.0	1.818	1.937	143,278.76	150,271.80	
WAUCHULA SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS SEP. CONTRACT		4,321.0	0.0	4,321.0	2.304	3.019	99,586.84	130,480.99	
SEMINOLE ELECTRIC CO-OP P JURISD.	SCH. -D	4,718.6	62.1	4,656.5	2.073	2.073	96,522.31	96,522.31	
SEMINOLE ELECTRIC CO-OP H JURISD.	SCH. -D	963.0	0.0	963.0	2.023	2.023	11,966.77	11,966.77	

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FOR THE MONTH OF: DECEMBER 1999

SCHEDULE A6
PAGE 2 OF 3

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
THE ENERGY AUTHORITY	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
PMPA		SCH. -O	96,384.0	96,384.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PART. TO FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR.& LT.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO JACKSONVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KISSIMMEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ORLANDO		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO PMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO SEMINOLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FT. PIERCE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LK. WORTH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ENERGY AUTHORITY		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE		SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: DECEMBER 1999

SCHEDULE A6
PAGE 3 OF 3

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)*(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)*(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. -M	6,014.0	0.0	6,014.0	3.116	3.116	187,519.83	187,519.83	
FLA. PWR. & LIGHT	JURISD.	SCH. -M	17,821.0	0.0	17,821.0	2.484	2.484	442,616.06	442,616.06	
CITY OF LAKELAND	JURISD.	SCH. -M	2,736.0	0.0	2,736.0	2.460	2.460	67,305.47	67,305.47	
ORLANDO UTIL. COMM.	JURISD.	SCH. -M	350.0	0.0	350.0	2.786	2.786	9,754.43	9,754.43	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -M	1,348.0	0.0	1,348.0	6.263	6.263	84,892.76	84,892.76	
RESDV CREEK	JURISD.	SCH. -M	346.0	0.0	346.0	2.893	2.893	9,946.62	9,946.62	
THE ENERGY AUTHORITY	JURISD.	SCH. -M	532.0	0.0	532.0	3.132	3.132	16,664.63	16,664.63	
TALLAHASSEE	JURISD.	SCH. -M	90.0	0.0	90.0	2.742	2.742	1,370.86	1,370.86	
ADJUSTMENTS TO PREVIOUS	MONYR TYPE	SCHED.								
NONE										
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.			17,546.0	0.0	17,546.0	1.679	1.906	294,649.31	334,233.63	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			6,311.0	62.1	6,248.9	2.667	2.667	166,619.06	166,619.06	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.			4,321.0	0.0	4,321.0	2.304	3.019	99,566.84	130,460.99	
SUB-TOTAL OTHER D POWER SALES			96,364.0	96,364.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE M POWER SALES-JURISD.			26,196.0	0.0	26,196.0	2.806	2.806	618,949.66	618,949.66	
TOTAL INCLUDING VARIABLE O & M COSTS			151,770.0	96,486.1	56,313.9	2.347	2.472	1,321,673.88	1,362,153.36	0.00
LESS VARIABLE O & M COSTS								0.00		
LESS VARIABLE O & M COSTS - HARDEE								0.00		
LESS TRANSMISSION COSTS SCH. O (SEP.)								(18,083.80)		
PLUS 80% OF ECON. ENERGY SALES PROFITS *								0.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS			151,770.0	96,486.1	56,313.9	2.316	2.472	1,303,490.08	1,362,153.36	0.00
CURRENT MONTH:										
DIFFERENCE			(61,844.0)	88.1	(61,700.1)	0.316	0.127	(1,063,169.91)	(1,376,846.64)	(249,360.00)
DIFFERENCE %			(28.9)	0.1	(52.3)	15.8	5.4	(44.7)	(49.7)	(100.0)
PERIOD TO DATE:										
ACTUAL			1,728,783.0	944,888.0	776,827.0	2.161	2.490	16,867,763.63	19,339,796.17	99,070.40
ESTIMATED			2,723,311.0	937,080.9	1,786,231.0	2.211	2.571	39,491,000.00	45,931,000.00	5,000,000.00
DIFFERENCE			(1,002,528.0)	7,776.0	(1,010,304.0)	(0.050)	(0.081)	(22,603,999.37)	(26,610,203.83)	(4,930,889.60)
DIFFERENCE %			(36.8)	0.8	(56.6)	(2.7)	(3.2)	(57.7)	(57.9)	(98.0)

* THERE WERE NO SALES TO HARDEE POWER PARTNERS FOR OTHERS FOR THE MONTH OF DECEMBER 1999.

SCHEDULE A7

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF DECEMBER 1999

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	1,814.0	0.0	929.0	885.0	9.761	9.761	87,000.00
HARDEE POWER PARTNERS	IPP	11,591.0	0.0	0.0	11,591.0	4.764	4.764	552,200.00
PECO	OTHER	54,095.0	54,095.0	0.0	0.0	0.000	0.000	0.00
FPC	OTHER	24,025.0	24,025.0	0.0	0.0	0.000	0.000	0.00
VARIOUS	OTHER	17,280.0	17,280.0	0.0	0.0	0.000	0.000	0.00
TOTAL	-	108,805.0	95,400.0	929.0	12,276.0	5.044	5.044	619,200.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	574.0	0.0	0.0	574.0	37.021	37.021	212,500.90
HARDEE PWR. PART.-OTHERS	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.	SCH.-Je	515.0	0.0	502.3	16.7	5.491	5.491	916.96
FLA. POWER CORP.	SCH.-Jc	6,099.0	0.0	0.0	6,099.0	3.026	3.026	183,742.25
FLA. POWER & LIGHT	SCH.-Je	625.0	0.0	625.0	0.0	0.000	0.000	0.00
FLA. POWER & LIGHT	SCH.-Jc	5,322.0	0.0	0.0	5,322.0	3.492	3.492	185,847.65
CITY OF LAKELAND	SCH.-Jc	1,731.0	0.0	0.0	1,731.0	3.695	3.695	63,957.50
THE ENERGY AUTH.	SCH.-Jc	1,040.0	0.0	0.0	1,040.0	3.847	3.847	40,012.80
TALLAHASSEE	SCH.-Jc	99.0	0.0	0.0	99.0	3.038	3.038	1,792.28
AQUILLA	SCH.-Je	99.0	0.0	50.9	18.1	4.174	4.174	755.48
AQUILLA	SCH.-Jc	526.0	0.0	0.0	526.0	4.281	4.281	22,520.00
AUBURNDALE POWER PARTNERS	SCH.-Jc	4,349.0	0.0	0.0	4,349.0	2.334	2.334	101,499.12
OKEELANTA	SCH.-O	5,553.0	0.0	0.0	5,553.0	4.186	4.186	232,471.00
FLA. POWER & LIGHT	SCH.-O	2.0	0.0	0.0	2.0	3.125	3.125	62.50
PECO	OTHER	54,095.0	54,095.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.	OTHER	24,025.0	24,025.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER & LIGHT	OTHER	17,274.0	17,274.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS:								
HARDEE PWR. PART.-NATIVE 11/99	IPP	(7,515.0)	0.0	0.0	(7,515.0)	4.816	4.816	(362,104.53)
HARDEE PWR. PART.-NATIVE 11/99	IPP	7,515.0	0.0	0.0	7,515.0	9.828	9.828	738,426.66
OKEELANTA 11/99	SCH.-O	(6,017.0)	0.0	0.0	(6,017.0)	4.067	4.067	(246,916.00)
OKEELANTA 11/99	SCH.-O	6,017.0	0.0	0.0	6,017.0	4.067	4.067	244,696.00
FLA. POWER CORP. 10/99	SCH.-Je	(14,942.0)	0.0	(7,477.7)	(7,464.3)	6.998	6.998	(522,378.16)
FLA. POWER CORP. 10/99	SCH.-Je	14,942.0	0.0	7,477.7	7,464.3	6.733	6.733	502,587.76
FLA. POWER CORP. 10/99	SCH.-Jc	(18,462.0)	0.0	0.0	(18,462.0)	3.856	3.856	(711,713.76)
FLA. POWER CORP. 10/99	SCH.-Jc	18,462.0	0.0	0.0	18,462.0	3.560	3.560	662,764.76
THE ENERGY AUTH. 10/99	SCH.-Je	(7,415.0)	0.0	(3,287.5)	(4,127.5)	7.293	7.293	(301,024.94)
THE ENERGY AUTH. 10/99	SCH.-Je	7,415.0	0.0	3,287.5	4,127.5	7.066	7.066	291,660.66
THE ENERGY AUTH. 10/99	SCH.-Jc	(7,876.0)	0.0	0.0	(7,876.0)	5.492	5.492	(432,565.23)
THE ENERGY AUTH. 10/99	SCH.-Jc	7,876.0	0.0	0.0	7,876.0	5.265	5.265	414,833.34
TALLAHASSEE 10/99	SCH.-Je	(2,327.0)	0.0	(1,352.3)	(974.7)	5.540	5.540	(53,997.67)
TALLAHASSEE 10/99	SCH.-Je	2,327.0	0.0	1,352.3	974.7	5.275	5.275	51,412.99
TALLAHASSEE 10/99	SCH.-Jc	(2,214.0)	0.0	0.0	(2,214.0)	4.296	4.296	(95,108.52)
TALLAHASSEE 10/99	SCH.-Je	2,214.0	0.0	0.0	2,214.0	4.031	4.031	89,238.48
AQUILLA 10/99	SCH.-Je	(872.0)	0.0	(421.0)	(451.0)	5.143	5.143	(23,194.89)
AQUILLA 10/99	SCH.-Je	872.0	0.0	421.0	451.0	4.881	4.881	22,012.89
AQUILLA 10/99	SCH.-Jc	(1,217.0)	0.0	0.0	(1,217.0)	4.217	4.217	(51,316.57)
AQUILLA 10/99	SCH.-Jc	1,217.0	0.0	0.0	1,217.0	3.949	3.949	48,064.72
MORGAN STANLEY 10/99	SCH.-Jc	(3,586.0)	0.0	0.0	(3,586.0)	4.174	4.174	(150,108.34)
MORGAN STANLEY 10/99	SCH.-Jc	3,586.0	0.0	0.0	3,586.0	4.028	4.028	144,840.13
TOTAL		121,832.0	95,394.0	1,178.2	25,259.8	5.169	5.169	1,305,767.73
CURRENT MONTH:								
DIFFERENCE	-	13,227.0	(6.0)	249.2	12,983.8	5.288	5.288	686,567.73
DIFFERENCE %	-	12.2	(0.0)	26.8	105.8	104.8	104.8	110.9
PERIOD TO DATE:								
ACTUAL	-	2,836,012.00	937,077.00	186,340.50	1,511,994.5	3.769	3.769	56,961,714.57
ESTIMATED	-	1,544,363.0	937,080.0	69,901.0	537,382.0	3.649	3.649	19,610,500.0
DIFFERENCE	-	1,090,649.0	(3.0)	116,339.5	974,312.5	0.120	0.120	37,371,214.57
DIFFERENCE %	-	70.6	0.0	166.4	181.3	3.3	3.3	190.6

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: OCTOBER 2000

SCHEDULE A6
PAGE 1 OF 3

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) ¢/KWH (A) FUEL COST	(6) ¢/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (6)*(5)/(A)	(8) TOTAL $ FOR TOTAL COST (6)*(5)/(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	102.0	0.0	102.0	2.204	2.940	3,700.00	4,800.00	700.00
VARIOUS	JURISD.	SCH.-D	5,864.0	0.0	5,864.0	2.088	2.088	122,898.00	122,898.00	
VARIOUS	SEPAR.	SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPAR.	CONTRACT	19,488.0	0.0	19,488.0	2.313	2.290	450,109.00	533,400.00	
FMPA		SCH.-D	111,888.0	0.0	111,888.0	1.800	1.800	2,014,884.00	2,014,884.00	
VARIOUS	JURISD.	SCH.-J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	137,872.0	0.0	137,872.0	1.800	2.026	2,891,164.00	2,775,384.00	700.00
LESS TRANSMISSION COSTS		-						0.00		
LESS VARIABLE O & M COSTS		-						(300.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS		-						700.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-	137,872.0	0.0	137,872.0	1.801	2.026	2,891,564.00	2,775,384.00	700.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENERGY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
OGLETHORPE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENN. VALLEY AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	SEPAR.	SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPAR.	SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPAR.	SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPAR.	SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPAR.	SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPAR.	SCH.-D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEP.	CONTRACT	73,166.0	0.0	73,166.0	2.382	3.184	1,742,760.30	2,330,880.10	
SEMINOLE ELECTRIC CO-OP PRSCO-1	JURISD.	SCH.-D	5,952.0	278.1	5,223.0	3.136	3.136	163,803.67	163,803.67	
SEMINOLE ELECTRIC CO-OP HARDEE	JURISD.	SCH.-D	936.0	0.0	936.0	2.272	2.272	21,239.98	21,239.98	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: OCTOBER 2006

SCHEDULE A6
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(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) (A) FUEL COST	(6) (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (6)(A)*100	(8) TOTAL $ FOR TOTAL COST (6)(B)*100	(9) 80% GAIN N ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA		SCH. O	84,916.0	0.0	84,916.0	1.576	1.576	1,334,000.00	1,334,000.00	
HARDEE POWER PART. TO FLA. PWR. CORP.		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR.& LT.		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO REEDY CREEK		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO GAINESVILLE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO JACKSONVILLE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KISSIMMEE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO NEW SMYRNA BCH.		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ORLANDO		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO STARKE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FMPA		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO HOMESTEAD		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO SEMINOLE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FT. PIERCE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO TALLAHASSEE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LAKELAND		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LK. WORTH		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KEY WEST		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO VERO BEACH		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ENERGY AUTHORITY		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR.& LT.		SCH.-MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP		SCH.-G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE		SCH.-G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: OCTOBER 2000

SCHEDULE A6
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(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)*(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)*(6)(B)	(9) 80% GAIN N ECONOMY ENERGY SALES
FLORIDA POWER & LIGHT		SCH. -MA	5,365.0	0.0	5,365.0	3.370	3.370	177,443.01	177,443.01	
FLORIDA POWER CORP.		SCH. -MA	66.0	0.0	66.0	4.997	4.997	2,298.06	2,298.06	
HOMESTEAD		SCH. -MA	10.0	0.0	10.0	3.780	3.780	378.03	378.03	
CARGILL ALLIANT		SCH. -MA	171.0	0.0	171.0	0.746	0.746	1,276.09	1,276.09	
ORLANDO		SCH. -MA	66.0	0.0	66.0	3.147	3.147	1,973.06	1,973.06	
ADJUSTMENTS TO PREVIOUS MONTHS	MO/YR TYP	SCHED.								
HARDEE POWER PART. EST.	9/00 SEPAR.	CONTRACT	(54,000.0)	0.0	(54,000.0)	2.536	3.363	(1,371,181.80)	(1,813,837.70)	
HARDEE POWER PART. ACT.	9/00 SEPAR.	CONTRACT	54,000.0	0.0	54,000.0	2.362	3.194	1,288,423.80	1,727,834.80	
CARGILL ALLIANT EST.	9/00	SCH. -MA	(166.0)	0.0	(166.0)	5.514	5.514	(9,154.76)	(9,154.76)	
CARGILL ALLIANT ACT.	9/00	SCH. -MA	166.0	0.0	166.0	5.310	5.310	8,974.76	8,974.76	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			6,437.0	278.1	6,165.9	3.004	3.004	186,043.85	186,043.85	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.			73,165.0	0.0	73,165.0	2.269	3.076	1,660,032.80	2,250,897.00	
SUB-TOTAL OTHER D POWER SALES			84,915.0	0.0	84,915.0	1.575	1.575	1,334,599.55	1,334,599.55	
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			5,546.0	0.0	5,546.0	3.286	3.286	182,748.31	182,748.31	
TOTAL INCLUDING VARIABLE O & M COSTS			170,083.0	278.1	169,784.9	2.134	2.482	3,822,466.41	4,213,346.81	0.00
LESS VARIABLE O & M COSTS								0.00		
LESS VARIABLE O & M COSTS - HARDEE								0.00		
LESS TRANSMISSION COSTS SCH. D (SEP.)								0.00		
PLUS 80% OF ECON. ENERGY SALES PROFITS								0.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS			170,083.0	278.1	169,784.9	2.134	2.482	3,822,466.41	4,213,346.81	0.00
CURRENT MONTH:										
DIFFERENCE			32,991.0	278.1	32,712.9	0.343	0.497	1,030,931.41	1,437,985.81	(700.00)
DIFFERENCE %			24.1	0.0	23.9	12.9	22.6	36.9	51.8	(100.0)
PERIOD TO DATE:										
ACTUAL			1,846,818.0	8,168.5	1,846,649.5	2.162	2.387	39,908,362.66	36,779,844.84	0.00
ESTIMATED			1,813,864.0	0.0	1,813,864.0	2.286	2.509	38,892,890.00	40,486,040.00	3,367,920.00
DIFFERENCE			(66,036.0)	8,168.5	(73,204.5)	(0.124)	(0.122)	(2,983,477.42)	(3,706,195.06)	(3,367,920.00)
DIFFERENCE %			(4.6)	0.0	(4.5)	(5.4)	(4.9)	(8.7)	(9.2)	(100.0)

* THERE WERE NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN OCTOBER.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONT OCTOBER 2000

SCHEDULE A7
PAGE 1 OF 2

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	¢/KWH (A) FUEL COST	¢/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	24,166.0	0.0	13,693.0	10,473.0	6.395	6.395	669,700.00
HARDEE POWER PARTNERS	IPP	10,700.0	0.0	0.0	10,700.0	4.400	4.400	470,800.00
VARIOUS	OTHER	13,904.0	0.0	0.0	13,904.0	2.589	2.589	360,000.00
TOTAL	-	48,770.0	0.0	13,693.0	35,077.0	4.278	4.278	1,500,500.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	50,448.0	0.0	0.0	50,448.0	7.131	7.131	3,597,588.08
HARDEE PWR. PART.-OTHERS	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.	SCH.-Je	2,930.0	0.0	1,403.1	1,526.9	8.138	8.138	124,253.54
FLA. POWER CORP.	SCH.-Jc	34,860.0	0.0	0.0	34,860.0	4.679	4.679	1,632,369.75
FLA. POWER & LIGHT	SCH.-Je	1,951.0	0.0	1,024.1	926.9	6.424	6.424	59,546.96
FLA. POWER & LIGHT	SCH.-Jc	19,879.0	0.0	0.0	19,879.0	6.301	6.301	1,252,582.60
CITY OF LAKELAND	SCH.-Je	6,431.0	0.0	2,579.8	3,851.2	16.888	16.888	611,676.69
CITY OF LAKELAND	SCH.-Jc	21,395.0	0.0	0.0	21,395.0	6.247	6.247	1,336,958.40
ORLANDO	SCH.-Je	3,153.0	0.0	1,708.3	1,444.7	8.470	8.470	122,373.12
ORLANDO	SCH.-Jc	2,247.0	0.0	0.0	2,247.0	7.233	7.233	162,516.00
ENTERGY MARKETING	SCH.-Je	670.0	0.0	208.7	461.3	9.496	9.496	43,807.26
ENTERGY MARKETING	SCH.-Jc	860.0	0.0	0.0	860.0	5.172	5.172	44,481.25
THE ENERGY AUTH.	SCH.-Je	418.0	0.0	387.2	30.8	7.415	7.415	2,283.93
THE ENERGY AUTH.	SCH.-Jc	3,999.0	0.0	0.0	3,999.0	6.056	6.056	240,480.89
REEDY CREEK	SCH.-Jc	175.0	0.0	0.0	175.0	5.017	5.017	8,780.00
OKEELANTA	SCH.-Jc	616.0	0.0	0.0	616.0	7.000	7.000	43,121.48
TALLAHASSEE	SCH.-Je	727.0	0.0	389.0	338.0	7.429	7.429	25,110.32
TALLAHASSEE	SCH.-Jc	8,567.0	0.0	0.0	8,567.0	5.879	5.879	504,848.68
AQUILA	SCH.-Je	46.0	0.0	0.0	46.0	8.583	8.583	3,948.00
OGLETHORPE	SCH.-Jc	98.0	0.0	0.0	98.0	3.210	3.210	3,146.00
MORGAN STANLEY	SCH.-Je	2,914.0	0.0	442.9	2,471.1	8.936	8.936	220,791.34
MORGAN STANLEY	SCH.-Jc	53,860.0	0.0	0.0	53,860.0	5.324	5.324	2,868,091.21
CARGILL ALLIANT	SCH.-Je	648.0	0.0	0.0	648.0	5.183	5.183	33,640.00
ENRON	SCH.-Je	637.0	0.0	0.0	637.0	5.104	5.104	32,513.25
KOCH	SCH.-Je	99.0	0.0	0.0	99.0	6.121	6.121	6,060.00
RELIANT	SCH.-Je	344.0	0.0	100.0	244.0	5.707	5.707	13,928.00
RELIANT	SCH.-Jc	1,969.0	0.0	0.0	1,969.0	5.659	5.659	111,426.00
SOUTHERN COMPANY	SCH.-Je	1,131.0	0.0	0.0	1,131.0	2.637	2.637	29,821.00
OKEELANTA	SCH.-D	7,937.0	0.0	0.0	7,937.0	3.360	3.360	266,291.22
AUBURNDALE	SCH.-D	1,918.0	0.0	0.0	1,918.0	2.334	2.334	44,763.32
ADJUSTMENTS TO PRIOR MONTHS:								
SEE PAGE 2 FOR DETAILS		(416.0)	0.0	0.0	(416.0)	(92.674)	(92.674)	385,109.27
TOTAL		230,312.0	0.0	8,243.1	222,068.9	6.224	6.224	13,821,491.37
CURRENT MONTH:								
DIFFERENCE	-	181,542.0	0.0	(5,449.9)	186,991.9	6.569	64.887	12,320,991.37
DIFFERENCE %	-	372.2	0.0	(39.5)	533.1	164.0	1,263.0	821.1
PERIOD TO DATE:								
ACTUAL	-	2,159,127.00	0.00	226,008.96	1,934,118.0	6.307	6.307	102,634,829.36
ESTIMATED	-	1,273,612.0	0.0	150,293.0	1,123,319.0	4.728	4.728	53,125,000.00
DIFFERENCE	-	885,515.0	0.0	74,716.0	810,799.0	0.579	0.579	49,509,829.36
DIFFERENCE %	-	69.5	0.0	49.7	72.1	12.2	12.2	93.2

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONT OCTOBER 2000

SCHEDULE A7
PAGE 2 OF 2

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) —CENTS/KWH— (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ADJUSTMENTS (SEP. 2000):									
HARDEE PWR. PART.-NATI	(EST)	IPP	(122,729.0)	0.0	0.0	(122,729.0)	6.021	6.021	(7,388,562.72)
HARDEE PWR. PART.-NATI	(ACT)	IPP	122,729.0	0.0	0.0	122,729.0	6.327	6.327	7,765,254.23
OKEELANTA	(EST)	SCH.-D	(9,667.0)	0.0	0.0	(9,667.0)	3.069	3.069	(296,362.20)
OKEELANTA	(ACT)	SCH.-D	9,247.0	0.0	0.0	9,247.0	3.194	3.194	295,392.20
RINGHAVER	(EST)	SCH.-Jc	(6,289.0)	0.0	0.0	(6,289.0)	1.691	1.691	(106,370.59)
RINGHAVER	(ACT)	SCH.-Jc	6,289.0	0.0	0.0	6,289.0	2.094	2.094	131,697.90
ENERGY AUTHORITY	(EST)	SCH.-Ja	(8,923.0)	0.0	(3,420.8)	(5,502.2)	8.098	8.098	(446,560.12)
ENERGY AUTHORITY	(ACT)	SCH.-Ja	8,923.0	0.0	3,420.8	5,502.2	8.105	8.105	445,928.04
ENERGY AUTHORITY	(EST)	SCH.-Jc	(11,518.0)	0.0	0.0	(11,518.0)	5.162	5.162	(594,803.47)
ENERGY AUTHORITY	(ACT)	SCH.-Jc	11,512.0	0.0	0.0	11,512.0	5.017	5.017	577,566.22
ENRON	(EST)	SCH.-Ja	(272.0)	0.0	0.0	(272.0)	7.317	7.317	(19,903.58)
ENRON	(ACT)	SCH.-Ja	272.0	0.0	0.0	272.0	7.438	7.438	20,230.00
ENRON	(EST)	SCH.-Jc	(2,993.0)	0.0	0.0	(2,993.0)	3.959	3.959	(118,496.32)
ENRON	(ACT)	SCH.-Jc	2,993.0	0.0	0.0	2,993.0	4.017	4.017	120,235.70
AQUILA	(EST)	SCH.-Ja	(480.0)	0.0	(69.0)	(411.0)	8.451	8.451	(34,731.60)
AQUILA	(ACT)	SCH.-Ja	480.0	0.0	69.0	411.0	8.425	8.425	34,624.90
AQUILA	(EST)	SCH.-Jc	(166.0)	0.0	0.0	(166.0)	6.866	6.866	(11,397.56)
AQUILA	(ACT)	SCH.-Jc	166.0	0.0	0.0	166.0	6.418	6.418	10,654.79
TALLAHASSEE	(EST)	SCH.-Ja	(2,499.0)	0.0	(557.4)	(1,941.6)	7.244	7.244	(140,641.16)
TALLAHASSEE	(ACT)	SCH.-Ja	2,499.0	0.0	557.4	1,931.6	7.418	7.418	143,290.80
TALLAHASSEE	(EST)	SCH.-Jc	(7,713.0)	0.0	0.0	(7,713.0)	4.963	4.963	(384,340.75)
TALLAHASSEE	(ACT)	SCH.-Jc	7,723.0	0.0	0.0	7,723.0	5.020	5.020	387,874.42
ENTERGY	(EST)	SCH.-Ja	(333.0)	0.0	(277.4)	(55.6)	15.810	15.810	(8,790.56)
ENTERGY	(ACT)	SCH.-Ja	333.0	0.0	277.4	55.6	9.396	9.396	5,223.68
ENTERGY	(EST)	SCH.-Jc	(60.0)	0.0	0.0	(60.0)	26.574	26.574	(15,944.58)
ENTERGY	(ACT)	SCH.-Jc	60.0	0.0	0.0	60.0	8.804	8.804	5,282.60
MORGAN STANLEY	(EST)	SCH.-Ja	(244.0)	0.0	(117.2)	(126.8)	11.570	11.570	(14,670.41)
MORGAN STANLEY	(ACT)	SCH.-Ja	244.0	0.0	117.2	126.8	8.771	8.771	11,122.02
MORGAN STANLEY	(EST)	SCH.-Jc	(1,104.0)	0.0	0.0	(1,104.0)	3.406	3.406	(37,603.37)
MORGAN STANLEY	(ACT)	SCH.-Jc	1,104.0	0.0	0.0	1,104.0	3.157	3.157	34,862.80
KOCH	(EST)	SCH.-Ja	(7,897.0)	0.0	(1,847.9)	(6,249.1)	7.795	7.795	(487,099.32)
KOCH	(ACT)	SCH.-Ja	7,894.0	0.0	1,847.9	6,246.1	7.841	7.841	489,771.59
KOCH	(EST)	SCH.-Jc	(6,834.0)	0.0	0.0	(6,834.0)	8.934	8.934	(512,509.15)
KOCH	(ACT)	SCH.-Jc	8,837.0	0.0	0.0	8,837.0	7.069	7.069	623,844.82
SUB-TOTAL (ADJUSTMENTS)			(416.0)	0.0	0.0	(416.0)	(92.574)	(92.574)	385,109.27

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: DECEMBER 2000

SCHEDULE A6
PAGE 1 OF 3

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT ((5)*(6)(A))	(8) TOTAL $ FOR TOTAL COST ((5)*(6)(B))	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:									
VARIOUS	ECON.	266.0	0.0	266.0	3.711	4.397	9,868.00	11,698.00	1,200.00
VARIOUS JURISDICTIONAL	SCH.-O	5,756.0	0.0	5,756.0	2.051	2.051	118,000.00	118,000.00	
VARIOUS SEPARATED	SCH.-O	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS SEPARATED	CONTRACT	12,666.0	0.0	12,666.0	2.241	3.184	284,400.00	404,600.00	
PMPA	SCH.-O	111,000.0	0.0	111,000.0	1.805	1.805	2,014,564.00	2,014,564.00	
VARIOUS JURISDICTIONAL	SCH.-J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS	-	130,304.0	0.0	130,304.0	1.864	1.998	2,426,364.00	2,548,364.00	1,200.00
LESS TRANSMISSION COSTS	-						0.00		
LESS VARIABLE O & M COSTS	-						(960.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS	-						1,200.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS	-	130,304.0	0.0	130,304.0	1.864	1.998	2,426,364.00	2,548,364.00	1,200.00
ACTUAL:									
FLA. PWR. CORP.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF ST. CLOUD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
PMPA	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SCMAT	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY, INC.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENRGY, INC.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENN. VALLEY AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	SEPAR. SCH.-O	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
PMPA	SEPAR. SCH.-O	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR. SCH.-O	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR. SCH.-O	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPAR. SCH.-O	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPAR. SCH.-O	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPAR. SCH.-O	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPAR. SCH.-O	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEP. CONTRACT	2,165.0	0.0	2,165.0	2.245	3.040	48,673.16	65,836.00	
SEMINOLE ELECTRIC CO-OP FRSCO-1	JURISD. SCH.-O	2,122.0	26.3	2,088.7	2.691	2.691	54,515.41	54,515.41	
SEMINOLE ELECTRIC CO-OP HARDEE	JURISD. SCH.-O	664.0	0.0	664.0	2.662	2.662	17,726.88	17,726.88	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: DECEMBER 2000

SCHEDULE A6
PAGE 2 OF 3

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
THE ENERGY AUTHORITY	JURISD.	SCH. J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA		SCH. O	101,366.0	0.0	101,366.0	1.934	1.934	1,960,364.93	1,960,364.93	
HARDEE POWER PART. TO FLA. PWR. CORP.		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FLA. PWR.& LT.		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO REEDY CREEK		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO GAINESVILLE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO JACKSONVILLE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KISSIMMEE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO NEW SMYRNA BCH.		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ORLANDO		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO STARKE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FMPA		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO HOMESTEAD		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO SEMINOLE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO FT. PIERCE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO TALLAHASSEE		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LAKELAND		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO LK. WORTH		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO KEY WEST		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO VERO BEACH		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE POWER PART. TO ENERGY AUTHORITY		ECON.C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELECTRIC CO-OP		SCH. G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE		SCH. G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: DECEMBER 2000

SCHEDULE A6
PAGE 3 OF 3

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) ¢/KWH (A) FUEL COST	(6) ¢/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT ($)(6)(A)	(8) TOTAL $ FOR TOTAL COST ($)(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FLA. PWR. CORP.	JURISD.	SCH. 4MA	3,440.0	0.0	3,440.0	12.368	12.368	425,139.32	425,139.32	
FLA. PWR. & LIGHT	JURISD.	SCH. 4MA	4,460.0	0.0	4,460.0	3.038	3.038	135,503.36	135,503.36	
LAKELAND	JURISD.	SCH. 4MA	1,988.0	0.0	1,988.0	3.369	3.369	67,227.86	67,227.86	
TALLAHASSEE	JURISD.	SCH. 4MA	50.0	0.0	50.0	2.666	2.666	1,326.15	1,326.15	
REEDY CREEK	JURISD.	SCH. 4MA	666.0	0.0	666.0	0.066	0.066	666.63	666.63	
ENRON	JURISD.	SCH. 4MA	10.0	0.0	10.0	277.040	277.040	27,704.00	27,704.00	
THE ENERGY AUTHORITY	JURISD.	SCH. 4MA	4,940.0	0.0	4,940.0	4.000	4.000	202,066.32	202,066.32	
OGLETHORPE	JURISD.	SCH. 4MA	208.0	0.0	208.0	12.000	12.000	25,700.00	25,700.00	
CORAL ENERGY	JURISD.	SCH. 4MA	134.0	0.0	134.0	2.960	2.960	3,963.40	3,963.40	
DUKE ENERGY	JURISD.	SCH. 4MA	362.0	0.0	362.0	4.663	4.663	16,413.06	16,413.06	
MORGAN STANLEY	JURISD.	SCH. 4MA	336.0	0.0	336.0	7.666	7.666	24,666.66	24,666.66	
CARGILL ALLIANT	JURISD.	SCH. 4MA	91.0	0.0	91.0	2.616	2.616	2,380.72	2,380.72	
HARDEE POWER PART. TO ENERGY AUTH	JURISD.	SCH. 4MA	73.0	0.0	73.0	7.666	7.666	5,563.75	5,563.75	
ADJUSTMENTS TO PREVIOUS MONTHS	MON/YR TY	SCHED.								
HARDEE POWER PARTNERS	11/00 SEPAR	CONTRACT	(51,975.0)	0.0	(51,975.0)	2.230	3.086	(1,162,161.00)	(1,607,639.25)	
HARDEE POWER PARTNERS	11/00 SEPAR	CONTRACT	51,975.0	0.0	51,975.0	2.246	3.040	1,167,366.66	1,564,717.75	
FMPA	01/00 SEPAR	SCH. - D	(110,666.0)	0.0	(110,666.0)	1.942	1.942	(2,152,667.46)	(2,152,667.46)	
FMPA	01/00 SEPAR	SCH. - D	110,666.0	0.0	110,666.0	1.942	1.942	2,153,012.46	2,153,012.46	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE G POWER SALES-SEPAR.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.			2,966.0	26.3	2,966.7	2.441	2.441	72,346.30	72,346.30	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART./CONTRACT SALES-SEPAR.			2,166.0	0.0	2,166.0	2.464	2.600	54,372.6	63,362.1	
SUB-TOTAL OTHER D POWER SALES			101,366.0	0.0	101,366.0	1.936	1.936	1,966,676.0	1,966,676.0	
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			16,416.0	0.0	16,416.0	5.715	5.715	937,836.2	937,836.2	
TOTAL INCLUDING VARIABLE O & M COSTS			123,176.0	26.3	123,149.7	2.466	2.466	3,036,627.66	3,036,266.66	0.00
LESS VARIABLE O & M COSTS								0.00		
LESS VARIABLE O & M COSTS - HARDEE								0.00		
LESS TRANSMISSION COSTS SCH. G (SEP.)								0.00		
PLUS 80% OF ECON. ENERGY SALES PROFITS *								0.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS *			123,176.0	26.3	123,149.7	2.466	2.466	3,036,627.66	3,036,266.66	0.00
CURRENT MONTH:										
DIFFERENCE			(7,136.0)	26.3	(7,164.3)	0.566	0.512	601,665.66	466,666.66	(1,200.00)
DIFFERENCE %			(5.5)	0.0	(5.5)	32.0	26.2	24.7	19.2	(100.0)
PERIOD TO DATE:										
ACTUAL			1,814,302.0	8,276.6	1,806,026.4	2.167	2.365	39,136,666.39	43,046,666.16	0.00
ESTIMATED			1,676,166.0	0.0	1,676,166.0	2.226	2.432	41,666,766.66	46,466,646.66	3,370,430.00
DIFFERENCE			(66,676.0)	8,276.6	(64,166.6)	(0.061)	(0.066)	(2,534,291.61)	(2,442,466.66)	(3,370,430.00)
DIFFERENCE %			(3.8)	0.0	(3.4)	(2.7)	(2.6)	(6.1)	(5.4)	(100.0)

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. SEC 60% OR $666.67 HAVE BEEN EXCLUDED.

SCHEDULE A7

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF : DECEMBER 2000

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	2,655.0	0.0	1,506.0	1,149.0	7.372	7.372	84,700.00
HARDEE POWER PARTNERS	IPP	27,177.0	0.0	0.0	27,177.0	5.530	5.530	1,503,000.00
VARIOUS	OTHER	14,272.0	0.0	0.0	14,272.0	2.597	2.597	370,600.00
TOTAL	-	44,104.0	0.0	1,506.0	42,598.0	4.597	4.597	1,958,300.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	68,648.0	0.0	0.0	68,648.0	7.884	7.884	5,410,039.62
HARDEE PWR. PART.-OTHERS	IPP	73.0	0.0	0.0	73.0	6.795	6.795	4,960.43
FLA. POWER CORP.	SCH.-Je	1,547.0	0.0	144.2	1,402.8	11.046	11.046	154,963.45
FLA. POWER CORP.	SCH.-Jc	33,344.0	0.0	0.0	33,344.0	4.943	4.943	1,648,269.00
FLA. POWER & LIGHT	SCH.-Je	2,656.0	0.0	472.4	2,183.6	7.433	7.433	162,305.86
FLA. POWER & LIGHT	SCH.-Jc	38,049.0	0.0	0.0	38,049.0	7.148	7.148	2,719,900.00
LAKELAND	SCH.-Je	775.0	0.0	177.0	598.0	56.204	56.204	336,100.00
LAKELAND	SCH.-Jc	4,066.0	0.0	0.0	4,066.0	11.622	11.622	472,561.50
ORLANDO	SCH.-Je	747.0	0.0	100.0	647.0	8.618	8.618	55,760.00
ORLANDO	SCH.-Jc	953.0	0.0	0.0	953.0	9.154	9.154	87,240.00
TALLAHASSEE	SCH.-Je	613.0	0.0	0.0	613.0	27.436	27.436	168,197.31
TALLAHASSEE	SCH.-Jc	1,663.0	0.0	0.0	1,663.0	12.324	12.324	204,947.81
THE ENERGY AUTHORITY	SCH.-Je	708.0	0.0	0.0	708.0	11.929	11.929	84,456.86
THE ENERGY AUTHORITY	SCH.-Jc	7,366.0	0.0	0.0	7,366.0	6.757	6.757	499,228.03
AQUILA	SCH.-Je	63.0	0.0	63.0	0.0	0.000	0.000	235.00
AQUILA	SCH.-Jc	1,466.0	0.0	0.0	1,466.0	7.739	7.739	113,612.60
OKEELANTA	SCH.-Je	139.0	0.0	0.0	139.0	5.940	5.940	8,256.11
OKEELANTA	SCH.-Jc	3,062.0	0.0	0.0	3,062.0	5.866	5.866	180,536.89
DUKE ENERGY TRADING	SCH.-Je	98.0	0.0	44.1	53.9	21.205	21.205	11,467.36
DUKE ENERGY TRADING	SCH.-Jc	2,621.0	0.0	0.0	2,621.0	9.288	9.288	243,446.94
REEDY CREEK	SCH.-Jc	1,806.0	0.0	0.0	1,806.0	4.393	4.393	79,295.00
LAKE WORTH	SCH.-Jc	24.0	0.0	0.0	24.0	11.663	11.663	2,799.07
ENRON	SCH.-Jc	384.0	0.0	0.0	384.0	6.466	6.466	24,824.00
SOUTHERN COMPANY	SCH.-Je	667.0	0.0	468.0	398.0	14.671	14.671	58,381.46
SOUTHERN COMPANY	SCH.-Jc	4,008.0	0.0	0.0	4,008.0	4.849	4.849	194,347.65
KOCH	SCH.-Je	86.0	0.0	0.0	86.0	30.698	30.698	26,400.00
KOCH	SCH.-Jc	282.0	0.0	0.0	282.0	9.151	9.151	25,806.00
ENTERGY MARKETING	SCH.-Je	141.0	0.0	0.0	141.0	9.787	9.787	13,800.00
OKEELANTA	SCH.-D	5,917.0	0.0	0.0	5,917.0	3.581	3.581	211,863.00
AUBURNDALE	SCH.-D	3,582.0	0.0	0.0	3,582.0	2.334	2.334	83,612.75
ADJUSTMENTS TO PRIOR MONTHS:								
HARDEE PWR. PART.-NATIV 11/00	IPP	(49,806.0)	0.0	0.0	(49,806.0)	9.232	9.232	(4,596,184.46)
HARDEE PWR. PART.-NATIV 11/00	IPP	49,806.0	0.0	0.0	49,806.0	6.033	6.033	3,004,790.76
ENERGY AUTHORITY 11/00	SCH.-Je	(530.0)	0.0	(157.0)	(373.0)	6.986	6.986	(26,067.00)
ENERGY AUTHORITY 11/00	SCH.-Je	531.0	0.0	157.0	374.0	6.970	6.970	26,067.00
ENERGY AUTHORITY 11/00	SCH.-Jc	(4,728.0)	0.0	0.0	(4,728.0)	6.976	6.976	(329,813.74)
ENERGY AUTHORITY 11/00	SCH.-Jc	4,728.0	0.0	0.0	4,728.0	7.005	7.005	331,195.71
TALLAHASSEE 11/00	SCH.-Je	(5,030.0)	0.0	0.0	(5,030.0)	6.201	6.201	(311,891.90)
TALLAHASSEE 11/00	SCH.-Je	5,030.0	0.0	0.0	5,030.0	6.269	6.269	315,326.02
ENRON 11/00	SCH.-Je	(7,326.0)	0.0	0.0	(7,326.0)	3.666	3.666	(267,957.24)
ENRON 11/00	SCH.-Je	7,326.0	0.0	0.0	7,326.0	3.662	3.662	268,298.18
KOCH 11/00	SCH.-Je	(966.0)	0.0	(27.6)	(966.4)	6.466	6.466	(42,564.29)
KOCH 11/00	SCH.-Je	966.0	0.0	27.6	966.4	6.446	6.446	42,564.29
KOCH 11/00	SCH.-Je	(5,666.0)	0.0	0.0	(5,666.0)	6.326	6.326	(373,216.06)
KOCH 11/00	SCH.-Je	5,667.0	0.0	0.0	5,667.0	6.329	6.329	373,216.06
MORGAN STANLEY 11/00	SCH.-Je	(7,901.0)	0.0	0.0	(7,901.0)	5.693	5.693	(449,771.14)
MORGAN STANLEY 11/00	SCH.-Je	7,901.0	0.0	0.0	7,901.0	5.695	5.695	449,935.77
CORAL POWER LLC 11/00	SCH.-Je	(3,036.0)	0.0	0.0	(3,036.0)	3.888	3.888	(118,138.78)
CORAL POWER LLC 11/00	SCH.-Je	3,036.0	0.0	0.0	3,036.0	3.888	3.888	118,155.86
TOTAL		185,839.0	0.0	1,906.6	184,329.4	6.352	6.352	11,706,494.96
CURRENT MONTH:								
DIFFERENCE	-	141,735.0	0.0	3.6	141,731.4	6.879	6.879	9,750,194.96
DIFFERENCE %	-	321.4	0.0	0.2	332.7	149.6	149.6	497.9
PERIOD TO DATE:								
ACTUAL	-	2,527,082.0	0.0	226,763.9	2,298,318.1	5.467	5.467	126,110,089.58
ESTIMATED	-	1,354,956.0	0.0	156,319.0	1,196,638.0	4.703	4.703	56,276,800.00
DIFFERENCE	-	1,172,124.0	0.0	70,444.9	1,101,679.1	0.764	0.764	69,833,289.58
DIFFERENCE %	-	86.5	0.0	44.5	92.1	16.7	16.7	124.1

Tampa Electric Company

Wholesale Power Sales
1999 - 2000

Line	Year	Total MWh Sold	Total MWh From Generation	Fuel Cost (¢/kWh)
	(1)	(2)	(3)	(4)
1	1999	1,720,783	775,927 [1]	2.15
2	2000	1,814,302	1,806,026	2.17
3	2001E	896,375	895,489	2.47

Sources: TECO Schedule A-6, Period to Date, December 1999, Page 3
TECO Schedule A-6, Period to Date, December 2000, Page 3
J. Denise Jordan Testimony, Actual/Estimated True-up,
January through December 2001, Sch E6

[1] This number reflects that the FMPA contract was served entirely by purchased power in 1999.

Tampa Electric Company

Power Purchased
1999 - 2000

Line	Year	Total MWh Purchased	Allocated to Retail Customers: Total MWh for Firm Loads	Allocated to Retail Customers: Total MWh for Non-Firm Loads	Fuel Costs (¢/kWh)
	(1)	(2)	(3)	(4)	(5)
1	1999	2,635,012	1,511,695	186,241	3.77
2	2000	2,527,082	2,298,318	228,764	5.49
3	2001E	2,546,560	2,440,602	105,958	6.10

Sources: TECO Schedule A-7, Period to Date, December 1999
TECO Schedule A-7, Period to Date, December 2000
J. Denise Jordan Testimony, Actual/Estimated True-up, January through December 2001, Sch E7

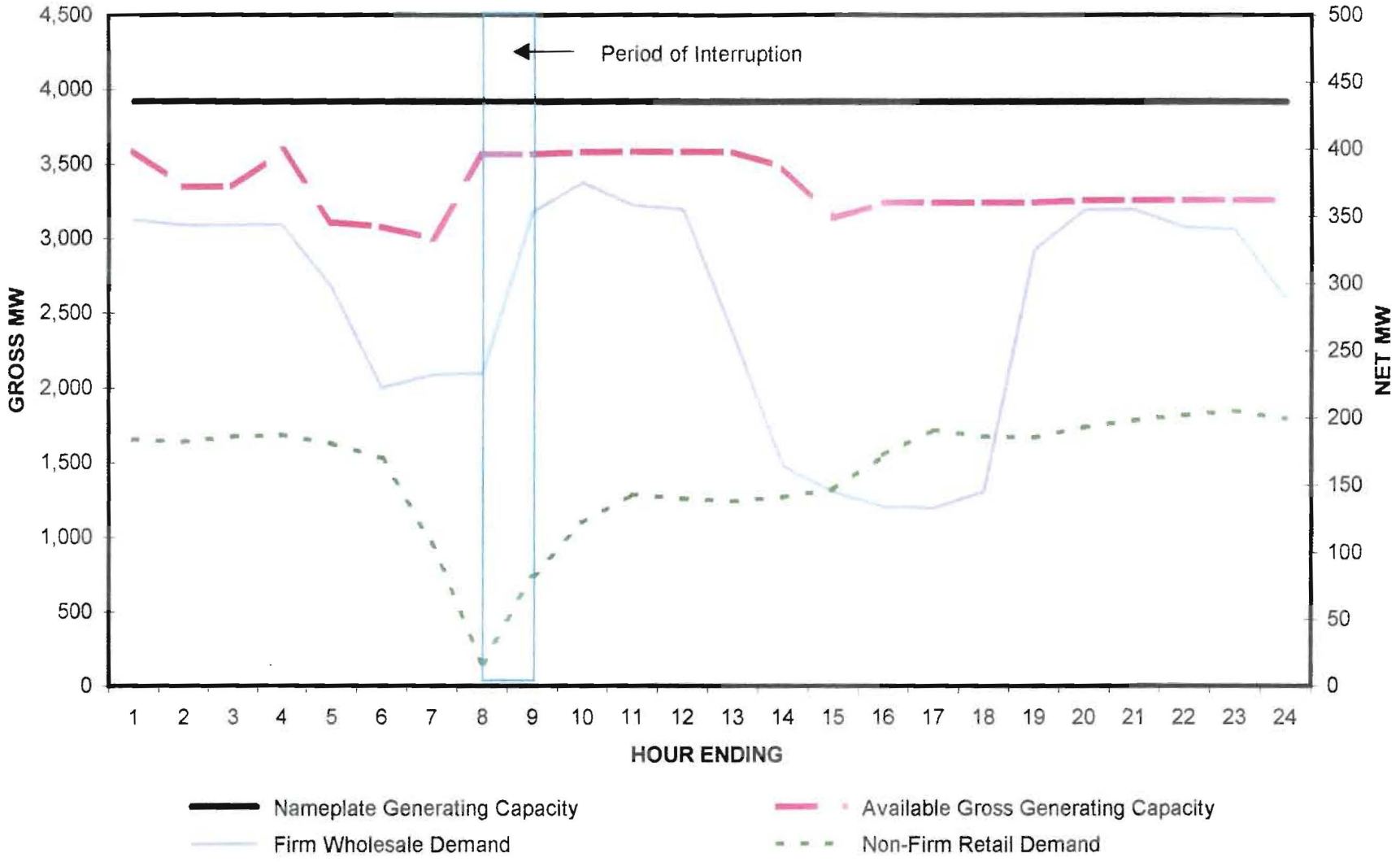
Tampa Electric Company

System Outages and Wholesale Sales on January 6, 1999

Line	Hour Ending	Outage Gross (MW)	Derated Gross (MW)	Total Unavailable Capacity (MW)	Percent of Total Internal Generation Capacity	Maximum Firm Wholesale Sales Contract Demand (MW)	Actual Firm Wholesale Sales Demand (MW)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	6:00 AM	654	187	841	21.46%	442	222
2	7:00 AM	732	187	919	23.45%	442	232
3	8:00 AM	171	187	358	9.13%	442	233
4	9:00 AM	171	187	358	9.13%	442	253
5	10:00 AM	171	167	338	8.62%	442	375

Sources: TECO Response to FIPUG's 3rd Set of Interrogatories, Interrogatory Nos. 36 and 65
TECO Response to FIPUG's 1st Set of Interrogatories, Interrogatory No. 11
TECO 10-Year Site Plan, January 2000 to December 2009

WHOLESALE DEMAND VS. RETAIL DEMAND
January 6, 1999



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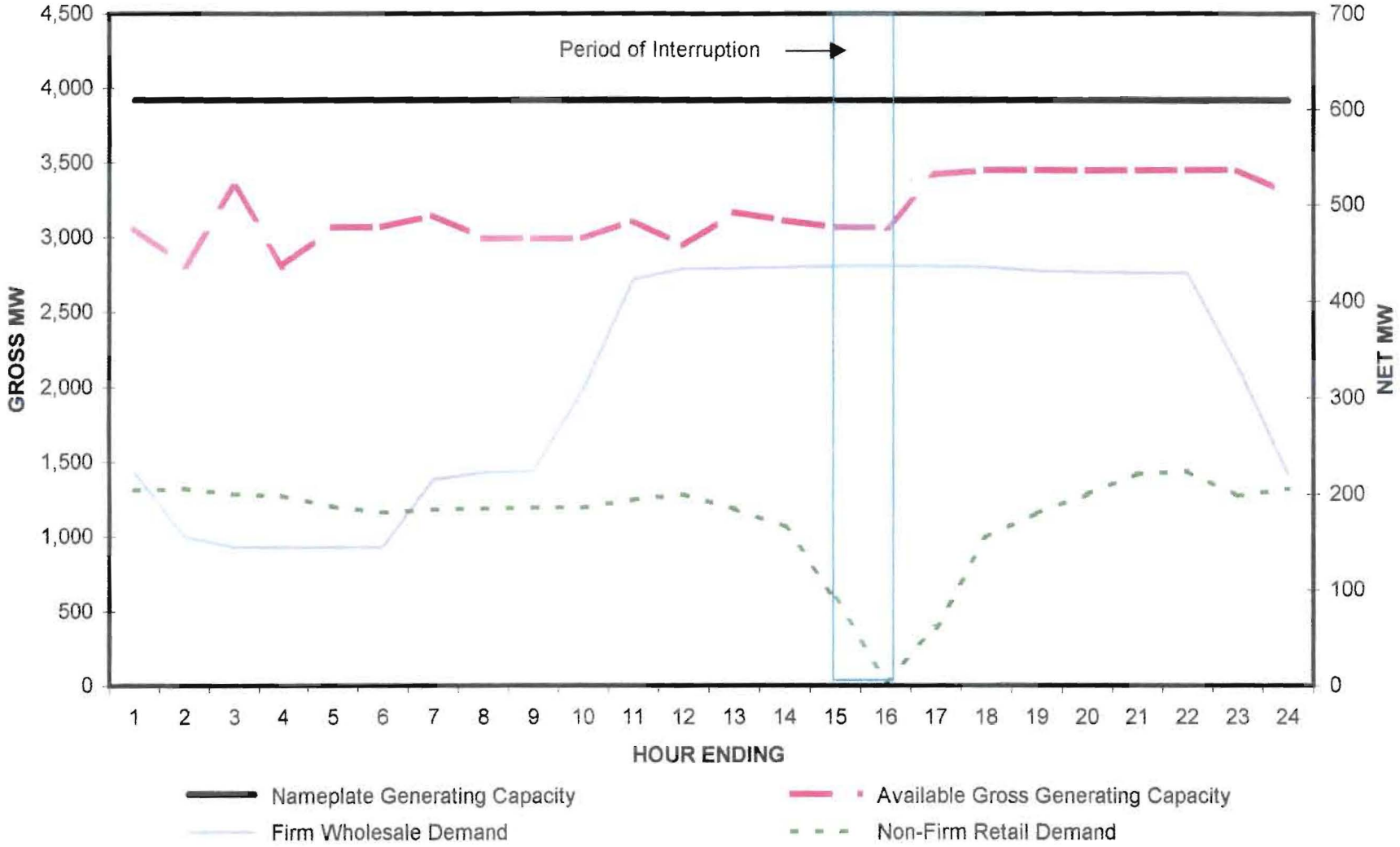
Tampa Electric Company

System Outages and Wholesale Sales on August 2, 1999

Line	Hour Ending	Outage Gross (MW)	Derated Gross (MW)	Total Unavailable Capacity (MW)	Percent of Total Internal Generation Capacity	Maximum Firm Wholesale Sales Contract Demand (MW)	Actual Firm Wholesale Sales Demand (MW)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	2:00 PM	760	47	807	20.59%	442	436
2	3:00 PM	760	90	850	21.69%	442	437
3	4:00 PM	760	90	850	21.69%	442	437
4	5:00 PM	315	185	500	12.76%	442	437
5	6:00 PM	278	190	468	11.94%	442	436

Sources: TECO Response to FIPUG's 3rd Set of Interrogatories, Interrogatory Nos. 36 and 65
TECO Response to FIPUG's 1st Set of Interrogatories, Interrogatory No. 11
TECO 10-Year Site Plan, January 2000 to December 2009

WHOLESALE DEMAND VS. RETAIL DEMAND
August 2, 1999



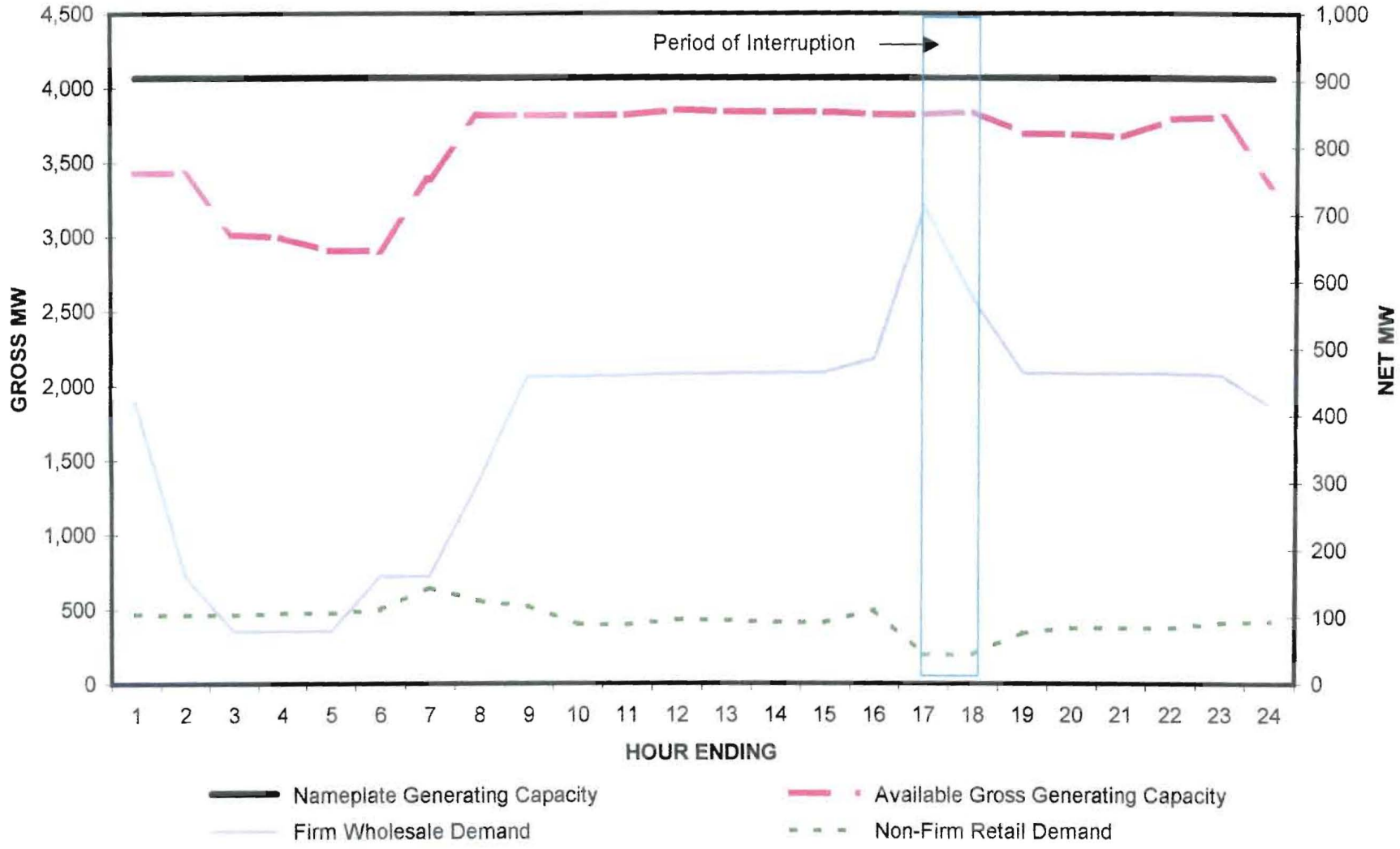
Tampa Electric Company

System Outages and Wholesale Sales on July 6, 2000

Line	Hour Ending	Outage Gross (MW)	Derated Gross (MW)	Total Unavailable Capacity (MW)	Percent of Total Internal Generation Capacity	Maximum Firm Wholesale Sales Contract Demand (MW)	Actual Firm Wholesale Sales Demand (MW)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	4:00 PM	71	178	249	6.12%	472	485
2	5:00 PM	71	178	249	6.12%	472	711
3	6:00 PM	53	178	231	5.68%	472	573
4	7:00 PM	53	328	381	9.36%	472	464

Sources: TECO Response to FIPUG's 3rd Set of Interrogatories, Interrogatory Nos. 36 and 65
TECO Response to FIPUG's 1st Set of Interrogatories, Interrogatory No. 11
TECO 10-Year Site Plan, January 2000 to December 2009

WHOLESALE DEMAND VS. RETAIL DEMAND
July 6, 2000



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Witness: Brian C. Collins
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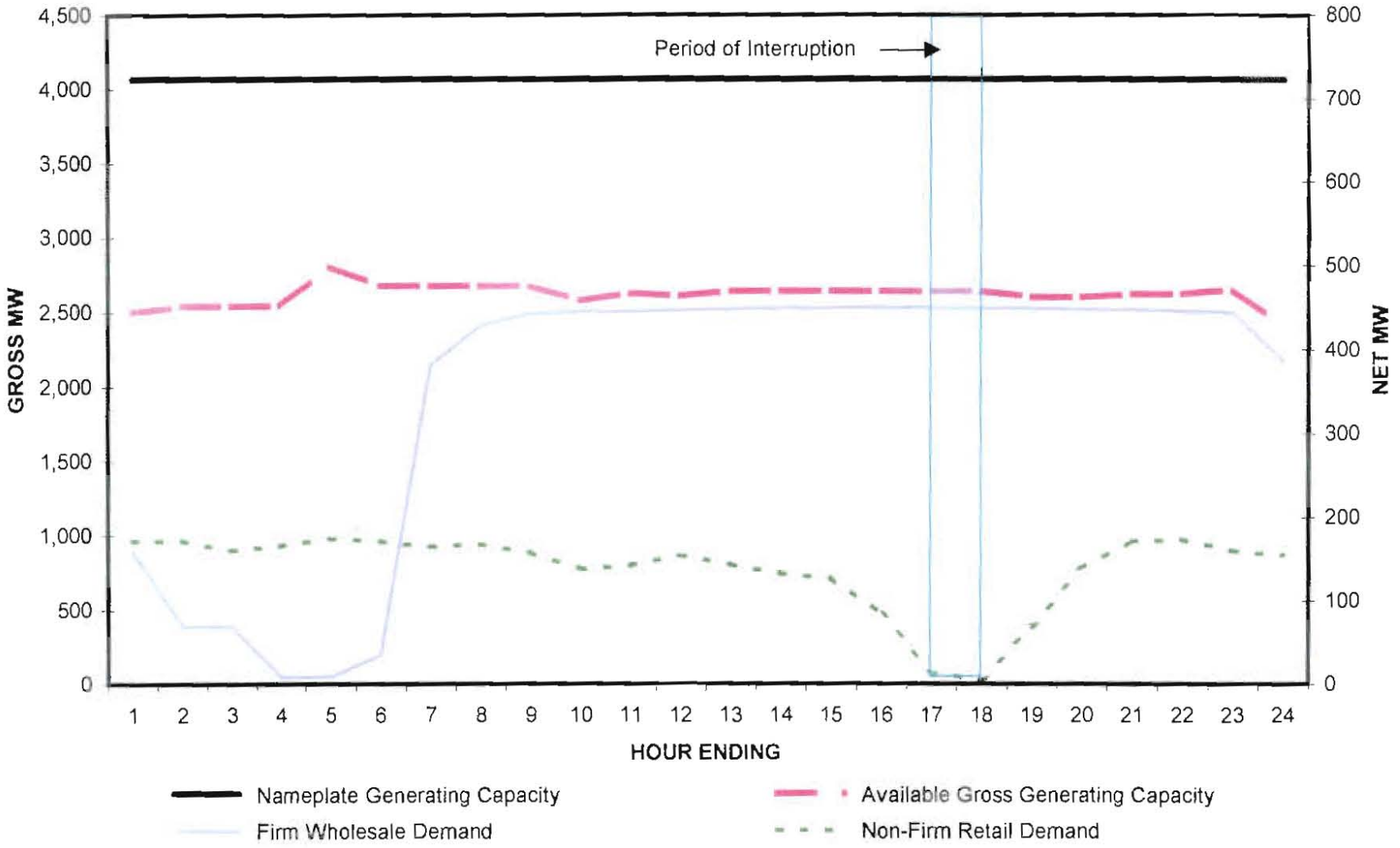
Tampa Electric Company

System Outages and Wholesale Sales on October 5, 2000

Line	Hour Ending	Outage Gross (MW)	Derated Gross (MW)	Total Unavailable Capacity (MW)	Percent of Total Internal Generation Capacity	Maximum Firm Wholesale Sales Contract Demand (MW)	Actual Firm Wholesale Sales Demand (MW)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	3:00 PM	1,219	209	1,428	35.09%	472	450
2	4:00 PM	1,219	209	1,428	35.09%	472	450
3	5:00 PM	1,219	209	1,428	35.09%	472	450
4	6:00 PM	1,219	209	1,428	35.09%	472	449
5	7:00 PM	1,219	209	1,428	35.09%	472	449

Sources: TECO Response to FIPUG's 3rd Set of Interrogatories, Interrogatory Nos. 36 and 65
TECO Response to FIPUG's 1st Set of Interrogatories, Interrogatory No. 11
TECO 10-Year Site Plan, January 2000 to December 2009

WHOLESALE DEMAND VS. RETAIL DEMAND
October 5, 2000



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TAMPA ELECTRIC COMPANY
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FIPUG'S 3RD SET OF INTERROGATORIES
INTERROGATORY NO. 36
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36. In the period 1998-2001, for the day before each curtailment of interruptible customers, the day of the curtailment of interruptible customers, and the day after the curtailment of interruptible customers, provide all unit deratings or unit limitations experienced by TECo generating units. For each derating or limitation include:

a. The amount of the derating or limitation in MW
b. The start and end times of the derating or limitation.
c. The reason for the derating or limitation.
d. The remedy for the derating or limitation.
e. Has the problem causing the derating or limitation previously occurred on the unit or other units?
f. What action did TECo take to prevent the re-occurrence of the problem?

A. See attached. Gross MW derated or limited are shown.

Deratings and Limitations the Day Before, Day of and Day After Interruption Periods
January 1998 - July 2001

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
From:	04/02/98	to:	04/04/98					
	BIG BEND 1							
04/03/98	07:46	04/04/98	06:44	LOW BTU FUEL	30	adjusted boiler combustion systems	yes	review fuel blend
	BIG BEND 3							
04/01/98	15:00	04/02/98	14:58	WINDBOX	8	monitor boiler operation	yes	repaired windbox next planned outage
04/02/98	15:00	04/02/98	23:39	SOOTBLOWER WALLBOX BURNTHROUGH	95	patched damaged area	yes	rebuilt wallbox during planned outage
04/02/98	23:40	04/03/98	00:49	S.SIDE COND C/EANED W/BRUSHES	305	cleaned fouled condenser	yes	routine work effort
04/03/98	10:30	04/04/98	01:39	LOW STEAM TEMPS	55	review boiler and sootblower operation, and fuel	yes	this is a boiler design phenomenon
04/04/98	01:40	04/04/98	03:30	"B" MILL-EAST INLET COAL LEAK	195	repaired leak	yes	preventative maintenance
04/04/98	03:31	04/04/98	07:00	LOW STEAM TEMPS	55	review boiler and sootblower operation, and fuel	yes	this is a boiler design phenomenon
04/04/98	07:01	04/05/98	23:49	WINDBOX	18	monitor boiler operation	yes	repaired windbox next planned outage
	BIG BEND 4							
04/01/98	23:05	04/02/98	04:40	A/C COND CLEANED W/BRUSHES	270	cleaned fouled condenser	yes	routine work effort
04/02/98	07:00	04/03/98	00:01	COND TUBES FOULING	3	schedule condenser cleaning at low load	yes	normal maintenance
04/03/98	23:45	04/04/98	04:20	A/C COND CLEANED W/BRUSHES	240	cleaned fouled condenser	yes	routine work effort
	GANNON 1							
04/01/98	00:01	04/04/98	22:54	LOW BTU FUEL	10	adjusted boiler combustion systems	yes	review fuel blend
04/04/98	22:55	04/05/98	01:04	CONDENSER PICK	80	picked condenser half	yes	normal maintenance
	GANNON 2							
04/01/98	00:01	04/05/98	01:09	LOW BTU FUEL	15	adjusted boiler combustion systems	yes	review fuel blend
	GANNON 3							
04/02/98	06:40	04/02/98	22:33	LOW BTU FUEL	5	adjusted boiler combustion systems	yes	review fuel blend
	GANNON 4							
04/02/98	13:00	04/02/98	15:14	4A BOILER FEED PUMP PROBLEMS	65	investigated pump & motor trips	yes	replaced pressure switch
	GANNON 5							
04/01/98	00:01	04/10/98	22:34	LOW BTU FUEL	5	adjusted boiler combustion systems	yes	review fuel blend
	GANNON 6							

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Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
04/02/98	13:50	04/03/98	06:39	PRECIPITATOR FOULING	45	perform temporary repair to casing leaks	yes	changed stones on weekend outage & perform permanent repairs during major outage
04/03/98	12:30	04/03/98	12:44	PRECIPITATOR FOULING	10	perform temporary repair to casing leaks	yes	changed stones on weekend outage & perform permanent repairs during major outage
04/03/98	12:45	04/03/98	12:59	PRECIPITATOR FOULING	15	perform temporary repair to casing leaks	yes	changed stones on weekend outage & perform permanent repairs during major outage
04/03/98	13:00	04/03/98	13:29	PRECIPITATOR FOULING	25	perform temporary repair to casing leaks	yes	changed stones on weekend outage & perform permanent repairs during major outage
04/03/98	13:30	04/03/98	16:59	PRECIPITATOR FOULING	45	perform temporary repair to casing leaks	yes	changed stones on weekend outage & perform permanent repairs during major outage
04/03/98	17:00	04/04/98	00:21	PRECIPITATOR FOULING	25	perform temporary repair to casing leaks	yes	changed stones on weekend outage & perform permanent repairs during major outage
04/04/98	00:22	04/04/98	05:04	6B PULVERIZER AIR SEAL REPLACEMENT	165	replaced seal	yes	normal maintenance
04/04/98	05:05	04/05/98	09:19	PRECIPITATOR FOULING	25	perform temporary repair to casing leaks	yes	changed stones on weekend outage & perform permanent repairs during major outage
From:	06/18/98	to:	06/24/98					
	BIG BEND 1							
06/17/98	23:13	06/18/98	00:09	HIGH OUTLET CANAL TEMP	35	restrict load to achieve allowable water temperature	yes	naturally occurring event
06/18/98	00:10	06/18/98	00:50	S.SIDE COND PICK	(180)	picked condenser half	yes	normal maintenance
06/18/98	01:05	06/18/98	01:50	N.SIDE COND PICK	255	picked condenser half	yes	normal maintenance
06/18/98	15:00	06/18/98	20:45	COND TUBES FOULING	(425)	schedule condenser cleaning	yes	normal maintenance
06/18/98	23:25	06/19/98	05:25	N.SIDE COND CLEANED W/BRUSHES	(180)	cleaned fouled condenser	yes	routine work effort
06/20/98	23:10	06/20/98	23:55	S.SIDE COND PICK	(200)	picked condenser half	yes	normal maintenance
06/21/98	00:15	06/21/98	02:25	N.SIDE COND PICK	(200)	picked condenser half	yes	normal maintenance
06/23/98	19:45	06/24/98	00:25	"B" MILL-ROCK IN FEEDER, FIRE	155	removed rock	yes	reviewed coal field operations
06/24/98	01:10	06/24/98	02:35	S.SIDE COND PICK	225	picked condenser half	yes	normal maintenance
06/24/98	02:55	06/24/98	03:40	N.SIDE COND PICK	210	picked condenser half	yes	normal maintenance
06/24/98	15:50	06/24/98	18:59	MAX AIR FLOW	5	no records available	yes	
06/24/98	19:00	06/24/98	21:38	MTLO HIGH TEMP	15	investigate cooling water system	yes	inspect system
06/24/98	21:39	06/26/98	12:00	MAX AIR FLOW	5	no records available	yes	
	BIG BEND 2							
06/17/98	00:02	06/18/98	02:54	MILLS, FUEL CONTROLS	20	reviewed control system	yes	routine work effort
06/18/98	02:55	06/18/98	05:25	S.SIDE COND PICK	250	picked condenser half	yes	normal maintenance
06/18/98	05:26	06/19/98	13:40	FUEL	5	adjusted boiler combustion systems	yes	review fuel blend
06/19/98	13:41	06/19/98	23:24	OUTLET CANAL HIGH TEMP	5	restrict load to achieve allowable water temperature	yes	naturally occurring event
06/19/98	23:25	06/20/98	00:05	S.SIDE COND PICK	230	picked condenser half	yes	normal maintenance

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Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
06/20/98	00:15	06/20/98	01:00	N.SIDE COND PICK	230	picked condenser half	yes	normal maintenance
06/20/98	19:00	06/21/98	03:30	OUTLET CANAL HIGH TEMP	20	restrict load to achieve allowable water temperature	yes	naturally occurring event
06/23/98	17:24	06/24/98	22:54	1ST PT HTR TUBE LEAK	13	repaired leak	yes	replaced heater next planned outage
06/24/98	22:55	06/25/98	00:27	S.SIDE COND PICK	230	picked condenser half	yes	normal maintenance
	B/G BEND 3							
06/18/98	21:05	06/19/98	00:34	OUTLET CANAL HIGH TEMP	35	restrict load to achieve allowable water temperature	yes	naturally occurring event
06/19/98	00:35	06/19/98	05:35	S.SIDE COND CLEANED W/BRUSHES	280	cleaned fouled condenser	yes	routine work effort
06/19/98	05:36	06/19/98	07:50	OUTLET CANAL HIGH TEMP	35	restrict load to achieve allowable water temperature	yes	naturally occurring event
06/19/98	07:51	06/19/98	12:14	LOW STEAM TEMPS	5	review boiler and sootblower operation, and fuel	yes	this is a boiler design phenomenon
06/19/98	12:15	06/19/98	16:44	OUTLET CANAL HIGH TEMP	35	restrict load to achieve allowable water temperature	yes	naturally occurring event
06/19/98	16:45	06/19/98	20:19	LOW STEAM TEMPS	5	review boiler and sootblower operation, and fuel	yes	this is a boiler design phenomenon
06/19/98	20:20	06/20/98	01:30	"B" PAF-COOLING WATER LEAK	165	repaired leak	yes	routiine maintenance
06/20/98	01:31	06/20/98	17:19	LOW STEAM TEMPS	5	review boiler and sootblower operation, and fuel	yes	this is a boiler design phenomenon
06/20/98	17:20	06/21/98	01:59	OUTLET CANAL HIGH TEMP	37	restrict load to achieve allowable water temperature	yes	naturally occurring event
06/21/98	02:00	06/21/98	02:35	N.SIDE COND PICK	245	picked condenser half	yes	normal maintenance
06/21/98	02:55	06/21/98	04:10	S.SIDE COND PICK	245	picked condenser half	yes	normal maintenance
06/21/98	04:11	06/23/98	00:44	LOW STEAM TEMPS	8	review boiler and sootblower operation, and fuel	yes	this is a boiler design phenomenon
06/23/98	00:45	06/23/98	04:55	N.SIDE COND CLEANED W/BRUSHES	275	cleaned fouled condenser	yes	routine work effort
06/23/98	04:56	06/23/98	16:34	LOW STEAM TEMPS	10	review boiler and sootblower operation, and fuel	yes	this is a boiler design phenomenon
06/23/98	16:35	06/23/98	19:29	A2 FEEDER-ROCK	35	cleared feeder & returned to service	yes	routine work effort
06/24/98	01:57	06/24/98	06:38	"C" PAF-OIL CHANGE	265	changed oil	yes	monitor oil condition
06/24/98	06:38	06/24/98	10:24	LOW STEAM TEMPS	10	review boiler and sootblower operation, and fuel	yes	this is a boiler design phenomenon
06/24/98	10:25	06/25/98	07:29	"B" COOLING TOWER FAN-GEAR BOX	112	replaced gear box	yes	preventative maintenance
	B/G BEND 4							
06/17/98	23:10	06/18/98	05:45	B/D COND CLEANED W/BRUSHES	260	cleaned fouled condenser	yes	routine work effort
06/18/98	12:20	06/18/98	13:20	"D" MILL-COAL FEEDER BELT, "E" MILL-NOISY, TAGGED FOR INSP	(380)	cleared"D" feeder & returned to service	yes	routine work effort

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
06/18/98	15:00	06/19/98	07:53	OUTLET CANAL HIGH TEMP	(437)	restrict load to achieve allowable water temperature	yes	naturally occurring event
06/19/98	12:18	06/19/98	16:45	OUTLET CANAL HIGH TEMP	(435)	restrict load to achieve allowable water temperature	yes	naturally occurring event
06/19/98	20:00	06/20/98	02:24	COND TUBES FOULING	45	schedule condenser cleaning at low load	yes	normal maintenance
06/20/98	02:25	06/20/98	03:15	A/C COND PICK	270	picked condenser half	yes	normal maintenance
06/20/98	03:35	06/20/98	04:25	B/D COND PICK	270	picked condenser half	yes	normal maintenance
06/20/98	15:30	06/21/98	05:45	OUTLET CANAL HIGH TEMP	57	restrict load to achieve allowable water temperature	yes	naturally occurring event
06/21/98	08:45	06/22/98	00:01	COND TUBES FOULING	65	schedule condenser cleaning at low load	yes	normal maintenance
06/22/98	00:02	06/22/98	05:15	A/C COND CLEANED W/BRUSHES	260	cleaned fouled condenser	yes	routine work effort
06/22/98	10:40	06/22/98	23:54	COND TUBES FOULING	37	schedule condenser cleaning at low load	yes	normal maintenance
06/22/98	23:55	06/23/98	07:00	B/D COND CLEANED W/BRUSHES	270	cleaned fouled condenser	yes	routine work effort
	GANNON 1							
06/16/98	03:10	06/18/98	03:09	LOW BTU FUEL	15	adjusted boiler combustion systems	yes	review fuel blend
06/18/98	03:10	06/18/98	04:19	CONDENSER PICK	80	picked condenser half	yes	normal maintenance
06/18/98	04:20	06/22/98	02:24	LOW BTU FUEL	15	adjusted boiler combustion systems	yes	review fuel blend
06/22/98	02:25	06/22/98	03:59	CONDENSER PICK	80	picked condenser half	yes	normal maintenance
06/22/98	04:00	06/24/98	02:59	LOW BTU FUEL	15	adjusted boiler combustion systems	yes	review fuel blend
06/24/98	03:00	06/24/98	04:29	CONDENSER PICK	80	picked condenser half	yes	normal maintenance
06/24/98	04:30	06/25/98	20:19	LOW BTU FUEL	15	adjusted boiler combustion systems	yes	review fuel blend
	GANNON 2							
06/18/98	09:16	06/18/98	23:24	HEADER RESTRICTION DUE TO BOILER TUBE CONDITION	25	minimized risk of tube failure	yes	maintain reduced pressure
06/18/98	23:25	06/19/98	04:49	CONDENSER BLOW	75	cleaned fouled condenser	yes	routine work effort
06/19/98	04:50	06/20/98	17:09	HEADER RESTRICTION DUE TO BOILER TUBE CONDITION	25	minimized risk of tube failure	yes	maintain reduced pressure
06/20/98	17:10	06/21/98	00:29	CONDENSER DIRTY	35	schedule condenser cleaning	yes	normal maintenance
06/21/98	00:30	06/21/98	02:59	CONDENSER PICK	75	picked condenser half	yes	normal maintenance
06/21/98	03:00	06/21/98	18:59	HEADER RESTRICTION DUE TO BOILER TUBE CONDITION	25	minimized risk of tube failure	yes	maintain reduced pressure
06/21/98	19:00	06/21/98	21:24	2A CYCLONE BURN THRU	55	ran at reduced load until after peak	yes	repaired damaged areas at time of low demand
06/22/98	03:45	06/22/98	10:45	HEADER RESTRICTION DUE TO BOILER TUBE CONDITION	25	minimized risk of tube failure	yes	maintain reduced pressure
06/22/98	12:33	06/22/98	14:39	HEADER RESTRICTION DUE TO BOILER TUBE CONDITION	25	minimized risk of tube failure	yes	maintain reduced pressure
06/24/98	05:57	06/26/98	01:09	HEADER RESTRICTION DUE TO BOILER TUBE CONDITION	25	minimized risk of tube failure	yes	maintain reduced pressure

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
06/24/98	05:57	06/26/98	01:09	HEADER RESTRICTION DUE TO BOILER TUBE CONDITION	25	minimized risk of tube failure	yes	maintain reduced pressure
	GANNON 3							
06/18/98	14:30	06/19/98	21:54	HIGH FURNACE PRESSURE	15	ensure sootblower operation	yes	review APH performance
06/20/98	06:11	06/24/98	00:14	HIGH FURNACE PRESSURE	15	ensure sootblower operation	yes	review APH performance
06/24/98	00:15	06/24/98	01:44	CONDENSER PICK	105	picked condenser half	yes	normal maintenance
06/24/98	01:45	06/25/98	06:29	HIGH FURNACE PRESSURE	15	ensure sootblower operation	yes	review APH performance
	GANNON 4							
06/17/98	04:00	06/17/98	05:24	CONDENSER PICK	130	picked condenser half	yes	normal maintenance
06/17/98	05:25	06/19/98	01:09	LOW BTU FUEL	10	adjusted boiler combustion systems	yes	review fuel blend
06/19/98	01:10	06/19/98	02:24	CONDENSER PICK	120	picked condenser half	yes	normal maintenance
06/19/98	02:25	06/19/98	04:21	4C COAL FEEDER MAINT.	10	repaired feeder during low load period	yes	normal operational practice
06/19/98	04:22	06/19/98	23:14	LOW BTU FUEL	10	adjusted boiler combustion systems	yes	review fuel blend
06/19/98	23:15	06/20/98	00:29	CONDENSER PICK	120	picked condenser half	yes	normal maintenance
06/20/98	00:30	06/22/98	00:14	LOW BTU FUEL	10	adjusted boiler combustion systems	yes	review fuel blend
06/22/98	00:15	06/22/98	05:49	CONDENSER PICK	140	picked condenser half	yes	normal maintenance
06/22/98	05:50	06/23/98	00:29	LOW BTU FUEL	10	adjusted boiler combustion systems	yes	review fuel blend
06/23/98	00:30	06/23/98	05:29	CONDENSER BLOW	120	cleaned fouled condenser	yes	routine work effort
06/23/98	05:30	06/25/98	23:39	LOW BTU FUEL	10	adjusted boiler combustion systems	yes	review fuel blend
	GANNON 5							
06/17/98	23:30	06/18/98	01:20	CONDENSER PICK	150	picked condenser half	yes	normal maintenance
06/18/98	01:20	06/18/98	06:29	HIGH FURNACE PRESSURE	20	ensure sootblower operation	yes	review APH performance & cleaned APH later in year
06/18/98	06:30	06/20/98	02:44	HIGH FURNACE PRESSURE	5	ensure sootblower operation	yes	review APH performance & cleaned APH later in year
06/20/98	02:45	06/20/98	03:54	CONDENSER PICK	160	picked condenser half	yes	normal maintenance
06/20/98	03:55	06/23/98	02:44	HIGH FURNACE PRESSURE	10	ensure sootblower operation	yes	review APH performance & cleaned APH later in year
06/23/98	02:45	06/23/98	04:29	CONDENSER PICK	150	picked condenser half	yes	normal maintenance
06/23/98	04:30	06/23/98	13:07	HIGH FURNACE PRESSURE	10	ensure sootblower operation	yes	review APH performance & cleaned APH later in year
06/23/98	13:08	06/24/98	13:59	HIGH FURNACE PRESSURE	15	ensure sootblower operation	yes	review APH performance & cleaned APH later in year
06/24/98	14:00	06/25/98	11:49	HIGH FURNACE PRESSURE	5	ensure sootblower operation	yes	review APH performance & cleaned APH later in year
	GANNON 6							
06/17/98	18:40	06/18/98	06:29	LOW BTU FUEL	150	adjusted boiler combustion systems	yes	review fuel blend
06/18/98	06:30	06/18/98	14:44	LOW BTU FUEL	125	adjusted boiler combustion systems	yes	review fuel blend

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
06/18/98	14:45	06/18/98	18:14	BOILER CASING BURN THRU	275	patched damaged casing	yes	repair casing
06/18/98	18:15	06/18/98	19:08	6A PULVERIZER MAINT.	120	repair pulverizer	yes	replaced broken shaft
06/18/98	19:10	06/18/98	20:13	CASING BURN THRU	275	ran at reduced until after peak	yes	repaired casing
06/19/98	10:01	06/20/98	01:00	PRECIPITATOR FOULING	195	repaired rectifiers & perform temporary repair to casing leaks	yes	perform permanent repairs during major outage
06/20/98	01:01	06/20/98	02:00	CONDENSER PICK	195	picked condenser half	yes	normal maintenance
06/20/98	02:01	06/21/98	03:29	6A PULVERIZER MAINT.	120	repair pulverizer	yes	replaced broken shaft
06/21/98	03:30	06/21/98	06:44	PRECIPITATOR FOULING	45	repaired rectifiers & perform temporary repair to casing leaks	yes	perform permanent repairs during major outage
06/21/98	06:45	06/21/98	12:14	PRECIPITATOR FOULING	145	repaired rectifiers & perform temporary repair to casing leaks	yes	perform permanent repairs during major outage
06/21/98	12:15	06/21/98	19:59	PRECIPITATOR FOULING	135	repaired rectifiers & perform temporary repair to casing leaks	yes	perform permanent repairs during major outage
06/21/98	20:00	06/21/98	21:29	PRECIPITATOR FOULING	75	repaired rectifiers & perform temporary repair to casing leaks	yes	perform permanent repairs during major outage
06/21/98	21:30	06/21/98	22:29	PRECIPITATOR FOULING	95	repaired rectifiers & perform temporary repair to casing leaks	yes	perform permanent repairs during major outage
06/21/98	22:30	06/22/98	11:29	PRECIPITATOR FOULING	110	checked hoppers & perform temporary repair to casing leaks	yes	perform permanent repairs during major outage
06/22/98	11:30	06/22/98	15:29	PRECIPITATOR FOULING	45	perform temporary repair to casing leaks	yes	perform permanent repairs during major outage
06/22/98	15:30	06/22/98	18:44	PRECIPITATOR FOULING	75	perform temporary repair to casing leaks	yes	perform permanent repairs during major outage
06/22/98	18:45	06/22/98	22:59	PRECIPITATOR FOULING	55	perform temporary repair to casing leaks	yes	perform permanent repairs during major outage
06/22/98	23:00	06/23/98	00:44	PRECIPITATOR FOULING	100	perform temporary repair to casing leaks	yes	perform permanent repairs during major outage
06/23/98	00:45	06/23/98	01:14	CONDENSER PICK	215	picked condenser half	yes	normal maintenance
06/23/98	01:15	06/23/98	06:59	PRECIPITATOR FOULING	100	perform temporary repair to casing leaks	yes	perform permanent repairs during major outage
06/23/98	07:00	06/23/98	12:59	PRECIPITATOR FOULING	65	perform temporary repair to casing leaks	yes	perform permanent repairs during major outage
06/23/98	13:00	06/24/98	11:44	PRECIPITATOR FOULING	80	perform temporary repair to casing leaks	yes	perform permanent repairs during major outage
06/24/98	11:45	06/24/98	16:59	PRECIPITATOR FOULING	65	perform temporary repair to casing leaks	yes	perform permanent repairs during major outage
06/24/98	17:00	06/24/98	22:49	PRECIPITATOR FOULING	50	perform temporary repair to casing leaks	yes	perform permanent repairs during major outage
06/24/98	22:50	06/25/98	06:59	PRECIPITATOR FOULING	175	perform temporary repair to casing leaks	yes	perform permanent repairs during major outage

From: 01/05/99 to: 01/07/99

BIG BEND 1

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
01/04/99	17:31	01/05/99	01:59	MAX FUEL	25	adjusted boiler combustion systems	yes	review fuel blend
01/05/99	02:00	01/07/99	00:01	APH AMPS SWING-HIGH EXIT GAS TEMP	37	ensure sootblower operation	yes	monitor APH performance
01/07/99	00:02	01/07/99	12:00	OPACITY	82	technicians investigated causes	yes	optimize precipitator, ash removal, boiler combustion systems
01/07/99	12:01	01/10/99	15:59	MAX BFP-RECIR VV LEAKING THRU	25	monitor system	yes	repair valve next planned outage
	BIG BEND 2							
01/05/99	00:30	01/05/99	01:40	N.SIDE PICK	250	picked condenser half	yes	normal maintenance
01/05/99	12:05	01/05/99	12:50	"C" PAF-HIGH VIBRATION	175	inspected fan & returned to service	yes	preventative maintenance
01/07/99	06:15	01/07/99	06:30	MAX AIR FLOW	15	ensure sootblower operation	yes	monitor APH performance
01/07/99	06:31	01/07/99	14:07	OPACITY	40	technicians investigated causes	yes	optimize precipitator, ash removal, boiler combustion systems
	BIG BEND 3							
01/04/99	22:50	01/05/99	00:25	N.SIDE PICK	200	picked condenser half	yes	normal maintenance
01/05/99	00:40	01/05/99	01:35	S.SIDE PICK	200	picked condenser half	yes	normal maintenance
01/05/99	11:00	01/05/99	18:48	"C" PAF-VIBRATION	140	cleaned fan	yes	normal maintenance
01/06/99	23:53	01/07/99	03:12	"B" PAF-CLEAN WHEEL	120	cleaned wheel	yes	normal maintenance
	BIG BEND 4							
01/04/99	12:16	01/05/99	23:21	"A" PAF MOTOR	237	sent motor for repair on rush basis	yes	normal maintenance
01/06/99	00:12	01/06/99	02:25	B/D COND PICK	245	picked condenser half	yes	normal maintenance
01/06/99	12:35	01/06/99	14:15	"D" MILL-BREAKER, "C" MILL TAGGED	95	meggered motor and returned to service	yes	routine work effort
01/07/99	21:26	01/08/99	02:00	"A" PAF TRIP-ELEC	205	meggered motor and returned to service	yes	routine work effort
	GANNON 1							
01/04/99	12:25	01/06/99	11:55	1B B.F.P. BAD MOTOR BERING	25	repaired motor bearing	yes	monitor oil/ vibration
	GANNON 3							
01/04/99	23:59	01/05/99	02:59	CONDENSER PICK	95	picked condenser half	yes	normal maintenance
01/05/99	03:00	01/05/99	06:24	3C COAL FEEDER DRAG CHAIN CONV. MAINT.	25	repaired chain & belt	yes	preventative maintenance
	GANNON 4							
01/04/99	20:15	01/06/99	09:09	HEADER RESTRICTION DUE TO BOILER TUBE CONDITION	20	minimized risk of tube failure	yes	maintain reduced pressure
01/06/99	09:10	01/10/99	22:59	HEADER RESTRICTION	10	minimized risk of tube failure	yes	maintain reduced pressure
	GANNON 6							
01/04/99	22:00	01/05/99	18:34	PLUGGAGE IN EAST SUPERHEATER	55	operate at reduced load until system load permits outage	yes	cleared pluggage during next outage, repaired damper controls
01/05/99	18:35	01/06/99	05:19	PLUGGAGE IN EAST SUPERHEATER	75	operate at reduced load until system load permits outage	yes	cleared pluggage during next outage, repaired damper controls

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
01/06/99	05:20	01/06/99	14:40	PLUGGAGE IN THE REHEATER	105	operate at reduced load until system load permits outage	yes	cleaned pluggage during next outage, repaired damper controls
From:	04/02/99	to:	04/07/99					
	BIG BEND 1							
04/02/99	00:12	04/02/99	23:30	FUEL	20	adjusted boiler combustion systems	yes	review fuel blend
04/03/99	15:21	04/06/99	07:00	FUEL	10	adjusted boiler combustion systems	yes	review fuel blend
04/07/99	03:20	04/07/99	04:55	S.SIDE PICK	235	picked condenser half	yes	normal maintenance
	BIG BEND 2							
04/03/99	13:20	04/03/99	19:00	OPACITY	25	technicians investigated causes	yes	optimize precipitator, ash removal, boiler combustion systems
04/03/99	19:01	04/03/99	22:39	1ST PT HEATER	18	repair heater leak	yes	replaced heater beginning 04/17/99
04/03/99	22:40	04/04/99	00:45	S.SIDE PICK	235	picked half of condenser	yes	normal maintenance
04/04/99	01:30	04/04/99	04:05	N.SIDE PICK	235	picked half of condenser	yes	normal maintenance
04/04/99	04:06	04/05/99	11:24	1ST PT HEATER	18	repair heater leak	yes	replaced heater beginning 04/17/99
04/05/99	11:25	04/05/99	14:53	"B" MILL-B2 FEEDER	165	repaired coal feeder	yes	review maintenance history and preventive maintenance program
04/05/99	14:54	04/05/99	17:04	1ST PT HEATER	18	repair heater leak	yes	replaced heater beginning 04/17/99
04/05/99	17:05	04/07/99	17:30	"B" FD FAN I/B BRG HOT-INLET VANE IMBALANCE	155	adjusted inlet vanes & repaired bearing thrust collar	yes	machined thrust collar during planned outage
04/07/99	17:31	04/07/99	22:49	1ST PT HTR	18	repair heater leak	yes	replaced heater beginning 04/17/99
04/07/99	22:50	04/08/99	05:07	"B" FD FAN I/B BRG HOT-INLET VANE IMBALANCE	155	adjusted inlet vanes & repaired bearing thrust collar	yes	machined thrust collar during planned outage
	BIG BEND 4							
04/01/99	23:55	04/02/99	00:48	B/D COND PICK	270	picked half of condenser	yes	normal maintenance
04/04/99	23:25	04/05/99	05:00	A/C W/BRUSHES	220	cleaned fouled condenser	yes	routine work effort
04/05/99	09:00	04/05/99	12:35	LOW STEAM TEMPS	3	review boiler and sootblower operation, and fuel	yes	review fuel quality and boiler operation
04/07/99	19:37	04/07/99	19:49	"A" MILL-NOISY/INSPECT	100	inspected, removed metal & returned to service	yes	normal operational procedure
04/07/99	19:50	04/07/99	22:40	"A" COAL FEEDER TRIP	100	inspected, repaired & returned to service	yes	normal operational procedure
04/07/99	23:55	04/08/99	05:00	B/D W/BRUSHES	270	cleaned fouled condenser	yes	routine work effort
	GANNON 1							
04/06/99	00:30	04/06/99	02:45	PICK CONDENSER	65	picked half of condenser	yes	normal maintenance
	GANNON 2							
04/04/99	23:50	04/05/99	06:20	BLOW PLUGS IN CONDENSER	55	cleaned fouled condenser	yes	routine work effort
	GANNON 3							
04/04/99	23:30	04/05/99	01:10	CHANGE OIL IN 3B FORCE DRAFT FAN LUBE OIL SYSTEM	70	changed oil	yes	normal event based on oil analysis program
04/07/99	03:10	04/07/99	05:35	PICK CONDENSER	100	picked half of condenser	yes	normal maintenance

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
	GANNON 4							
04/02/99	17:10	04/02/99	18:45	A BURN THROUGH ON 4C CYCLONE	40	temporarily repaired casing	yes	perform permanent repair during next major outage
04/03/99	23:30	04/04/99	1:14	PICK CONDENSER	90	picked half of condenser	yes	normal maintenance
	GANNON 5							
03/31/99	22:30	04/02/99	08:44	5A PRIMARY AIR FAN INBOARD BEARING REPLACEMENT	125	replaced fan bearing	yes	review oil analysis records and alignment
04/02/99	08:45	04/02/99	12:00	HIGH TUBE METAL TEMPS	15	deslagged boiler	yes	review combustion
04/03/99	11:30	04/03/99	23:29	HIGH TUBE METAL TEMPS.	5	deslagged boiler	yes	review combustion
04/03/99	23:30	04/04/99	00:14	PICK CONDENSER	125	picked half of condenser	yes	normal maintenance
04/04/99	01:15	04/04/99	13:58	REPAIR 5A PULVERIZER AIR SEAL	155	repaired pulverizer air seal	yes	review installation
04/04/99	14:00	04/06/99	09:58	HIGH TUBE METAL TEMPS.	5	deslagged boiler	yes	review combustion
04/06/99	10:00	04/06/99	14:04	OBSTRUCTION IN 5A1 COAL FEEDER	65	removed obstruction	yes	review coal field foreign object removal systems
04/06/99	14:05	04/08/99	02:59	HIGH TUBE METAL TEMPS.	5	deslagged boiler	yes	review combustion
From:	04/14/99	to:	04/16/99					
	BIG BEND 1							
04/14/99	16:00	04/14/99	23:29	FUEL	8	adjusted boiler combustion systems	yes	review fuel blend
04/14/99	23:30	04/15/99	03:20	"A" FD FAN-REPLACE I/B FAN BRG SIGHT GLASS.	235	replaced sight glass	yes	normal maintenance
04/14/99	03:21	04/15/99	19:00	FUEL	2	adjusted boiler combustion systems	yes	review fuel blend
04/16/99	01:05	04/16/99	02:00	S.SIDE PICK	235	picked half of condenser	yes	normal maintenance
04/16/99	02:15	04/16/99	03:20	N.SIDE PICK	235	picked half of condenser	yes	normal maintenance
04/16/99	23:52	04/17/99	03:15	"C" PAF-CLEAN WHEEL	175	cleaned wheel	yes	normal maintenance
	BIG BEND 2							
04/14/99	22:45	04/15/99	05:05	S.SIDE W/BRUSHES	235	cleaned fouled condenser	yes	routine work effort
04/15/99	05:25	04/17/99	22:42	"B" CWPP-REPLACE BEARINGS	172	replaced bearings	yes	performed alignment
	BIG BEND 3							
04/13/99	23:10	04/14/99	01:50	S.SIDE PICK	245	picked half of condenser	yes	normal maintenance
04/14/99	02:00	04/14/99	03:10	N.SIDE PICK	245	picked half of condenser	yes	normal maintenance
04/15/99	23:20	04/16/99	00:38	"B" PAF-CLEAN WHEEL	145	cleaned wheel	yes	normal maintenance
04/16/99	02:03	04/16/99	03:50	"B" PAF-CLEAN WHEEL	145	cleaned wheel	yes	normal maintenance
	BIG BEND 4							
04/14/99	17:40	04/15/99	02:34	COND TUBES FOULING	25	schedule condenser cleaning	yes	normal maintenance
04/15/99	02:35	04/15/99	03:50	A/C COND PICK	270	picked half of condenser	yes	normal maintenance
04/15/99	04:07	04/15/99	04:50	B/D COND PICK	270	picked half of condenser	yes	normal maintenance
04/16/99	01:50	04/16/99	08:36	"D" TOWER-QUENCHER LEAK; "A" TOWER TAGGED	110	repaired leak	yes	normal FGD maintenance
04/16/99	22:55	04/17/99	01:20	B/D PICK	225	picked half of condenser	yes	normal maintenance
	GANNON 2							
04/15/99	17:00	04/16/99	03:20	SALT LEAK IN CONDENSER	55	plugged leak	yes	inspect condensor during planned outage

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
	GANNON 3							
04/16/99	00:10	04/16/99	01:30	PICK CONDENSER	95	picked half of condenser	yes	normal maintenance
From:	04/22/99	to:	04/27/99					
	BIG BEND 1							
04/21/99	23:45	04/22/99	04:25	S.SIDE W/BRUSHES	235	cleaned fouled condenser	yes	routine work effort
04/22/99	23:10	04/23/99	05:20	N.SIDE W/BRUSHES	255	cleaned fouled condenser	yes	routine work effort
04/23/99	21:58	04/23/99	22:43	N.SIDE COND LEAK	235	plugged leaking tube	yes	routine event, review location and history of leaks
04/23/99	22:45	04/24/99	02:25	S.SIDE COND LEAK	285	plugged leaking tube	yes	routine event, review location and history of leaks
04/24/99	02:26	04/25/99	15:30	BOILER WATER CHEMISTRY	135	reduce load until proper water chemistry is achieved	yes	routine event following startup or condenser leak
04/25/99	23:10	04/26/99	12:35	S.SIDE COND LEAK	235	plugged leaking tube	yes	routine event, review location and history of leaks
04/26/99	12:36	04/26/99	22:59	VWO	5	improve fuel quality	yes	review fuel blend
04/26/99	23:00	04/27/99	01:15	N.SIDE W/BRUSHES	235	cleaned fouled condenser	yes	routine work effort
04/27/99	01:16	04/27/99	14:59	VWO	5	improve fuel quality	yes	review fuel blend
04/27/99	15:00	04/27/99	18:00	OPACITY-F/A HOPPER HIGH LEVEL	20	cleared precipitator hoppers	yes	optimize precipitator, ash removal, boiler combustion systems
04/27/99	18:01	04/27/99	18:00	VWO	5	improve fuel quality	yes	review fuel blend
04/27/99	18:01	04/27/99	24:00	COND TUBES FOULING	15	schedule condenser cleaning	yes	normal maintenance
	BIG BEND 2							
04/25/99	08:10	04/26/99	17:55	"B" CWPP	197	rebuilt circulator due to bearing failure	yes	review bearing material and shaft alignment
04/26/99	17:56	04/27/99	11:59	REPAIR 1ST AND 2ND PT HEATER EXTRACTION VALVES	18	repaired valves	yes	preventative maintenance
04/27/99	12:00	04/28/99	04:59	OPACITY-F/A HOPPER HIGH LEVEL	74	technicians investigated causes	yes	optimize precipitator, ash removal, boiler combustion systems
	BIG BEND 3							
04/25/99	00:35	04/25/99	01:09	"B" MILL COAL LEAKS	170	performed temporary repair to coal chute	yes	plan for permanent repair/replace at next major outage
04/25/99	01:10	04/25/99	02:15	N.SIDE PICK	230	picked half of condenser	yes	normal maintenance
04/25/99	02:30	04/25/99	03:50	S.SIDE PICK	230	picked half of condenser	yes	normal maintenance
04/25/99	03:51	04/25/99	05:30	"B" MI L-COAL LEAKS	170	performed temporary repair to coal chute	yes	plan for permanent repair/replace at next major outage
04/25/99	07:50	04/25/99	09:20	"A" MILL MOTOR-OIL CHANGE	145	changed oil	yes	normal event , review oil analysis
	BIG BEND 4							
04/23/99	16:45	04/24/99	01:44	COND TUBES FOULING	18	schedule condenser cleaning	yes	normal maintenance
04/24/99	01:45	04/24/99	02:40	A/C COND PICK	300	picked half of condenser	yes	normal maintenance
04/24/99	03:00	04/24/99	03:50	B/D COND PICK	300	picked half of condenser	yes	normal maintenance
04/26/99	15:00	04/26/99	22:15	"A" MILL-"A" FEEDER MOTOR	70	replaced motor with one from stock	yes	review preventive maintenance of feeder motors
04/27/99	23:30	04/28/99	05:00	B/D W/BRUSHES	270	cleaned fouled condenser	yes	routine work effort

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Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Reoccurrence
	GANNON 1							
04/24/99	01:30	04/24/99	04:15	PICK CONDENSER	65	picked half of condenser	yes	normal maintenance
	GANNON 2							
04/26/99	01:00	04/26/99	10:30	PICK CONDENSER & REPAIR SALT LEAK (IN CONDENSER)	55	picked half of condenser	yes	normal maintenance
	GANNON 3							
04/24/99	04:30	04/24/99	08:45	PICK CONDENSER	90	picked half of condenser	yes	normal maintenance
04/27/99	01:00	04/27/99	03:30	PICK CONDENSER	100	picked half of condenser	yes	normal maintenance
	GANNON 4							
04/22/99	01:30	04/22/99	03:55	PICK CONDENSER	120	picked half of condenser	yes	normal maintenance
From:	05/05/99	to:	05/07/99					
	BIG BEND 1							
05/05/99	07:00	05/06/99	10:59	VWO	5	improve fuel quality	yes	review fuel blend
05/06/99	11:00	05/06/99	23:19	REDUCED HEADER-COND SALT LEAK	97	reduced load until condenser tube leak could be repaired	yes	review tube leak location and history
05/06/99	23:20	05/07/99	11:30	S.SIDE COND LEAK	255	cleaned fouled condenser	yes	routine work effort
05/07/99	11:31	05/07/99	13:45	REDUCED HEADER-COND LEAK	110	cleaned fouled condenser	yes	routine work effort
05/07/99	13:46	05/08/99	06:59	VWO	5	cleaned fouled condenser	yes	routine work effort
	BIG BEND 2							
05/04/99	08:56	05/05/99	23:54	HIGH EXIT GAS TEMP	20	tuned boiler	yes	monitor performance
05/05/99	23:55	05/06/99	05:04	N.SIDE W/BRUSHES	250	cleaned fouled condenser	yes	routine work effort
05/06/99	05:05	05/06/99	05:40	"A" MILL-CLEAN PAF WHEEL	155	cleaned wheel	yes	normal maintenance
05/06/99	05:41	05/06/99	07:00	HIGH EXIT GAS TEMP	20	tuned boiler	yes	monitor performance
05/07/99	07:00	05/07/99	11:30	HIGH EXIT GAS TEMP	20	tuned boiler	yes	monitor performance
	BIG BEND 3							
05/04/99	23:55	05/05/99	03:33	"C" MILL-COAL LEAKS	145	performed temporary repair to coal chute	yes	performed permanent repair during next unit outage
05/06/99	03:10	05/06/99	08:45	"B" MILL-COAL LEAKS	145	performed temporary repair to coal chute	yes	performed permanent repair during next unit outage
	BIG BEND 4							
05/05/99	08:00	05/06/99	14:09	COND TUBES FOULING	93	schedule condenser cleaning	yes	normal maintenance
05/06/99	14:10	05/07/99	00:29	MAX BFP	15	adjusted recirc. Vlv. Control	yes	review feedwater control system
05/07/99	00:30	05/07/99	02:30	B/D COND PICK	270	picked condenser half	yes	normal maintenance
05/07/99	02:55	05/07/99	04:00	A/C COND PICK	270	picked condenser half	yes	normal maintenance
05/07/99	07:20	05/12/99	17:19	3RD PT HEATER LEAK	25	repaired leak	yes	installed explosive plugs during next planned outage
	GANNON 1							
05/06/99	23:00	05/07/99	04:00	PICK CONDENSER	65	picked condenser half	yes	normal maintenance
	GANNON 2							
05/07/99	05:30	05/07/99	07:00	PICK CONDENSER	55	picked condenser half	yes	normal maintenance

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
	GANNON 3							
05/06/99	03:00	05/07/99	21:39	REHEAT STRAINERS PLUGGING UP	15	clean strainers	yes	monitor strainer performance
05/07/99	21:40	05/08/99	00:12	CONVERYOR FIRE (CONSERVE COAL FOR PEAK)	95	refurbished equipment & replaced belt	yes	conveyor system inspections
From:	07/28/99	to:	08/03/99					
	BIG BEND 1							
07/27/99	23:40	07/28/99	00:40	S.SIDE COND PICK	235	picked condenser half	yes	normal maintenance
07/28/99	00:41	07/28/99	05:15	"A" MILL-COAL LEAK	165	performed temporary repair to coal chute	yes	performed permanent repair during next unit outage
07/28/99	05:16	07/28/99	07:00	MAX AIR FLOW	5	no records available	yes	
07/28/99	15:30	07/28/99	24:00	DISCH CANAL TEMP	25	restrict load to achieve allowable water temp	yes	naturally occuring event
07/29/99	00:01	07/29/99	06:59	MAX AIR FLOW	5	no records available	yes	
07/29/99	13:30	07/29/99	23:34	DISCH CANAL TEMP	50	restrict load to achieve allowable water temp	yes	naturally occuring event
07/29/99	23:35	07/30/99	00:45	S.SIDE COND PICK	235	picked condenser half	yes	normal maintenance
07/30/99	01:00	07/30/99	01:40	N.SIDE COND PICK	235	picked condenser half	yes	normal maintenance
07/30/99	12:30	07/31/99	07:00	DISCH CANAL TEMP	30	restrict load to achieve allowable water temp	yes	naturally occuring event
07/31/99	07:01	07/31/99	13:39	MAX AIR FLOW	5	no records available	yes	
07/31/99	13:40	08/01/99	00:59	OPACITY	49	technicians investigated causes	yes	optimize precipitator, ash removal, boiler combustion systems
08/01/99	01:00	08/01/99	04:35	N.SIDE COND CLEANED W/BRUSHES	255	cleaned fouled condenser	yes	routine work effort
08/01/99	04:55	08/01/99	06:30	S.SIDE COND PICK	255	picked condenser half	yes	normal maintenance
08/03/99	00:50	08/03/99	05:05	S.SIDE CLEANED W/BRUSHES	270	cleaned fouled condenser	yes	routine work effort
08/03/99	07:00	08/03/99	15:39	MAX STEAM FLOW	5	improve fuel quality	yes	review fuel blend
08/03/99	15:40	08/03/99	19:16	DISCH CANAL TEMP	35	restrict load to achieve allowable water temp	yes	naturally occuring event
08/03/99	19:17	08/03/99	21:04	"C" MILL-HIGH SPEED PINION BEARING	155	replaced bearing	yes	monitor lube oil &vibration
08/03/99	21:05	08/04/99	01:45	N.SIDE CLEANED W/BRUSHES	235	cleaned fouled condenser	yes	routine work effort
	BIG BEND 2							
07/27/99	17:00	07/28/99	00:15	WET COAL-FEEDERS PLUGGING	15	clear pluggage	yes	bunker with dry coal when possible
07/28/99	00:16	07/28/99	05:05	N.SIDE COND CLEANED W/BRUSHES	235	cleaned fouled condenser	yes	routine work effort
07/28/99	05:06	07/28/99	18:22	WET COAL-FEEDERS PLUGGING	12	clear pluggage	yes	bunker with dry coal when possible
07/28/99	18:23	07/28/99	22:10	OPACITY	40	technicians investigated causes	yes	optimize precipitator, ash removal, boiler combustion systems
07/28/99	22:11	07/29/99	01:34	WET COAL-FEEDERS PLUGGING	10	clear pluggage	yes	bunker with dry coal when possible
07/29/99	01:35	07/29/99	02:50	S.SIDE COND PICK	235	picked condenser half	yes	normal maintenance
07/29/99	03:05	07/29/99	04:07	N.SIDE COND PICK	235	picked condenser half	yes	normal maintenance
07/29/99	04:07	07/29/99	13:29	WET COAL-FEEDERS PLUGGING	10	clear pluggage	yes	bunker with dry coal when possible
07/29/99	13:30	07/29/99	24:00	DISCH CANAL TEMP	35	restrict load to achieve allowable water temp	yes	naturally occuring event
07/30/99	00:01	07/30/99	11:59	WET COAL-FEEDERS PLUGGING	10	clear pluggage	yes	bunker with dry coal when possible
07/30/99	12:00	07/30/99	23:29	DISCH CANAL TEMP	39	restrict load to achieve allowable water temp	yes	naturally occuring event
07/30/99	23:30	07/31/99	04:30	N.SIDE COND CLEANED WBRUSHES	270	cleaned fouled condenser	yes	routine work effort
07/31/99	04:31	08/01/99	04:14	WET COAL-FEEDERS PLUGGING	5	clear pluggage	yes	bunker with dry coal when possible
08/01/99	04:15	08/01/99	06:15	S.SIDE COND PICK	255	picked condenser half	yes	normal maintenance
08/02/99	03:10	08/02/99	04:20	N.SIDE COND PICK	255	picked condenser half	yes	normal maintenance
08/02/99	04:30	08/02/99	05:35	S.SIDE COND PICK	255	picked condenser half	yes	normal maintenance

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
06/02/99	05:35	06/03/99	00:14	WET COAL-FEEDERS PLUGGING	5	clear pluggage	yes	bunker with dry coal when possible
06/03/99	00:15	06/03/99	05:05	S.SIDE COND CLEANED W/BRUSHES	270	cleaned fouled condenser	yes	routine work effort
06/03/99	05:06	06/03/99	07:00	WET COAL-FEEDERS PLUGGING	5	clear pluggage	yes	bunker with dry coal when possible
06/03/99	15:40	06/03/99	21:00	DISCH CANAL TEMP	35	restrict load to achieve allowable water temp	yes	naturally occuring event
06/03/99	21:01	06/04/99	05:10	N.SIDE COND CLEANED W/BRUSHES	415	cleaned fouled condenser	yes	routine work effort
	BIG BEND 3							
07/27/99	17:16	07/28/99	03:09	DISCH CANAL TEMP	25	restrict load to achieve allowable water temp	yes	naturally occuring event
07/28/99	03:10	07/28/99	05:30	PICKED CONDENSERS	305	picked condenser half	yes	normal maintenance
07/28/99	10:45	07/28/99	15:10	FUEL	15	adjusted boiler combustion systems	yes	review fuel blend
07/28/99	15:11	07/28/99	24:00	DISCH CANAL TEMP	90	restrict load to achieve allowable water temp	yes	naturally occuring event
07/29/99	00:01	07/29/99	04:40	N.SIDE COND CLEANED W/BRUSHES	295	cleaned fouled condenser	yes	routine work effort
07/29/99	16:30	07/30/99	01:29	DISCH CANAL TEMP	113	restrict load to achieve allowable water temp	yes	naturally occuring event
07/30/99	01:30	07/30/99	04:40	S.SIDE COND CLEANED W/BRUSHES	295	cleaned fouled condenser	yes	routine work effort
07/30/99	10:47	07/31/99	00:29	DISCH CANAL TEMP	85	restrict load to achieve allowable water temp	yes	naturally occuring event
07/31/99	00:30	07/31/99	05:30	N.SIDE COND CLEANED W/BRUSHES	265	cleaned fouled condenser	yes	routine work effort
06/02/99	15:51	06/03/99	10:58	REDUCED HEADER-FURNACE TUBE THINNING	95	increased header pressure	yes	repaired thinned tubes next planned outage
06/03/99	13:10	06/03/99	14:05	N.SIDE COND PICK	245	picked condenser half	yes	normal maintenance
06/03/99	14:27	06/03/99	15:07	S.SIDE COND PICK	245	picked condenser half	yes	normal maintenance
06/03/99	17:40	06/03/99	20:29	COND TUBES FOULING	5	schedule condenser cleaning	yes	normal maintenance
06/03/99	20:30	06/04/99	01:58	COND TUBES FOULING	30	schedule condenser cleaning	yes	normal maintenance
	BIG BEND 4							
07/27/99	04:15	07/28/99	06:14	3RD PT HEATER LEAK / MAX BFP	40	repair heater leak at next unit outage	yes	review location of leak and review history
07/28/99	06:15	07/28/99	06:45	B/D COND PICK	290	picked half of condenser	yes	normal maintenance
07/28/99	06:46	07/28/99	07:04	3RD PT HEATER LEAK / MAX BFP	40	repair heater leak at next unit outage	yes	review location of leak and review history
07/28/99	07:05	07/28/99	08:07	A/C COND PICK	290	picked half of condenser	yes	normal maintenance
07/28/99	08:08	07/28/99	15:10	3RD PT HEATER LEAK / MAX BFP	35	repair heater leak at next unit outage	yes	review location of leak and review history
07/28/99	15:11	07/29/99	00:49	DISCH CANAL TEMP	83	restrict load to achieve allowable water temp	yes	naturally occuring event
07/29/99	00:50	07/29/99	05:30	B/D COND CLEANED W/BRUSHES	290	cleaned fouled condenser	yes	routine work effort
07/29/99	05:31	07/29/99	13:29	3RD PT HEATER LEAK / MAX BFP	40	repair heater leak at next unit outage	yes	review location of leak and review history
07/29/99	13:30	07/30/99	01:04	DISCH CANAL TEMP	90	restrict load to achieve allowable water temp	yes	naturally occuring event
07/30/99	01:05	07/30/99	05:10	A/C COND CLEANED W/BRUSHES	270	cleaned fouled condenser	yes	routine work effort
07/30/99	05:11	07/30/99	11:58	3RD PT HEATER LEAK / MAX BFP	40	repair heater leak at next unit outage	yes	review location of leak and review history
07/30/99	12:00	07/31/99	05:58	DISCH CANAL TEMP	63	restrict load to achieve allowable water temp	yes	naturally occuring event
07/31/99	06:00	07/31/99	12:10	B/D COND CLEANED W/BRUSHES	270	cleaned fouled condenser	yes	routine work effort

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Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
07/31/99	12:11	07/31/99	14:06	3RD PT HEATER LEAK / MAX BFP	40	repair heater leak at next unit outage	yes	review location of leak and review history
07/31/99	14:07	07/31/99	23:34	COND TUBES FOULING	80	schedule condenser cleaning	yes	normal maintenance
07/31/99	23:35	08/01/99	00:50	A/C COND PICK	260	picked half of condenser	yes	normal maintenance
08/01/99	01:06	08/01/99	03:05	B/D COND PICK	260	picked half of condenser	yes	normal maintenance
08/01/99	03:06	08/01/99	11:59	3RD PT HEATER LEAK / MAX BFP	40	repair heater leak at next unit outage	yes	review location of leak and review history
08/01/99	12:00	08/01/99	21:03	COND TUBES FOULING	69	schedule condenser cleaning	yes	normal maintenance
08/01/99	23:25	08/02/99	01:45	B/D COND PICK	270	picked half of condenser	yes	normal maintenance
08/02/99	02:50	08/02/99	04:20	A/C COND PICK	270	picked half of condenser	yes	normal maintenance
08/02/99	04:21	08/02/99	11:14	3RD PT HEATER LEAK / MAX BFP	40	repair heater leak at next unit outage	yes	review location of leak and review history
08/02/99	11:15	08/02/99	11:50	"B" MILL-PYRITE PLUGGAGE; "E" MILL TAGGED	130	cleaned out pyrite chute	yes	normal operation
08/02/99	11:55	08/02/99	13:39	3RD PT HEATER LEAK / MAX BFP	40	repair heater leak at next unit outage	yes	review location of leak and review history
08/02/99	13:40	08/03/99	02:59	COND TUBES FOULING	83	schedule condenser cleaning	yes	normal maintenance
08/03/99	03:00	08/03/99	04:00	PICKED "C" COND SECTION	300	picked condenser half	yes	normal maintenance
08/03/99	04:10	08/03/99	05:45	PICKED "D" COND SECTION	250	picked condenser half	yes	normal maintenance
08/03/99	05:46	08/03/99	15:30	3RD PT HEATER LEAK / MAX BFP	40	repair heater leak at next unit outage	yes	review location of leak and review history
08/03/99	15:31	08/03/99	18:59	DISCH CANAL TEMP	70	restrict load to achieve allowable water temp	yes	naturally occuring event
08/03/99	19:00	08/03/99	23:09	COND TUBES FOULING	92	schedule condenser cleaning	yes	normal maintenance
08/03/99	23:10	08/04/99	01:15	A/C COND PICK	300	picked condenser half	yes	normal maintenance
	GANNON 1							
07/27/99	04:50	07/27/99	08:50	PICK CONDENSER	65	picked half of condenser	yes	normal maintenance
07/31/99	04:30	07/31/99	08:30	PICK CONDENSER	65	picked half of condenser	yes	normal maintenance
08/01/99	23:20	08/02/99	00:44	PICK CONDENSER	65	picked half of condenser	yes	normal maintenance
08/02/99	07:10	08/02/99	11:55	COAL FEEDER BELT	35	repaired coal feeder belt	yes	normal maintenance
08/02/99	15:55	08/02/99	21:29	COAL FEEDER BELT	25	replaced belt	yes	normal maintenance
08/03/99	21:30	08/04/99	13:20	COAL FEEDER BELT	15	belt repaired	yes	inspect feeders during planned outages
	GANNON 2							
07/30/99	00:45	07/30/99	02:10	PICK CONDENSER	55	picked half of condenser	yes	normal maintenance
08/01/99	01:00	08/01/99	02:24	CONDENSER DIRTY	5	schedule condenser cleaning	yes	normal maintenance
08/02/99	23:30	08/03/99	00:59	PICK CONDENSER	55	picked condenser half	yes	normal maintenance
	GANNON 3							
07/27/99	02:20	07/26/99	13:59	CONDENSATE PUMP	45	no information available		
07/28/99	14:00	07/28/99	14:59	CONDENSER DIRTY ,LOW VACCUM.	30	schedule condenser cleaning	yes	normal maintenance
07/28/99	13:10	07/28/99	14:14	CONDENSER DIRTY	20	schedule condenser cleaning	yes	normal maintenance
07/28/99	14:15	07/28/99	17:59	CONDENSER DIRTY	30	schedule condenser cleaning	yes	normal maintenance

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
07/28/99	18:00	07/28/99	18:19	CONDENSER DIRTY	40	schedule condenser cleaning	yes	normal maintenance
07/28/99	18:20	07/28/99	19:24	CONDENSER DIRTY	35	schedule condenser cleaning	yes	normal maintenance
07/28/99	19:25	07/28/99	21:24	PICK CONDENSER	95	picked half of condenser	yes	normal maintenance
07/28/99	22:00	07/29/99	04:49	CONDENSER DIRTY	10	schedule condenser cleaning	yes	normal maintenance
07/29/99	04:50	07/29/99	06:40	PICK CONDENSER	95	picked half of condenser	yes	normal maintenance
07/29/99	08:15	07/29/99	09:44	HIGH FURNACE PRESS.	5	operate air heater sootblower	yes	inspect air preheater at next outage
07/29/99	09:45	07/29/99	11:29	PICK CONDENSER	95	picked half of condenser	yes	normal maintenance
07/30/99	04:00	07/30/99	05:30	PICK CONDENSER	95	picked half of condenser	yes	normal maintenance
07/30/99	09:00	07/30/99	10:10	PICK CONDENSER	95	picked half of condenser	yes	normal maintenance
07/31/99	00:15	07/31/99	01:45	PICK CONDENSER	95	picked half of condenser	yes	normal maintenance
07/31/99	08:15	07/31/99	10:10	PICK CONDENSER	95	picked half of condenser	yes	normal maintenance
08/02/99	00:35	08/02/99	02:00	PICK CONDENSER	95	picked half of condenser	yes	normal maintenance
08/02/99	23:30	08/03/99	06:10	BLOW CONDENSER	110	cleaned fouled condenser	yes	routine work effort
08/03/99	23:25	08/04/99	01:15	PICK CONDENSER	95	picked condenser half	yes	normal maintenance
	GANNON 4							
07/27/99	23:30	07/29/99	05:59	BLOW PLUGS IN CONDENSER	135	cleaned fouled condenser	yes	routine work effort
07/29/99	09:45	07/29/99	11:20	PICK CONDENSER	120	picked half of condenser	yes	normal maintenance
07/29/99	23:30	07/30/99	05:45	PICK CONDENSER	120	picked half of condenser	yes	normal maintenance
07/30/99	09:50	07/30/99	12:09	PICK CONDENSER	120	picked half of condenser	yes	normal maintenance
07/31/99	02:30	07/31/99	04:00	PICK CONDENSER	120	picked half of condenser	yes	normal maintenance
07/31/99	09:27	07/31/99	09:39	PICK CONDENSER	120	picked half of condenser	yes	normal maintenance
07/31/99	17:00	07/31/99	23:49	CONDENSER DIRTY	5	schedule condenser cleaning	yes	normal maintenance
07/31/99	23:50	07/31/99	24:00	PICK CONDENSER	120	picked half of condenser	yes	normal maintenance
08/01/99	00:01	08/01/99	02:00	PICK CONDENSER	120	picked half of condenser	yes	normal maintenance
08/02/99	07:20	08/02/99	09:35	PICK CONDENSER	120	picked half of condenser	yes	normal maintenance
08/02/99	17:00	08/02/99	24:00	CONDENSER DIRTY	5	schedule condenser cleaning	yes	normal maintenance
	GANNON 5							
07/27/99	07:00	07/28/99	09:59	CONDENSER DIRTY	25	schedule condenser cleaning	yes	normal maintenance
07/28/99	10:00	07/29/99	02:29	CONDENSER DIRTY	40	schedule condenser cleaning	yes	normal maintenance
07/28/99	02:30	07/28/99	04:19	PICK CONDENSER	155	picked half of condenser	yes	normal maintenance
07/30/99	01:39	07/30/99	03:59	PICK CONDENSER	155	picked half of condenser	yes	normal maintenance
07/31/99	08:20	07/31/99	11:24	BOILER FEED PUMP AUX. OIL PUMP MOTOR BAD	70	replaced motor	yes	performed root cause analysis of failure
08/01/99	08:20	08/01/99	11:25	BOILER FEED WATER PUMP AUX.OIL PUMP.	70	replaced motor	yes	performed root cause analysis of failure
08/02/99	01:00	08/02/99	02:15	PICK CONDENSER	155	picked half of condenser	yes	normal maintenance
08/03/99	16:00	08/04/99	00:14	CONDENSER DIRTY	100	schedule condenser cleaning	yes	normal maintenance
08/03/99	16:00	08/04/99	00:14	CONDENSER DIRTY	100	schedule condenser cleaning	yes	normal maintenance
	GANNON 6							
07/28/99	03:10	07/28/99	04:00	PICK CONDENSER	200	picked half of condenser	yes	normal maintenance

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
07/28/99	19:30	07/29/99	00:30	CONDENSER DIRTY	10	schedule condenser cleaning	yes	normal maintenance
07/29/99	00:31	07/29/99	01:30	PICK CONDENSER	200	picked half of condenser	yes	normal maintenance
08/01/99	18:36	08/01/99	20:00	LOW BTU FUEL	25	adjusted boiler combustion systems	yes	review fuel blend
08/01/99	16:45	08/02/99	04:00	CONDENSER DIRTY	30	schedule condenser cleaning	yes	normal maintenance
08/02/99	04:00	08/02/99	05:15	PICK CONDENSER	205	picked half of condenser	yes	normal maintenance
	POLK 1 GASIFIER							
07/27/99	21:53	07/28/99	00:26	ACID PLANT TRIP	5	troubleshoot system, opened recirc valve	yes	normal maintenance
07/28/99	04:19	07/28/99	05:00	ACID PLANT TRIP COMPRESSOR VIBRATION	16	troubleshoot system, bypass faulty vibration probe	yes	normal maintenance & replaced probe & cable
08/01/99	00:00	08/27/99	15:00	ASU ADSORBER BREAK-THRU (5048)	2	cleaned absorber	yes	use higher pressure steam to shorten regen cycle
08/02/99	14:10	08/07/99	15:18	MDEA CARRYOVER PLUGGAGE OF CLEAN GAS PREHEATER	15	removed pluggage	no	MDEA reclaim to remove HSS was installed
From:	09/03/99	to:	09/05/99					
	BIG BEND 1							
09/02/99	23:35	09/03/99	00:25	S.SIDE COND.-PICK	255	picked half of condenser	yes	normal maintenance
09/03/99	00:40	09/03/99	01:30	N.SIDE COND.-PICK	255	picked half of condenser	yes	normal maintenance
09/04/99	15:00	09/04/99	15:50	HIGH OPACITY	45	technicians investigated causes	yes	optimize precipitator, ash removal, boiler combustion systems
09/05/99	23:00	09/05/99	23:49	"A" MILL OUT FOR COAL LEAK REPAIR	180	repaired coal leak	yes	wear areas investigated, repairs/replacements performed at next planned outage
09/05/99	23:50	09/06/99	00:40	N.SIDE COND.- PICK	235	picked half of condenser	yes	normal maintenance
	BIG BEND 2							
09/02/99	22:55	09/03/99	04:35	N.SIDE COND.- CLEAN W/BRUSHES	245	cleaned fouled condenser	yes	routine work effort
09/04/99	10:00	09/04/99	23:06	"C" PAF OUT DUE TO HI VIBRATION	155	cleaned fan wheel and balanced	yes	normal maintenance
09/04/99	23:07	09/05/99	00:05	S.SIDE COND.- PICK	235	picked half of condenser	yes	normal maintenance
09/05/99	00:22	09/05/99	01:00	N.SIDE COND.- PICK	235	picked half of condenser	yes	normal maintenance
09/05/99	01:01	09/05/99	08:15	"C" PAF OUT - TROUBLESHOOTING AND REPAIRING HI VIB. PROBLEM	155	installed new thrust collar	yes	reviewed preventive maintenance and operation
	BIG BEND 3							
09/03/99	02:35	09/03/99	03:20	S.SIDE COND.- PICK	245	picked half of condenser	yes	normal maintenance
09/03/99	03:40	09/03/99	04:25	N.SIDE COND.- PICK	245	picked half of condenser	yes	normal maintenance
09/05/99	00:15	09/05/99	01:50	S.SIDE COND.- PICK	280	picked half of condenser	yes	normal maintenance
09/05/99	02:15	09/05/99	03:00	N.SIDE COND.- PICK	280	picked half of condenser	yes	normal maintenance
	BIG BEND 4							
09/02/99	14:31	09/03/99	23:14	LOW STEAM TEMPS	10	continue operation until boiler slags after startup	yes	normal event following unit startup
09/03/99	23:30	09/04/99	04:54	B/D COND. SECTIONS- CLEAN W/BRUSHES	270	cleaned fouled condenser	yes	routine work effort

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
09/04/99	04:55	09/06/99	00:49	MAX FUEL- LOW BTU	7	adjusted boiler combustion systems	yes	review fuel blend
	GANNON 1							
09/05/99	06:10	09/05/99	21:40	F000LEAK IN 1C CYCLONE	25	removed cyclone from service	yes	repaired scroll leak
	GANNON 2							
09/04/99	03:00	09/04/99	05:10	F000PICK CONDENSER	60	picked half of condenser	yes	normal maintenance
	GANNON 3							
09/02/99	07:01	09/03/99	02:59	F000HIGH FURN. PRESSURE	5	operate air heater sootblower	yes	inspect air preheater at next outage
09/03/99	03:00	09/03/99	03:59	F000PICK CONDENSER	100	picked half of condenser	yes	normal maintenance
09/03/99	04:00	09/03/99	06:49	F000HIGH FURN. PRESSURE	5	operate air heater sootblower	yes	inspect air preheater at next outage
09/03/99	06:50	09/03/99	09:47	F0003A & B CYCLONE IGNITOR PROBLEMS	35	replaced ignitor cable	yes	normal maintenance
09/03/99	09:48	09/04/99	05:44	F000HIGH FURN. PRESSURE	5	operate air heater sootblower	yes	inspect air preheater at next outage
09/04/99	05:45	09/04/99	06:14	F000PICK CONDENSER	95	picked half of condenser	yes	normal maintenance
09/04/99	06:15	09/04/99	13:04	F000HIGH FURN. PRESSURE	5	operate air heater sootblower	yes	inspect air preheater at next outage
09/04/99	13:05	09/04/99	13:44	F0003C CYCLONE IGNITOR PROBLEMS	15	repaired refractory adjacent to ignitor	yes	perform casing and refractory permanent repair at next planned outage
09/04/99	13:45	09/04/99	21:21	F0003C COAL FEEDER PROBLEMS	35	replaced feeder belt due to tire	yes	occasional occurrence in coal feeder
09/04/99	22:10	09/05/99	05:59	F000HIGH FURN. PRESSURE	5	operate APH sootblower	yes	wash APH at next planned outage
09/05/99	06:00	09/05/99	06:15	F000PICK CONDENSER	95	picked half of condenser	yes	normal maintenance
09/05/99	06:16	09/05/99	13:29	F000HIGH FURN. PRESSURE	5	operate APH sootblower	yes	wash APH at next planned outage
09/05/99	13:30	09/05/99	18:49	F0003D COAL FEEDER DRAG CHAIN PROBLEMS	15	replaced drag chain	yes	normal maintenance
09/05/99	18:50	09/06/99	07:30	F000HIGH FURN. PRESSURE	5	operate APH sootblower	yes	wash APH at next planned outage
	GANNON 4							
09/03/99	13:00	09/03/99	13:29	F000HEADER RESTRICTION TO BOILER TUBE CONDITION.	25	reduce header pressure to minimize tube failures	yes	plan to replace thin tubes during next major outage
09/03/99	13:30	09/03/99	13:59	F000HEADER RESTRICTIOND DUE TO BOILER TUBE CONDITIONS.	20	reduce header pressure to minimize tube failures	yes	plan to replace thin tubes during next major outage
09/03/99	23:30	09/04/99	01:54	F000PICK CONDENSER	120	picked half of condenser	yes	normal maintenance
09/04/99	08:00	09/04/99	08:40	F000HOT SPOT ON SLAG TANK.	40	perform temporary repair of slag tank	yes	perform permenent repair during next planned outage
09/04/99	18:30	09/04/99	19:44	F000B COAL FEEDER TROUBLE	10	limited coal feeder speed to avoid tripping	yes	troubleshoot and repair/replace control components when feeder can be taken out of service
09/05/99	01:45	09/05/99	03:59	F000PICK CONDENSER	120	picked half of condenser	yes	normal maintenance
	GANNON 5							
09/03/99	04:33	09/03/99	10:14	F000HIGH FURN. PRESSURE	10	operate air,heater sootblower	yes	inspect air preheater at next outage
09/03/99	17:25	09/03/99	19:39	F000LOW BTU FUEL	70	adjusted boiler combustion systems	yes	review fuel blend

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
09/03/99	19:40	09/03/99	20:59	F000LOW BTU FUEL	115	adjusted boiler combustion systems	yes	review fuel blend
09/03/99	21:00	09/03/99	21:29	F000LOW BTU FUEL	80	adjusted boiler combustion systems	yes	review fuel blend
09/03/99	21:30	09/04/99	09:39	F000LOW BTU FUEL	85	adjusted boiler combustion systems	yes	review fuel blend
09/04/99	09:40	09/04/99	11:10	F000HIGH FURN. PRESSURE	15	operate air heater sootblower	yes	inspect air preheater at next outage
09/05/99	02:50	09/05/99	05:09	F000A PULVERIZER WIRING	135	replace wiring	yes	all wiring replaced - none required
09/05/99	01:10	09/05/99	02:29	F000PICK CONDENSER	155	picked half of condenser	yes	normal maintenance
09/05/99	15:30	09/05/99	18:40	F000HIGH FURN. PRESSURE	10	operate APH sootblower	yes	inspect & wash APH at next planned outage
09/05/99	18:40	09/05/99	20:09	F000A PULVERIZER COAL LEAK	140	repaired coal leak	yes	inspect thickness, repair/replace at next planned outage
09/05/99	20:10	09/07/99	14:59	F000HIGH FURN. PRESSURE	10	operate APH sootblower	yes	inspect & wash APH at next planned outage
	GANNON 6							
09/02/99	23:15	09/03/99	04:15	F000BLOW PLUGS IN CONDENSER	240	cleaned fouled condenser	yes	routine work effort
09/03/99	04:16	09/03/99	20:29	F000OPACITY	35	technicians investigated causes	yes	optimize precipitator, ash removal, boiler combustion systems
09/03/99	20:30	09/04/99	14:29	F000OPACITY	50	technicians investigated causes	yes	optimize precipitator, ash removal, boiler combustion systems
09/04/99	14:30	09/04/99	15:04	F000CONDENSER DIRTY	65	schedule condenser cleaning	yes	normal maintenance
09/04/99	15:05	09/04/99	23:19	F000CONDENSER DIRTY	85	schedule condenser cleaning	yes	normal maintenance
09/04/99	23:20	09/05/99	00:55	F000PICK CONDENSER	230	picked half of condenser	yes	normal maintenance
09/05/99	00:55	09/05/99	15:44	F000OPACITY	50	inspect/clean hoppers	yes	optimize precipitator, ash removal, boiler combustion systems
09/05/99	15:45	09/05/99	16:29	F000CONDENSER DIRTY	15	schedule condenser cleaning	yes	normal maintenance
09/05/99	16:30	09/05/99	23:29	F000CONDENSER DIRTY	35	schedule condenser cleaning	yes	normal maintenance
09/05/99	23:30	09/06/99	01:09	F000PICK CONDENSER	215	picked half of condenser	yes	normal maintenance
From:	09/27/99	to:	09/29/99					
	BIG BEND 1							
09/26/99	23:10	09/27/99	04:40	N.SIDE COND.- CLEAN W/BRUSHES	245	cleaned fouled condenser	yes	routine work effort
09/27/99	05:00	09/28/99	12:45	HIGH EXIT GAS TEMP	20	adjust dampers, operate sootblowers	yes	review sootblower operation
09/27/99	13:50	09/27/99	18:15	A FEEDER TRIPPED- C/A PROBLEM	85	repair control switch	yes	review maintenance history
09/29/99	00:20	09/29/99	05:45	C MILL OUT FOR LEVEL PROBE REPAIR	155	repaired level probe	yes	normal maintenance
09/29/99	10:30	10/01/99	00:09	1ST. & 2ND. PT. HTRS BYPASSED- LEAK IN 2ND. PT.	35	repaired htr. Tube leak	yes	review tube thickness for repairs/replace at next major outage
	BIG BEND 2							
09/27/99	23:55	09/28/99	01:20	N.SIDE COND.- PICK	245	picked half of condenser	yes	normal maintenance
09/28/99	01:30	09/28/99	03:20	S.SIDE COND.- PICK	235	picked half of condenser	yes	normal maintenance
	BIG BEND 3							

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
09/27/99	09:30	09/27/99	20:56	BOILER BURN THRU	225	perform temporary repair of casing	yes	perform permanent repair during unit outage
09/29/99	23:35	09/30/99	00:30	S.SIDE COND.- PICK	245	picked half of condenser	yes	normal maintenance
	BIG BEND 4							
09/27/99	01:10	09/27/99	01:55	A/C COND. SECTIONS- PICK	270	picked half of condenser	yes	normal maintenance
09/27/99	02:10	09/27/99	03:35	B/D COND. SECTIONS- PICK	270	picked half of condenser	yes	normal maintenance
09/27/99	03:36	09/28/99	23:14	2ND. PT. HTR. OUT	25	repair heater leak	yes	review leak location and history
09/28/99	23:15	09/29/99	05:10	C MILL OUT FOR COAL FEEDER CLEAN OUT CONVEYOR REPAIR	125	replaced gear reducer	yes	reviewed preventive maintenance program & returned rebuilt reducer to stock
09/29/99	05:11	09/29/99	18:59	2ND. PT. HTR. OUT	25	removed heater from service	yes	repaired head leak/reviewed heater head installation procedure
09/29/99	19:00	09/30/99	01:59	LOW VACUUM	50	clean condenser	yes	normal maintenance
	GANNON 1							
09/27/99	02:40	09/27/99	04:30	F000PICK CONDENSER	65	picked half of condenser	yes	normal maintenance
09/28/99	01:20	09/28/99	03:30	F000PICK CONDENSER	65	picked half of condenser	yes	normal maintenance
09/29/99	04:45	09/29/99	07:00	F000PICK CONDENSER	75	picked half of condenser	yes	normal maintenance
09/28/99	20:30	09/29/99	23:16	F000CONDENSER DIRTY	25	schedule condenser cleaning	yes	normal maintenance
09/29/99	23:16	09/30/99	01:17	F000PICK CONDENSER	75	picked half of condenser	yes	normal maintenance
	GANNON 2							
09/28/99	04:08	09/28/99	06:16	F000PICK CONDENSER	55	picked half of condenser	yes	normal maintenance
	GANNON 3							
09/26/99	04:55	09/27/99	03:25	F000HIGH FURN. PRESSURE	5	operate APH sootblower	yes	wash APH at next planned outage
09/27/99	03:25	09/27/99	05:40	F000HIGH FURN. PRESSURE	95	operate APH sootblower	yes	wash APH at next planned outage
09/27/99	05:40	09/27/99	23:30	F000HIGH FURN. PRESSURE	5	operate APH sootblower	yes	wash APH at next planned outage
09/27/99	23:30	09/28/99	01:15	F000PICK CONDENSER	95	picked half of condenser	yes	normal maintenance
09/28/99	01:15	09/29/99	02:20	F000HIGH FURN. PRESSURE	5	operate APH sootblower	yes	wash APH at next planned outage
09/29/99	02:20	09/29/99	04:00	F000PICK CONDENSER	95	picked half of condenser	yes	normal maintenance
09/29/99	04:00	09/30/99	02:30	F000HIGH FURN. PRESSURE	5	operate APH sootblower	yes	wash APH at next planned outage
	GANNON 4							
09/25/99	17:15	09/27/99	00:01	F000HDR. RESTRICTION BOILER TUBES	10	limit header pressure to reduce tube failures	yes	replace tubes at next major outage
09/27/99	00:01	09/27/99	00:30	F0004C COAL FEEDER BELT MAINT.	20	repaired coal feeder belt	yes	perform review of feeder maintenance
09/27/99	00:30	09/27/99	02:30	F000PICK CONDENSER	120	picked half of condenser	yes	normal maintenance
09/27/99	02:30	09/28/99	20:45	F000HEADER RESTRICTION DUE TO BOILER TUBE CONDITION	10	limit header pressure to reduce tube failures	yes	replace tubes at next major outage
09/28/99	20:45	09/28/99	23:20	F000CONDENSER DIRTY	30	schedule condenser cleaning	yes	normal maintenance
09/28/99	23:20	09/29/99	00:55	F000PICK CONDENSER	120	picked half of condenser	yes	normal maintenance
09/29/99	00:55	09/30/99	05:12	F000HEADER RESTRICTION DUE TO BOILER TUBE CONDITION	10	limit header pressure to reduce tube failures	yes	replace tubes at next major outage
	GANNON 5							
09/24/99	04:50	09/27/99	00:01	F000HIGH FURN. PRESSURE	20	operate APH sootblower	yes	wash APH at next planned outage
09/27/99	00:01	09/27/99	04:30	F000BLOW PLUGS IN CONDENSER	155	cleaned fouled condenser	yes	routine work effort
09/27/99	04:30	09/27/99	14:30	F000HIGH FURN. PRESSURE	20	operate APH sootblower	yes	wash APH at next planned outage
09/27/99	04:30	09/27/99	14:30	F000HIGH FURN. PRESSURE	20	operate APH sootblower	yes	wash APH at next planned outage

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
09/27/99	14:30	09/28/99	15:00	F000LOW BTU FUEL	45	adjusted boiler combustion systems	yes	review fuel blend
09/28/99	15:00	09/29/99	09:00	F000HIGH FURN. PRESSURE	5	operate APH sootblower	yes	wash APH at next planned outage
09/28/99	17:40	09/29/99	19:30	F000LOW BTU FUEL	15	adjusted boiler combustion systems	yes	review fuel blend
09/29/99	19:30	09/30/99	13:30	F000LOW BTU FUEL	55	adjusted boiler combustion systems	yes	review fuel blend
	GANNON 6							
09/27/99	14:30	09/27/99	16:00	F000LOW BTU FUEL	35	adjusted boiler combustion systems	yes	review fuel blend
09/27/99	16:09	09/28/99	03:41	F000LOW BTU FUEL	20	adjusted boiler combustion systems	yes	review fuel blend
	HOOKERS PT 4							
09/27/99	09:50	09/27/99	21:08	F0004A CIRCULATOR VIBRATION	13	replaced impeller	yes	caused by foreign object in intake canal
From:	10/19/99	to:	10/21/99					
	BIG BEND 1							
10/18/99	10:00	10/19/99	23:57	OPACITY	61	technicians investigated causes	yes	optimize precipitator, ash removal, boiler combustion systems
10/19/99	23:56	10/20/99	01:10	N.SIDE COND.- PICK	245	picked half of condenser	yes	normal maintenance
10/20/99	01:27	10/20/99	03:17	S.SIDE COND.- PICK	245	picked half of condenser	yes	normal maintenance
	BIG BEND 3							
10/19/99	21:45	10/20/99	05:35	"B" PAF HI VIBRATION	185	cleaned fan bearings & wheel & balanced	yes	normal maintenance & made motor adjustment
10/21/99	00:35	10/21/99	01:30	S.SIDE COND.- PICK	265	picked half of condenser	yes	normal maintenance
10/21/99	01:31	10/21/99	05:00	"B" PAF HI VIBRATION	195	cleaned fan bearings & wheel & balanced	yes	normal maintenance & made motor adjustment
	BIG BEND 4							
10/20/99	00:30	10/20/99	03:10	"C" MILL REPLACE LUBE OIL PUMP	75	replaced oil pump	yes	normal maintenance
10/20/99	16:50	10/21/99	02:25	LOW VACUUM	25	clean condenser	yes	normal maintenance
10/21/99	02:30	10/21/99	03:30	A/C COND. SECTIONS- PICK	275	picked half of condenser	yes	normal maintenance
10/21/99	03:50	10/21/99	05:00	A/C COND. SECTIONS- PICK	275	picked half of condenser	yes	normal maintenance
	GANNON 1							
10/18/99	21:00	10/19/99	05:55	BLOW PLUGS IN CONDENSER	65	cleaned fouled condenser	yes	routine work effort
10/19/99	07:30	10/19/99	10:15	PICK CONDENSER	65	picked half of condenser	yes	normal maintenance
10/19/99	14:30	10/19/99	16:00	CONDENSER DIRTY	5	schedule condenser cleaning	yes	normal maintenance
10/19/99	19:00	10/19/99	23:30	CONDENSER DIRTY	25	schedule condenser cleaning	yes	normal maintenance
10/19/99	23:30	10/20/99	06:20	PICK CONDENSER	75	picked half of condenser	yes	normal maintenance
10/20/99	10:50	10/20/99	12:40	PICK CONDENSER	75	picked half of condenser	yes	normal maintenance
10/20/99	17:30	10/20/99	18:00	CONDENSER DIRTY	10	schedule condenser cleaning	yes	normal maintenance
10/20/99	18:00	10/21/99	00:10	CONDENSER DIRTY	25	schedule condenser cleaning	yes	normal maintenance

TAMPA ELECTRIC COMPANY
DOCKET NO. 010001-EI
FIPUG'S 3RD SET OF INTERROGATORIES
INTERROGATORY NO. 36
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FILED: SEPTEMBER 27, 2001

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
10/21/99	00:10	10/21/99	03:45	CONDENSER DIRTY	35	schedule condenser cleaning	yes	normal maintenance
10/21/99	03:45	10/21/99	08:05	PICK CONDENSER	75	picked half of condenser	yes	normal maintenance
10/21/99	09:13	10/21/99	11:00	CONDENSER DIRTY	15	schedule condenser cleaning	yes	normal maintenance
10/21/99	11:00	10/21/99	13:15	PICK CONDENSER	75	picked half of condenser	yes	normal maintenance
10/21/99	16:16	10/21/99	17:00	CONDENSER DIRTY	5	schedule condenser cleaning	yes	normal maintenance
10/21/99	17:00	10/21/99	19:00	CONDENSER DIRTY	25	schedule condenser cleaning	yes	normal maintenance
10/21/99	19:00	10/21/99	22:15	CONDENSER DIRTY	35	schedule condenser cleaning	yes	normal maintenance
10/21/99	22:15	10/22/99	04:15	CONDENSER DIRTY	45	schedule condenser cleaning	yes	normal maintenance
	GANNON 2							
10/19/99	01:15	10/19/99	01:45	PICK CONDENSER	55	picked half of condenser	yes	normal maintenance
10/19/99	13:32	10/19/99	16:35	2A COAL FEEDER PROBLEMS	15	no information available		
10/19/99	16:52	10/19/99	17:45	2A COAL FEEDER PROBLEMS	15	no information available		
10/20/99	03:30	10/20/99	05:30	PICK CONDENSER	55	picked half of condenser	yes	normal maintenance
	GANNON 3							
10/19/99	00:30	10/20/99	08:00	3B COAL FEEDER BELT REPLACEMENT	25	replaced feeder belt	yes	inspect coal field reject equipment
	GANNON 6							
10/16/99	18:05	10/22/99	01:15	HDR. RESTRICTION BOILER TUBES	40	reduced header to minimize tube failure	yes	investigate replacement at next major outage
	HOOKERS PT 5							
10/19/99	10:53	10/19/99	21:54	F600REDUCED HEADER	15	limit header pressure to reduce tube failures	yes	replace tubes at next major outage
	POLK 1							
10/19/99	11:00	10/19/99	13:00	LOWERED LOAD TO SUPPORT TRANSITION TO KENTUCKY 9	10	normal occurrence	yes	normal operation
10/19/99	13:00	10/20/99	09:45	LOWERED LOAD TO TRANSTION TO KENTUCKY 9	15	normal occurrence	yes	normal operation
From:	01/23/00	to:	01/25/00					
	BIG BEND 1							
01/23/00	10:30	01/26/00	17:45	LEAK IN THE 2ND. PT. HTR.	28	repaired leak in weld at valve	yes	normal maintenance
	BIG BEND 2							
01/23/00	23:20	01/24/00	04:55	S. SIDE CONDENSER-PICK	220	picked half of condenser	yes	normal maintenance
	BIG BEND 3							
01/23/00	05:07	01/23/00	11:27	RDUCED LOAD DUE TO SUSPECTED TU	10	repaired tube leak at next outage	yes	reviewed tube failure root cause, inspected adjacent tubes
	BIG BEND 4							

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
01/25/00	07:00	01/25/00	11:08	"A" CONDENSATE PP. UNAVAILABLE-BINDING UP	65	replaced pump shaft and upper bushing	yes	reviewed pump reassembly procedure
	GANNON 3							
01/21/00	08:00	01/23/00	23:14	BEARING WENT BAD,ON SPARE EXCITER	55	repair exciter motor	yes	reviewed bearing failure root cause
01/23/00	23:14	01/24/00	01:00	PICK CONDENSER	105	picked half of condenser	yes	normal maintenance
01/24/00	01:00	01/26/00	12:16	ON SPARE EXCITER	55	repair exciter motor	yes	reviewed bearing failure root cause
	GANNON 4							
01/22/00	21:00	01/23/00	11:30	HEADER RESTRICTION DUE TO BOIL	5	reduce header to minimize tube failures	yes	maintain reduced header until repairs at planned outage
01/23/00	11:30	01/24/00	03:27	AIR RESTRICTION	15	wash air preheater at next outage	yes	inspect air preheater sootblower operation
01/24/00	03:27	01/24/00	04:05	4A CONDENSATE PUMP BREAKER WOULD'T CLOSE	100	repaired breaker	yes	review 480V breaker maintenance
01/24/00	04:05	01/25/00	09:45	HEADER RESTRICTION DUE TO BOIL	5	reduce header to minimize tube failures	yes	maintain reduced header until repairs at planned outage
01/25/00	09:45	01/25/00	17:10	HIGH OPACITY	15	clean flyash hoppers	yes	optimize precipitator, ash removal, boiler combustion systems
01/25/00	17:10	01/26/00	06:58	HIGH OPACITY	120	clean flyash hoppers	yes	optimize precipitator, ash removal, boiler combustion systems
	GANNON 5							
01/24/00	20:10	01/25/00	23:45	HEADER RESTRICTION DUE TO BOIL	40	reduce header to minimize tube failures	yes	maintain reduced header until repairs at planned outage
01/25/00	23:45	01/26/00	00:25	PICK CONDENSER	135	picked half of condenser	yes	normal maintenance
	POLK 1							
01/20/00	07:15	01/23/00	23:46	SEALING THE DOME AND SLURRY CON	5	repair dome seal at next outage	yes	review seal design for improvements
From:	07/05/00	to:	07/07/00					
	BIG BEND 1							
07/04/00	11:00	07/05/00	01:40	H.P. HTRS OUT DUE TO LEAK IN 2N	18	repaired leak	yes	inspected all tubes, plugged failed tubes with explosive plugs
07/05/00	01:41	07/05/00	04:15	A2 COAL FEEDER CLEAN OUT CONVEY	165	repaired cleanout conveyor	yes	inspect for proper operation
07/05/00	04:16	07/05/00	23:14	HP HTRS OUT- LEAK IN 2ND. PT	18	repaired leak	yes	inspected all tubes, plugged failed tubes with explosive plugs
07/05/00	23:15	07/06/00	01:08	N.SIDF COND.- PICK	270	picked half of condenser	yes	normal maintenance
07/06/00	01:30	07/06/00	03:30	S.SIDE COND.- PICK	270	picked half of condenser	yes	normal maintenance
07/06/00	03:31	07/06/00	06:42	H.P. HTRS. OUT- LEAK IN 2ND. PT.	18	repaired leak	yes	inspected all tubes, plugged failed tubes with explosive plugs
	BIG BEND 2							
07/05/00	09:00	07/06/00	02:19	LOW BTU FUEL	25	adjusted boiler combustion systems	yes	review fuel blend
07/06/00	02:20	07/06/00	03:49	A1 COAL FEEDER REPAIRS	165	repaired coal feeder	yes	perform root cause analysis
07/06/00	03:50	07/06/00	06:00	S.SIDE COND.- PICK	235	picked half of condenser	yes	normal maintenance
07/06/00	06:01	07/06/00	23:29	LOW BTU FUEL	25	adjusted boiler combustion systems	yes	review fuel blend
07/06/00	23:30	07/07/00	01:10	N.SIDE COND.- PICK	260	picked half of condenser	yes	normal maintenance

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
07/07/00	01:11	07/07/00	04:15	"A" PAF- WHEEL CLEAN	185	cleaned fan wheel & balanced	yes	normal maintenance
07/07/00	04:16	07/08/00	18:59	LOW BTU FUEL	25	adjusted boiler combustion systems	yes	review fuel blend
	BIG BEND 3							
07/04/00	21:11	07/05/00	04:15	A1 COAL FEEDER- WIRES FROM TERM	170	replaced coal feeder wires	yes	check condition of other feeder wiring
07/05/00	21:30	07/06/00	11:00	2ND PT HTR OUT TO REPLACE NORMA	40	replaced regulator valve	yes	normal maintenance
07/06/00	20:16	07/07/00	09:00	HIGH OPACITY	15	review precipitator systems	yes	optimize precipitator, ash removal, boiler combustion systems
	BIG BEND 4							
07/04/00	23:15	07/05/00	06:00	A/C COND. SECTIONS- CLEAN W/BRU	270	schedule condenser cleaning	yes	normal maintenance
07/06/00	01:10	07/06/00	06:10	B/D COND. SECTIONS- CLEAN W/BRU	270	schedule condenser cleaning	yes	normal maintenance
	GANNON 2							
07/07/00	03:00	07/07/00	05:10	PICK CONDENSER	65	picked half of condenser	yes	normal maintenance
	GANNON 3							
07/07/00	00:10	07/07/00	02:40	PICK CONDENSER	95	picked half of condenser	yes	normal maintenance
	GANNON 4							
07/04/00	23:30	07/05/00	06:10	BLOW PLUGS IN CONDENSER	115	schedule condenser cleaning	yes	normal maintenance
	GANNON 5							
07/05/00	06:15	07/06/00	14:00	REPAIR 5A PULVERIZER TRUNNION GEAR	120	realigned trunnion gear	yes	inspect bearings and review alignment requirements
	GANNON 6							
07/04/00	23:30	07/05/00	06:40	TO UNPLUG WEST END OF PULVERIZE	150	clean out pulverizer	yes	minimize wet coal condition
07/05/00	12:15	07/05/00	18:30	REPAIRING 6B1 COAL GATE	120	repaired coal gate valve	yes	normal maintenance
07/05/00	19:19	07/06/00	03:30	WEST END OF PULVERIZER PLUGGED	155	clean out pulverizer	yes	minimize wet coal condition
07/06/00	18:19	07/07/00	03:10	WEST END OF PULVERIZER PLUGGED	150	clean out pulverizer	yes	minimize wet coal condition
07/06/00	23:00	07/07/00	05:25	REPAIR PRECIPITATOR TOP HOUSE BLOWER	225	repair blower	yes	review preventive maintenance for blowers
	HOOKERS PT 5							
07/05/00	12:00	07/05/00	21:45	REDUCED HEADER	15	reduce header to minimize tube failures	yes	maintain reduced header until repairs at planned outage
07/06/00	11:48	07/06/00	21:54	REDUCED HEADER	15	reduce header to minimize tube failures	yes	maintain reduced header until repairs at planned outage
From:	07/16/00	to:	07/21/00					
	BIG BEND 1							
07/16/00	12:00	07/18/00	00:25	WET COAL	35	reviewed fuel blend	yes	review fuel deliveries vs. specifications
07/18/00	00:26	07/18/00	01:50	N.SIDE COND.- PICK	235	picked half of condenser	yes	normal maintenance
07/18/00	02:10	07/18/00	04:00	S.SIDE COND.- PICK	235	picked half of condenser	yes	normal maintenance
07/19/00	00:00	07/19/00	04:25	HIGH OPACITY	25	review precipitator systems	yes	optimize precipitator, ash removal, boiler combustion systems

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
07/19/00	04:26	07/20/00	15:00	LOW BTU FUEL	15	adjusted boiler combustion systems	yes	review fuel blend
07/21/00	09:00	07/21/00	23:14	HIGH OPACITY	36	power off rap flyash precipitator	yes	optimize precipitator, ash removal, boiler combustion systems
07/21/00	23:15	07/22/00	00:30	S.SIDE COND.- PICK	235	picked half of condenser	yes	normal maintenance
	BIG BEND 2							
07/19/00	05:56	07/19/00	08:14	LOW VACUUM, ALSO SOME AIR IN LE	85	reduce load until condenser can be cleaned	yes	normal operation
07/19/00	08:15	07/19/00	09:30	N.SIDE COND.- PICK	235	picked half of condenser	yes	normal maintenance
07/19/00	09:56	07/19/00	11:05	S.SIDE COND.- PICK	235	picked half of condenser	yes	normal maintenance
07/19/00	19:10	07/19/00	21:05	C MILL OUT FOR REPAIR TO C2 COA	165	repaired coal feeder	yes	reviewed preventive maintenance program for coal feeder
07/20/00	00:00	07/20/00	14:30	HIGH OPACITY	15	review precipitator systems	yes	optimize precipitator, ash removal, boiler combustion systems
07/20/00	19:44	07/21/00	00:00	LOW VACUUM	25	reduce load until condenser can be cleaned	yes	normal operation
07/22/00	23:55	07/23/00	01:15	"B" MILL-REPLACE GEARBOX GUARD	165	replaced coupling guard	yes	reviewed coupling guard installation and design
07/23/00	01:16	07/23/00	23:24	WET/LOW BTU FUEL	10	adjusted boiler combustion systems	yes	review fuel blend
07/23/00	23:25	07/24/00	02:35	N.SIDE COND PICK	265	picked half of condenser	yes	normal maintenance
07/24/00	03:00	07/24/00	04:25	S.SIDE COND PICK	265	picked half of condenser	yes	normal maintenance
07/24/00	04:26	07/24/00	05:00	"B" MILL-COAL LEAKS	165	patched coal leak temporarily	yes	performed permanent repair during next unit outage
07/24/00	05:01	07/24/00	10:29	WET/LOW BTU FUEL	10	adjusted boiler combustion systems	yes	review fuel blend
07/24/00	23:30	07/25/00	04:40	"C" MILL-C2 FEEDER CLEANOUT CON	155	repaired cleanout conveyor	yes	inspect for proper operation
07/21/00	00:01	07/21/00	01:42	N.SIDE COND.- PICK	255	picked half of condenser	yes	normal maintenance
07/21/00	01:56	07/21/00	03:50	S.SIDE COND.- PICK	255	picked half of condenser	yes	normal maintenance
07/21/00	03:51	07/21/00	08:53	C MILL- COAL LEAK REPAIR	175	repaired leak	yes	inspect for repair/replace at planned outage
07/21/00	09:50	07/21/00	13:10	C MILL OUT DUE TO PLUGGAGE ON WEST END	135	clean out mill	yes	minimize wet coal flow to mill
07/21/00	14:30	07/21/00	21:00	HIGH GENERATOR AND OIL TEMPS- HIGH COOLING WTR TEMP	35	reduce load	yes	clean coolers at next planned outage
07/21/00	22:00	07/22/00	23:54	WET/LOW BTU FUEL	10	adjusted boiler combustion systems	yes	review fuel blend
	BIG BEND 3							
07/18/00	16:00	07/19/00	05:30	REDUCED HEADER DUE TO DRUM SAFE	35	reset safety valve setting after repair	yes	normal maintenance
07/19/00	19:00	07/20/00	11:34	REDUCED HEADER DUE TO DRUM SAFE	10	reset safety valve setting after repair	yes	normal maintenance
07/20/00	11:35	07/21/00	00:00	MAX. SUPERHEAT DIFF. PRESSURE	60	operate sootblowers to clean superheater	yes	reviewed sootblower operation
07/21/00	00:01	07/21/00	06:10	LOW LOAD FOR BOILER DESLAGGING	295	normal maintenance	yes	normal operation
	BIG BEND 4							
07/18/00	12:05	07/19/00	00:04	LOW VACUUM	20	reduce load until condenser can be cleaned	yes	normal operation

TAMPA ELECTRIC COMPANY
DOCKET NO. 010001-EI
FIPUG'S 3RD SET OF INTERROGATORIES
INTERROGATORY NO. 36
PAGE 26 OF 28
FILED: SEPTEMBER 27, 2001

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
07/19/00	00:04	07/19/00	05:55	A/C COND. SECTIONS- CLEAN W/BRU	280	schedule condenser cleaning	yes	normal maintenance
07/20/00	00:15	07/20/00	05:36	S/D COND. SECTIONS- CLEAN W/BRU	270	schedule condenser cleaning	yes	normal maintenance
	GANNON 1							
07/17/00	19:00	07/18/00	09:30	REPLACE 1C COAL FEEDER DRAG CHA	55	replaced drag chain	yes	expected maintenance - reviewed maintenance schedule
07/17/00	22:30	07/18/00	02:30	PICK CONDENSER	80	picked half of condenser	yes	normal maintenance
07/18/00	15:15	07/19/00	04:10	DIRTY CONDENSER (LOW VACUUM)	20	reduce load until condenser can be cleaned	yes	normal operation
07/19/00	04:10	07/19/00	08:00	PICK CONDENSER	80	picked half of condenser	yes	normal maintenance
07/20/00	03:10	07/20/00	04:50	PICK CONDENSER	80	picked half of condenser	yes	normal maintenance
07/21/00	03:00	07/21/00	05:10	PICK CONDENSER	80	picked half of condenser	yes	normal maintenance
	GANNON 2							
07/18/00	01:15	07/18/00	03:35	PICK CONDENSER	75	picked half of condenser	yes	normal maintenance
07/21/00	09:04	07/21/00	13:58	SLAG TANK BUILD UP	65	removed cyclone from service	yes	see below
	GANNON 3							
07/19/00	03:40	07/19/00	05:58	PICK CONDENSER	95	picked half of condenser	yes	normal maintenance
07/19/00	23:45	07/20/00	01:45	PICK CONDENSER	95	picked half of condenser	yes	normal maintenance
	GANNON 5							
07/21/00	23:45	07/22/00	00:30	PICK CONDENSER	165	picked half of condenser	yes	normal maintenance
	GANNON 6							
07/18/00	18:30	07/18/00	22:47	LOW BTU COAL	15	reviewed fuel blend	yes	review fuel deliveries vs. specifications
From:	10/04/00	to:	10/06/00					
	BIG BEND 1							
10/03/00	11:07	10/04/00	00:45	LOW STEAM TEMPS	20	continued start up until boiler slagged up	yes	normal event following unit startup
10/04/00	04:03	10/04/00	07:48	LOW STEAM TEMPS	20	continued start up until boiler slagged up	yes	normal event following unit startup
10/06/00	02:56	10/07/00	07:39	LOW STEAM TEMPS	20	continued start up until boiler slagged up	yes	normal event following unit startup
	BIG BEND 2							
10/03/00	23:00	10/04/00	04:55	N.SIDE COND CLEANED W/BRUSHES	225	cleaned half of condenser	yes	normal maintenance
10/04/00	04:56	10/04/00	23:19	FURN PRESS	55	operate at max furnace pressure & operate APH sootblowers	yes	washed APH baskets
10/04/00	23:20	10/05/00	01:45	S.SIDE COND PICK	265	picked half of condenser	yes	normal maintenance
10/05/00	02:00	10/05/00	04:48	N.SIDE COND PICK	265	picked half of condenser	yes	normal maintenance
10/05/00	04:49	10/05/00	23:24	FURN PRESS	55	operate at max furnace pressure & operate APH sootblowers	yes	washed APH baskets
10/05/00	23:25	10/06/00	04:20	S.SIDE COND CLEANED W/BRUSHES	245	cleaned half of condenser	yes	normal maintenance

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
10/06/00	04:21	10/06/00	23:46	FURN PRESS	55	operate at max furnace pressure & operate APH sootblowers	yes	washed APH baskets
10/06/00	23:47	10/07/00	05:35	N.SIDE COND CLEANED W/BRUSHES	245	cleaned half of condenser	yes	normal maintenance
	BIG BEND 3							
09/30/00	09:01	10/06/00	11:09	2ND. PT. HTR. OUT	45	isolated heater from service, operated at max load with heater out	yes	repaired leaking tubes next planned outage
10/06/00	11:10	10/06/00	14:58	"B" MILL-REPAIR B1 FEEDER	180	repaired feeder	yes	preventative maintenance
10/06/00	14:51	10/06/00	00:26	MAX AIR FLOW-"B" FAN LOW SPEED ONLY	55	operated at max air flow with fan in low speed	yes	reshimmed the motor feet
	BIG BEND 4							
10/02/00	05:28	10/05/00	00:39	"C" BOILER CIRC PP MOTOR HIGH TEMP	43			
10/05/00	04:51	10/07/00	16:14	"C" BOILER CIRC PUMP UNAVAILABLE	75	ran at max load with 3 circ pumps until cooler repaired	yes	sent pump to shop for repair next planned outage
	GANNON 1							
10/05/00	17:45	10/05/00	20:00	DIRTY CONDENSER (LOW VACUUM)	40	cleaned half of condenser	yes	normal maintenance
10/05/00	20:00	10/05/00	22:40	DIRTY CONDENSER (LOW VACUUM)	20	cleaned half of condenser	yes	normal maintenance
10/05/00	23:00	10/06/00	01:45	PICK CONDENSER	80	cleaned half of condenser	yes	normal maintenance
	GANNON 3							
10/04/00	02:05	10/04/00	04:45	PICK CONDENSER	105	picked half of condenser	yes	normal maintenance
10/06/00	06:40	10/06/00	07:55	3A B.F.P. WOULDN'T START (ELEC. SHOP)	85	check electrical circuit	yes	replaced circuit breaker
10/06/00	10:00	10/06/00	12:50	DIRTY CONDENSER (LOW VACUUM)	20	cleaned half of condenser	yes	normal maintenance
10/06/00	12:50	10/06/00	14:05	DIRTY CONDENSER (LOW VACUUM)	25	cleaned half of condenser	yes	normal maintenance
10/06/00	14:05	10/06/00	23:30	PICK CONDENSER DIRTY CONDENSER (LOW VACUUM)	65	cleaned half of condenser	yes	normal maintenance
10/06/00	23:30	10/07/00	03:30	PICK CONDENSER	105	cleaned half of condenser	yes	normal maintenance
	GANNON 4							
10/06/00	03:00	10/06/00	04:45	PICK CONDENSER	120	cleaned half of condenser	yes	normal maintenance
10/06/00	21:00	10/18/00	06:45	4B B.F.P. MOTOR WENT TO GROUND (FIRE WATER)	70	reapaired leaking fire water line	no	repaired motor
	GANNON 5							
10/06/00	09:20	10/06/00	13:40	I-BEAM LAYING ACROSS COOLING TOWER FANS	150	jib crane fell off mount, removed from tower	no	repaired crane & mounts
	HOOKERS PT 2							
10/04/00	08:28	10/04/00	14:17	GAS DUCT LEAKS	17	patched hot spots on #5 boiler	yes	repair duct work during planned outage
10/05/00	11:06	10/05/00	21:37	GAS DUCT LEAK	17	patched hot spots on #5 boiler	yes	repair duct work during planned outage
10/06/00	10:45	10/06/00	21:42	GAS DUCT LEAKS	22	patched hot spots on #5 boiler	yes	repair duct work during planned outage
	HOOKERS PT 3							
10/04/00	07:49	10/04/00	14:09	GAS DUCT LEAKS	17	patched hot spots on #5 boiler	yes	repair duct work during planned outage

Start Date	Start Time	End Date	End Time	Reason	Gross Derated MW	Remedy	Occurred Previously On Another Unit	Action Taken to Prevent Recurrence
10/05/00	10:25	10/05/00	21:35	GAS DUCT LEAK	17	patched hot spots on #5 boiler	yes	repair duct work during planned outage
10/06/00	08:15	10/06/00	21:34	GAS DUCT LEAKS	22	patched hot spots on #5 boiler	yes	repair duct work during planned outage
From:	04/02/01	to:	04/04/01					
	BIG BEND 2							
04/02/01	00:25	04/02/01	04:00	"B" MILL-COAL LEAK REPAIRS	165	patched coal pipe elbow	yes	replace coal pipe elbow at next outage
04/03/01	10:30	04/06/01	01:25	OPACITY	35	inspect/clean hoppers & electrical system	yes	optimize precipitator, ash removal, boiler combustion systems
	BIG BEND 3							
03/31/01	20:01	04/03/01	17:29	MAX BOOSTER FAN CAPACITY	50	replaced motor on failed booster fan	yes	rewound motor stator winding
04/03/01	17:30	04/04/01	03:00	OPACITY	110	inspect/clean hoppers with vacuum truck	yes	optimize precipitator, ash removal, boiler combustion systems
04/04/01	09:30	04/06/01	23:35	MAX BOOSTER FAN CAPACITY	50	replaced motor on failed booster fan	yes	rewound motor stator winding
	GANNON 1							
04/04/01	00:25	04/04/01	03:10	PICK CONDENSER	80	picked half of condenser	yes	normal maintenance
	GANNON 2							
04/02/01	18:47	04/02/01	19:50	BAD BUILD UP IN SLAG TANK	65	reduced load to clear slag tank buildup	yes	review coal blend and flux material
	GANNON 3							
04/01/01	23:15	04/02/01	04:45	PICK CONDENSER	95	picked half of condenser	yes	normal maintenance
04/02/01	15:10	04/02/01	16:10	BAD BUILD UP IN SLAG TANKS	95	reduced load to clear slag tank buildup	yes	review coal blend and flux material
04/03/01	15:15	04/03/01	21:25	BAD BUILD UP IN SLAG TANKS	90	reduced load to clear slag tank buildup	yes	review coal blend and flux material
	GANNON 5							
04/01/01	21:20	04/02/01	09:55	INBOARD BEARING FAILURE	160	replaced pulverizer gear reducer bearing	yes	reviewed oil analysis reports/ performed root cause analysis
04/03/01	12:40	04/03/01	17:00	HEADER RESTRICTION DUE TO BOIL	135	reduced load until water chemistry improved	yes	normal process after unit startup

Note: Polk 1 data available beginning in May 1999. Polk 2 began operation in June 2000.

Tampa Electric Company

Calculation of Wholesale Subsidy for 1999-2001

Line	Description	1999-2001 MWh	1999-2001 Subsidy $/MWh	Total Subsidy $
	(1)	(2)	(3)	(4)
1	Total Separated Sales	1,447,532	$31.18	$45,130,500
2	Total Wholesale Sales	3,477,443	$31.18	$108,418,151

Sources: Monthly Schedules A-1's, January through December 1999
Monthly Schedules A-1's, January through December 2000
J. Denise Jordan Testimony, Actual/Estimated True-up,
January 2001 through December 2001, Sch. E6

Tampa Electric Company

Equivalent Forced Outage Rates (EFOR)

Line	Unit	Generator Maximum Nameplate (MW)	EFOR NERC GADS 1995-1999	Historical Actual EFOR						
				1995	1996	1997	1998	1999	2000	2001
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Big Bend 1	445.5	8.18%	7.10%	11.80%	9.00%	11.40%	11.80%	12.60%	14.60%
2	Big Bend 2	445.5	8.18%	10.50%	7.80%	9.10%	10.60%	10.20%	7.70%	16.30%
3	Big Bend 3	445.5	8.18%	13.20%	10.60%	11.70%	16.20%	19.50%	11.50%	15.00%
4	Big Bend 4	486.0	8.18%	5.00%	3.50%	5.20%	8.00%	8.60%	7.50%	3.20%
5	Gannon 1	125.0	6.41%	2.50%	9.90%	20.00%	16.80%	9.30%	12.60%	14.50%
6	Gannon 2	125.0	6.41%	13.50%	25.40%	14.70%	25.10%	4.30%	20.90%	26.10%
7	Gannon 3	179.5	6.41%	4.60%	22.60%	8.40%	12.10%	9.80%	8.10%	23.40%
8	Gannon 4	187.5	6.41%	2.00%	14.40%	18.10%	15.10%	22.70%	10.50%	34.00%
9	Gannon 5	239.4	6.38%	7.50%	13.50%	23.50%	15.50%	17.30%	33.00%	35.70%
10	Gannon 6	445.0	8.18%	5.00%	5.10%	14.50%	18.80%	19.50%	62.50%	14.50%

Sources: TECO Response to FIPUG's 3rd Set of Interrogatories, Interrogatory No. 34
NERC Generating Unit Statistical Brochure, 1995-1999, October 2000, Generating Availability Data System
TECO 10-Year Site Plan, January 2000 to December 2009

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Witness: Brian C. Collins
Exhibit ___ (BCC-14)
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Tampa Electric Company

Equivalent Availability Factors

Line	Unit	Generator Maximum Nameplate (MW)	Actual EAF 2000	NERC GADS Data 1995-1999
	(1)	(2)	(3)	(4)
1	Big Bend 1	445.5	75.80%	81.49%
2	Big Bend 2	445.5	85.60%	81.49%
3	Big Bend 3	445.5	75.00%	81.49%
4	Big Bend 4	486	87.80%	81.49%
5	Gannon 5	239	55.60%	84.52%
6	Gannon 6	445	33.20%	81.49%

Sources: TECO Original Sheet No. 8.461.00A, Page 6 of 28 in Testimony of Brian Buckley
NERC Generating Unit Statistical Brochure, 1995-1999, October 2000, Generating Availability Data System

Tampa Electric Company

Purchased Power on Selected Days

Line	Date	Purchased Energy (MWh)	Purchased Power Cost ($)	Purchased Power Cost ($/MWh)
	(1)	(2)	(3)	(4)
1	January 6, 1999	[redacted]	[redacted]	[redacted]
2	April 3, 1999			
3	April 5, 1999			
4	April 6, 1999			
5	April 15, 1999			
6	April 23, 1999			
7	April 24, 1999			
8	April 26, 1999			
9	May 6, 1999			
11	July 29, 1999			
12	July 30, 1999			
13	July 31, 1999			
14	August 2, 1999			
10	September 4, 1999			
15	September 28, 1999			
16	October 20, 1999			
17	January 24, 2000			
18	July 6, 2000			
19	July 19, 2000			
20	July 20, 2000			
21	October 5, 2000			

Sources: TECO Response to FIPUG's 3rd Set of Interrogatories, Interrogatory Nos. 43 and 51

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 7
COMPANY/ WITNESS. Collins
DATE: 10-20 & 21-01

Tampa Electric Company

Calculation of Subsidy to Wholesale Customers for 1999-2001

Line	Date	Hour Ending	Retail Fuel Cost $/MWh	Retail Fuel Cost $	Wholesale Fuel Cost $	Purchased Power Expense $	Total System Fuel & Purchased Power $	Wholesale Load MW	Firm Retail Load MW	Non-Firm Retail Load MW	Total Load MW	Wholesale Share of Feul and Purchased Power Expense $	Subsidy $
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	1/6/99	8	20.40	60,404	2,085			128	2,944	17	3,089		
2	4/3/99	15	20.87	44,453	4,289			235	2,013	117	2,365		
3		16	20.87	45,643	4,544			249	2,090	97	2,436		
4		17	20.87	45,914	4,581			251	2,083	117	2,451		
5	4/5/99	18	20.87	48,168	4,836			265	2,273	35	2,573		
6		19	20.87	46,624	4,563			250	2,230	4	2,484		
4	4/6/99	15	20.87	47,417	4,782			262	2,179	93	2,534		
8		16	20.87	48,147	4,818			264	2,244	63	2,571		
9		17	20.87	49,963	4,836			265	2,332	62	2,659		
10		18	20.87	50,171	4,836			265	2,340	64	2,669		
11	4/15/99	18	20.87	47,730	4,800			263	2,149	138	2,550		
12	4/23/99	15	20.87	47,312	4,855			266	2,236	31	2,533		
13		16	20.87	49,274	4,855			266	2,359	2	2,627		
14		17	20.87	50,610	4,855			266	2,422	3	2,691		
15		18	20.87	49,879	4,836			265	2,388	2	2,655		
16		19	20.87	47,709	4,818			264	2,285	1	2,550		
17		20	20.87	44,954	4,818			264	2,152	2	2,418		
18		21	20.87	44,704	4,818			264	2,128	14	2,406		

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Tampa Electric Company

Calculation of Subsidy to Wholesale Customers for 1999-2001

Line	Date	Hour Ending	Retail Fuel Cost $/MWh	Retail Fuel Cost $	Wholesale Fuel Cost $	Purchased Power Expense $	Total System Fuel & Purchased Power $	Wholesale Load MW	Firm Retail Load MW	Non-Firm Retail Load MW	Total Load MW	Wholesale Share of Feul and Purchased Power Expense $	Subsidy $
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
19	4/24/99	13	20.87	43,326	4,782			262	2,004	72	2,338		
20		14	20.87	43,848	4,544			249	2,100	1	2,350		
21		15	20.87	46,144	4,544			249	2,210	1	2,460		
22		16	20.87	47,918	4,544			249	2,296	0	2,545		
23		17	20.87	49,065	4,563			250	2,351	0	2,601		
24		18	20.87	48,043	4,563			250	2,302	0	2,552		
25		19	20.87	46,269	4,563			250	2,217	0	2,467		
26		20	20.87	43,931	4,544			249	2,095	10	2,354		
27	4/26/99	16	20.87	53,824	4,873			267	2,552	27	2,846		
28		17	20.87	54,450	4,873			267	2,608	1	2,876		
29		18	20.87	53,198	4,873			267	2,549	0	2,816		
30	5/6/99	17	20.58	54,969	5,025			267	2,566	105	2,938		
31		18	20.58	54,516	5,025			267	2,555	94	2,916		
32	7/29/99	14	21.23	60,314	5,991			315	2,783	58	3,156		
33		15	21.23	60,866	5,991			315	2,818	49	3,182		
34		16	21.23	61,822	5,991			315	2,867	45	3,227		
35		17	21.23	61,418	6,010			316	2,860	33	3,209		
36		18	21.23	61,588	6,010			316	2,869	32	3,217		
37		19	21.23	59,784	5,991			315	2,787	29	3,131		
38		20	21.23	59,593	5,972			314	2,724	83	3,121		

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Witness: Brian C. Collins
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Tampa Electric Company

Calculation of Subsidy to Wholesale Customers for 1999-2001

Line	Date	Hour Ending	Retail Fuel Cost $/MWh	Retail Fuel Cost $	Wholesale Fuel Cost $	Purchased Power Expense $	Total System Fuel & Purchased Power $	Wholesale Load MW	Firm Retail Load MW	Non-Firm Retail Load MW	Total Load MW	Wholesale Share of Feul and Purchased Power Expense $	Subsidy $
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
39	7/30/99	17	21.23	57,639	5,972			314	2,660	55	3,029		
40		18	21.23	58,383	5,972			314	2,684	66	3,064		
41		19	21.23	55,899	5,953			313	2,602	31	2,946		
42	7/31/99	16	21.23	62,416	5,991			315	2,770	170	3,255		
43		17	21.23	54,476	5,991			315	2,559	7	2,881		
44		18	21.23	53,266	5,991			315	2,482	27	2,824		
45	8/2/99	15	21.29	64,125	7,072			332	2,921	91	3,344		
46		16	21.29	63,274	7,072			332	2,967	5	3,304		
47	9/4/99	16	21.48	58,941	6,031			265	2,567	177	3,009		
48		17	21.48	59,457	6,031			265	2,608	160	3,033		
49		18	21.48	58,812	6,031			265	2,566	172	3,003		
50		19	21.48	57,395	6,031			265	2,495	177	2,937		
51	9/28/99	16	21.48	60,488	6,077			267	2,656	160	3,083		
52		17	21.48	60,187	6,077			267	2,694	108	3,069		
53	10/20/99	16	21.98	54,510	5,402			266	2,470	10	2,746		
54		17	21.98	54,488	5,402			266	2,476	3	2,745		
55	1/24/00	12	20.72	35,846	3,850			161	1,559	171	1,891		
56	7/6/00	17	21.96	65,221	18,888			761	2,927	43	3,731		

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Tampa Electric Company

Calculation of Subsidy to Wholesale Customers for 1999-2001

Line	Date	Hour Ending	Retail Fuel Cost $/MWh	Retail Fuel Cost $	Wholesale Fuel Cost $	Purchased Power Expense $	Total System Fuel & Purchased Power $	Wholesale Load MW	Firm Retail Load MW	Non-Firm Retail Load MW	Total Load MW	Wholesale Share of Feul and Purchased Power Expense $	Subsidy $
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
57	7/19/00	17	21.96	69,306	11,566			466	3,100	56	3,622		
58	7/20/00	14	21.96	66,495	11,541			465	2,902	126	3,493		
59		15	21.96	68,559	11,566			466	3,098	24	3,588		
60		16	21.96	66,846	11,591			467	3,040	4	3,511		
61		17	21.96	66,385	11,591			467	3,021	2	3,490		
62	10/5/00	17	21.20	61,247	10,211			450	2,875	14	3,339		
63		18	21.20	60,229	10,188			449	2,836	5	3,290		
64	**Total**							18,929 MWh					$590,160

$/MWh Subsidy = (Total Subsidy $ / Total Wholesale MWh Sold) $31.18 per MWh

Sources: Monthly Schedules A-1's, January through December 1999
Monthly Schedules A-1's, January through December 2000
TECO Response to FIPUG's 1st Set of Interrogatories, Interrogatory No. 11
TECO Confidential Response to FIPUG's 3rd Set of Interrogatories, Interrogatory No. 43; No. 51

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Witness: Brian C. Collins
Exhibit _____ (BCC-12)
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Tampa Electric Company

Comparison of Power Bought to Serve FMPA Contract
Versus Price of Power Bought for Retail Customers

Line	Date	Price for Power Bought to Serve FMPA ($/MWh)	Maximum Market Price Paid for Power to Serve Retail ($/MWh)
	(1)	(2)	(3)
1	January 6, 1999	[redacted]	[redacted]
2	August 2, 1999		

Source: TECO Response to FIPUG's 3rd Set of Interrogatories, Interrogatory No. 51

29. Referring to Tampa Electric Company's response to Interrogatory No. 14 of FIPUG's First Set of Interrogatories, please provide the following information for each firm wholesale sale listed:

a. Contract term, beginning date and ending date;

b. Contract capacity;

c. Type of wholesale sale (e.g., unit power sale, system sale, etc.); and

d. A statement that describes how the fuel costs of these sales were treated (as described in TECO's response to Interrogatory No. 6).

A.

	a.		b.	c.
Customer	Term of Sale Beginning	Term of Sale Ending	Contract Capacity Amount (MW)	Type of Sale
City of Fort Meade	03/25/1993	12/31/1998	5 - 15	Station Sale
City of Wauchula	06/01/1992	12/31/1998	5 - 15	Station Sale
Reedy Creek Improvement District	01/01/1992	12/31/1999	15 - 20	Station Sale
Florida Municipal Power Agency	12/16/1996	03/15/2001	85 - 150	Unit Power Sale
TECO Power Services	01/01/1993	12/31/2002	145	Unit Power Sale
Reedy Creek Improvement District	01/01/1998	10/01/1998	15	Unit Power Sale
Reedy Creek Improvement District	01/01/1998	12/31/2017	75	System Sale-PR Contract
Florida Power Corporation	10/01/1993	02/28/2011	50 - 60	System Sale-PR
City of Fort Meade	01/01/1997	12/31/2013	Load following	System Sale-PR
City of St. Cloud	01/01/1997	12/31/2012	10 - 15	System Sale-PR
City of Wauchula	01/01/1997	12/31/2013	Load following	System Sale-PR

d. The fuel cost for each of the sales listed in the top half of the table above is recovered from each respective customer per the contract. Both the fuel revenue and fuel expense associated with the aforementioned sales are flowed through the fuel cost recovery clause or netted, resulting in no impact to retail ratepayers.

The Reedy Creek Improvement District contract sale and the four partial requirements service sales shown in the lower portion of the table above are governed by a FERC-approved contract or by Tampa Electric's AR-1 tariff and are subject to annual true-up mechanisms. After the initial one-year period, any fuel deficiency (surplus) is rolled over to the subsequent cost recovery period and collected (refunded) with interest.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 8
COMPANY/ WITNESS: Tampa Electric Company
DATE: 11-20-21-01

30. Please state whether there are any additional firm wholesale contracts that will become effective in 2002. For each additional firm wholesale sale listed, please provide the same information as requested in Interrogatory No. 29.

A. At this time, there are no additional firm wholesale sales contracts that will become effective in 2002.

Docket No. 010001-EI
Witness: Jeffry Pollock
Exhibit ____ (JP-1)

Tampa Electric Company

History of Service Interruptions
1996 - September 2001

Line	Year	Number of Interruptions	Duration (Hours)
1	1996	3	1
2	1997	2	0.5
3	1998	4	11
4	1999	16	53
5	2000	5	8.7
6	2001*	1	0

*January-September

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 9
COMPANY/ WITNESS. Pollock
DATE: 11-20-01

Docket No. 010001-EI
Witness: Jeffry Pollock
Exhibit ____ (JP-2)

Tampa Electric Company

History of Economic Interruptions
1996 - May 2001

Line	Year	Energy Purchased for Interruptible Customers in Lieu of Interruption (MWh) (1)	TECO Cost Incurred for Optional Provision Purchases (2)	Average Cost (¢/kWh) (3)
1	1996	16,427	$856,112	5.2 ¢
2	1997	94,208	$5,179,376	5.5 ¢
3	1998	96,460	$6,726,436	7.0 ¢
4	1999	185,922	$17,472,803	9.4 ¢
5	2000	221,217	$18,570,077	8.4 ¢
6	2001*	39,425	$4,640,796	11.8 ¢

*January-May

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re:	)	
	)	
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE AND GENERATING PERFORMANCE INCENTIVE FACTOR	)	Docket No. 010001-EI

ORIGINAL

TELEPHONE DEPOSITION OF JEFFRY POLLOCK

Taken on behalf of Tampa Electric Company
November 1, 2001

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 10
COMPANY/ WITNESS. Pollock
DATE: 11-20-01

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re:	)	
	)	
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE AND GENERATING PERFORMANCE INCENTIVE FACTOR	)	Docket No. 010001-EI

TELEPHONE DEPOSITION OF JEFFRY POLLOCK, produced, sworn, and examined on behalf of Tampa Electric Company on November 1, 2001, between the hours of eight o'clock in the forenoon and six o'clock in the afternoon of that day at the offices of Brubaker & Associates, 1215 Fern Ridge Parkway, St. Louis, Missouri, before JANINA A. JAEGER, a Registered Professional Reporter and a Notary Public within and for the State of Missouri.

A P P E A R A N C E S

Tampa Electric Company was represented by James D. Beasley, Attorney at Law, of the firm of Ausley & McMullen, 227 South Calhoun Street, Tallahassee, Florida 32301.

The Florida Industrial Power Users Group was represented by John W. McWhirter, Jr., Attorney at Law, of the firm of McWhirter Reeves, 117 South Gadsden Street, Tallahassee, Florida, 32301.

JEFFRY POLLOCK,

being produced, sworn and examined on behalf of Tampa Electric Company, deposes and says:

MR. BEASLEY: First of all, I would like to start out by, instead of reading, maybe just incorporating by reference the agreement that we, that I read into the deposition of Mr. Collins.

Mr. McWhirter, are you comfortable with that same agreement applying here regarding confidential information?

MR. McWHIRTER: Yes.

MR. BEASLEY: Okay.

DIRECT EXAMINATION

QUESTIONS BY MR. BEASLEY:

Q. Mr. Pollock, would you please state your name and address?

A. Jeffry Pollock. Business address is 1215 Fern Ridge Parkway, St. Louis, Missouri 63141.

Q. Are you the same Jeffry Pollock who filed testimony in this proceeding?

A. Yes.

Q. Would I be correct in saying that you have been deposed on numerous occasions in numerous proceedings?

A. Yes.

Q. And that you're fully comfortable and knowledgeable about the deposition process?

A. As comfortable as one can get, yes.

Q. Good. Good.

Did you bring any documents with you to your deposition?

A. I have brought just my testimony and exhibits, Mr. Collins' testimony and exhibits, and Mr. Collins.

Q. Are they the confidential versions of the testimony and the exhibits?

A. I don't believe any of my testimony is confidential. I think its all nonconfidential.

Q. Do you have anything that hasn't been filed before the Public Service Commission with you in this case?

A. Anything besides my direct testimony and exhibits?

Q. Right.

A. No.

Q. Does your testimony have any handwritten comments, margin notes, or the like on it?

A. No.

Q. Do you have the confidential or the redacted version of Mr. Collins' testimony and exhibits?

A. I have the redacted version.

Q. Is there anything written on that set of documents?

A. No.

Q. When were you contacted and asked to participate in this proceeding?

A. We opened up the project on this in late February of this year, and were asked to at that point to commence an analysis.

Q. Of what?

A. Basically the concerns that were raised to me were that the frequency and duration of physical and economic interruptions to nonfirm loads had increased greatly. There were concerns from a number of clients about that situation, and they requested that we take a look at the situation and try to determine the causes of the increase.

Q. When you say economic disruptions, what are you referring to?

A. I'm sorry. I meant to say economic interruptions, meaning instances when under the interruptible tariffs the customers would basically buy-through under the optional purchase provision.

Q. It's not an interruption of electric service, is it?

A. No. But the other issue was the service interruption, actual interruptions where there was not service provided to nonfirm customers had also grown or increased in frequency.

Q. When did you set about to address the matters that you were engaged to address in late February of this year?

A. As I said, the project was opened up. I really don't recall the specific times. I know that I was involved in drafting an initial set of interrogatories and production of document request sometime in the spring. I think that there were a couple of rounds that I worked on in that regard before Mr. Collins came into the picture and when we hired him in June.

Q. Did you decide what to ask for in those interrogatories and request for production of documents, or did someone suggest to you what you should be asking for?

A. Pretty much. Many of the questions were ones that I wanted to see the answers to in order to understand what was going on. That is not to say that our attorneys didn't also suggest particular questions in that process. It was something of a collaborative process in trying to get some initial discovery in play, and then pretty much to us to follow up once we got did responses.

Q. When did you develop the plan to determine a subsidy, as that term is used in Mr. Collins' testimony and exhibits, and in your own?

A. Well, that was pretty far down the road when we got to that point. I mean we were just trying to figure out what was going on in the way of why the nonfirm customers being, having to buy through interruptions and why were the buy-through costs as high as they were, and the physical interruptions, as I mentioned before, and also I think the concern generally about just the overall level of TECO's fuel adjustment factor for retail customers, and at that point we had no real preconceived idea that there was any kind of subsidy going on, but, as you know from our past work with Tampa Electric, we have observed differences in cost between retail and wholesale customers in the way of fuel and purchased power, so we naturally wanted to know more about why those differences existed and what was the explanation for those differences.

Q. Is it your interpretation that interruptible customers are required to purchase buy-through or optional provision power?

A. It's my understanding that that provision has changed somewhat over time. I think -- I'll say in not so recent times I think the election was pretty automatic. I

think more recently the company and the customers, it's my understanding have come to an understanding that they can now choose whether to buy through or not.

Q. Hasn't it always been an option for the interruptible customer to take buy-through power as opposed to being interrupted?

A. That's the way it's stated in the tariff, optional purchased provision. I think though that most of the customers elected always to buy through because really until recent times, the buy-through price, although higher than, obviously higher than what they were paying for electricity from TECO, it was not the magnitude that we began to see in the late '90's, '98 and '99 time frame, and it's only when those wholesale prices really shot up and those buy-through costs became a very significant component of their electricity bill were there concerns raised about always having to buy through, and there might even be times when it would be better not to.

Q. What familiarity do you have with the change between the tariff language and the practice that I think you referred to between Tampa Electric and its interruptible customers of late?

A. What familiarity. It's just an understanding based upon conversation I have had with, you know, one of the clients and our attorneys.

Q. Uh-huh. And how many, which client was that, by the way?

A. That would be IMC Agrico.

Q. Are you aware of any of Tampa Electric's interruptible customers electing not to buy-through power at any time in the recent past?

A. I don't have any specific knowledge of that, no.

Q. You don't know of any that did, in other words?

A. When you say did, either chose not to purchase or chose to always purchase?

Q. Right.

A. No. My assumption was, and my working knowledge was that until the recent times all of the customers chose to buy-through, but that had changed.

Q. How did it change?

A. Well, as I said before, it changed because prices got real high, the frequency and duration of the optional provision purchases rose dramatically, and so on.

Q. And since that change, are you familiar with any interruptible customers of Tampa Electric who have opted not to take buy-through power?

A. Not specifically, no.

Q. Do you know whether any have elected not to

take it?

A. I don't know.

Q. Okay. Were you given any kind of verbal or written description of the subject matter you were asked to address in this docket?

A. No. Pretty much what I have told you in terms of why we started the project and what our objectives were, and what we were responding to was pretty much the extent of the verbal instruction.

Q. Were you informed back in late February of when the hearing would take place in this proceeding, and by that I mean the hearing now scheduled for November, 2001?

A. I'm not sure if I knew quite all of those details. I did know that the hearings were later in the year. Actually my recollection, and Mr. Collins corrected me, was the hearing in November or December, and that that was my recollection.

Q. Do you recall when the first batch of discovery requests that you worked on were sent to Tampa Electric?

A. Not as to specific day, I don't, but I think generally I think we started promulgating discovery, I want to say in March sometime. When the actual discovery was filed, I just don't recall, but we started the process

off shortly after we were engaged to do the analysis.

Q. Do you know how many months over which FIPUG's discovery requests of Tampa Electric have been spread in this proceeding in advance of the November hearing?

A. Well, we started in March and we have had discovery responses received as early, or as late as, well, yesterday, in one case. That is quite an appreciable period of time.

Q. When have you sent discovery requests to Tampa Electric? On how many occasions have you sent discovery to Tampa Electric over the period of time from March until the present?

A. I don't recall. I think we are up to six or seven sets of interrogatories, you know, and maybe a few lesser production od document requests, but normally what we do is we submit the interrogatories and the production of document request. Obviously that takes 30 days or more to get the responses back.

We quickly looked at the responses and, as soon as we could, and then getting that the responses were incomplete, redacted, or just not provided, then we would provide for follow-up interrogatories and production of document requests.

Q. When you say incomplete or redacted, are you

aware of whether any objections were filed to discovery?

A. I know that there has been -- there has been more, I'll say more than a typical amount of objections concerning confidentiality of data and so on.

Q. Do you know, Mr. Pollock, whether the commission has granted any of Tampa Electric's requests for confidential classification of documents that were requested by FIPUG in this proceedings?

A. I'm aware that some of the documents have been so classified, yes.

Q. Okay. Are you aware of whether FIPUG has responded to Tampa Electric's discovery request in this proceedings?

A. I have heard that there were discovery requests propounded on FIPUG, and that FIPUG had rejected those requests, but beyond that I have no direct knowledge.

Q. Is it your understanding that the comission's procedures contemplate a party having, every party having a right to object to discovery that the party believes is objectionable?

A. I wouldn't disagree with that. I think that is generally true in most jurisdictions where, you know, where parties can object to discovery. Usually, though, the objections are on the basis of confidentiality or

trade secret, and my experience in most places has been that there are accomodations made to allow, you know, confidential trade secret information to be provided to the parties on a timely basis.

Q. On that point, Mr. Pollock, are you aware of Tampa Electric's efforts to enter into a nondisclosure agreement with FIPUG?

A. Again, that was not something that I -- that's something I was aware of but not really directly involved in. I know that there were discussions about whether the data that was being provided should be accorded confidential treatment, but beyond that, that is the extent of my knowledge.

Q. You don't know whether Tampa Electric offered up a nondisclosure agreement or when it was done; is that correct?

A. I recall that I think that the company had offered one up. I don't know when that offer was actually made.

Q. Do you know when a nondisclosure agreement was ultimately entered into between FIPUG and Tampa Electric?

A. Again, I don't remember the exact day. I know that before we could get any of what I call the essential information to begin our analysis we had to wait

until those hoops were kind of cleared.

Q. Uh-huh. Do you know how many times Tampa Electric offered FIPUG an opportunity to enter into a nondisclosure agreement?

A. I do not.

Q. Do you know whether, in fact, the commission has ruled that before FIPUG can look at confidential information of Tampa Electric they were required to enter into a nondisclosure agreement with the company?

A. I can't say -- I do not know what the commission ruled in those instances. I mean I understand the process and the concerns that any data that the company deems confidential is generally provided under the terms of a nondisclosure agreement, but usually that is done up front and it's not having to be repeated every time you submit a data request.

Q. I guess my question was whether you knew whether the commission had required FIPUG to enter into a nondisclosure agreement before getting access to this confidential information?

A. I don't know if they required it or not.

Q. Okay. And I think you said you are not sure when Tampa Electric and FIPUG ultimately entered into a nondisclosure agreement?

A. Not specifically the month or day, no. We

obviously didn't get the data that we needed to begin our analysis until that barrier was crossed.

Q. Do you know how it came to be crossed?

A. No, I don't.

Q. Can you describe for me any discovery requests that you have asked for that haven't been sent to you in this proceeding?

A. Well, at the time that I was involved in the case, I don't recall really receiving any discovery responses that were complete enough that we could begin any kind of a definitive analysis. It really wasn't until Mr. Collins came on board that we started getting information that we could do the type of analysis that we felt was appropriate, given the concerns that had been raised.

Q. Do you know if any delay in your getting information was caused by Tampa Electric Company's unwillingness to provide that information, or was it caused by FIPUG's unwillingness to sign a nondisclosure agreement?

A. I couldn't comment on that.

Q. You are not aware of it being FIPUG's fault or Tampa Electric's fault; is that correct?

A. That's correct.

Q. You have testified for FIPUG previously, have

you not, Mr. Pollock?

A. I have.

Q. How many times?

A. I haven't a clue.

Q. Has it been a number of times?

A. I'll agree with that.

Q. Okay. How many times have you testified for an intervenor who intervened to present positions adverse to those of a regulated public utility?

A. Again, I don't keep count of that, but usually we intervene to obviously protect the client's interest. Sometimes that means taking a position adverse to the utility. Sometimes it doesn't.

Q. How about a regulatory public utility in Florida, regulated public utility in Florida, have you testified on behalf of clients taking positions adverse to public utilities in Florida?

A. Well, if you mean adverse to public utilities in opposition of their proposals, yes, I have testified to that a number of times.

Q. How about Tampa Electric Company?

A. Yes.

Q. Okay. You testified in taking positions adverse to those of Tampa Electric?

A. Yes.

Q. Going back to the confidential information, I don't want to dwell on that too long, but would you agree that it would be imprudent for a public utility to place into the public domain proprietary confidential business information for anyone's use before obtaining some sort of protection, either a nondisclosure agreement or other protection to keep that confidential information from being made known to the public?

A. I think probably as a general statement I will agree to that. I think there is always a concern about whether information that a utility provides is really confidential.

Q. Recognizing that that can be questioned, do you agree that it would be imprudent for a public utility to put into the public domain information that truly and factually is confidential and proprietary and would hurt the utility if it were made known to the public?

A. I would not disagree with that in concept as a general principle, and it works the other way, too.

Q. Would it be fair to say that your firm traditionally has sponsored testimony favoring positions advocated by industrial customers and adverse to the positions advocated on behalf of the public utilities involved in those cases where you have submitted testimony on behalf of the industrial customers?

A. Well, again, in instances when we took positions -- well, for example, four years ago on the separation issue and other times when the utility made a proposal that the customers disagreed with, yes, that is generally what we've done.

There have been cases, and I can even recall cases back when Big Bend 4 was under construction that we actually supported the utility in some respects in their rate proceeding, so we are not always against or in opposition to the utility proposal. Sometimes the group feels that the utility has got the proper proposal and wants the commission to hear that side of the equation.

Q. Did you testify for FIPUG in Tampa Electric's 1985 rate case concerning Big Bend Unit 4?

A. I believe so.

Q. Did FIPUG support phasing in that over a number of years as opposed to putting in a rate case?

A. You're really testing my memory now. That could be, but I would have to be honest, I don't recall exactly what our position was in that case.

Q. Mr. Pollock, you mentioned four years ago, and this is what -- here we are again. Which case was it four years ago that you participated in?

A. That was the case in which the treatment of the off system sales to FMPA in Lakeland, the regulatory

treatment of those sales was being contested.

Q. Okay. On page 2, line 20 to 21 of your testimony, you mention testimony in a federal district court case. What did that involve, Mr. Pollock? Who were the parties and what were the issues?

A. That was a case in Missouri, and it was a case brought about by certain wholesale customers of the utility that claimed that the utility was basically putting them out of business. I think the operative term at that time was price squeeze, and I was asked to testify on behalf of the utility in regards to that particular issue.

Q. Okay. On page 2 of your testimony at line 6, and I asked the same question of Mr. Collins earlier, you said that your company and its predecessor had participated in over 700 proceedings in the last five years. Is that a correct number, 700 proceedings in the last five years?

A. It's a good approximation. We don't count every single proceeding, but there have been -- yeah, I would say that is a reasonable estimate.

Q. Which utilities have been your customers, clients, Mr. Pollock, say in the last five years?

A. Oh, boy. You are asking me for which of the utilities that I have been hired to represent customers in

either a regulatory proceeding or some other project?

Q. No. I'm talking about the proceedings in which the utility has been your client?

A. Oh, I'm sorry. I misunderstood.

The one instance that I can recall personally was, in fact, a Florida case where I was hired by Florida Power Corporation, who at the time was opposing the transmission line that Tampa Electric Company was proposing to build.

Q. On page 3, lines 10 and 11, you refer to the participating FIPUG members in this case. Who are they?

A. I don't have a list of them.

Q. Does anyone, to your knowledge, have a list of who they are?

A. I'm certain that counsel will have a list.

Q. Can you name any FIPUG members who are participating in this proceedings?

A. I know that IMC Agrico is participating in this proceedings and possibly others, but IMC I do know.

Q. Do you know which FIPUG members -- well, I guess you only know of one. Do you know if they are taking service under firm tariffs or interruptible tariffs of Tampa Electric?

A. IMC is primarily taking interruptible power from Tampa Electric, and some standby power.

Q. How is it that you are aware of details regarding IMC but not with respect to any other FIPUG members participating in this case?

A. Well, we had a fairly close relationship with IMC concerning a request or proposal that they issued several years ago to basically replace the electricity that they were purchasing from the utilities, in this case Tampa Electric and Florida Power Corporation.

Q. How does that connect up with this case, Mr. Pollock?

A. I don't know that it does.

Q. Do you have a continuing relationship with IMC Agrico?

A. Well, I'm not sure what the continuing relationship is. I mean basically once the RFP process had been finished we had not really had any ongoing engagements with IMC specifically until this proceeding.

Q. How did you come to learn that they are participants in this proceeding?

A. That IMC is a participant?

Q. Yes.

A. Discussions with counsel and discussions with IMC.

Q. On page 3 at lines 16 through 22 of your testimony you address FIPUG's interest in the docket we

are involved in.

A. Yes.

Q. There you state that virtually all of the proposed increase for Tampa Electric can be traced to the proposed $86 million true-up.

Have you personally performed any kind of audit or analysis to determine the appropriateness of Tampa Electric's proposed true-up?

A. I have not.

Q. Has anyone, to your knowledge?

A. I can't speak -- you mean anyone at BAI?

Q. Anyone that you are aware of, whether affiliated with BAI or not?

A. I don't know. I have no way of answering the question except for people that I work with.

Q. Do you know, for example, whether the Florida Public Service Commission audits Tampa Electric's fuel and purchased power expenses and any proposed true-up that they may be asking for in this proceeding?

A. I'm certain that the commission staff will do a pretty thorough review of the company's filing, yes, as they routinely do.

Q. Do you know what period of time Tampa Electric's proposed true-up relates to?

A. I don't have that information in front of me,

and I don't want to misstate anything.

Q. Did you personally study the basis for the company's requested true-up in preparing your testimony?

A. I reviewed the company's testimony, but very briefly, and all only to get really a better context for this whole proceeding.

Q. So you haven't done any kind of analysis from which you could conclude that that true-up was unwarranted and unjustified, have you?

A. My testimony obviously relies on my colleague, Mr. Collins, who has done the analysis and forms the basis for my recommendation.

Q. Mr. Collins came to work for you back in June; is that correct?

A. Yes.

Q. Did you supply him with any type of template or proposed calculation or model which Mr. Collins used in his analysis that shows up as Exhibit 12 to his testimony?

A. No, not at all. At that point we weren't even thinking about, you know, a schedule or Exhibit 12 of his testimony. I think we were just trying to figure out what was going on.

Q. What was going on?

A. Yes.

Q. When did you start getting an inkling of what

was going on?

A. Well, when we finally got all of the answers back to the initial discovery request, Mr. Collins set about the task of trying to put all of the pieces to the puzzle together and figure out what was happening on the system that led to the outages for the nonfirm customers, and in that respect what was happening on the wholesale side of the business.

Q. When was that, Mr. Pollock?

A. I would say probably late spring into the summer, summer months that he was slowly but surely trying to fit all of the pieces together.

Q. He started working for you in June; right?

A. That's right.

Q. He wouldn't have been doing any of that prior to June, would he?

A. No. That's why I said late spring and mostly in the summer. This is one of the early assignments that he had, so he really got, had to come to work running.

Q. When did you say you got the information you needed with which to, for Mr. Collins to put together his Exhibit 12?

A. Well, I don't think we got all of the information for Exhibit 12 until, I would say August, September, late August, maybe September.

Q. That would have been about the time that FIPUG ultimately agreed to sign the nondisclosure agreement; wouldn't it?

A. I don't have any knowledge of when they signed the nondisclosure agreement.

Q. Okay. You didn't get any confidential information before that nondisclosure agreement was signed, did you?

A. It's possible that we got some. It may have been information that the company thought was confidential that the commission said we should have, and to that extent, I think to the extent that the commission said there was additional confidential information, but, no, we didn't get it until, I would imagine we wouldn't have gotten it until after the agreement was signed, whenever that happened.

Q. Did you get any confidential information from Tampa Electric prior to the nondisclosure agreement being signed?

A. Not that I am aware of, and you are talking about in this proceeding?

Q. That's right.

A. Not that I am aware of.

Q. I'm sorry. I missed the last part.

A. Not that I am aware of. I mean we obviously

got some information that the commission ordered the company to provide, but my assumption was that nothing was provided on a confidential basis.

Q. As you worked along, when did the calculation that shows up as Mr. Collins Exhibit 12 come into being?

A. That came into being within, I would say a week or two of the actual date that we filed testimony.

Q. Week or two before you filed testimony?

A. Yes.

Q. So this, what he refers to as an audit, came into being, was created a week or two before your filing date for testimony; right?

A. No. The audit had to do with the examination of system conditions on selected days as requested in the very first set of interrogatories that we submitted back in the spring. And it was his analysis of the system conditions on those days, that's what we characterized as an audit, and his conclusions drawn from that analysis that led to the development of a subsidy calculation.

Q. Did anyone at any time suggest to you that they wanted you to determine a subsidy?

A. No. Nobody said find the subsidy. What they wanted to know is what is going on and why are our costs going up in an alarming rate, and what is going on, you know, what's behind all of this.

Q. Mr. Pollock, you do not render any opinion on the prudence of Tampa Electric's entry into its long-term firm separated wholesale sales contracts in this proceeding, do you?

A. I give no direct testimony on whether the company should or should not have entered into those contracts; however, I think the consequences of that decision are really what is driving our positions in this proceedings.

Q. Would you agree that the prudence of a utility's decision to enter into an agreement should be judged based on the facts and circumstances known to the utility at the time that it did that, made that commitment?

A. I think that is debatable. I think in the normal sense, to the extent that you had, you know, reasonably known and measurable circumstances, that you could judge the prudence of something, that is one thing; however, I don't think that regulators can be unmindful of the consequences of the decision that may have been either not revealed or occurred because of changes in circumstances that weren't contemplated at the time the decision was made.

Q. Do you suggest that there is any contractual leeway that Tampa Electric could have used in

administering or managing its long-term firm separated wholesale contracts any differently than it has?

A. In terms of the wholesale contracts, of course that is not a subject that we are even addressing, nor is it relevant to this proceeding in our view. It's not the contracts themselves that are the issue really. It's how the costs, as Mr. Collins has said, how the costs are being handled and managed, and the concern that the retail customers are basically getting a higher cost and inferior quality of service which can be traced to the way that the wholesale contracts are being managed by the company.

Q. When you say being managed, what do you mean?

A. In terms of the fact that the wholesale contract customers seem to be getting first priority over the company's low cost resources and that that continuing priority has meant that the retail customers are more at risk for the consequences of system outages, particularly nonfirm customers, whenever the company runs out of internal generation. In those circumstances the company has to go find the power sometimes at very, very high exorbitant prices, so those are the kind of consequences that we are really asked to figure out, what the origin, what the cause was.

Q. You don't know what Tampa Electric's specific

contractual obligations are under these agreements, do you?

A. Only in a general sense, to the extent that these contracts are firm separated sales or firm nonseparated sales, as the case may be. I mean there is an obligation of the company to provide capacity, except as may be provided for in the contract.

Q. Mr. Pollock, do you accept and personally endorse the statistical analysis utilized by Mr. Collins in his study? By this I mean the selection of 63 hours covering 21 days of the three-year period he addresses in his audit?

A. Well, I have to be perfectly frank, we would have liked to have done a much better, a much more comprehensive analysis, but we did not have the time or the tools or the means to do that and, as I said, the analysis really, the origin of the analysis was not to find a subsidy. The origin of the analysis was to determine why interruptible customers were being, experiencing large numbers of interruptions, both physical and economic, why the cost of the buy-through purchases were so high, and yet why there was such a large difference between retail and wholesale fuel cost that on the surface couldn't be explained, and that kind of evolved into the analysis that Mr. Collins has presented.

Q. Do you accept and personally endorse the statistical analysis utilized by Mr. Collins' study?

A. I think that was a long winded answer to say yes, I do, and we recognize that it's not, it's not the final say, but only an indication of the magnitude of the problem that we believe exists.

Q. Why didn't you get started working on it earlier back in January or February?

A. I guess in a perfect world the client would have hired us sooner and we would have had all of the information at our disposal to be able to do the analysis.

As I told you before, we weren't hired until late February. We didn't begin to get all of the information we needed to start putting all of the pieces of the puzzle together really until late spring, early summer, and even then, you know, we are not, as in most regulatory proceedings, we don't have unlimited resources. That is just not a luxury that we have ever had to work with, and we had to be mindful of that.

Q. Whose resources are you referring to?

A. Since it's the client that is paying us, it's the clients resources and, of course, they have obviously a large say on how much they are willing to support our work.

Q. They are all large industrial customers, are

they not?

A. That may be, and as we have seen in recent months some of these large customers have experienced some pretty distressed times. I mean there have been a number of companies that have had to shut down, and economic times have been pretty hard, particularly in the agricultural industry, and the phosphate industry, which is highly concentrated in the Tampa Electric service territory.

Q. And so that is what you attribute to their inability to get their show going sooner in this docket; is that correct?

A. I can't tell you or speculate what they had in mind in terms of why they contacted us when they did and that, but it really wouldn't have made any difference because, frankly, until we got all of the information together at the same time at the same place, we really weren't able to make much in the way of progress, and by then it was already, we were down to two months or so before due date of testimony and just starting the analysis. So it wouldn't have mattered if we got hired in January. It wouldn't have mattered if we were hired before that. The problem was that we just didn't have all of the information that we needed to do the analysis.

Q. Do you have any factual basis that would

support attributing any of that fault to Tampa Electric?

A. I'm not going to say that it's anybody's fault. Obviously it's very, very frustrating to us to, you know, diligently submit interrogatories and then wait 30 days and then get the answers back and have stuff that is not, that is redacted, or answers that weren't complete or didn't fully address the question, and that is partly, you know, a problem with the discovery process, but, you know, I really think, based on my experiences in other jurisdictions, and Texas comes to mind because I do a lot of work there, we sign confidential agreements at the beginning of the proceedings and it's good for the entire proceeding, and I think if we had been able to accomplish that we might have been able to do a lot more with what we had.

Q. Can you point to any discovery in this case that was delayed a single day because of the way that nondisclosure agreement was administered in this proceedings?

A. Well, that is kind of a, you know, it's kind of a meaningless question because, yeah, you answered the discovery responses on time as you were supposed to, but from our perspective, unless the information is all there, you know, it's worthless. It's just a pile of paper that we can't do anything about, and that is really why I'm

referencing, and perhaps I'm showing a little more frustration in my testimony, but that is really what we are responding to in the way of why we felt a little pushed because of the lack of timeliness of getting the responses.

Q. Are you aware that Tampa Electric on three separate occasions on its own offered up a nondisclosure agreement to FIPUG?

A. I think you asked me that already, and I said I was not.

Q. Do you consider any of Tampa Electric's objections or unwillingness to provide confidential information to have been offered up in bad faith or erroneously?

A. Let me put it this way. After the first nondisclosure agreement was entered into, and I don't recall when that date was, it just seems to me that that should not have been an issue in providing information to subsequent interrogatories. Now, I'm just talking from my experience in other jurisdictions and discovery processes that I have been through, and that just seemed to be highly unusual, and it really made our situation a lot more difficult to handle the analysis because we just didn't have the right tools to do the job.

Q. Are you aware of FIPUG having asked for

certain information in this proceeding, and then upon finding out it would cost something to have that information copied, told Tampa Electric that FIPUG no longer wanted that information?

A. I know that there were some instances when there were costs that were involved, but how that ultimately got handled, I don't know. Again that is one of those little hurdles that make the discovery process anything but smooth and really, in all frankness, delayed the start of what we could really do.

Q. On page 4, lines 12 and 13 of your testimony, you say that Tampa Electric has put its own interests and those of its long-term wholesale contract customers ahead of the interests of its retail native load customers.

My question to you is what other than abiding by the obligations under the terms and conditions of the wholesale contracts that it's a party to has Tampa Electric done to accomplish this?

A. Based on Mr. Collins' analysis, it's the way that the -- in the fuel reports that the purchased power costs have been allocated as between retail native load customers and wholesale customers, that really is the focal point of our concerns and this particular passage in my testimony.

Q. Are you familiar with how nonseparated

wholesale sales are accounted for by Tampa Electric?

A. Yes. To some degree, yes.

Q. Do you know, Mr. Pollock, whether the purchased power costs of those sales are reflected in the A Schedules that Mr. Collins looked at in performing his study?

A. I'm not making the assumption that all relevant fuel and purchased power costs are included in the A Schedules for purposes of determining what fuel cost factor that the retail customers are responsible for, and so in that sense, since fuel costs in nonseparated sales as well as the corresponding plant and fixed costs are all basically jurisdictional in nature, those costs would show up in the A Schedules.

Q. I'm talking about the cost that the retail customers are not responsible for and which the wholesale customers are responsible for. Do you think those costs are reflected in the A Schedules?

A. Again, its my understanding and consistent, I think, with what Mr. Collins said earlier today about all relevant, you know, fuel and purchased power costs are reflected in the A Schedules, and if that is the case, then those costs are included.

Q. Is that for wholesale and retail?

A. Yes. And again we are focused on the fuel

and purchased power costs that go to the fuel and purchased power cost recovery cost.

Q. Wholesale or retail?

A. It's my understanding that the company reports its total system fuel costs in those schedules.

Q. On page 4, lines 13 through 16 you say that Tampa Electric's wholesale customers have and continue to benefit from more reliable and cost-effective supply of electricity than have Tampa Electric's retail customers.

Does this include firm retail customers?

A. Yes. In that context it's more of a cost issue than a reliability issue.

Q. On what do you base this conclusion?

A. Basically that the consequences of outages and the fact that wholesale sales, as Mr. Collins explained, remain, are served on a continuing basis, and further that the costs associated with the wholesale sales are essentially based on the company's low cost coal fired resources leads me to believe and conclude in my testimony that the retail customers, both firm and nonfirm, are the ones basically making up the slack, meaning that all of the costs that aren't being recovered or being allocated to wholesale customers are being allocated and collected from retail customers, and that based on the volatility of those costs and the fact that the fuel factor for retail

customers is much higher than for wholesale customers, that they are getting basically a less cost effective, in the case of firm retail sales, and a less reliable in the case of nonfirm retail sales, service than are the wholesale customers.

Q. Are you aware of the reliability of service of Tampa Electric Company's interruptible customers over the last five years?

A. I'm not sure what you mean by reliability.

Q. The percentage of time that they were served divided by the total possible time they could have been served?

A. I think my Exhibit 1 may shed some light a little bit on that, and I don't want to dispute that the duration of service interruptions hasn't been all that high. I mean the number, the frequency and duration except for in '98-'99 really has been, I would say very nominal.

Q. So the number of interruptions has continued to decrease since 1999, has it not?

A. Well, we don't know exactly all of 2001 yet, but I suspect that, you know, it's likely that the number of interruptions will be less, yes, unless we get some kind of a freak, you know, weather event.

Q. Okay. You say that interruptions, both

frequency and duration, have been pretty much the same since '96 with the exception of '99?

A. Exhibit 1 really speaks for itself. It shows the history from '96 through September of 2001, and experiences I think varied from very few interruptions of very short duration to much longer interruptions toward '98-'99 than had been the case in the past.

Q. I think you said that the number and duration have not really been significant over this time frame?

A. I didn't really mean to say it quite that way. What I meant to say was that the number had grown pretty significantly from '96 to '99. That was partly one of the concerns that was driving our analysis and why we were retained to review the company's operations.

Q. In your testimony on page 4 you say that since 1997 nonfirm customers have experienced dramatic increases in both the frequency and duration of interruptions, and that is not supported by your Exhibit JP-1, is it?

A. That really gets to the second exhibit, that there are two types of interruptions.

Q. Just let me get through JP-1. That is not supported by that first exhibit, is it?

A. If you say going from one hour to 53 hours is not a significant increase, I guess based on that

yardstick, yes, I would agree, but I obviously disagree with that characterization that that is not a significant change.

Q. Going from 53 to zero and 16 to one is not a dramatic increase, is it?

A. Well, it's a, I would call it more normal because interruptible is really supposed to be the resource and last resort. Things really have to be going south in a hurry to prompt you to kick the interruptible customers completely off the system.

Q. Is that in the interruptible tariffs, the part about having to be, going way south and things falling apart?

A. That is probably a nontechnical nontariff term that I just invented. Essentially that is really the role of interruptible power I think that is reflected at least in how we view the interruptible service, and how it's been historically viewed.

Q. Interruptible customers are compensated for the potential of being interrupted, aren't they?

A. Well, the interruptible customers pay a lower rate because there is no generation capacity planned to serve the interruptible customers.

Q. The utilities size their generating plant and choose to make fuel selection decisions and build

transmission capacity to serve interruptible customers, don't they?

A. Well, I think that there is -- I have heard statements to the effect that you look at the entire load and the load shape in determining what is the optimal mix of generation, but my analysis of that really suggests that once you're beyond a certain load factor and way below where the interruptible customers operate, that you really have pretty much chosen the base load option anyway, and the interruptible customers are there to really help you to utilize those facilities more than what otherwise would be the case if they weren't there, and to be able to use that capacity to serve firm customers if the capacity was needed to serve firm customers.

Q. So you don't really have to have the whole operation going south in order for an interruptible customer to be interrupted; correct?

A. I think under normal planning criteria and normal -- you know, if the system is operating normally the interruptible customers should always receive system service, and it should only be under extraordinary circumstances where you've got a combination of lots of units either forced out, or out of maintenance, or you simply don't have enough capacity to meet your firm needs that that is where the role of interruptible -- and load

management too, not just interruptible, but I think that its primary role is to provide that cushion if unexpected things happen, then you basically don't take the whole system down. You have a way to release the, relieve the system of some of the load that it was previously serving so that you can maintain service to your firm loads.

Q. If an interruptible customer receives essentially firm service, do you think that suggests something is suspect about the lower rate that they pay?

A. I disagree with the premise of your question. An interruptible customer by definition doesn't receive firm service because that customer's power supply can be yanked at any moment with or without notice.

Q. I guess I'll ask if that never happened?

A. Well, if you've got a customer that signed an agreement and is taking service on interruptible tariff, that customer is getting nonfirm service. Now, whether or not that service is interrupted doesn't, to me doesn't tell you that they are getting anything about nonfirm service. As I said, if the system is planned and operated properly, interruptible customers under most conditions should continue to be served. It's only when things start to go south, my term, and the capacity is needed to serve retail or firm customers, then the interruptible provides that important safety valve.

Q. Have you performed, Mr. Pollock, any analysis yourself of the reliability of Tampa Electric's internal generation, or do you just rely on Mr. Collins' analysis?

A. I have not done that analysis.

Q. Were you in the room when Mr. Collins indicated that he hasn't looked at any of Tampa Electric's units or their characteristics or how they are operated?

A. I believe he said he has looked at the data but has really not conducted an extensive analysis of specific operations of specific generating units. Obviously his testimony does examine the status of generating units on the days on which he focused his analysis.

Q. He didn't perform any kind of Tampa Electric unit specific operational analysis, did he?

A. I'm not sure I know what that means, but --

Q. Well, if you don't know, I'll try to explain it for you.

A. Go ahead.

Q. He didn't look at any of Tampa Electric's units, how long they have been in place, how old they are, what kind of fuels they burn, and how their operational characteristics have transpired over time?

A. He has not conducted an exhaustive analysis of that.

Q. Has he conducted any analysis of that?

A. I think by definition, when you look at the equivalent availabilty factor and similar statistics you are conducting an analysis of comparing the reliability of Tampa Electric's generation to similar generation that is owned by utilities across the country, so in a general sense that is an analysis to compare the overall reliability of the company's plants without, you know, trying to figure out if that difference is really attributed to something that is unique to Tampa Electric.

Q. Have you personally verified the results of the audit Mr. Collins performed, or did you just rely on the results of his audit?

A. We went over the calculations in some detail before the exhibit was prepared, and we are in agreement with the calculations.

Q. Did you go over the assumptions behind his calculations and agree with them as well?

A. Any specific ones you want to talk about?

Q. Just whatever forms the basis for his conclusions?

A. I was very skeptical about Mr. Collins' analysis, and I made him show me without question that convinced me that what he was saying was totally accurate and correct. And once he was able to convince me that

there was some serious problems going on here, we worked diligently, I would say together, to try to figure out a way to try to quantify what the impact of all this was, given the time that we had left.

Q. And this was when, approximately two weeks before the testimony was filed?

A. I would say within the last several weeks, but concentrated probably in those last two weeks.

Q. Have you performed any studies personally to support your statement on page 5 at lines 11 and 12 that, "Not only are retail customers receiving an inferior quality of service, they are paying excessively for it"?

A. Well, I think in a general sense when I look at the cost of buy-through purchases and seeing that average costs are in the seven cent range, starting in '98 and going all the way up to 11.8 cents on average, and then looking at the purchase, some specific purchases that were reported in the A Schedules about that, I'm very concerned that retail customers, those purchased power prices of those magnitude, or of that magnitude is, in my opinion, is excessive, and no utility ought to be at the mercy of the market and have to incur those costs.

Q. When you say retail customers, you really mean interruptible customers, don't you?

A. In my last answer that is correct, but keep

in mind, too, that some of those purchases do spill over to firm retail customers, and as I have observed not only in this case, but in the past, there has always been a larger retail fuel factor, or higher fuel factor for retail customers and wholesale customers that, frankly, I can't explain.

Q. Okay. On page 5 you refer to replacement purchases. What exactly do you mean by replacement purchases?

A. I'm referring to anything that replaces the energy that would normally be provided by TECO's internal generation.

Q. Does that include all purchased power?

A. Well, with the possible exception of economy, and I think that is where maybe I disagree a little bit with Mr. Collins, but not seriously. Yes, that is what I'm referring to. The economy purchases are replacement in a sense, but they are more purchases that you make when it's cheaper to do so, and not because you don't have the resources there to provide it yourself.

Q. Does it include optional purchases for interrupible customers?

A. Absolutely, yes, because in that situation the company has run out of, I'll call system energy, and having to go out in the market to replace that to allow

the interruptible customers to continue receiving service.

Q. Do you believe those should be allocated to all retail customers?

A. I haven't really rendered an opinion about that, but clearly to the extent that some of those optional purchases are occurring while wholesale customers are continuing to receive very low cost very reliable power, I think there is more of an issue of should some of those costs be allocated to wholesale.

Q. I said retail.

A. I know. I'm saying I hadn't taken a position on that. My position is that those costs probably should be allocated to wholesale.

Q. You can render an opinion about wholesale, but not retail?

A. Like I said, the purpose of my analysis was not to look at how different retail customers are being treated. It's to determine whether the retail customer as a whole is being treated fairly vis-a-vis the wholesale customer.

Q. On page 5, lines 18 through 20 you say that, "The retail customers who are supporting the fixed costs of generation capacity should be the beneficiaries of the lower operating costs of this capacity."

Which capacity are you referring to?

A. It's basically all of the generation capacity that has not been jurisdictionally separated.

Q. You're excluding the separated capacity you referred to?

A. Yes. To the extent that that capacity is separated the costs are, and again I'll say in theory because one never knows from case to case if the allocation factors are tracking the reality, but ignoring that shortcut, to the extent that the retail customer, or those costs are not being borne by retail customers, then you would not expect that they would have any entitlement to the operating costs associated with this separated sales.

Q. And that would include the separated, your term, low cost, coal fire capacity that you referred to; correct?

A. It would.

Q. With that separated, why do retail customers who are not paying for it have some inherent right to that capacity?

A. I'm not saying that they do. I think what we are saying is that to the extent that they are resources that the retail customers have, and to the extent that wholesale customers are, are being served from I'll say more than their share of separated capacity of those

resources, then that is where the subsidy occurs between the retail and the wholesale customers, and that is really the heart of the issue in this case is we are not arguing about the separations, per se. What we are saying is that the wholesale customers are always getting their power regardless of how the separated units are operated, whether they are operating fully or not, and that is the practice that I think we feel is a serious problem.

Q. How do you know that to be the case?

A. I rely on Mr. Collins' analysis and my skepticism which directed me to make him prove it and convince me that what he was saying was correct.

Q. Were you in the room when we discussed Mr. Collins' analysis, his use of 63 hours out of 21 days covering a two-year period extrapolated to cover a three-year period?

A. I understand the -- yes, I was in the room.

Q. In your professional opinion, is there any statistical reliability whatsoever supporting the conclusions Mr. Collins draws from that study?

A. Well, you know, from a purely statistical perspective, I don't know how many days or how many hours or observations it takes to create a sample. I mean I think in load research, if you get 30 observations, that is generally viewed as a statistically valid sample, and

we are not holding our analysis out as a necessarily statistically valid sample. What we are trying to say is that we see a problem. We think it needs to be looked at further and given a little more attention before we can really draw any conclusions about the magnitude of the problem. We think it's a serious problem but again would defer to a more thorough analysis to determine the real magnitude of it.

Q. Would you agree that the selection of 63 hours out of all the thousands of hours over a two-year period, they being the only hours when interruptions occurred over a two-year period, extrapolated to cover a three-year period and be representative of a three-year period, has any statistical reliability to it at all?

A. Well, again, I harp back to the idea that although the calculation, that it might be based on the experience of 21 days of which we looked at I think a full, the number of hours on those days, there are a number of other days that we simply didn't have time to look at. As Mr. Collins said, you know, he looked at the day before and the day after, so I think his review really encompassed more than just the 21 days and the 63 hours, but I understand that the concern is that, well, you know, those are just so many days out of the year, and we are not disagreeing that we think a more indepth analysis

should be given.

Having said that, though, having seen this practice on those 21 days, which is probably, and I'll say this, probably the most severe days on the system, leaves me to really worry that the practice is, you know, may be more serious on days when the situation is less severe, so I really think in all fairness we need to do, we need to have the commission focus its efforts on all of the other days and focus on the practice and not necessarily harp on, well, is it 40 million or a hundred million.

Q. When you say the 21 days were the most severe on Tampa Electric's system, what do you mean?

A. Any time you have to curtail anybody, and in this case it's nonfirm loads, it's indicative that you have run out of capacity and you can't go out in the system and buy it to avoid having to curtail loads, so in that sense, you know, I would characterize it as a severe situation.

Q. Wouldn't that skew Mr. Collins' result in favor of the highest cost differential and thereby produce the greatest subsidy on each of those 63 hours?

A. That is what we really need to find out. And I'm not sure -- it could work one way or the other way. The truth of the matter is we don't know. As I said, if the company is not doing anything to curtail or allocate

the higher cost of purchased power to wholesale on those days, which are the most severe, then I really have to believe that there is other stuff that needs to be found out when we go do the analysis for the rest of the period, and that is really what I'm concerned about.

Q. Why did you select 63 days when interruptions occurred? Why didn't you select -- or not even select 63 days? If you wanted to use 63 days have some kind of random number generator that generated 63 randomly selected days from the, or hours from the 20,000 or whatever number I read Mr. Collins earlier in the three-year period --

A. Yeah.

Q. Wouldn't it have been more representative?

A. I don't know if it would or would not. As we told you again and again that the purpose of this analysis was not to calculate subsidy. The purpose of the analysis was to answer a concern expressed by the customers that the cost and quality of their power has just become outrageous and, you know, they were concerned about what was happening and why it was happening, and that is why we chose the days that we did.

Q. Why did you calculate a subsidy if that wasn't the purpose of your study, or Mr. Collins' study?

A. Because we wanted to show, or at least give

the commission an appreciation of what the potential magnitude of this practice is, and what its potential impact on retail customers is. To say that is not a million or two million dollar issue, this is not a hundred thousand dollar issue, this is a tens of millions dollars issue, and just give the commission something to appreciate this is a serious practice, a serious problem.

Q. Doesn't it rise to those levels only when you seize on the 63 hours out of the two-year period when interruptible customers are being interrupted and everything was as severe as you say it was on Tampa Electric's system?

A. Well, again, we could look at other days, you know, before and after, and see the same problem. Perhaps the cost consequences aren't in all cases as high. Now, remember not all of the instances that Mr. Collins looked at were wholesale prices all that high. I mean there were some times when the wholesale prices weren't that high, so I think looking at it over the period we did, we didn't just focus or capture all of the high cost hours. I think we captured some of them, possibly a lot of them, but I think they were spread out over a long enough time, and there were other days when the prices would probably go higher because it was available and somebody knew that the company needed to buy the power and they accordingly

jacked the price up.

Q. Did you ask for or look at any other hours other than the 63 hours when customers that are interruptible were being interrupted?

A. It's my understanding that Mr. Collins looked at the 21 days, the day before the interruption and the day after, so in effect if you take 21 times three, he really looked at 63 days.

Q. He didn't include those 63 days or any hour of those 63 days, or excuse me, yeah, of those 63 days in his 63 hours, did he?

A. We just ran out of time and, as you remember, we asked for a slight delay in filing of his testimony, and this is very data intensive, as Mr. Collins said, very data intensive issue and process, and we are not working with the most perfect of tools, I'll grant that. Yes, I would have liked to have done a full, complete audit, but we just simply didn't have the resources, the time, or the budget to do it.

Q. On page 6 of your testimony, Mr. Pollock, on lines 10 through 14 you suggest that, "Tampa Electric should be ordered to cease," your term, "its current practice of allocating a hundred percent of replacement power costs to retail customers and to allocate a pro rata share of all replacement power purchases to wholesale

operations."

Again, replacement power, I think you said includes everything but economy purchases?

A. Yes.

Q. On what do you base your apparent belief that this is not already being done by Tampa Electric Company?

A. It's based on Mr. Collins' analysis of the fuel reports and my own brief review of those reports that show basically, list all of the purchases and shows which purchases are being allocated to wholesale and which ones are being retained by retail customers.

Q. On page 6 of your testimony at lines 20 through 23 you state that, "The commission should conduct a more thorough investigation of Tampa Electric's affiliate transactions and its procurement of power for wholesale customers."

What do you base the assertion on regarding affiliate transactions?

A. It's really the sentence that follows that. It's Mr. Collins' observation that where Tampa Electric has had an opportunity to go out and buy low cost power at wholesale markets, for some reason or other the low cost power found its way to the native retail customers.

Q. Is that from an affiliate company?

A. You would have to ask Mr. Collins that

question.

Q. You don't know the answer to that?

A. No, I don't.

Q. Do you know whether he made a conclusion in that regard in his testimony?

A. You would have to ask him. I don't know.

Q. Do you have any independent reason to suggest that Tampa Electric's affiliated transactions are not being adequately scrutinized by the commission in this proceeding?

A. I don't have any information one way or the other.

Q. What do you base your assertion regarding the procurement of power for wholesale customers on?

A. Well, again, I think I answered that. Basically the company has done a pretty good job of providing its wholesale customers with the lowest cost energy that one can provide, but for some reason the retail customers have not been able to share in that benefit.

Q. Based on Mr. Collins' study?

A. Based on that and based on the fuel report, and based on the fact of the increasing differential between the retail and wholesale fuel factors.

Q. On page 8, lines 9 through 13 you appear to

endorse Mr. Collins' claim that the overcharge that he alleges has been somewhere between $45 and $108 million in the '99 through 2001 time period.

Do you, Mr. Pollock, personally endorse that estimate?

A. I'm not sure what a personal endorsement means.

Q. You put your professional reputation on the line insofar as even putting forth that estimate.

A. With all of the qualifications that I have given you in this deposition, I would stand behind it, and I recognize, as I have told you before, that this is only an estimate, and that is why we recommend a more thorough investigation to quantify what is ultimately the appropriate amount.

Q. What would that investigation entail, Mr. Pollock?

A. I suspect that the investigation would be to do something very similar to what Mr. Collins has done, but expand it to a broader time period, and one that I think that the parties all felt would be enough observation that they would be comfortable with the analysis.

Q. How could you expand it to a broader sample when you have already sampled all the days, or the hours

when interruptible customers were being interrupted?

A. Well, we haven't covered, like I said before, the day before and the day after. That is not part of the quantitative analysis, even though it was part of the qualitative analysis that Mr. Collins did and, two, we asked the questions -- we really had intended to cover all of the days in which the interruptible customers were having to buy optional provision power, and for some reason we just didn't get that point across and cover the days, additional days there, so I think that there are a number of additional time periods that should be considered in coming up with what the subsequent docket would do.

Q. Mr. Pollock, you said Mr. Collins just ran out of time, he didn't have time to incorporate those day before and day after?

A. That's what I said. That is the truth. I mean we were struggling to get everything completed by the deadline.

Q. That was a pretty hastily assembled study, wasn't it?

A. No. The principle is there. There is just a lot of data. We are not at all unhappy with the time frame other than we wish we could have done a more thorough analysis. It was not hastily put together. We

worked on this analysis for -- and I'll say the underlying investigation that culminated in this particular analysis in Exhibit 12 of Mr. Collins, we worked on that long and hard over the summer months once we had all of the right data at hand.

Q. On page 11, line 5 you indicate that the average delivered cost of electricity to residential customers was around 7.7 cents as of December, 1999.

Do you know what the average cost of power delivered to interruptible customers as of December of '99 was?

A. I do not know.

Q. Does either Mr. Collins' analysis or your testimony take into account the discount below the otherwise applicable firm price that interruptible customers have paid Tampa Electric during the time period covered by Mr. Collins' analysis?

MR. McWHIRTER: I object to the form of the question because it uses the word discount without defining what discount means.

MR. BEASLEY: I mean by discounting the amount below the otherwise applicable firm rate that the interruptible customers pay.

MR. McWHIRTER: Why would it be appropriate to call it a rate differential between interruptible and

firm discount when interruptible customers by definition don't get firm service?

MR. BEASLEY: We won't call it that.

BY MR. BEASLEY:

Q. Mr. Pollock, have you determined what the difference is between what the interruptible customers have paid and what they would have paid had they been on the firm service otherwise applicable rate?

A. I made no analysis of that, but knowing the -- as we discussed before one interruptible customer in particular, I doubt very seriously that they could buy any power at the firm rate and stay in business.

Q. On page 11, lines 8 and 9 you refer to the "extremely high prices" Tampa Electric is paying for some of its optional purchases.

Don't utilities in general this day and time frequently have to all purchase extremely high priced power?

A. That is exactly right, and that is my point is that the circumstances, the regulatory and market circumstances that the customers are facing now is quite a bit different than when your rates were last set and when we determined what the appropriate level of the interruptible rate was and the associated terms and conditions. This is a whole new environment that didn't

exist really until after Order 888 occurred, and that is exactly the point.

And my point is simply this, that no one, certainly not the customers, certainly not the interruptible customers never thought that we would be looking at an environment where they would have to pay over 11 cents a kilowatt hour of replacement energy. That was just not something that back in 1995 or 1992 or 1985, that was just not something that anybody could imagine would ever happen.

Q. And the interruptible customers willingness to pay these higher prices for buy-through power is a decision that they have made voluntarily; is that not correct?

A. Well, they made the decision. I don't think there was a lot of choice in the matter. It was either pay an exorbitant price for power, or shut down and pay an exorbitant price. Either way it was pick your poison. It really isn't a choice.

Q. Do you agree that a utility in this day and time has a significant incentive to minimize all of its costs to provide service to its customers?

A. I'm not sure what you mean by particular day and time.

Q. Well, with deregulation potentially on the

horizon, with market base pricing such that it is, with large customers perhaps making decisions on whether they are going to construct a plant?

A. Well, you know, I think that all of those things might be considerations, but I think you have to really consider, you know, the specifics and the climate at hand. I mean yes, there is customer choice in a number of states. Is it going to happen in Florida any time soon? I rather doubt it, you know, so is that really a factor? Well, maybe generally, but on the other hand we've got California, and maybe it's just not something that matters.

I'm more concerned with the idea if that is really the case, the problem I see is that the current regulatory structure that allows all of these pass-throughs is a major problem and one that if the utility is really going to get incentivized to do what you're saying, that is to minimize cost for everybody, then I think there has to be a total re-examination of pass-throughs because that is just not, that tool is just not compatible with the idea that utilities have an obligation to provide service at the lowest cost.

Q. Do you think utilities watch each others rates and try to stay competitive with each other?

A. They certainly might but, you know, as a

reality, if you have customers that are captive, and there are very few alternatives, it really doesn't make any difference. I'm talking about retail customers, and not wholesale.

Q. Do you think utilities have regulatory incentives to minimize their rates?

A. Well, no, not -- let me put it this way. With the plethora of cost recovery mechanisms, I don't think that that ennvironment provides a very good incentive for utilities to minimize their costs.

Q. On page 13, lines 9 and 10 you're asked a question concerning what TECO's customers agree to regarding "insulating TECO from price risks resulting from the deregulated wholesale power markets."

Are you suggesting that Tampa Electric is somehow obligated to underwrite decisions by FERC in its Order No. 888?

A. I'm sorry, did you say underwrite? I didn't quite understand the question.

Q. Underwrite those decisions, or take the responsibility for what the FERC decided in Order No. 888?

A. Okay. I think it's a shared obligation. I think the utility has an obligation to provide service at the lowest reasonable costs, and if that means timely putting in generation or taking steps to purchase capacity

and energy at the lowest price, I think they should do that.

Q. On page 15, lines 11 through 13 you state that retail customers pay the lion's share, and that is your term, of the fixed cost required to construct, operate and maintain TECO's internal generation capacity.

Did they pay any of the fixed cost associated with separated wholesale sales?

A. To the extent that the allocation factors reflect the current separations, that is the relative demands of the separated customers vis-a-vis the system, then they would not pay the fixed cost.

Q. As far as retail customers are concerned, is there any distinction what a firm retail customer contributes and what an interruptible customer pays?

A. You are asking me if there are differences in rates charged between firm and nonfirm retail customers?

Q. Right, to cover the fixed costs required to construct, operate, and maintain those internal generation capacities?

A. Yes. Historically there has always been a difference between firm and interruptible rates.

Q. Do you know what that is?

A. I couldn't tell you off the top of my head, no.

Q. Interruptible is an insignificant portion compared to what the firm customers pay; is that correct?

A. I won't agree with that. I think insignificant is a relative term.

Q. Do you know when Tampa Electric executed or entered into its most recently executed long-term firm separated wholesale sale contract?

A. It's most recent?

Q. Most recent?

A. I would have to refer to Mr. Collins' exhibit for that. I can't tell from that exhibit which is the most recent. I think there was some interrogatories on that, too, but Mr. Collins really would know that.

Q. Mr. Pollock, do you know whether the most recent agreement was entered into on a relative basis, like was it two years ago, five years ago, ten years ago, or do you have any understanding of that?

A. I think there were some contracts that were entered into in 1998 that I won't -- again I'm referring to Mr. Collins' Exhibit 1 for that information.

Q. It looks like his exhibit suggests that all of the contracts were entered into in 1998. We will just have to defer that.

A. I will be happy to bring Mr. Collins back and you can ask him if you would like.

Q. It's okay. I think those contracts will show what they show as far as their origination date.

A. Certainly.

Q. On page 14, lines 2 through 4 you state that a wholesale power buyer will tend to choose another supplier if the buyer doesn't have any confidence in the seller's ability to live up to the agreement.

Is having the confidence of buyers in the market important to sellers of wholesale power?

A. Well, I think yes in the sense that a customer is not going to want to necessarily pick the lowest offer if that customer feels that the supplier really can't stand behind that lowest offer, and we are dealing, for example, with customers in the Texas customer choice market right now, and they are getting proposals that are all over the map, but the lowest proposal isn't necessarily the best one. They want to make sure that the supplier can stand behined the proposal because, as in any contract, there are provisions that, you know, what happens if there is force majeure, what happens if there is a change in the law and all of this other, all the trappings that go into evaluating the deal.

Q. If a wholesale power seller were to interrupt a firm wholesale sale and use that power elsewhere, how would that likely impact the buyer's confidence in the

seller?

A. It depends on the terms and circumstances under which the interruption occurred. If it was force majeure, which most contracts have a force majeure provision, then that is the risk that they undertake in entering into the agreement.

Q. But what if it wasn't?

A. If it wasn't and the contract didn't allow for it, then presumably there would be some remedy in the contract that would make the wholesale customer whole or at least to compensate for the damages caused by that failure to live up to the agreement.

Q. What impact would that event have on the buyer's confidence in the seller?

A. I think it would depemd on the circumstances and how often something like that occurred.

Q. I'm talking about the latter instance and not a force majeure, where the seller just flat interrupted it and did something else with the power?

A. Again, unless there was a good reason, I would suspect that the buyer would seriously question the entity's performance under the contract, and if the damages did not compensate enough for the inconvenience, then I would think that the buyer might try to take some other actions.

Q. What would it do to the buyer's confidence in the seller?

A. Again, I think it depends on the circumstances, whether it's force majeure or not. If it was just something that the seller did arbitrarily without explanation, I would think that the buyer would have to seriously question the seller's willingness to live by the terms of the contract.

Q. If that were the case, what would the impact be on the buyer's confidence in the seller?

A. I don't know. You would have to ask the buyer. I think the buyer would be pretty, and maybe legitimately concerned that the seller could not live up to the deal.

Q. But it wouldn't have any impact in your view on the buyer's confidence in the seller?

A. I think I just said it would. They might reconsider whether or not the seller can live up to the rest of the deal and might initiate actions to either change the agreement or to punish the seller for their errant behavior.

Q. Might it undermine the buyer's confidence in the seller?

A. I think I answered that already.

Q. What was your answer, yes or no?

A. I'll say yes with the aforementioned explanation.

Q. Okay. I'll take that.

On what do you rely as the basis of your statement on page 15, lines 8 and 9 that Tampa Electric has been giving preferential treatment to its wholesale customers?

A. Based on the results of Mr. Collins' analysis and the fact that the wholesale contract, long-term whole contract continued to receive uninterrupted continuous supply of low cost energy while retail customers have borne significant increases in their fuel and purchased power costs, and in the case of nonfirm retail customers a significant increase in the amount of service and/or buy-through interruptions, economic interruptions, and the associated costs of those interruptions.

Q. How do you know there has been a continuous supply to those contracts, to the wholesale contracts?

A. We can look at the data and the fuel reports, we can look at the graphs in Mr. Collins' exhibit, and you can pretty much see that despite the fact that the units are going down all over the place, the wholesale customers are continuing to be served to their full extent, but more importantly the costs associated with those sales continue to remain at the low level that the wholesale customers

are getting even with the system operating normally, which suggests to me that it's the retail customers that are picking up the slack.

Q. Okay. On page 16, lines 3 and 4, on what do you base your conclusion that Tampa Electric has the current practice of allocating a hundred percent of the replacement power cost to retail customers?

A. I base that on Mr. Collins' analysis and my review of the fuel reports.

Q. Okay. Were you in the room when I asked Mr. Collins about, you know, I gave him the example that if his study did not take into account all of the costs that are allocated to wholesale customers and there were, indeed, a fair share of costs allocated to wholesale customers that are not reflected, that is not reflected in the A Schedules that Mr. Collins looked at, what the impact would be on the conclusions that he reached, were you there when I asked him that?

A. Yes, I was.

Q. What would be the impact to you on Mr. Collins' conclusions and your adoption of them if that is proven to be the case in this proceeding?

A. I don't really know.

MR. McWHIRTER: Mr. Pollock, I object to the form of the question unless you define what you mean by

fair share.

BY MR. BEASLEY:

Q. If they are allocated a prorated portion of all fuel and purchased power costs in making the sales.

MR. McWHIRTER: You may proceed to answer with that understanding.

A. I think in my testimony I said that the separated sales should be allocated average system costs, which means they get a slice of the fuel as well as a slice of the purchased power costs, and in that sense, if that can be shown that that is happening and you can convince us, and since we are from Missouri you've got to show us, then we would obviously be not as concerned.

On the other hand, we said on the subsidy, nonseparated sales there should be an incremental cost, and again you need to show us that that is happening and that the customers are not being harmed accordingly.

BY MR. BEASLEY:

Q. Isn't that a subject that is being addressed in another docket before the Florida Public Service Commission?

A. I'm not certain which other docket you're talking about.

Q. Okay. Bear with me a moment. I'll guarantee you that the time I'm taking will save more time than I am

taking.

A. I'm happy to do that.

Q. On page 16, lines 4 through 17 you say that Tampa Electric's wholesale customers or shareholders should be required to bear some of the consequences resulting from "frequent and severe outages and capacity derations" of Tampa Electric's internal generating capacity.

Have you analyzed the nature and the causes of any of Tampa Electric's outages or derations?

A. Mr. Collins would have conducted that analysis, and I think the issue there is who should be required to bear the consequences of that regardless of what the cause is. There may be perfectly legitimate causes, but it's a question of who pays for that.

Q. I don't think, from my recollection, Mr. Collins addresses any unit specific outages or derations.

A. He does not address the underlying causes other than reports that units were either derated for various reasons as shown in one of the exhibits in his testimony, so in that sense he is reporting what information was provided to him, besides the fact, though, that the real issue is who bears the consequences of that unreliability, and to us it does not appear that the wholesale customers are bearing any responsibility, and

that's the problem.

Q. Why do you include the shareholders in that statement?

A. Well, because what will happen is that you're allowed by contract or by FERC tariff to charge so much for the electricity you get from wholesale, to the extent that a proper separation of fuel costs results in an allocation of fuel costs that's more than what is assumed to be recovered through the contract or through the FERC or through tariff, then some of the consequences will be borne by the company's shareholders. Properly so.

Q. Do you personally know, or do you defer to Mr. Collins' study what purchased power cost Tampa Electric currently charges to and collects from the wholesale customers it currently serves pursuant to separated wholesale sales?

A. I think neither of us have looked at the issue and neither of us believe that that is really the relevant issue in this case. We understand that you have tariffs and contracts with wholesale customers, but that is not the issue.

Q. Okay. Well, do you know what purchased power costs Tampa Electric currently allocates to its wholesale customers pursuant to separated wholesale sales?

Do you address that, or do you you defer to

Mr. Collins' study in that regard?

A. I do not address that in my testimony. I think Mr. Collins addresses that in his.

Q. Do you know what that is? Do you know what purchased power cost Tampa Electric currently allocates to wholesale customers served pursuant to separated wholesale sales?

A. As I recall Mr. Collins' testimony on that, and correct me if I'm wrong, or he'll correct me if I'm wrong, I think you can see in the A Schedules what costs are being incurred and which ones are being allocated to wholesale and which ones are being paid by retail. I think that is the focal point of the analysis.

Q. In preparing your testimony, Mr. Pollock, did you look at any Florida Public Service Commission orders addressing the appropriate treatment of separated and nonseparated wholesale sales and the fuel and power purchase, purchased power cost recovery cost?

A. Yes. I have looked at several orders, yes.

Q. Do you recall which ones they were, what years?

A. The ones I have looked at specifically are the '97 orders, the '97 order stating a generic policy about assigning average system cost. I think Mr. Collins referenced this in his deposition, and I refer to that.

And I also, I participated in the Lakeland FMPA separation issue, also reviewed the terms of the commission's order in that case as well.

Q. That '97 order, that is the order that said it applied prospectively, is it not?

A. You're talking about the generic case?

Q. The '97 order addressing separated and nonseparated wholesale sales?

A. I'm not sure it said prospectively, but, you know, yes, I reviewed it. I obviously haven't remembered every single word in it, but it seems to me that --

A. It says what it says; right?

A. It says what it says, and whatever it says we should follow.

Q. Do you have any evidence to support or suggest that Tampa Electric is in violation of any commission prescribed policy concerning the allocation of cost between the retail and wholesale markets between separated and nonseparated wholesale sales?

A. I think Mr. Collins' analysis raises some serious questions about that, yes.

Q. You don't have any?

A. Well, I'm relying on Mr. Collins.

Q. Okay.

A. And, too, as I said before, you know, there

is this unexplained difference between the retail and wholesale average fuel costs that continues to be worrisome.

Q. Any evidence you have is only hearsay then since you simply rely on what Mr. Collins' concludes?

A. I reviewed Mr. Collins' work, of course, and have reviewed his testimony and have reviewed his analysis and I have done a separate review of the fuel reports, so to some degree I'm relying on Mr. Collins, but I'm also relying on knowledge that I personally have about the company and my experience with the company and the review of their reports.

Q. Do you think the audits performed by the Florida Public Service Commission addressed these issues?

A. These are issues that -- and no criticism intended of the commission. I think these are issues that are not typically considered in a regulatory review process. We are talking about some very, very specific data intensive types of analyses, and maybe the commission has done this. I noticed they have submitted a number of interrogatories, and perhaps they have submitted their, or are about to submit the results of their analysis, but this is not the kind of analysis that would be done, I would say, in a routine recurring form like a fuel adjustment case, and this is a very highly specialized

specific type of analysis that you do only when you have an occasion that there might be a serious problem.

Q. Mr. Collins, we are not necessarily -- Mr. Pollock, we are not necessarily talking about the analysis that Mr. Collins performed or attempted to perform.

We are talking about the analysis that the Florida Public Service Commission does to satisfy itself that the utilities it regulates are doing exactly what they are supposed to do in the way of allocating costs, charging costs, collecting costs, and things related to that.

Do you believe that the commission -- first of all, are you aware of what the Florida Public Service Commission does when it audits electric utilities under its jurisdiction?

A. I'm not familiar with the practices of the Florida Commission in that regard, and my response to you wasn't trying to evade the question. It was simply that this is not the kind of analysis that would, that I would think would normally be the subject of a commission audit in a recurring regulatory proceeding like a fuel and purchased power case. Quite possibly the commission is doing the same analysis. The truth is, we don't know.

Q. Do you have any reason to believe that the Florida Public Service Commission is doing an adequate job

when it comes to evaluating and passing muster on the way in which the utilities under its jurisdiction allocate costs as between wholesale and retail customers?

A. I have no question that the commission is doing the best job that it can with the personnel and the staff and the budget that it has. I can't really say, and I wouldn't presume to judge whether that is an adequate job or a great job, or terrible job. My experience is that the commissions do the best they can do with the tools that they have.

Q. Well, if you had some sort of special investigation, who would be the final party to make a recommendation to the commission as to what results you'd obtain?

A. Well, I would hope that intervenors that bring a problem to the commission's attention would trigger the kind of analysis and kind of investigation that we think really needs to be done in this case, and we are hopeful that the staff will carefully review and objectively analyze the evidence that we have brought in this case, and make a determination accordingly.

Q. You don't know of any commission prescribed policy that Tampa Electric is in violation of, do you?

A. Well, other than the average system cost policy that we have talked about, and other than the fact

that, you know -- the commission's policies are fine, but you have to keep in mind the context in which the policies are implemented.

This last several years, since Order 888, the wholesales markets and so on, I don't think commission policy really, in all fairness really contemplated the impact of these tremendous changes in the market environment that we have experienced, and so even if the commission said you do it this way, the fact of the matter is that if circumstances change and the commission sees that as a result customers are being harmed, you know, just harmed, then the commission should feel free to make new policy and address the problem.

Q. You were in the room, were you not, when I asked Mr. Collins some questions regarding large interruptible customers and whether their scheduling of their demand, and whether their shutting down and starting up their processes could have an impact on the operations of an electric utility, were you not?

A. I was in the room, yes.

Q. All right. Do you think it would be appropriate for interruptible customers who have significant levels of demand to provide notice to a utility like, for example, Tampa Electric when they plan to make significant changes in their levels of demand or

take their operations down on a temporary basis?

A. I think actually customers do have to coordinate things like starting motors and that with you, because that has such an impact on the system's integrity and particularily on the voltage in the system, that I would think that that protocol has already been in place.

I'm pretty sure, at least in the case of IMC is coordinating those things with you already. You know, the system is obviously a lot bigger than the interruptible customers, and they are one part of the overall system. The generators see the diverse loads of all of the customers, but clearly if there is a situation where customers suddenly bring load on or take load off, you know, that is something that should be coordinated, and I suspect that in some respects is already coordinated.

Q. Would you think that perhaps a 90-day notice requirement might be reasonable for the protection of the utility's system and the coordination of the system with the system of the large industrial customer?

A. To be perfectly honest, I have not really thought about this in context of this proceedings what the requirement should be, if any.

You know, I think you have to look at the circumstances and if the company says that we went out,

you know, we incurred these costs because we thought your power demand was going to be at one level, and it turned out to be different, and that has a significant impact on customers as a whole, then I think it's legitimate to have discussions with your customers and see if you can't have a better working relationship to provide for that coordination.

I will say that in some jurisdictions customers that are under some rates and tariffs are required to periodically submit schedules of their power demands. I'm not suggesting that that is the solution here. I rather think that we need to have more, a better analysis of the problem and its consequences to see what solution is best for all parties.

MR. BEASLEY: Your witness, Mr. McWhirter.

MR. McWHIRTER: I have no questions of the witness.

We want to read and sign.

MR. BEASLEY: Do any parties that might be on the line have any questions of the witness?

There may not be any other parties on the line.

SIGNATURE PAGE

(This is the signature page to the telephone deposition of JEFFRY POLLOCK, taken on November 1, 2001, In re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor.)

_____

JEFFRY POLLOCK

Subscribed and sworn to before me this _____ day of _____, A.D., 2001.

My commission expires _____.

_____

Notary Public, within and for the State of Missouri

Please return signature page and correction sheets to:

Messrs. Ausley & McMullen
Attn: James D. Beasley
227 South Calhoun Street
Tallahassee, Florida 32301

NOTARIAL CERTIFICATE

STATE OF MISSOURI)
) SS.
COUNTY OF ST. CHARLES)

I, JANINA A. JAEGER, a Registered Professional Reporter and a duly commissioned Notary Public within and for the State of Missouri, do hereby certify that there came before me at the offices of Brubaker & Associates, 1215 Fern Ridge Parkway, St. Louis, Missouri,

JEFFRY POLLOCK,

who was by me first duly sworn to testify to the truth and nothing but the truth of all knowledge touching and concerning the matters in controversy in this cause; that the witness was thereupon carefully examined under oath and said examination was reduced to writing by me; that the signature of the witness was not waived; and that this deposition is a true and correct record of the testimony given by the witness.

I further certify that I am neither attorney nor counsel for nor related nor employed by any of the parties to the action in which this deposition is taken; further, that I am not a relative or employee of any attorney or counsel employed by the parties hereto or financially interested in this action.

IN WITNESS WHEREOF, I have hereunto set my hand and seal this_____day of November, 2001.

My commission expires April 1, 2004.

_____
Notary Public, within and
for the State of Missouri

WITNESS: JEFFRY POLLOCK

In Re: Fuel and Purchased Power Cost Recovery Clause and Performance Incentive Factor
November 1, 2001

DEPOSITION CORRECTION SHEET

UPON READING THE DEPOSITION AND BEFORE SUBSCRIBING THERETO, THE DEPONENT INDICATED THE FOLLOWING CHANGES SHOULD BE MADE:

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Deponent

NOTARIAL CERTIFICATE

STATE OF MISSOURI)
) SS.
COUNTY OF ST. CHARLES)

I, JANINA A. JAEGER, a Registered Professional Reporter and a duly commissioned Notary Public within and for the State of Missouri, do hereby certify that there came before me at the offices of Brubaker & Associates, 1215 Fern Ridge Parkway, St. Louis, Missouri,

JEFFRY POLLOCK,

who was by me first duly sworn to testify to the truth and nothing but the truth of all knowledge touching and concerning the matters in controversy in this cause; that the witness was thereupon carefully examined under oath and said examination was reduced to writing by me; that the signature of the witness was not waived; and that this deposition is a true and correct record of the testimony given by the witness.

I further certify that I am neither attorney nor counsel for nor related nor employed by any of the parties to the action in which this deposition is taken; further, that I am not a relative or employee of any attorney or counsel employed by the parties hereto or financially interested in this action.

IN WITNESS WHEREOF, I have hereunto set my hand and seal this_____day of November, 2001.

My commission expires April 1, 2004.

Notary Public, within and
for the State of ~~Missouri~~

WITNESS: JEFFRY POLLOCK

In Re: Fuel and Purchased Power Cost Recovery Clause and
Performance Incentive Factor
November 1, 2001

DEPOSITION CORRECTION SHEET

UPON READING THE DEPOSITION AND BEFORE SUBSCRIBING THERETO, THE DEPONENT INDICATED THE FOLLOWING CHANGES SHOULD BE MADE:

Page 12 Line 15 Should read: "objected" replaces "rejected"

Reason assigned for change:

Page 35 Line 7 Should read: Strike "not"

Reason assigned for change:

Page 39 Line 8 Should read: Strike "and" and insert "of"

Reason assigned for change:

Page Line Should read:

Reason assigned for change:

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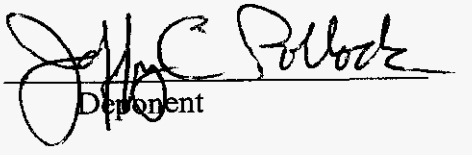
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Deponent

SIGNATURE PAGE

(This is the signature page to the telephone deposition of JEFFRY POLLOCK, taken on November 1, 2001, In re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor.)

JEFFRY POLLOCK

Subscribed and sworn to before me this 19th day of November, A.D., 2001.

My commission expires

BRENDA A. ETHERIDGE
MY COMMISSION # CC 934834
EXPIRES: May 8, 2004
Bonded Thru Notary Public Underwriters

Notary Public, within and for the State of Missouri

Please return signature page and correction sheets to:

Messrs. Ausley & McMullen
Attn: James D. Beasley
227 South Calhoun Street
Tallahassee, Florida 32301

7555

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re:	)	
Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor	)	Docket No. 010001-EI

Intervenor Testimony and Exhibits of

Jeffry Pollock

On behalf of

Florida Industrial Power Users Group

October 2001

BAI

BRUBAKER & ASSOCIATES, INC.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: **Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor**	**Docket No. 010001-EI**

Intevenor Testimony of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock; 1215 Fern Ridge Parkway, Suite 208; St. Louis, MO 63141-2000.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and a principal in the firm of Brubaker & Associates, Inc. (BAI).

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I am a graduate of Washington University. I hold the degrees of Bachelor of Science in Electrical Engineering and Master of Business Administration. At various times prior to graduation, I worked for the McDonnell Douglas Corporation in the Corporate Planning Department; Sachs Electric Company; and L. K. Comstock & Company. While at McDonnell Douglas, I analyzed the direct operating cost of commercial air-craft.

Upon graduation, in June 1975, I joined the firm of Drazen-Brubaker & Associates, Inc. Drazen Brubaker & Associates, Inc. (DBA) was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. Brubaker & Associates, Inc. (BAI) was formed in April, 1995. In the last five years, BAI and its predecessor firm has participated in more than 700 regulatory proceeding in forty states and Canada.

During my tenure at both DBA and BAI, I have prepared numerous financial and economic studies of investor-owned, cooperative and municipal utilities, including revenue requirements, cost of service studies, rate design, site evaluations and service contracts. Recent engagements have included advising clients on electric restructuring issues, developing responses to utility request for proposals (RFPs), and managing RFPs for clients. I am also responsible for developing and presenting seminars on electricity issues.

I have worked on various projects in over twenty states and in two Canadian provinces, and have testified before the regulatory commissions of Alabama, Arizona, Colorado, Delaware, Florida, Georgia, Illinois, Iowa, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, Ohio, Pennsylvania, Texas, Virginia and Washington. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets.

Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Kerrville, Texas; Plano, Texas; Denver, Colorado; and Chicago, Illinois.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). The participating FIPUG members are customers of Tampa Electric Company (TECO). They purchase substantial quantities of electricity from TECO under a variety of firm and non-firm tariffs.

Q WHAT ARE FIPUG'S INTERESTS IN THIS DOCKET?

A According to the testimony filed by TECO witness, J. Denise Jordan, TECO forecasts that its fuel and purchased cost recovery would increase from 2.82¢ to 3.30¢ per kWh, which would be a 17% increase in charges to TECO's retail customers. Virtually all of this increase can be traced to the proposed $86 million true-up. As fuel costs are a significant component of the electricity costs incurred by FIPUG members, BAI was requested to determine the cause and render an opinion on the appropriateness of this increase.

Q WHAT ISSUES ARE YOU ADDRESSING IN YOUR DIRECT TESTIMONY?

A I shall summarize the results of the audit conducted by my colleague, Mr. Brian C. Collins, of how TECO has been managing various long-term wholesale power contracts. In particular, my testimony addresses whether retail customers have been harmed by TECO's administration of these contracts and recommends specific actions that the Commission should undertake to protect the interests of TECO's retail customers. Finally, I shall address several other issues raised in Ms. Jordan's testimony, on behalf of TECO.

Summary

Q WOULD YOU PLEASE SUMMARIZE THE FINDINGS REVEALED IN MR. COLLINS' AUDIT?

A Yes. TECO has put its own interests, and those of its long-term wholesale contract customers, ahead of the interests of its retail native load customers. As Mr. Collins testifies, wholesale customers have benefited from, and are continuing to receive, a much more reliable and cost-effective supply of electricity than have TECO's retail customers.

While wholesale customers are directly benefiting from TECO's lowest cost generation and low-cost purchases, retail customers are having to bear the excessive costs of the power that TECO must purchase in volatile deregulated wholesale markets to replace internal generation. Since 1997, non-firm customers have experienced dramatic increases in both the frequency and duration of interruptions. Optional Provision Purchases have increased over 200% since 1997. This 200% increase has coincided with the time frame when most of TECO's long-term wholesale contracts were entered into. Because TECO's wholesale load

exceeds its non-firm loads, some of these purchases are also being made for the benefit of TECO's firm retail customers.

The more frequent interruptions and off-system purchases can also be traced to the deteriorating reliability of TECO's internal generation. Mr. Collins' analysis reveals that there were instances when over 800 MW or 22% of TECO's internal generation capacity was unavailable because of forced outages or capacity deratings. Despite these circumstances, during which non-firm customers are being curtailed and TECO is having to purchase expensive replacement power, TECO's wholesale customers are continuing to receive their full entitlement to TECO's cheap coal-fired capacity.

Not only are retail customers receiving an inferior quality of service, they are paying excessively for it. Retail customers pay the fixed costs incurred by TECO to construct, operate and maintain its generating capacity, including several large relatively low operating cost coal-fired units, in their base rates. However, despite supporting the fixed costs of TECO's generation capacity, retail customers are paying significantly higher fuel costs. These higher costs may be attributed to the fact that the cost of all replacement purchases are allocated by TECO entirely to native retail customers. This practice is unfair. The retail customers who are supporting the fixed costs of generation capacity should be the beneficiaries of the lower operating costs of this capacity. To do otherwise would be tantamount to a forced subsidy by retail customers of TECO's long-term wholesale contracts.

Mr. Collins has also quantified the subsidies to wholesale customers on days when non-firm load was being curtailed – because of either a service interruption or an economic interruption. On these particular days, he determined that retail

customers were overcharged by over 3¢/kWh. Extrapolating this amount over 3 years (1999-2001) would yield a subsidy of between $45 and $108 million. A precise calculation of the subsidy could not be made because it would require considerably more data, time and resources than could be devoted. Also, most of the required data was not provided in a timely manner.

Q WHAT ACTIONS SHOULD THE COMMISSION UNDERTAKE AS A RESULT OF THE AUDIT CONDUCTED BY MR. COLLINS?

A Based on these findings, the Commission should take the following actions:

(1) TECO should be ordered to cease its current practice of allocating 100% of replacement power costs to retail customers and to allocate a pro rata share of all replacement power purchases to wholesale operations. Separated sales should be charged average system fuel and purchased power costs, while non-separated sales should be charged system incremental costs.

(2) Because TECO refused to fully respond to all FIPUG data requests, we are not able to quantify the magnitude of the past overcharges to retail customers. The Commission should open a docket requiring TECO to quantify the refunds due to retail customers as a result of TECO's inappropriate management of its long-term wholesale contracts.

(3) The Commission should hold the proposed $86 million fuel true-up in abeyance pending the outcome of this new docket.

(4) The Commission should conduct a more thorough investigation of TECO's affiliate transactions and its procurement of power for wholesale customers. Specifically, Mr. Collins has observed that TECO has purchased low-cost

power at wholesale and directly allocated this purchase to wholesale customers. The issue to be resolved is whether this practice and TECO's affiliate transactions are both prudent and beneficial to retail customers.

Q SHOULD A NEW FUEL FACTOR BE APPROVED AT THIS TIME?

A No. The fuel factor should not be implemented until after the Commission completes a thorough investigation of TECO's wholesale pricing practices. Even if the Commission ultimately decides for TECO, it will not be hurt because it will receive full recovery, with interest. In light of the fact that fuel costs are now trending downward for the other utilities in this state, raising TECO's fuel factor to the level proposed, prior to the investigation, would cause unnecessary economic harm and place some customers at a competitive disadvantage.

Audit of Wholesale Pricing Practices

Q WHAT IS THE BASIS FOR YOUR CLAIM THAT TECO HAS PUT THE INTERESTS OF ITS WHOLESALE CUSTOMERS AHEAD OF ITS OBLIGATION TO SERVE RETAIL NATIVE LOAD CUSTOMERS?

A This statement is based on the results of Mr. Collins' audit of TECO's wholesale pricing practices. Specifically, Mr. Collins determined that:

- TECO has been inappropriately allocating more expensive replacement purchased power solely to retail customers while simultaneously selling low-cost native generation to wholesale customers.

- TECO has been purchasing low-cost power on the wholesale market and reselling it to wholesale customers, rather than using this lower cost power to reduce the fuel costs paid by retail customers.
- Wholesale customers have continued to receive their full entitlement of cheap, native load generation while non-firm customers are being curtailed and the rest of the TECO system is experiencing severe shortages of native generation due to outages and frequent deratings of internal generation, including the specific generators from which wholesale sales are being made.

As a result of these practices, we estimate that retail customers are subsidizing wholesale customers and TECO's shareholders, who are the beneficiaries of the higher margins derived from wholesale sales. Based on this estimate, retail customers have been overcharged by between $45 and $108 million for fuel costs during the years 1999, 2000 and 2001.

Q **HOW WAS THIS ESTIMATE DERIVED?**

A Mr. Collins derived the estimated subsidies by analyzing the cost of purchased power charged to retail customers, which should have been allocated to wholesale contract customers. The analysis was on specific days when non-firm load was being curtailed. This includes both service and economic interruptions. On these days, the wholesale customers were being charged only for energy as though it had been generated entirely from TECO's low-cost coal-fired resources. During economic curtailments, non-firm customers are charged directly for the more expensive wholesale power purchases while any remaining purchases are allocated to firm retail customers. Thus, retail customers are subsidizing the low-cost energy sales to wholesale contract customers because they alone are forced to bear the higher costs incurred by TECO to maintain both its wholesale sales and system reliability.

Q **HAVE ANY SPECIFIC CUSTOMERS BORNE THE BRUNT OF TECO'S INAPPROPRIATE MANAGEMENT OF ITS WHOLESALE POWER CONTRACTS?**

A Yes. All retail customers have been charged higher replacement costs for power that TECO purchased. However, the non-firm customers have borne the brunt of TECO's ever-increasing need to purchase replacement power due to frequent and major outages of its own generation resources. Exhibit ____ (JP-1) is a history of service interruptions since 1996.

As can be seen, both the frequency and duration of service interruptions have increased since 1996. There were only 3 interruptions in 1996 as compared to

16 interruptions in 1999. The total duration of these interruptions has increased from about one hour in 1996 to over 53 hours in 1999.

Q WHAT ARE ECONOMIC INTERRUPTIONS?

A Economic interruptions occur when TECO does not have sufficient internal resources to continue providing system service to non-firm customers. If available elsewhere, TECO will purchase power in lieu of a service interruption of non-firm service. These purchases are made under the Optional Provision in TECO's various non-firm tariffs.

Q WHAT HAS BEEN THE HISTORY OF ECONOMIC INTERRUPTIONS?

A Economic interruptions have been increasing both in frequency and in duration. Exhibit ____ (JP-2) summarizes the amount of energy that TECO purchased during these interruptions (i.e., "Optional Provision Purchases"). As can be seen, since 1996, the amount of Optional Provision Purchases has increased by 13 times. Mr. Collins has observed that this dramatic increase in economic interruptions has coincided with the effective dates of TECO's long-term wholesale contracts.

Q WHAT IS TECO PAYING FOR THE OPTIONAL PROVISION PURCHASES FOR NON-FIRM CUSTOMERS DURING ECONOMIC INTERRUPTIONS?

A More serious than the increase in both the frequency and duration of economic interruptions is the cost of the Optional Provision Purchases. Exhibit ____ (JP-2) also summarizes the cost of these purchases from 1996 through mid-2001.

As can be seen, in 1996, the average cost of the Optional Provision Purchases was 5.2¢ per kWh. By 1999, the average cost had risen to 9.4¢, an 81% increase. Thus far in 2001, the average cost of Optional Purchases has been 11.8¢. To put these costs into perspective, the average delivered cost of electricity to residential customers was around 7.7¢ as of December 1999. Thus, the Optional Purchases have become significantly more expensive than the total delivered cost of electricity sold to residential customers.

Not shown in this Exhibit are the extremely high prices TECO is paying for some of this Optional Purchases. According to TECO's fuel reports, the average cost of certain power purchases has ranged from 10¢ to up to 340¢ per kWh.

Q DOES IT COST A UTILITY MORE THAN 10¢ PER kWh TO GENERATE ELECTRICITY AT WHOLESALE?

A No. This is well-above the incremental cost of generating electricity. The extra charges provide a contribution to fixed costs and profit to the selling party.

Q THEN WHY IS TECO PAYING SUCH HIGH PRICES FOR REPLACEMENT ENERGY?

A TECO has no incentive to minimize the cost of purchased energy. This is because all purchased energy costs are directly flowed through to customers. Initially, the non-firm customers are directly charged for purchases made under the Optional Provision. However, any residual purchases not charged to non-firm customers are flowed through the fuel and purchased power cost recovery clause. Thus, firm retail customers are clearly impacted by TECO's wholesale pricing practices.

Q WHY ARE THESE REPLACEMENT POWER PURCHASES SO EXPENSIVE?

A Since FERC Order No. 888, wholesale markets have been deregulated. Many wholesale participants – including utilities, marketers, brokers, and other traders – have sought and received FERC approval to buy and sell electricity at market-based prices. This means that if these suppliers want to sell electricity to TECO and TECO is in the market to buy electricity, TECO will have to pay the market price. As previously stated, market prices in many instances will be well above the actual incremental cost to generate electricity.

Q IS TECO HARMED BY PURCHASING ELECTRICITY AT MARKET-BASED PRICES?

A No. TECO can pass through dollar-for-dollar every fuel and purchased power cost that it incurs, subject to Commission review. Further, I am not aware of any ongoing review of the reasonableness of the Optional Provision Purchases that are being directly charged to non-firm customers.

Q WHAT ARE THE CONSEQUENCES OF THE DEREGULATION OF THE WHOLESALE MARKETS?

A Wholesale price deregulation means that native load customers in general (and non-firm customers in particular) are being exposed to considerable price risk. This is a fundamental change in the regulatory bargain. Prior to wholesale deregulation, wholesale transactions were made either at cost of service or on a split the savings basis. In the latter event, the split the savings was based on the difference between the sellers' and the buyers' actual cost. Thus, prices generally remained stable.

Today, and in the recent past, wholesale participants that have been granted market based pricing authority from the FERC can charge whatever the market will bear for replacement energy. Utilities that are having to buy power in the wholesale markets more frequently, either because they lack sufficient internal generation or the existing capacity is unreliable, will experience significant price risk. However, all of this risk is passed through to retail customers since they are the ones who are required to bear these costs under the present regulatory policy.

Q DID TECO'S CUSTOMERS AGREE TO INSULATE TECO FROM PRICE RISKS RESULTING FROM THE DEREGULATED WHOLESALE POWER MARKETS?

A No. TECO's last full rate case pre-dated FERC Order No. 888 and the subsequent deregulation of the wholesale power markets. Thus, TECO's retail rates, terms and conditions and the Commission's rules governing Non-Firm Loads were established in a totally different regulatory environment than currently exists. Clearly, the fact that TECO's retail customers are having to bear excessively higher replacement purchased energy costs, while TECO maintains significant low-cost sales to wholesale customers, is a fundamental shift in risk from TECO's shareholders to its retail customers. This is not the bargain that retail customers agreed to.

Q WHY IS TECO MOTIVATED TO SELL VERY LOW-COST ELECTRICITY INTO THE WHOLESALE MARKETS?

A TECO's motivation is profit. Longer term wholesale markets are highly competitive. In contrast to regulation, competition tends to drive prices down because customers can purchase electricity from another supplier. However, in order to effectively

compete in these wholesale markets, the seller must not only offer a low price, the low price must be guaranteed for the life of the contract. Without this guarantee, the buyer will not have the confidence in the seller's ability to live up to the agreement and will choose another supplier.

Given the competitive nature of long-term wholesale markets, the only way to make a profit is to provide power at the lowest possible cost. The margins on these sales are the difference between the selling price and the associated cost. The lower the associated costs of selling power under long-term wholesale contracts, the greater the margins.

Thus, TECO has a strong incentive to minimize the fuel costs associated with long-term wholesale sales. By minimizing the actual cost, TECO can maximize its profit. These profits flow 100% to TECO's shareholders for sales that have been jurisdictionally separated. All other off-system sales margins are shared 80%/20% between retail customers and TECO's shareholders, respectively after a threshold is met. However, TECO can raise its 20% share of these margins by selling as much low-cost power to wholesale customers as is possible.

Q ARE TECO'S SHAREHOLDERS REQUIRED TO BEAR ANY PRICE RISK ASSOCIATED WITH WHOLESALE SALES?

A No. As previously stated, TECO does not allocate the higher cost of replacement power purchases to wholesale customers. The wholesale customers benefit from low-cost energy generated from TECO's most efficient coal-fired units. Further, all other purchased energy costs are passed through to retail customers. This means

that neither the wholesale customers nor TECO's shareholders bear any market price risk.

Q IS THE DRAMATIC SHIFT IN MARKET PRICE RISK FROM TECO'S SHAREHOLDERS TO CUSTOMERS CONSISTENT WITH TECO'S OBLIGATION TO SERVE?

A No. Utilities have an obligation to provide reliable service to all retail customers (firm and non-firm) at the lowest reasonable cost. TECO, on the other hand, has clearly been giving preferential treatment to its wholesale customers. Retail customers have borne the brunt of very expensive power purchases in the wholesale markets. This is despite the fact that the retail customers pay the lion's share of the fixed costs required to construct, operate, and maintain TECO's internal generation capacity. Fairness demands that these customers are entitled to receive the benefits of the lower cost energy that can be provided from these capacity resources.

Instead, TECO has been siphoning its low-cost generation to wholesale markets and replacing it with higher cost purchases, which have been borne solely by retail customers. Not only does this practice not comport with TECO's obligation to serve, it demonstrates how TECO has reneged on this regulatory bargain to its captive retail customers.

Q WHAT ACTION SHOULD THE COMMISSION TAKE TO PROTECT THE INTERESTS OF RETAIL CUSTOMERS?

A First, TECO's 2002 fuel rates should not be adjusted from current levels until a thorough investigation into the issues presented in this testimony is completed.

Second, TECO should be ordered to cease its current practice of allocating 100% of replacement power costs to retail customers. Wholesale customers or TECO's shareholders should be required to bear some of the consequences resulting from frequent and severe outages and capacity deratings of its internal generation capacity. Thus, the Commission should require TECO to allocate a pro rata share of all replacement purchased energy costs to wholesale operations. This treatment would be especially appropriate when TECO is simultaneously purchasing high-cost power while selling low-cost power to its long-term wholesale contract customers.

Third, this practice has been ongoing since at least 1997. However, because of time and resource limitations and also TECO's resistance in responding to critical requests for production of documents and interrogatories, we have not been able to conduct a thorough analysis to quantify the impact on retail customers of TECO's wholesale sales practices. Mr. Collins has estimated that the potential harm to retail customers from 1999 through 2001 could be between $45 and $108 million. However, a more thorough investigation is required.

My recommendation is that the Commission convene an investigation and require TECO to quantify the impact of its wholesale costing and pricing practices on retail customers. The goal of this investigation would be to quantify the subsidies provided by retail customers to help underwrite TECO's low-cost wholesale sales and to assure that TECO's wholesale purchases from affiliate companies were prudent.

Q IN LIGHT OF THESE FINDINGS, SHOULD THE COMMISSION APPROVE TECO'S REQUEST TO RECOVER $86 MILLION OF PAST UNDER-COLLECTIONS?

A No. Given the amount of money at stake, it would be premature to allow TECO to begin recovering past under-collected amounts from retail customers. Therefore, I recommend that the Commission put the $86 million true-up in abeyance pending the outcome of the further investigation.

Q SHOULD ANY OTHER ACTIONS BE TAKEN BY THE COMMISSION AT THIS TIME?

A Yes. Mr. Collins also observed that TECO has purchased low-cost power from the wholesale markets and assigned 100% of the cost to wholesale customers. In other words, TECO did not take advantage of the opportunity to purchase low-cost power in the wholesale markets for the benefit of its native retail customers. The Commission should, therefore, investigate whether this practice is prudent and why TECO is not also purchasing low-cost power for the benefit of retail customers.

Other Issues

Q TECO IS PROPOSING TO RECOVER ANY GAINS OR LOSSES FROM HEDGING ITS FUEL TRANSACTIONS THROUGH FUTURES CONTRACTS THROUGH THE FUEL AND PURCHASED POWER COST RECOVERY CLAUSE. SHOULD THIS PROPOSAL BE IMPLEMENTED?

A No. According to the testimony of TECO witness, W. Lynn Brown, TECO does not purchase or sell wholesale energy derivatives. Further, Mr. Brown states that the cost of conducting physical and financial hedges in a developing market, such as Florida's wholesale energy market, could be quite high. He recommends that the Commission conduct an assessment of the quantitative and qualitative costs and benefits of physical and/or financial hedging.

Accordingly, it would be premature to authorize cost recovery until the Commission has had an opportunity to assess the costs and benefits of a specific hedging program that TECO proposes to implement.

Q TECO CLAIMS THAT THE APPROPRIATE REGULATORY TREATMENT FOR CAPITAL PROJECTS THAT ARE EXPECTED TO REDUCE LONG-TERM FUEL COST SHOULD BE RECOVERED THROUGH THE FUEL AND PURCHASED POWER COST RECOVERY CLAUSE. DO YOU CONCUR?

A No. It would not be appropriate to recover the costs of investments and the associated carrying costs through the fuel and purchased power cost recovery clause. These are the very types of costs that are properly recovered in base rates. Attempts to distinguish the purpose of specific investments could also invite gaming. A utility could claim that the entire investment in a new state-of-the-art power plant

that was installed to replace an older, less efficient plant should be recovered through the fuel and purchased power cost recovery clause just because it may result in lower long-term fuel costs. No purpose would be served by giving such investments special treatment or more timely recovery than is accorded to all other rate base investments. Special cost recovery for such investments could send the wrong incentive. A utility would be encouraged to over-invest in capital just to save fuel costs. However, there is no assurance that the combination of increased capital costs and lower fuel costs would result in the lowest overall costs for the utility's retail customers.

Q WHY ELSE WOULD RECOVERY OF SPECIAL CAPITAL PROJECTS NOT BE APPROPRIATE?

A This Commission has historically maintained a clear separation between base rates and fuel costs. The recovery of capital projects and the associated carrying costs through the fuel and purchased power cost recovery clause would blur this distinction. To quote Ms. Jordan, "Mixing the fuel adjustment mechanism with base rates would cause nothing but confusion, delay and inequity. This would defeat the very purpose of the fuel adjustment clause."

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

EXHIBIT NO. _____
DOCKET NO. 010001-EI
TAMPA ELECTRIC COMPANY
(JDJ-4)

TAMPA ELECTRIC COMPANY
WHOLESALE PROJECTED AVERAGE SYSTEM FUEL COST ADJUSTMENT

FOR THE PERIOD JANUARY 2002 THROUGH DECEMBER 2002

	DOLLARS	MWH	CENTS/ KWH
1. TOTAL FUEL AND NET POWER TRANSACTIONS (Schedule E-1, Line 28)	524,987,155	18,930,734	
1a. LESS FERC NON-RECOV. FUEL EXPENSES	(1,437,577)		
2. PEABODY COAL CONTRACT BUY-OUT AMORT.	3,615,631		
3. JURISDICTIONAL SALES O & M AND GAINS	3,349,700		
4. FIRM EMERGENCY PURCHASE O & M	0		
5. TOTAL (LINES 1 THRU 4)	530,514,909	18,930,734	2.802
6. LOSS FACTOR			0.97570
7. AVERAGE SYSTEM FUEL COSTS INCL. LOSSES (Line 5 X Line 6)			2.734
8. BASE AVERAGE SYSTEM FUEL COSTS (Per FERC AR-1 Tariff)			2.159
9. ADJUSTMENT (Line 7 - Line 8)			0.575

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 11
COMPANY/ WITNESS: Jordan
DATE: 11-1-01 & 11-21-01

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

Final True-Up Amount
January through December 2000

VARIANCE ANALYSIS (JP-1)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 13
COMPANY/ WITNESS. Portuondo
DATE: 11-20&21-01

Florida Power Corporation
Docket No. 010001-EI
Witness: Portuondo
Exhibit No. (JP-1)
Sheet 1 of 3

FLORIDA POWER CORPORATION
Fuel Adjustment Clause
Summary of Final True-Up Amount
January 2000 through December 2000

Line No.	Description	Contribution to Over/(Under) Recovery Period to Date
1	**KWH Sales:**	
2	Jurisdictional KWH Sales	258,589,546
3	Non-Jurisdictional KWH Sales	109,417,882
4	Total System KWH Sales Increased	
5	Schedule A2, pg 2 of 4, Line C1 through C3	368,007,428
6		
7	**System:**	
8	Fuel and Net Purchased Power Costs - Difference	
9	Schedule A2, page 3 of 4, Line D4	$ 155,763,456
10		
11	**Jurisdictional:**	
12	Fuel Revenues - Difference	
13	Schedule A2, page 3 of 4, Line D3	$ 66,424,398
14		
15	True Up Provision for the Period Over/(Under)	
16	Collection - Estimated	
17	Schedule A2, page 3 of 4, Line D7	(1,603)
18		
19	Net Fuel Revenues	66,422,795
20		
21		
22	Fuel and Net Purchased Power Costs - Difference	
23	Schedule A2, page 3 of 4, Line D6	148,989,105
24		
25	True Up Amount for the Period	(82,566,310)
26		
27	True Up for the Prior Period - Actual	
28	Schedule A2, page 3 of 4, Line D9+D10	(1)
29		
30	Interest Provision - Actual	
31	Schedule A2, page 3 of 4, Line D8	(2,029,715)
32		
33	Actual True Up ending balance for the period	
34	January 2000 through December 2000	(84,596,026)
35		
36	Estimated True Up ending balance for the period included in	
37	filing of Levelized Fuel Cost Factors January through December 2001,	
38	Docket No. 000001-EI.	(55,217,807)
39		
40	Final True Up for the period January 2000 through	
41	December 2000 (Line 34 - Line 38)	$ (29,378,219)

FLORIDA POWER CORPORATION
Docket No. 010001-EI
Witness: Portuondo
Exhibit No. ____ (JP-1)
Sheet 2 of 3

FUEL AND NET POWER VARIANCE ANALYSIS
FOR THE PERIOD OF: JANUARY - DECEMBER 2000

	(A) ENERGY SOURCE	(B) MWH VARIANCES	(C) HEAT RATE VARIANCES	(D) PRICE VARIANCES	(E) TOTAL
1	Heavy Oil	$6,511,649	$1,122,970	$64,976,323	$72,610,942
2	Light Oil	7,803,969	(1,064,689)	13,132,750	19,872,030
3	Coal	631,447	(2,124,864)	2,115,878	622,461
4	Gas	(6,784,724)	4,605,675	51,385,856	49,206,807
5	Nuclear	884,338	(209,306)	1,291,126	1,966,158
6	Other Fuel	0	0	0	0
7	Total Generation	9,046,679	2,329,786	132,901,933	144,278,398
8	Firm Purchases	10,758,218	0	3,120,009	13,878,227
9	Economy Purchases	15,948,121	0	21,540,446	37,488,567
10	Schedule E Purchases	0	0	0	0
11	Qualifying Facilities	(2,648,891)	0	13,635,359	10,986,468
12	Total Purchases	24,057,448	0	38,295,814	62,353,262
13	Economy Sales	0	0	(3,210,011)	(3,210,011)
14	Other Power Sales	3,447,680	0	(5,429,316)	(1,981,636)
15	Supplemental Sales	(16,445,815)	0	(30,990,816)	(47,436,631)
16	Total Sales	(12,998,135)	0	(39,630,143)	(52,628,278)
17	Nuclear Fuel Disposal Cost	0	0	259,409	259,409
18	Nuclear Decom & Decon	0	0	145,040	145,040
19	Other Jurisdictional Adjustments Sch A2 Page 1 of 4 Line 6b	0	0	1,355,625	1,355,625
20	Total Fuel and Net Power	$20,105,992	$2,329,786	$133,327,678	$155,763,456

FLORIDA POWER CORPORATION
Docket No. 010001-E1
WITNESS: PORTUONDO
EXHIBIT NO. (JP-1)
Sheet 3 of 3

GAS CONVERSION PROJECTS
SCHEDULE OF SYSTEM DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY, 2000 THROUGH DECEMBER, 2000

		INTERCESSION CITY 7 & 9	INTERCESSION CITY 8 & 10	DEBARY 8	DEBARY 7 & 9	BARTOW 2 & 4	SUWANNEE 1 & 3	TOTAL
	PLANT INVESTMENT							
1	BEGINNING BALANCE	$ 2,340,875	$ 1,646,809	$ 1,062,537	$ 3,352,257	$ 2,444,925	$ 3,460,560	$ 14,307,963
2	ADD INVESTMENT	-	-	-	-	-	-	-
3	LESS RETIREMENTS	2,178,580	-	-	-	-	-	2,178,580
4	ENDING BALANCE	162,295	1,646,809	1,062,537	3,352,257	2,444,925	3,460,560	12,129,383
5								
6	ACCUMULATED DEPRECIATION							
7	BEG. BALANCE ACCUM. DEPRECIATION	1,944,614	1,101,691	(76,321)	1,632,504	1,198,557	1,323,578	7,124,623
8	DEPRECIATION EXPENSE	366,954	329,364	212,508	670,452	488,976	692,112	2,760,366
9	LESS RETIREMENTS	2,178,580	-	-	-	-	-	2,178,580
10	END. BALANCE ACCUM. DEPRECIATION	132,988	1,431,055	136,187	2,302,956	1,687,533	2,015,690	7,706,409
11								
12								
13	ENDING NET INVESTMENT (LINE 4-10)	$ 29,307	$ 215,754	$ 926,350	$ 1,049,301	$ 757,392	$ 1,444,870	$ 4,422,974
14								
15	TOTAL RETURN REQUIREMENTS	20,446	48,184	119,633	160,406	116,072	207,486	$ 672,227
16								
17	TOTAL ACCUMULATED DEPRECIATION							
18	AND RETURN (LINE 8+ 15)	$ 387,400	$ 377,548	$ 332,141	$ 830,858	$ 605,048	$ 899,598	$ 3,432,593
19								
20								
21	ESTIMATED FUEL SAVINGS	2,703,947	3,617,093	1,182,484	2,390,924	666,794	632,504	11,193,746
22								
23	TOTAL DEPRECIATION & RETURN (1)	387,400	377,548	332,141	830,858	605,048	899,598	3,432,593
24								
24	NET BENEFIT (COST) TO RATEPAYER	$ 2,316,547	$ 3,239,545	$ 850,343	$ 1,560,066	$ 61,746	$ (267,094)	$ 7,761,153
25								
25								
26								

27 **DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.**
28 **RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 8.37% (EQUITY 5.12%, DEBT 3.25%). THIS IS THE MIDPOINT AUTHORIZED BY THE FPSC IN DOCKET NO. 91-0890-EI.**
29 **RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY INCOME TAX RATE OF 38.575%**
30 **(1) TOTAL AMOUNT DIFFERS FROM SCHEDULE A-2, PAGE 1 OF 4, LINE 6b BECAUSE A-2 EXCLUDES COST ASSIGNED TO SUPPLEMENTAL KWH SALES.**

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

Final True-Up Amount
January through December 2000

CAPACITY COST RECOVERY (JP-2)

FLORIDA POWER CORPORATION
Capacity Cost Recovery Clause
Summary of Actual True-Up Amount
January 2000 through December 2000

Line No.	Description	Actual	Original Estimate	Variance
1				
2	**Jurisdictional:**			
3	Capacity Cost Recovery Revenues			
4	Sheet 2 of 3, Line 51	312,686,769	315,249,846	(2,563,077)
5				
6	Capacity cost Recovery Expenses			
7	Sheet 2 of 3, Line 47	314,816,992	315,249,846	(432,854)
8				
9	Plus/(Minus) Interest Provision			
10	Sheet 2 of 3, Line 53	584,470	581,738	2,732
11				
12	Sub Total Current Period Over/(Under) Recovery	(1,545,753)	581,738	(2,127,491)
13				
14	Prior Period True-up - January through			
15	December 1999 - Over/(Under) Recovery			
16	Sheet 2 of 3, Line 55	28,834,883	33,314,649	(4,479,766)
17				
18	Prior Period True-up - January through			
19	December 1999 - (Refunded)/Collected			
20	Sheet 2 of 3, Line 56	(28,834,883)	(33,314,649)	4,479,766
21				
22				
23				
24				
25				
26	Actual True-up ending balance Over/(Under) recovery			
27	for the period January through December 2000			
28	Sheet 2 of 3, Column G, Line 58	(1,545,753)	581,738	(2,127,491)
29				
30	Estimated True-up ending balance for the			
31	period included in the filing of Levelized			
32	Fuel Cost Factors January through December 2001			
33	Docket No. 000001 - E1.	(143,205)		
34				
35				
36	Final Over/(Under) Recovery for the period January			
37	through December 2000 (Line 28 - Line 33)	(1,402,548)		

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
TRUE-UP CALCULATION
FOR THE PERIOD JANUARY 2000 THROUGH
DECEMBER 2000

Florida Power Corporation
Docket 010001-EI
Witness: Portuondo

Exhibit No. (JP-2)
Sheet 2 of 3

	Description	2000 JANUARY	2000 FEBRUARY	2000 MARCH	2000 APRIL	2000 MAY	2000 JUNE	2000 JULY	2000 AUGUST	2000 SEPTEMBER	2000 OCTOBER	2000 NOVEMBER	2000 DECEMBER	(g) 12 Months Cumulative
	Base Production Level Capacity Charges:													
1	Auburndale Power Partners, L.P. (AUBRDLAS)	0	0	0	0	0	0	0	0	0	0	0	0	$0
2	Auburndale Power Partners, L.P. (AUBRDLFC)	532,220	554,320	554,320	554,320	554,320	554,320	554,320	554,320	554,320	554,320	554,319	554,320	$6,629,739
3	Auburndale Power Partners, L.P. (AUBSET)	1,799,539	1,891,454	1,891,454	1,891,454	1,891,454	1,891,454	1,891,454	1,891,454	1,891,454	1,891,454	1,891,454	1,891,454	$22,605,528
4	Bay County (BAYCOUNT)	172,480	183,260	183,260	183,260	183,260	183,260	183,260	183,260	183,260	183,260	183,260	183,260	$2,188,340
5	Cargill Fertilizer, Inc. (CARGILLF)	372,900	391,950	391,950	391,950	391,950	391,950	391,950	391,950	391,950	391,950	391,950	391,950	$4,684,350
6	Central Power & Lime (FLACRUSH)	0	0	0	0	0	0	0	0	0	0	0	0	$0
7	Citrus World	0	0	0	0	0	0	0	0	0	0	0	0	$0
8	Jefferson Power L.C. (JEFFPOWER)	0	0	0	0	0	(13,592)	0	0	0	0	0	0	($13,592)
9	Lake County (LAKCOUNT)	326,910	347,565	347,565	347,565	347,565	347,565	347,565	347,565	347,565	347,565	347,565	347,565	$4,150,125
10	Lake Cogen Limited (LAKECOGL)	3,800,169	2,093,313	1,996,699	1,996,699	1,996,699	96,614	1,996,699	1,996,699	1,996,699	1,996,699	1,996,699	1,996,699	$23,960,386
11	Metro-Dade County (METRDADE)	661,535	681,237	658,786	695,167	682,087	702,330	684,371	626,878	624,422	624,348	627,951	632,571	$7,901,682
12	Metro-Dade County (METRDDAS)	0	0	0	0	0	0	0	0	0	0	0	0	$0
13	Orange Cogen (ORANGEAS)	0	0	0	0	0	0	0	0	0	0	0	0	$0
14	Orange Cogen (ORANGECO)	1,626,195	1,709,550	1,709,550	1,709,550	1,709,550	1,709,550	1,709,550	1,709,550	1,709,550	1,709,550	1,709,550	1,709,550	$20,431,243
15	Orlando Cogen Limited (ORLACOGL)	1,434,850	1,508,138	1,508,138	1,508,138	1,508,138	1,508,138	1,508,138	1,508,138	1,508,138	1,508,138	1,508,138	1,508,138	$18,024,364
16	Orlando Cogen Limited (ORLACOGAS)	0	0	0	0	0	0	0	0	0	0	0	0	$0
17	Pasco Cogen Limited (PASCOGL)	2,511,928	3,388,303	3,401,493	2,855,607	2,189,229	2,893,028	2,893,028	2,893,028	2,893,028	2,893,028	2,893,028	2,890,587	$34,595,316
18	Pasco County Resource Recovery (PASCOUNT)	589,490	626,980	626,980	626,980	626,980	626,980	626,980	626,980	626,980	626,980	626,980	626,980	$7,486,270
19	PCS Phosphate (OCSWFCRK)	0	0	0	0	0	0	0	0	0	0	0	0	$0
20	PCS Phosphate (OCSWHSPRS)	0	0	0	0	0	0	0	0	0	0	0	0	$0
21	Perpetual Energy (PRPETUAL)	0	0	0	0	0	0	0	0	0	0	0	0	$0
22	Pinellas County Resource Recovery (PINCOUNT)	1,403,243	1,492,485	1,492,485	1,492,485	1,492,485	1,492,485	1,492,485	1,492,485	1,492,485	1,492,485	1,492,485	1,492,485	$17,820,578
23	Polk Power Partners, L. P. (MULBERY)	2,065,402	2,149,564	2,149,564	2,149,564	2,149,564	2,149,564	2,149,564	2,149,564	2,149,564	2,149,564	1,972,430	2,009,515	$24,736,348
24	Polk Power Partners, L. P. (ROYSTER)	746,390	784,832	784,832	784,832	784,832	784,832	784,832	784,832	784,832	784,832	784,627	784,832	$10,744,072
25	St. Joe Forest Products (ST JOEFOR)	0	0	0	0	0	0	0	0	0	0	0	0	$784,832
26	Tiger Bay Limited Partnership (ECOPEAT)	1,051,000	1,051,000	1,051,000	1,051,000	1,051,000	1,051,000	1,051,000	1,051,000	1,051,000	1,051,000	1,051,000	1,051,000	$12,612,000
27	Tiger Bay Limited Partnership (GENPEAT)	3,743,000	3,743,000	3,743,000	3,743,000	3,743,000	3,743,000	3,743,000	3,743,000	3,743,000	3,743,000	3,743,000	3,743,000	$44,916,000
28	Tiger Bay Limited Partnership (TIMBER2)	131,000	131,000	131,000	131,000	131,000	131,000	131,000	131,000	131,000	131,000	131,000	131,000	$1,572,000
29	Timber Energy Resources, Inc. (TIMBER)	342,740	342,740	342,740	342,740	361,250	361,250	361,250	361,250	311,948	361,250	361,250	361,250	$4,211,656
30	U.S. Agri-Chemicals (AGRICHEM)	35,848	37,699	37,699	37,699	37,699	37,699	37,699	37,699	46,742	37,699	37,699	37,699	$459,582
31	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	800,946	800,946	800,946	800,946	800,946	800,946	800,946	760,684	745,671	772,042	775,646	788,451	$9,449,113
32	Tiger Bay (EcoPeat lease credit)	(66,667)	(66,667)	(66,667)	(416,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	($1,150,004)
33	UPS Purchase (409 total mw)	2,961,829	4,220,527	4,143,387	4,094,281	4,014,158	4,082,607	3,377,480	4,033,470	4,474,493	3,971,328	3,914,582	3,876,890	$47,165,032
34	Other Power Sales	0	0	0	0	(4,000)	0	0	0	0	0	0	0	(4,000)
35	Subtotal - Base Level Capacity Charges	27,042,946	28,063,196	27,880,181	26,971,570	26,576,499	25,459,313	26,649,903	27,208,138	27,591,433	27,154,824	26,927,945	26,942,528	325,960,961
36	Base Production Jurisdictional Responsibility	96.543%	96.543%	97.232%	97.232%	97.232%	97.232%	97.232%	97.232%	97.232%	97.232%	97.232%	97.232%	97.094%
37	Base Level Jurisdictional Capacity Charges	26,108,072	27,093,052	27,108,458	26,224,996	25,840,861	24,754,599	25,912,233	26,455,017	26,827,703	26,403,179	26,182,579	26,196,759	315,107,508
	Intermediate Production Level Capacity Charges:													
38	TECO Power Purchase (60 mw)	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	$6,786,804
39	Schedule H Capacity Sales	(2,385)	(2,231)	(2,385)	(2,308)	(2,385)	(2,308)	(2,385)	(2,385)	(2,308)	(2,385)	(2,308)	(2,385)	($28,155)
40	FP&L & Morgan Stanley Capital Group, Reedy Crk	223,861	0	0	0	0	0	0	38,295	76,590	0	0	407,097	745,843
41	Subtotal - Intermediate Level Capacity Charges	787,043	563,336	563,182	563,259	563,182	563,259	563,182	601,477	639,849	563,182	563,259	970,279	7,504,492
42	Intermediate Production Jurisdict. Responsibility	69.682%	69.682%	70.241%	70.241%	70.241%	70.241%	70.241%	70.241%	70.241%	70.241%	70.241%	70.241%	70.129%
43	Intermediate Level Jurisdict. Capacity Charges	548,427	392,544	395,585	395,639	395,585	395,639	395,585	422,484	449,436	395,585	395,639	681,534	5,263,681
44	Sebring Base Rate Credits	(305,966)	(411,549)	(280,546)	(302,252)	(320,185)	(399,053)	(409,398)	(369,363)	(406,628)	(353,126)	(272,751)	(299,249)	(4,130,066)
45	Adjustments-Premium/Liquidating Damages						898,616	898,616	928,629	(734,884)	0	0		1,990,977
46	Retail Wheeling	(254,711)	(179,582)	(254,637)	(77,477)	(382,519)	(444,328)	(383,575)	(405,696)	(446,298)	(250,960)	(154,669)	(180,658)	(3,415,109)
47	Jurisdictional Capacity Charges	26,095,822	26,894,465	26,968,860	26,240,906	25,533,742	25,205,473	26,413,461	27,031,070	25,689,329	26,194,678	26,150,798	26,398,386	314,816,992
48	Capacity Cost Recovery Revenues (net of tax)	19,523,062	23,631,263	18,890,195	20,173,947	21,514,590	27,767,751	29,119,806	27,879,449	29,696,608	24,304,057	20,271,361	21,079,798	283,851,888
49	Capacity Cost Revenues Adjustment (Net of Tax)													0
50	Prior Period True-Up Provision	2,776,221	2,776,221	2,776,221	2,776,221	2,776,221	2,776,221	2,776,221	2,776,221	2,776,221	2,776,221	2,776,221	(1,703,547)	28,834,881
51	Current Period Capacity Cost Recovery Revenues (net of tax) (sum of lines 46 through 48)	22,299,283	26,407,484	21,666,416	22,950,168	24,290,810	30,543,971	31,896,027	30,655,670	32,472,829	27,080,278	23,047,582	19,376,250	312,686,769
52	True-Up Provision - Over/(Under) Recovery (line 49 - line 45)	(3,796,539)	(486,981)	(5,302,445)	(3,290,738)	(1,242,932)	5,338,499	5,482,566	3,624,600	6,783,500	885,600	(3,103,216)	(7,022,136)	(2,130,223)
53	Interest Provision for the Month	121,355	100,232	75,147	41,736	16,897	13,539	27,896	37,458	50,795	56,795	36,551	6,069	584,470
54	Current Cycle Balance (line 50 + line 51) Cumulative	(3,675,184)	(4,061,934)	(9,289,232)	(12,538,234)	(13,764,268)	(8,412,230)	(2,901,769)	760,289	7,594,583	8,536,978	5,470,313	(1,545,754)	
55	True-Up & Interest Provision (beginning)	28,834,883	28,834,883	28,834,883	28,834,883	28,834,883	28,834,883	28,834,883	28,834,883	28,834,883	28,834,883	28,834,883	28,834,883	
56	Prior Period True-Up Collected/(Refunded) Cumulative	(2,776,222)	(5,552,443)	(8,328,664)	(11,104,885)	(13,881,106)	(16,657,326)	(19,433,547)	(22,209,768)	(24,985,989)	(27,762,209)	(30,538,430)	(28,834,883)	
57	Other:				0	0	0	0	0	0	0	0	0	
58	End of Period Net True-Up (lines 50 through 55) Over / (Under)	$22,383,477	$19,220,506	$11,216,987	$5,191,764	$1,189,509	$3,765,327	$6,499,567	$7,385,404	$11,443,478	$9,609,652	$3,766,766	($1,545,753)	($1,545,753)

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
TRUE-UP CALCULATION
FOR THE PERIOD JANUARY 2000 THROUGH DECEMBER 2000

		(a) 1 2000	(b) 2 2000	(c) 3 2000	(d) 4 2000	(e) 5 2000	(f) 6 2000	(g) 7 2000	(h) 8 2000	(i) 9 2000	(j) 10 2000	(k) 11 2000	(l) 12 2000
	Description	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
	Interest Provision:												
1.	Beginning True-Up	$28,834,883	$22,383,477	$19,220,506	$11,216,987	$5,191,764	$1,189,509	$3,765,327	$6,499,567	$7,385,404	$11,443,478	$9,609,652	$3,766,766
2.	Ending True-Up	$22,262,122	$19,120,275	$11,141,840	$5,150,028	$1,172,612	$3,751,787	$6,471,671	$7,347,946	$11,392,683	$9,552,857	$3,730,215	($1,551,822)
3.	Total True-Up (line 1 + line 2)	$51,097,005	$41,503,752	$30,362,347	$16,367,015	$6,364,376	$4,941,297	$10,236,998	$13,847,513	$18,778,087	$20,996,335	$13,339,867	$2,214,944
4.	Average True-Up (50% of line 3)	$25,548,502	$20,751,876	$15,181,173	$8,183,508	$3,182,188	$2,470,648	$5,118,499	$6,923,757	$9,389,043	$10,498,167	$6,669,933	$1,107,472
5.	Interest Rate - First Day of Reporting Month	5.600%	5.800%	5.800%	6.070%	6.180%	6.570%	6.580%	6.500%	6.480%	6.500%	6.490%	6.650%
6.	Interest Rate - First Day of Subsequent Month	5.800%	5.800%	6.070%	6.180%	6.570%	6.580%	6.500%	6.480%	6.500%	6.490%	6.650%	6.500%
7.	Total Interest (line 5 + line 6)	11.400%	11.600%	11.870%	12.250%	12.750%	13.150%	13.080%	12.980%	12.980%	12.990%	13.140%	13.150%
8.	Average Interest Rate (50% of line 7)	5.700%	5.800%	5.935%	6.125%	6.375%	6.575%	6.540%	6.490%	6.490%	6.495%	6.570%	6.575%
9.	Monthly Average Interest Rate (line 8 / 12)	0.4750%	0.483%	0.495%	0.510%	0.531%	0.548%	0.545%	0.541%	0.541%	0.541%	0.548%	0.548%
10.	Interest Provision (line 4 x line 9)	$121,355	$100,232	$75,147	$41,736	$16,897	$13,539	$27,896	$37,458	$50,795	$56,795	$36,551	$6,069
11.	Cumulative Interest for the Period Ending	$121,355	$221,587	$296,734	$338,470	$355,367	$368,906	$396,802	$434,260	$485,054	$541,849	$578,401	$584,470

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

Final True-Up Amount
January through December 2000

TIGER BAY REVENUES AND EXPENSES (JP-3)

Florida Power Corporation
Docket No. 010001-EI
Witness: Portuondo
Exhibit No. (JP-3)
Sheet 1 of 1

TIGER BAY EXPENSE AND REVENUE TRACKING

Line #	***Capacity Clause Revenues***	A Jan-00	B Feb-00	C Mar-00	D Apr-00	E May-00	F Jun-00	G Jul-00	H Aug-00	I Sep-00	J Oct-00	K Nov-00	L Dec-00
1	Retail Capacity Revenues	$ 4,690,380	$ 4,690,380	$ 4,723,854	$ 4,383,542	$ 4,723,854	$ 4,723,854	$ 4,723,854	$ 4,723,854	$ 4,723,854	$ 4,723,854	$ 4,723,854	$ 4,723,854
2													
3	Retail Related Interest on Reg. Asset	1,777,317	1,830,177	1,815,106	1,802,625	1,618,545	1,607,408	1,608,874	1,593,717	1,578,877	1,305,734	1,290,534	1,279,584
4													
5	Funds Available for Amortization	$ 2,913,063	$ 2,860,204	$ 2,908,748	$ 2,580,917	$ 3,105,309	$ 3,116,446	$ 3,114,980	$ 3,130,137	$ 3,144,977	$ 3,418,120	$ 3,433,320	$ 3,444,270
6													
7													
8	***Fuel Adjustment Clause Revenues***												
9													
10	Retail Energy Revenues	$ 1,320,202	$ 1,731,439	$ 635,799	$ 1,952,749	$ 1,995,811	$ 2,602,496	$ 3,260,032	$ 3,300,653	$ 2,606,269	$ 2,564,943	$ 1,477,790	$ 1,849,813
11													
12	Retail Fuel Expenses	3,870,536	3,730,502	1,983,872	1,600,078	2,919,565	3,798,395	3,713,720	3,792,282	3,723,497	3,280,462	2,964,098	4,438,619
13													
14	Funds Available for Amortization	$ (2,550,335)	$ (1,999,063)	$ (1,348,074)	$ 352,672	$ (923,755)	$ (1,195,900)	$ (453,688)	$ (491,629)	$ (1,117,228)	$ (715,519)	$ (1,486,308)	$ (2,588,806)
15													
16	Underrecovery	-	-	-	-	-	-	-	-	-	-	-	-
17													
18													
19													
20													
21	***Tiger Bay Regulatory Asset - R***												
22													
23	Beginning Balance	$ 297,817,871	$ 297,455,143	$ 296,594,002	$295,033,328	$ 292,099,739	$ 288,005,671	$ 286,081,086	$283,427,870	$ 280,726,675	$ 232,161,528	$ 229,458,927	$227,511,915
24													
25	Amortization (Line 5+ Line 14 + Line 16)	(362,728)	(861,141)	(1,560,674)	(2,933,589)	(4,094,069)	(1,924,585)	(2,653,216)	(2,701,195)	(2,027,749)	(2,702,601)	(1,947,012)	(855,464)
26													
27	Additional Amortization									(46,537,398)			
28													
29	Ending Balance	$ 297,455,143	$ 296,594,002	$ 295,033,328	$292,099,739	$ 288,005,671	$ 286,081,086	$ 283,427,870	$280,726,675	$ 232,161,528	$ 229,458,927	$ 227,511,915	$226,656,451

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

Final True-Up Amount
January through December 2000

SCHEDULES A1 through A9 (JP-4)
(Period-to-Date)

FLORIDA POWER CORPORATION

REVISED
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
DECEMBER 2000

	$				MWH				CENTS/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1 FUEL COST OF SYSTEM NET GENERATION (SCH A3)	83,795,173	41,654,977	42,140,196	101.2	2,797,505	2,426,465	371,040	15.3	2.9954	1.7167	1.2787	74.5
2 SPENT NUCLEAR FUEL DISPOSAL COST	544,305	508,160	36,145	7.1	544,305	543,487	818	0.2	0.1000	0.0935	0.0065	7.0
3 COAL CAR INVESTMENT	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3b NUCLEAR DECOMMISSIONING AND DECONTAMINATION	5,646	0	5,646	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4 ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	(4,470,383)	249,000	(4,719,383)	(1,895.3)	(134,533)	0	(134,533)	0.0	3.3229	0.0000	3.3229	0.0
4a ADJUSTMENTS TO FUEL COST - DISPOSAL COST REFUND	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
5 TOTAL COST OF GENERATED POWER	79,874,741	42,412,137	37,462,604	88.3	2,662,972	2,426,465	236,507	9.8	2.9995	1.7479	1.2516	71.6
6 ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	4,561,502	2,973,387	1,588,115	53.4	294,156	207,704	86,452	41.6	1.5507	1.4316	0.1191	8.3
7 ENERGY COST OF SCH C,X ECONOMY PURCHASES - BROKER (SCH A9)	27,000	0	27,000	0.0	450	0	450	0.0	6.0000	0.0000	6.0000	0.0
8 ENERGY COST OF ECONOMY PURCHASES - NON-BROKER (SCH A9)	7,430,777	562,470	6,868,307	1,221.1	75,384	25,244	50,140	198.6	9.8572	2.2281	7.6291	342.4
9 ENERGY COST OF SCH E PURCHASES (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
10 CAPACITY COST OF ECONOMY PURCHASES (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
11 PAYMENTS TO QUALIFYING FACILITIES (SCH A8)	13,062,890	10,513,153	2,539,737	24.2	567,457	561,831	5,626	1.0	2.3002	1.8712	0.4290	22.9
12 TOTAL COST OF PURCHASED POWER	25,072,169	14,049,010	11,023,159	78.5	937,447	794,779	142,668	18.0	2.6745	1.7677	0.9068	51.3
13 TOTAL AVAILABLE MWH					3,600,419	3,221,244	379,175	11.8				
14 FUEL COST OF ECONOMY SALES (BROKER) (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
14a GAIN ON ECONOMY SALES (BROKER) - 80% (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
15 FUEL COST OF OTHER POWER SALES (SCH A6)	(4,021,751)	(2,012,260)	(2,009,491)	99.9	(120,135)	(120,793)	658	(0.5)	3.3477	1.6659	1.6818	101.0
15a GAIN ON OTHER POWER SALES - 100% (SCH A6)	(2,198,876)	(289,902)	0	0.0	(120,135)	(120,793)	658	(0.5)	1.8303	0.2400	1.5903	662.6
16 FUEL COST OF SEMINOLE BACK-UP SALES (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
17 FUEL COST OF SUPPLEMENTAL SALES	(7,384,721)	(2,980,536)	(4,404,185)	147.8	(226,092)	(135,537)	(90,555)	66.8	3.2662	2.1991	1.0671	48.5
18 TOTAL FUEL COST AND GAINS ON POWER SALES	(13,605,348)	(5,282,698)	(8,322,650)	157.6	(346,227)	(256,330)	(89,897)	35.1	3.9296	2.0609	1.8687	90.7
19 NET INADVERTENT AND WHEELED INTERCHANGE					8,956	0	8,956					
20 TOTAL FUEL AND NET POWER TRANSACTIONS	91,341,562	51,178,449	40,163,113	78.5	3,263,148	2,964,914	298,234	10.1	2.7992	1.7261	1.0731	62.2
21 NET UNBILLED	10,832,965	2,404,231	8,428,734	350.6	(418,915)	(139,284)	(279,631)	200.8	0.4116	0.0906	0.3210	354.3
22 COMPANY USE	338,458	258,920	79,538	30.7	(13,088)	(15,000)	1,912	(12.7)	0.0129	0.0098	0.0031	31.6
23 T & D LOSSES	5,154,511	2,730,954	2,423,557	88.7	(199,327)	(158,212)	(41,115)	26.0	0.1959	0.1030	0.0929	90.2
24 ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 4)	91,341,562	51,178,449	40,163,113	78.5	2,631,818	2,652,418	(20,600)	(0.8)	3.4707	1.9295	1.5412	79.9
25 WHOLESALE KWH SALES (EXCLUDING SUPPLEMENTAL SALES)	(2,849,857)	(1,383,491)	(1,466,366)	106.0	(82,210)	(71,702)	(10,508)	14.7	3.4666	1.9295	1.5371	79.7
26 JURISDICTIONAL KWH SALES	88,491,705	49,794,958	38,696,747	77.7	2,549,608	2,580,716	(31,108)	(1.2)	3.4708	1.9295	1.5413	79.9
27 JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.0021	88,677,537	49,924,425	38,753,112	77.6	2,549,608	2,580,716	(31,108)	(1.2)	3.4781	1.9345	1.5436	79.8
28 PRIOR PERIOD TRUE-UP	(5,830,552)	612,185	(6,442,737)	(1,052.4)	2,549,608	2,580,716	(31,108)	(1.2)	(0.2287)	0.0237	(0.2524)	#######
28a MARKET PRICE TRUE-UP	0	0	0	0.0	2,549,608	2,580,716	(31,108)	(1.2)	0.0000	0.0000	0.0000	0.0
28b RECOVERY OF PRIOR PERIOD NUCLEAR REPLACEMENT COST	0	0	0	0.0	2,549,608	2,580,716	(31,108)	(1.2)	0.0000	0.0000	0.0000	0.0
29 TOTAL JURISDICTIONAL FUEL COST	82,846,985	50,536,610	32,310,375	63.9	2,549,608	2,580,716	(31,108)	(1.2)	3.2494	1.9582	1.2912	65.9
30 REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
31 FUEL COST ADJUSTED FOR TAXES									3.2517	1.9596	1.2921	65.9
32 GPIF	87,323	87,258			2,549,608	2,580,716			0.0034	0.0034	0.0000	0.0
33 TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									3.255	1.963	1.292	65.8

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14-Mar-01

FLORIDA POWER CORPORATION

SCHEDULE A1
PAGE 2 OF 2

REVISED
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
TWELVE MONTH PERIOD ENDING - DECEMBER, 2000

	$				MWH				CENTS/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1 FUEL COST OF SYSTEM NET GENERATION (SCH A3)	785,463,890	600,315,216	185,148,674	30.8	33,340,112	31,551,516	1,788,596	5.7	2.3559	1.9027	0.4532	23.8
2 SPENT NUCLEAR FUEL DISPOSAL COST	6,194,814	5,935,405	259,409	4.4	6,202,492	6,348,026	(145,534)	(2.3)	0.0999	0.0935	0.0064	6.8
3 COAL CAR INVESTMENT	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3b NUCLEAR DECOMMISSIONING AND DECONTAMINATION	1,661,040	0	1,661,040	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4 ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	(35,978,651)	5,052,000	(41,030,651)	(812.2)	(1,347,448)	0	(1,347,448)	0.0	2.6701	0.0000	2.6701	0.0
4a ADJUSTMENTS TO FUEL COST - DISPOSAL COST REFUND	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
5 TOTAL COST OF GENERATED POWER	757,341,092	611,302,621	146,038,471	23.9	31,992,664	31,551,516	441,148	1.4	2.3672	1.9375	0.4297	22.2
6 ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	50,390,152	36,511,925	13,878,227	38.0	3,242,163	2,504,288	737,875	29.5	1.5542	1.4580	0.0962	6.6
7 ENERGY COST OF SCH C,X ECONOMY PURCHASES - BROKER (SCH A9)	2,466,208	0	2,466,208	0.0	32,252	0	32,252	0.0	7.6467	0.0000	7.6467	0.0
8 ENERGY COST OF ECONOMY PURCHASES - NON-BROKER (SCH A9)	56,882,834	21,860,475	35,022,359	160.2	815,225	490,000	325,225	66.4	6.9776	4.4613	2.5163	56.4
9 ENERGY COST OF SCH E PURCHASES (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
10 CAPACITY COST OF ECONOMY PURCHASES (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
11 PAYMENTS TO QUALIFYING FACILITIES (SCH A8)	138,522,239	127,535,771	10,986,468	8.6	6,568,408	6,707,728	(139,320)	(2.1)	2.1089	1.9013	0.2076	10.9
12 TOTAL COST OF PURCHASED POWER	248,261,433	185,908,171	62,353,262	33.5	10,658,048	9,702,016	956,032	9.9	2.3293	1.9162	0.4131	21.6
13 TOTAL AVAILABLE MWH					42,650,713	41,253,532	1,397,181	3.4				
14 FUEL COST OF ECONOMY SALES (BROKER) (SCH A6)	(2,426,996)	0	(2,426,996)	0.0	(145,608)	0	(145,608)	0.0	1.6668	0.0000	1.6668	0.0
14a GAIN ON ECONOMY SALES (BROKER) - 80% (SCH A6)	(783,015)	0	(783,015)	0.0	(145,608)	0	(145,608)	0.0	0.5378	0.0000	0.5378	0.0
15 FUEL COST OF OTHER POWER SALES (SCH A6)	(37,897,240)	(33,347,440)	(4,549,800)	13.6	(1,331,456)	(1,445,001)	113,545	(7.9)	2.8463	2.3078	0.5385	23.3
15a GAIN ON OTHER POWER SALES - 100% (SCH A6)	(7,960,329)	(10,528,493)	2,568,164	(24.4)	(1,331,456)	(1,445,001)	113,545	(7.9)	0.5979	0.7286	(0.1307)	(17.9)
16 FUEL COST OF SEMINOLE BACK-UP SALES (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
17 FUEL COST OF SUPPLEMENTAL SALES	(93,394,318)	(45,957,687)	(47,436,631)	103.2	(2,618,016)	(1,928,059)	(689,957)	35.8	3.5674	2.3836	1.1838	49.7
18 TOTAL FUEL COST AND GAINS ON POWER SALES	(142,461,898)	(89,833,620)	(52,628,278)	58.6	(4,095,080)	(3,373,060)	(722,020)	21.4	3.4789	2.6633	0.8156	30.6
19 NET INADVERTENT AND WHEELED INTERCHANGE					53,282	0	53,282					
20 TOTAL FUEL AND NET POWER TRANSACTIONS	863,140,628	707,377,172	155,763,456	22.0	38,608,914	37,880,472	728,442	1.9	2.2356	1.8674	0.3682	19.7
21 NET UNBILLED	7,685,635	3,053,984	4,631,651	151.7	(343,784)	(74,081)	(269,703)	364.1	0.0214	0.0086	0.0128	148.8
22 COMPANY USE	2,814,822	3,339,517	(524,695)	(15.7)	(125,909)	(180,000)	54,091	(30.1)	0.0078	0.0094	(0.0016)	(17.0)
23 T & D LOSSES	49,360,515	38,549,481	10,811,034	28.0	(2,207,931)	(2,063,108)	(144,823)	7.0	0.1374	0.1084	0.0290	26.8
24 ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 4)	863,140,628	707,377,172	155,763,456	22.0	35,931,290	35,563,283	368,007	1.0	2.4022	1.9891	0.4131	20.8
25 WHOLESALE KWH SALES (EXCLUDING SUPPLEMENTAL SALES)	(26,773,564)	(19,898,854)	(6,874,710)	34.6	(1,114,095)	(1,004,677)	(109,418)	10.9	2.4032	1.9806	0.4226	21.3
26 JURISDICTIONAL KWH SALES	836,367,064	687,478,318	148,888,746	21.7	34,817,195	34,558,606	258,589	0.8	2.4022	1.9893	0.4129	20.8
27 JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.0021	838,254,906	689,265,762	148,989,144	21.6	34,817,195	34,558,606	258,589	0.8	2.4076	1.9945	0.4131	20.7
28 PRIOR PERIOD TRUE-UP	903,441	7,346,176	(6,442,735)	(87.7)	34,817,195	34,558,606	258,589	0.8	0.0026	0.0213	(0.0187)	(87.8)
28a MARKET PRICE TRUE-UP	0	0	0	0.0	34,817,195	34,558,606	258,589	0.8	0.0000	0.0000	0.0000	0.0
28b RECOVERY OF PRIOR PERIOD NUCLEAR REPLACEMENT COST	0	0	0	0.0	34,817,195	34,558,606	258,589	0.8	0.0000	0.0000	0.0000	0.0
29 TOTAL JURISDICTIONAL FUEL COST	839,158,348	696,611,938	142,546,410	20.5	34,817,195	34,558,606	258,589	0.8	2.4102	2.0158	0.3944	19.6
30 REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
31 FUEL COST ADJUSTED FOR TAXES									2.4119	2.0173	0.3947	19.6
32 GPIF	1,047,894	1,047,140			34,817,195	34,558,606			0.0030	0.0030	0.0000	100.0
33 TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									2.415	2.020	0.395	19.5

CALCULATION OF TRUE-UP AND INTEREST PROVISION
FLORIDA POWER CORPORATION
DECEMBER 2000

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
A .	FUEL COSTS AND NET POWER TRANSACTIONS								
1 .	FUEL COST OF SYSTEM NET GENERATION	$83,795,173	$41,654,977	$42,140,196	101.2	$785,463,890	$600,315,216	$185,148,674	30.8
1a.	NUCLEAR FUEL DISPOSAL COST	$544,305	508,160	36,145	7.1	6,194,814	5,935,405	259,409	4.4
1b.	NUCLEAR DECOM & DECON	$5,646	0	5,646	100.0	1,661,040	0	1,661,040	100.0
2 .	FUEL COST OF POWER SOLD	($4,021,751)	(2,012,260)	(2,009,491)	99.9	(40,324,236)	(33,347,440)	(6,976,796)	20.9
2a.	GAIN ON POWER SALES	($2,198,876)	(289,902)	(1,908,974)	658.5	(8,743,344)	(10,528,493)	1,785,149	(17.0)
3 .	FUEL COST OF PURCHASED POWER	$4,561,502	2,973,387	1,588,115	53.4	50,390,152	36,511,925	13,878,227	38.0
3a.	ENERGY PAYMENTS TO QUALIFYING FAC.	$13,052,890	10,513,153	2,539,737	24.2	138,522,239	127,535,771	10,986,468	8.6
3b.	DEMAND & NON FUEL COST OF PURCH POWER	$0	0	0	0.0	0	0	0	0.0
4 .	ENERGY COST OF ECONOMY PURCHASES	$7,457,777	562,470	6,895,307	1,225.9	59,349,042	21,860,475	37,488,567	171.5
5 .	TOTAL FUEL & NET POWER TRANSACTIONS	103,196,666	53,909,985	49,286,681	91.4	992,513,597	748,282,859	244,230,738	32.6
6 .	ADJUSTMENTS TO FUEL COST:								
6a.	FUEL COST OF SUPPLEMENTAL SALES	($7,384,721)	(2,980,536)	(4,404,185)	147.8	(93,394,318)	(45,957,687)	(47,436,631)	103.2
6b.	OTHER- JURISDICTIONAL ADJUSTMENTS (see detail below)	($4,470,383)	249,000	(4,719,383)	(1,895.3)	(35,978,651)	5,052,000	(41,030,651)	(812.2)
6c.	OTHER - PRIOR PERIOD ADJUSTMENT	$0	0	0	0.0	0	0	0	0.0
7 .	ADJUSTED TOTAL FUEL & NET PWR TRNS	$91,341,562	$51,178,449	$40,163,113	78.5	$863,140,628	$707,377,172	$155,763,456	22.0
		($0)							

FOOTNOTE: DETAIL OF LINE 6B ABOVE

INSPECTION & FUEL ANALYSIS REPORTS {Wholesale Portion}	2,215	0	2,215	26,815	0	26,815
PIPELINE EXPENSES {Wholesale Portion}	5,621	0	5,621	39,593	0	39,593
UNIV.OF FL STEAM REVENUE ALLOCATION {Wholesale Portion}	3,120	0	3,120	37,170	0	37,170
ADD'L ADJUSTMENT FOR 518.13 CLEANUP	(5,646)	0	(5,646)	(75,088)	0	(75,088)
GAS CONVERSION PROJECTS. {DEPRECIATION & RETURN}	219,845	249,000	(29,155)	3,041,760	5,052,000	(2,010,240)
EMISSIONS	187,705	0	187,705	1,986,737	0	1,986,737
TANK BOTTOM ADJUSTMENT {Grossed up}	0	0	0	159,852	0	159,852
INTERCESSION U-12-13-14 INEFFICIENT PORTION	(301,679)	0	(301,679)	(325,214)	0	(325,214)
TIGER BAY NET GENERATION	(4,581,564)	0	(4,581,564)	(40,870,276)	0	(40,870,276)
SUBTOTAL LINE 6B SHOWN ABOVE	($4,470,383)	249,000	(4,719,383)	(35,978,651)	5,052,000	(41,030,651)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
FLORIDA POWER CORPORATION
DECEMBER 2000
REVISED

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
B .	SALES REVENUES (EXCLUDE REVENUE TAXES)								
1 .	JURISDICTIONAL SALES REVENUE								
1a.	BASE FUEL REVENUE	$0	$0	$0	0.0	$0	$0	$0	0.0
1b.	FUEL RECOVERY REVENUE	59,338,902	52,098,617	7,240,285	13.9	757,639,178	697,657,388	59,981,790	8.6
1c.	JURISDICTIONAL FUEL REVENUE	59,338,902	52,098,617	7,240,285	13.9	757,639,178	697,657,388	59,981,790	8.6
1d.	NON FUEL REVENUE	131,313,002	132,692,083	(1,379,081)	(1.0)	1,743,978,136	1,776,314,124	(32,335,988)	(1.8)
1e.	TOTAL JURISDICTIONAL SALES REVENUE	190,651,904	184,790,700	5,861,204	3.2	2,501,617,314	2,473,971,512	27,645,802	1.1
2 .	NON JURISDICTIONAL SALES REVENUE	23,409,365	11,707,689	11,701,676	100.0	270,347,480	176,435,260	93,912,220	53.2
3 .	TOTAL SALES REVENUE	$214,061,269	$196,498,389	$17,562,880	8.9	$2,771,964,794	$2,650,406,772	$121,558,022	4.6
C .	KWH SALES								
1 .	JURISDICTIONAL SALES	2,549,607,848	2,580,716,000	(31,108,152)	(1.2)	34,817,195,546	34,558,606,000	258,589,546	0.8
2 .	NON JURISDICTIONAL (WHOLESALE) SALES	82,210,003	71,702,000	10,508,003	14.7	1,114,094,882	1,004,677,000	109,417,882	10.9
3 .	TOTAL SALES	2,631,817,851	2,652,418,000	(20,600,149)	(0.8)	35,931,290,428	35,563,283,000	368,007,428	1.0
4 .	JURISDICTIONAL SALES % OF TOTAL SALES	96.88	97.30	(0.42)	(0.4)	96.90	97.17	(0.27)	(0.3)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
FLORIDA POWER CORPORATION
DECEMBER 2000

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
D .	TRUE UP CALCULATION								
1 .	JURISDICTIONAL FUEL REVENUE (LINE B1c)	59,338,902	$52,098,617	$7,240,285	13.9	$757,639,178	$697,657,388	$59,981,790	8.6
2 .	ADJUSTMENTS: PRIOR PERIOD ADJ	0	0	0	0.0	0	0	0	0.0
2a.	TRUE UP PROVISION + RECOVERABLE NUC REPL FUEL	5,830,552	(612,181)	6,442,733	(1,052.4)	(903,441)	(7,346,172)	6,442,731	(87.7)
2b.	INCENTIVE PROVISION	(87,261)	(87,262)	1	0.0	(1,047,140)	(1,047,018)	(122)	0.0
2c.	OTHER: MARKET PRICE TRUE UP	0	0	0	0.0	0	0	0	0.0
3 .	TOTAL JURISDICTIONAL FUEL REVENUE	65,082,193	51,399,174	13,683,019	26.6	755,688,597	689,264,198	66,424,398	9.6
4 .	ADJ TOTAL FUEL & NET PWR TRNS (LINE A7)	91,341,562	51,178,449	40,163,113	78.5	863,140,628	707,377,172	155,763,456	22.0
5 .	JURISDICTIONAL SALES % OF TOT SALES (LINE C4)	96.88	97.30	(0.42)	(0.4)				
6 .	JURISDICTIONAL FUEL & NET POWER TRANSACTIONS (LINE D4 * LINE D5 * .21% "LINE LOSSES")	88,677,537	49,924,409	38,753,128	77.6	838,254,906	689,265,801	148,989,105	21.6
7 .	TRUE UP PROVISION FOR THE MONTH OVER/(UNDER) COLLECTION (LINE D3 - D6)	(23,595,344)	1,474,765	(25,070,109)	0.0	(82,566,309)	(1,603)	(82,564,707)	0.0
8 .	INTEREST PROVISION FOR THE MONTH (LINE E10)	(380,872)				(2,029,715)			
9 .	TRUE UP & INT PROVISION BEG OF MONTH/PERIOD	(54,789,257)				(903,442)			
10.	TRUE UP COLLECTED (REFUNDED)	(5,830,552)				903,441	7,346,172	(6,442,731)	0.0
11.	END OF PERIOD TOTAL NET TRUE UP (LINES D7 + D8 + D9 + D10)	(84,596,026)				(84,596,026)			
12.	OTHER:								
13.	END OF PERIOD TOTAL NET TRUE UP (LINES D11 + D12)	(84,596,026)				(84,596,026)			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
FLORIDA POWER CORPORATION
DECEMBER 2000

		CURRENT MONTH				PERIOD TO DATE		
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE
E .	INTEREST PROVISION							
1 .	BEGINNING TRUE UP (LINE D9)	($54,789,257)	N/A	--	--			
2 .	ENDING TRUE UP (LINES D7 + D9 + D10 +D12)	(84,215,154)	N/A	--	--		NOT	
3 .	TOTAL OF BEGINNING & ENDING TRUE UP	(139,004,411)	N/A	--	--			
4 .	AVERAGE TRUE UP (50% OF LINE E3)	(69,502,205)	N/A	--	--			
5 .	INTEREST RATE - FIRST DAY OF REPORTING MONTH	6.650	N/A	--	--			
6 .	INTEREST RATE - FIRST DAY OF SUBSEQUENT MONTH	6.500	N/A	--	--			
7 .	TOTAL (LINE E5 + LINE E6)	13.150	N/A	--	--		APPLICABLE	
8 .	AVERAGE INTEREST RATE (50% OF LINE E7)	6.575	N/A	--	--			
9 .	MONTHLY AVERAGE INTEREST RATE (LINE E8/12)	0.548	N/A	--	--			
10.	INTEREST PROVISION (LINE E4 * LINE E9)	($380,872)	N/A	--	--			

FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA
Schedule A-3

FUEL COST OF SYSTEM		ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
NET GENERATION ($)					
1	HEAVY OIL	206,541,419	133,930,477	72,610,942	54.2%
2	LIGHT OIL	63,600,189	43,728,159	19,872,030	45.4%
3	COAL	254,102,210	253,479,749	622,461	0.2%
4	GAS	237,565,411	147,488,329	90,077,082	61.1%
5	NUCLEAR	23,654,659	21,688,501	1,966,158	9.1%
6					
7					
8	TOTAL ($)	785,463,890	600,315,215	185,148,675	30.8%
SYSTEM NET GENERATION (MWH)					
9	HEAVY OIL	5,394,486	5,144,366	250,120	4.9%
10	LIGHT OIL	824,503	699,655	124,848	17.8%
11	COAL	14,427,374	14,391,530	35,844	0.2%
12	GAS	6,086,880	4,967,939	1,118,941	22.5%
13	NUCLEAR	6,606,870	6,348,026	258,844	4.1%
14					
15					
16	TOTAL (MWH)	33,340,113	31,551,516	1,788,597	5.7%
UNITS OF FUEL BURNED					
17	HEAVY OIL (BBL)	8,412,339	8,142,910	269,429	3.3%
18	LIGHT OIL (BBL)	1,868,092	1,623,267	244,825	15.1%
19	COAL (TON)	5,493,054	5,479,453	13,601	0.2%
20	GAS (MCF)	53,169,726	45,231,896	7,937,830	17.5%
21	NUCLEAR (MMBTU)	67,768,561	65,722,729	2,045,832	3.1%
22					
23					

FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA
Schedule A-3

	FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
BTUS BURNED (MILLION BTU)					
24	HEAVY OIL	55,082,394	52,114,623	2,967,771	5.7%
25	LIGHT OIL	10,866,191	9,414,959	1,451,232	15.4%
26	COAL	136,896,531	137,715,271	-818,740	-0.6%
27	GAS	54,885,584	45,231,896	9,653,688	21.3%
28	NUCLEAR	67,768,561	65,722,729	2,045,832	3.1%
29					
30					
31	TOTAL (MILLION BTU)	325,499,260	310,199,478	15,299,782	4.9%
GENERATION MIX (% MWH)					
32	HEAVY OIL	16.2	16.30	-0.1	-0.8%
33	LIGHT OIL	2.5	2.22	0.3	11.5%
34	COAL	43.3	45.61	-2.3	-5.1%
35	GAS	18.3	15.75	2.5	16.0%
36	NUCLEAR	19.8	20.12	-0.3	-1.5%
37					
38					
39	TOTAL (% MWH)	100.0	100.0	0.0	0.0%

FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA
Schedule A-3

	FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
	FUEL COST PER UNIT ($)				
40	HEAVY OIL ($/BBL)	24.55	16.45	8.10	49.3%
41	LIGHT OIL ($/BBL)	34.05	26.94	7.11	26.4%
42	COAL ($/TON)	46.26	46.26	0.00	0.0%
43	GAS ($/MCF)	4.47	3.26	1.21	37.0%
44	NUCLEAR ($/MBTU)	0.35	0.33	0.02	5.8%
45					
46					
	FUEL COST PER MILLION BTU ($/MILLION BTU)				
47	HEAVY OIL	3.75	2.57	1.18	45.9%
48	LIGHT OIL	5.85	4.64	1.21	26.0%
49	COAL	1.86	1.84	0.02	0.8%
50	GAS	4.33	3.26	1.07	32.7%
51	NUCLEAR	0.35	0.33	0.02	5.8%
52					
53					
54	SYSTEM ($/MBTU)	2.41	1.94	0.48	24.7%
	BTU BURNED PER KWH (BTU/KWH)				
55	HEAVY OIL	10,211	10,130	80	0.8%
56	LIGHT OIL	13,179	13,457	-277	-2.06%
57	COAL	9,489	9,569	-81	-0.8%
58	GAS	9,017	9,105	-88	-1.0%
59	NUCLEAR	10,257	10,353	-96	-0.9%
60					
61					
62	SYSTEM (BTU/KWH)	9,763	9,832	-69	-0.7%

FLORIDA POWER CORPORATION

GENERATING SYSTEM COMPARATIVE DATA

Schedule A-3

FUEL COST OF SYSTEM		ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
GENERATED FUEL COST PER KWH (CENTS/KWH)					
63	HEAVY OIL	3.83	2.60	1.23	47.1%
64	LIGHT OIL	7.71	6.25	1.46	23.4%
65	COAL	1.76	1.76	0.00	0.0%
66	GAS	3.90	2.97	0.93	31.5%
67	NUCLEAR	0.36	0.34	0.02	4.8%
68					
69					
70	SYSTEM (CENTS/KWH)	2.36	1.90	0.45	23.8%

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FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
Schedule A-4

Jan 00 Thru Dec 00
FINAL

(A) PLANT	(B) NET CAP (MW)	(C) NET GENERATION (MWH)	(D) CAP FAC (%)	(E) EQUIV AVAIL FAC (%)	(F) NET OUTPUT FAC (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURN (UNITS)	(J) FUEL HEAT VALUE (MMBTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH CENTS/KWH	(N) FUEL COST PER UNIT ($)
Steam													
Anclote													
UNIT 1	510	2,184,116.00	49			10,114				22,089,579	85,998,613	3.937	
		1,920,366.27					#6	2,953,173	6.577	19,422,083	75,288,350	3.921	25.494
		259,970.44					GS	2,554,818	1.029	2,629,273	10,452,975	4.021	4.091
		3,779.30					#2	6,563	5.824	38,223	257,288	6.808	39.203
UNIT 2	509	1,914,301.00	43			10,063				19,263,742	72,138,558	3.768	
		1,572,929.18					#6	2,409,651	6.569	15,828,494	59,381,043	3.775	24.643
		333,159.47					GS	3,264,418	1.027	3,352,607	12,231,116	3.671	3.747
		8,212.34					#2	14,190	5.824	82,641	526,398	6.410	37.096
Bartow													
UNIT 1	122	399,542.00	37			10,248				4,094,467	14,676,470	3.673	
		398,913.34					#6	629,380	6.495	4,088,024	14,644,316	3.671	23.268
		628.66					#2	1,110	5.804	6,442	32,153	5.115	28.967
UNIT 2	120	417,509.00	40			10,641				4,442,828	15,601,917	3.737	
		417,509.00					#6	683,720	6.498	4,442,828	15,600,665	3.737	22.817
		0.00					#2	0	0.000	0	1,252	0.000	
UNIT 3	206	898,284.00	50			10,127				9,096,554	32,258,977	3.591	
		777,582.85					#6	1,210,580	6.505	7,874,263	27,902,833	3.588	23.049
		120,701.15					GS	1,190,208	1.027	1,222,291	4,356,144	3.609	3.660
Crystal River 1 & 2													
UNIT 1	381	2,469,078.00	74			9,685				23,913,777	39,792,980	1.612	
		5,635.99					#2	9,393	5.811	54,586	334,780	5.940	35.641
		2,463,442.01					CA	947,348	25.185	23,859,191	39,458,200	1.602	41.651
UNIT 2	477	2,203,857.00	53			9,689				21,353,171	35,989,282	1.633	
		4,662.03					#2	7,773	5.811	45,170	279,366	5.992	35.941
		2,199,194.97					CA	845,163	25.212	21,308,000	35,709,916	1.624	42.252

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FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
Schedule A-4

Jan 00 Thru Dec 00
FINAL

(A) PLANT	(B) NET CAP (MW)	(C) NET GENERATION (MWH)	(D) CAP FAC (%)	(E) EQUIV AVAIL FAC (%)	(F) NET OUTPUT FAC (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURN (UNITS)	(J) FUEL HEAT VALUE (MMBTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH CENTS/KWH	(N) FUEL COST PER UNIT ($)
Crystal River 4 & 5													
UNIT 4	717	4,628,248.00	73			9,392				43,468,572	86,876,891	1.877	
		49,255.97					#2	80,290	5.762	462,613	2,979,212	6.048	37.106
		4,578,992.03					CA	1,733,364	24.811	43,005,959	83,897,679	1.832	48.402
UNIT 5	725	5,214,987.00	82			9,397				49,002,635	96,904,546	1.858	
		29,719.04					#2	48,184	5.796	279,255	1,868,131	6.286	38.771
		5,185,267.96					CA	1,963,116	24.819	48,723,380	95,036,416	1.833	48.411
Suwannee Plant													
UNIT 1	33	71,054.00	25			12,708				902,926	3,607,685	5.077	
		70,468.70					#6	137,302	6.522	895,488	3,571,488	5.068	26.012
		456.98					GS	5,660	1.026	5,807	28,945	6.334	5.114
		128.32					#2	278	5.865	1,631	7,252	5.651	26.086
UNIT 2	32	69,501.00	25			12,207				848,387	3,469,972	4.993	
		68,486.80					#6	131,004	6.382	836,007	3,409,186	4.978	26.024
		865.73					GS	10,300	1.026	10,568	52,674	6.084	5.114
		148.47					#2	309	5.865	1,812	8,112	5.464	26.252
UNIT 3	81	158,231.00	22			10,924				1,728,574	6,955,750	4.396	
		155,176.70					#6	257,568	6.582	1,695,208	6,743,538	4.346	26.182
		2,775.92					GS	29,420	1.031	30,325	199,522	7.188	6.782
		278.37					#2	519	5.859	3,041	12,690	4.559	24.451
TOTAL	3,913	20,628,708.00				9,705				200,205,211	494,271,640	2.396	
Nuclear													
Crystal River 3													
UNIT 3	774	6,606,869.84	97			10,258				67,770,488	23,670,303	0.358	
		0					NF	67,768,561	1.000	67,768,561	23,654,659	0.000	0.349
		0					#2	341	5.651	1,927	15,643	0.000	45.874
TOTAL	774	6,606,869.84				10,258				67,770,488	23,670,303	0.358	
Gas Turbine													
Avon Park Peaker	56	30,566.00	6			17,111				523,012	2,566,826	8.398	
		8,566.61					#2	25,195	5.818	146,582	861,984	10.062	34.213
		21,999.39					GS	365,550	1.030	376,429	1,704,843	7.750	4.664

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FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
Schedule A-4

Jan 00 Thru Dec 00
FINAL

(A) PLANT	(B) NET CAP (MW)	(C) NET GENERATION (MWH)	(D) CAP FAC (%)	(E) EQUIV AVAIL FAC (%)	(F) NET OUTPUT FAC (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURN (UNITS)	(J) FUEL HEAT VALUE (MMBTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH CENTS/KWH	(N) FUEL COST PER UNIT ($)
Bartow Peaker	203	114,289.00	6			15,833				1,809,561	8,686,389	7.600	
		31,206.63					#2	85,382	5.787	494,101	2,643,421	8.471	30.960
		83,082.37					GS	1,277,547	1.030	1,315,460	6,042,968	7.273	4.730
Bayboro Peaker	199	126,046.00	7			13,480				1,699,143	10,784,393	8.556	
		126,046.00					#2	292,543	5.808	1,699,143	10,784,393	8.556	36.864
Debary Peaker	642	538,700.00	10			13,601				7,326,908	38,560,610	7.158	
		274,288.87					#2	641,082	5.819	3,730,628	21,590,357	7.871	33.678
		264,411.13					GS	3,455,271	1.041	3,596,280	16,970,254	6.418	4.911
Higgins Peaker	125	84,222.00	8			16,738				1,409,719	6,529,358	7.753	
		1,346.66					#2	3,860	5.840	22,540	108,263	8.039	28.047
		82,875.34					GS	1,346,266	1.030	1,387,179	6,421,095	7.748	4.770
Hines Energy	507	2,722,410.00	61			7,295				19,859,839	89,774,070	3.298	
		0.00					#2	0	0.000	0	3,222	0.000	0.000
		2,722,410.00					GS	19,257,115	1.031	19,859,839	89,770,849	3.297	4.662
Intercession City Peaker	917	647,807.00	8			13,419				8,692,807	43,244,999	6.676	
		187,365.18					#2	432,127	5.818	2,514,220	14,244,912	7.603	32.965
		460,441.82					GS	5,985,006	1.032	6,178,587	29,000,086	6.298	4.845
Rio Pinar Peaker	15	2,714.00	2			18,843				51,140	304,039	11.203	
		2,714.00					#2	8,812	5.803	51,140	304,039	11.203	34.503
Suwannee Peaker	172	124,031.00	8			13,971				1,732,778	8,888,443	7.166	
		32,693.11					#2	78,373	5.828	456,740	2,461,531	7.529	31.408
		91,337.89					GS	1,239,314	1.030	1,276,038	6,426,912	7.036	5.186
Tiger Bay Cogen	215	1,347,448.00	71			7,658				10,318,464	40,869,876	3.033	
		1,347,448.00					GS	9,998,376	1.032	10,318,464	40,869,876	3.033	4.088
Turner Peaker	165	54,138.00	4			14,292				773,754	4,275,792	7.898	
		54,138.00					#2	133,015	5.817	773,754	4,275,792	7.898	32.145
Univ of Florida Cogen	42	312,164.00	85			10,656				3,326,436	13,037,152	4.176	
		312,164.00					GS	3,190,457	1.043	3,326,436	13,037,152	4.176	4.086
TOTAL	3,255	6,104,535.00				9,423				57,523,561	267,521,947	4.382	
SYSTEM TOTAL	7,942	33,340,112.84				9,763				325,499,260	785,463,890	2.356	

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
Schedule A-4

(A) PLANT	(B) NET CAP (MW)	(C) NET GENERATION (MWH)	(D) CAP FAC (%)	(E) EQUIV AVAIL FAC (%)	(F) NET OUTPUT FAC (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURN (UNITS)	(J) FUEL HEAT VALUE (MMBTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH CENTS/KWH	(N) FUEL COST PER UNIT ($)

NOTE: Includes the following steam transfers:

Plant	Unit	Fuel Type	Cost	Burn	BTUS
Crystal River 1 & 2	UNIT 1	Coal	$9,686.44	238.00	5,944,288,256
Crystal River 1 & 2	UNIT 2	Coal	$13,486.85	328.00	8,226,343,936

NOTE: Includes the following aerial survey adjustment:

Plant	Tons	Dollars	MMBTU
Crystal River 1 & 2	-15,069	-627,306.05	-376,707.18
Crystal River 4 & 5	27,874	1,347,260.87	688,158.91

FLORIDA POWER [illegible]PORATION

SYSTEM GENERATION FUEL COST

Schedule A-5

			Actual	Estimated	Difference	Difference (%)
HEAVY OIL	1	PURCHASES				
	2	Units (BBL)	7,712,846	8,142,910	-430,064	-5.3%
	3	Unit Cost ($/BBL)	25.45	16.29	9.16	56.2%
	4	Amount ($)	196,272,038	132,645,965	63,626,073	48.0%
	5	BURNED				
	6	Units (BBL)	8,412,339	8,142,910	269,429	3.3%
	7	Unit Cost ($/BBL)	24.55	16.45	8.10	49.3%
	8	Amount ($)	206,541,419	133,930,477	72,610,942	54.2%
	9	ADJUSTMENTS				
	10	Units (BBL)	-14,550			
	11	Amount ($)	-1,652,492			
	12	ENDING INVENTORY				
	13	Units (BBL)	339,220	800,000	-460,780	-57.6%
	14	Unit Cost ($/BBL)	26.77	16.36	10.41	63.6%
	15	Amount ($)	9,080,881	13,090,323	-4,009,442	-30.6%
	16					
	17	DAYS SUPPLY	0	0	0	0.0%
LIGHT OIL	18	PURCHASES				
	19	Units (BBL)	1,685,553	1,623,267	62,286	3.8%
	20	Unit Cost ($/BBL)	37.96	26.94	11.03	40.9%
	21	Amount ($)	63,986,743	43,723,805	20,262,938	46.3%
	22	BURNED				
	23	Units (BBL)	1,868,092	1,623,267	244,825	15.1%
	24	Unit Cost ($/BBL)	34.05	26.94	7.11	26.4%
	25	Amount ($)	63,600,189	43,728,159	19,872,030	45.4%
	26	ADJUSTMENTS				
	27	Units (BBL)	-99,980			
	28	Amount ($)	-3,134,670			
	29	ENDING INVENTORY				
	30	Units (BBL)	402,293	550,000	-147,707	-26.9%
	31	Unit Cost ($/BBL)	36.53	26.97	9.56	35.5%
	32	Amount ($)	14,695,191	14,832,211	-137,020	-0.9%
	33					
	34	DAYS SUPPLY	0	0	0	0.0%

FLORIDA POWER CORPORATION
SYSTEM GENERATION FUEL COST
Schedule A-5

Jan 00 Thru Dec 00
FINAL

			Actual	Estimated	Difference	Difference (%)
COAL	35	PURCHASES				
	36	Units (TON)	5,248,397	5,500,000	-251,603	-4.6%
	37	Unit Cost ($/TON)	46.55	45.94	0.62	1.3%
	38	Amount ($)	244,329,263	252,653,890	-8,324,627	-3.3%
	39	BURNED				
	40	Units (TON)	5,493,054	5,479,453	13,601	0.2%
	41	Unit Cost ($/TON)	46.26	46.26	0.00	0.0%
	42	Amount ($)	254,102,210	253,479,749	622,461	0.2%
	43	ADJUSTMENTS				
	44	Units (TON)	-1,402			
	45	Amount ($)	-64,235			
	46	ENDING INVENTORY				
	47	Units (TON)	580,428	552,235	28,193	5.1%
	48	Unit Cost ($/TON)	48.29	45.95	2.34	5.1%
	49	Amount ($)	28,027,534	25,375,991	2,651,543	10.4%
	50					
	51	DAYS SUPPLY	0	0	0	0.0%
OTHER	52					
	53					
	54					
	55					
	56					
	57					
	58					
	59					
	60					
	61					
	62					
	63					
	64					
	65					

FLORIDA POWER CORPORATION
SYSTEM GENERATION FUEL COST
Schedule A-5

Jan 00 Thru Dec 00
FINAL

			Actual	Estimated	Difference	Difference (%)
GAS	66	BURNED				
	67	Units (MCF)	53,169,726	45,231,896	7,937,830	17.5%
	68	Unit Cost ($/MCF)	4.47	3.26	1.21	37.0%
	69	Amount ($)	237,565,411	147,488,329	90,077,082	61.1%
NUCLEAR	70	BURNED				
	71	Units (MM BTU)	67,768,561	65,722,729	2,045,832	3.1%
	72	Unit Cost ($/MM BTU)	0.35	0.33	0.02	5.8%
	73	Amount ($)	23,654,659	21,688,501	1,966,158	9.1%

NOTE: Purchase dollars and units do not include plant to plant transfers. See schedule A-5, Attachment #1 for detail of adjustments.

FLORIDA POWER CORPORATION
SCHEDULE A6

POWER SOLD
FOR THE MONTH OF:
DEC 2000

(1)	(2)	(3)	(4)	(5)	(6a)	(6b)	(7)	(8)	(9)	(10)
SOLD TO	TYPE & SCHEDULE	TOTAL KWH SOLD (000)	KWH WHEELED FROM OTHER SYSTEMS (000)	KWH FROM OWN GENERATION (000)	FUEL COST C/KWH	TOTAL COST C/KWH	FUEL ADJ. TOTAL $	TOTAL COST $	80% GAIN ON ECONOMY ENERGY SALES $	NON FUEL AMOUNT FOR FUEL ADJ. $
ESTIMATED		120,793	0	120,793	1.666	1.666	2,012,260	2,012,260	0	289902
ACTUAL:										
SubTotal - Gain on Economy Energy Sales		-		-			-	-	-	
SEMINOLE	Load Following	1,697		1,697	4.36	4.36	73,916	73,916	Not Applicable	-
Aquila Energy Marketing Corporation	Schedule OS	8,231		8,231	5.20	7.19	427,738	592,060	"	164,322
Cargill-Alliant, LLC	MR-1	810		810	2.81	6.96	22,766	56,397	"	33,631
Cinergy Services, Inc.	MR-2	800		800	5.44	7.09	43,503	56,741	"	13,239
City of Homestead, FL	Schedule OS	380		380	3.71	6.16	14,102	23,412	"	9,310
City of Lakeland, FL	*Schedule OS*	100		100	3.42	5.21	3,418	5,210	"	1,792
City of New Smyrna Beach, FL	Schedule H	-		-	-	-	-		"	-
City of New Smyrna Beach, FL	Schedule I	-		-	-	-	6,212	6,212	"	-
City of Tallahassee, FL	Schedule A	52		52	6.84	6.84	3,555	3,555	"	-
City of Tallahassee, FL	Schedule OS	4,865		4,865	2.86	4.13	139,294	201,011	"	61,716
Coral Power, L. L. C.	Schedule OS	6,504		6,504	2.69	5.72	175,053	371,725	"	196,672
Duke Energy Trading & Marketing, L. L	Schedule OS	52		52	2.11	7.98	1,099	4,148	"	3,049
El Paso Merchant Energy, L.P.	MR-1	515		515	3.33	5.61	17,166	28,893	"	11,727
Enron Power Marketing, Inc.	Schedule OS	2,968		2,968	3.13	5.74	92,870	170,434	"	77,563
Florida Power & Light Company	Schedule OS	2,700		2,700	2.71	3.16	73,051	85,284	"	12,233
LG & E Energy Marketing, Inc.	Schedule J	900		900	1.68	2.42	15,090	21,749	"	6,659
LG & E Energy Marketing, Inc.	Schedule OS	20,196		20,196	3.17	4.65	640,538	939,341	"	298,803
Morgan Stanley Capital Group, Inc.	MR-1	680		680	2.53	6.73	17,174	45,738	"	28,564
Oglethorpe Power Corporation	MR-2	7,330		7,330	3.11	5.03	228,196	368,535	"	140,340
Orlando Utilities Commission	Schedule OS	1,230		1,230	3.45	4.92	42,382	60,530	"	18,148
Reedy Creek Improvement District	Schedule OS	3,565		3,565	2.57	1.99	91,601	70,856	"	(20,745)
Reliant Energy Services, Inc.	Schedule OS	2,945		2,945	6.23	8.58	183,485	252,598	"	69,113
Southern Company Services, Inc.	MR-1	3,450		3,450	4.08	5.83	140,732	201,073	"	60,341
Tampa Electric Company	Schedule J	34,891		34,891	2.94	4.81	1,027,031	1,679,248	"	652,217
Tennessee Valley Authority	MR-1	7,170		7,170	4.27	6.84	305,829	490,172	"	184,343
The Energy Authority	MR-1	3,363		3,363	3.28	6.01	110,327	202,035	"	91,708
The Energy Authority	Schedule OS	4,741		4,741	2.65	4.42	125,823	209,750	"	84,126
ADJUSTMENTS										
Florida Municipal Power Agency		0		-	-	-	-	3.00	"	3
SubTotal - Gain on Other Power Sales		120,135		120,135			4,021,751.30	6,220,627.20		2,196,876
CURRENT MONTH TOTAL		120,135		120,135	3.043	4.707	4,021,751.30	6,220,627.20	-	2,196,876
DIFFERENCE		(658)		(658)	(278)	(581)	2,009,491	4,208,367	-	1,906,974
DIFFERENCE %		*0.00%*		*0.00%*	*0.000*	*0.000*	*0.00%*	0.00%	0.00%	0.00%
CUMULATIVE ACTUAL		1,477,064		1,477,064	2.482	3.032	40,324,236	49,263,334	783,015	7,960,329
CUMULATIVE ESTIMATED		1,423,350		1,423,350	2.081	2.116	32,588,251	33,129,724	433,178	7,233,956
CUMULATIVE DIFFERENCE		53,714		53,714	13.093	27.306	7,735,985	16,133,610	349,837	726,373
CUMULATIVE DIFFERENCE %		3.77%		3.77%	0.572	1.173	23.74%	48.70%	80.80%	

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FLORIDA POWER CORPORATION
SCHEDULE A7

PURCHASED POWER
EXCLUSIVE OF ECONOMY PURCHASES
FOR THE MONTH OF:
DEC 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	KWH FOR OTHER UTILITIES (000)	KWH FOR INTERRUPTIBLE (000)	KWH FOR FIRM (000)	FUEL COST C/KWH	TOTAL COST C/KWH	TOTAL AMOUNT FOR FUEL ADJ $	FUEL COST $
ESTIMATED		207,704			207,704	1.432	1.432	2,973,387	2,973,387
ACTUAL									
Glades	Firm	11			11	11.00	11.000	1,210.00	1,210.00
Southern Company Servic	Southern UPS	266,665			266,665	1.41	1.408	3,755,221.05	3,755,221.05
Tampa Electric Company	TECO AR1	27,480			27,480	2.93	2.932	805,759.00	805,759.00
		-			-	-	0.000		-
Adjustments									
Tampa Electric Company	TECO AR1	-			-	-	-	(688.50)	(688.50)
		-			-	-	-		-
CURRENT MONTH TOTAL		294,156			294,156	1.551	1.551	4,561,502	4,561,502
DIFFERENCE		86,452			86,452	0.119	0.119	1,588,115	1,588,115
DIFFERENCE %		41.6			41.6	8.3	8.3	53.4	53.4
CUMULATIVE ACTUAL		3,242,163			3,242,163	1.554	1.554	50,390,152	50,390,152
CUMULATIVE ESTIMATED		2,287,122			2,287,122	1.596	1.596	36,511,925	36,511,925
CUMULATIVE DIFFERENCE		955,041			955,041	(0.042)	(0.042)	13,878,227	13,878,227
CUMULATIVE DIFFERENCE %		41.8			41.8	(2.6)	(2.6)	38.0	38.0

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25-Jan-01

FLORIDA POWER CORPORATION
SCHEDULE A8

ENERGY PAYMENT TO QUALIFYING FACILITIES
FOR THE MONTH OF:
DEC 2000

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL KWH PURCHASED (000)	(4) KWH FOR OTHER UTILITIES (000)	(5) KWH FOR NTERRUPTIBLE (000)	(6) KWH FOR FIRM (000)	(7) ENERGY COST C/KWH	(8) TOTAL COST C/KWH	(9) TOTAL AMOUNT FOR FUEL ADJ $
ESTIMATED		561,831			561,831	1.871	1.871	10,513,153
ACTUAL								
AUBURNDALE (EL DORADO)	CO-GEN	78,578			78,578	2.457	2.457	1,930,814.04
ADJ		0			0			(71,307.23)
AUBURNDALE LFC POWER SYSTEMS	CO-GEN	7,820			7,820	1.770	1.770	138,409.75
ADJ		0			0			(15,144.26)
BAY COUNTY	CO-GEN	5,934			5,934	1.738	1.738	103,132.92
ADJ		-			-			(4,174.66)
CARGILL FERTILIZER	CO-GEN	4,531			4,531	1.363	1.363	61,757.53
ADJ		-			-			(13,484.00)
CENTRAL POWER & LIME (FLACRUSH	CO-GEN	-			-	0.000	0.000	-
ADJ		-			-			-
CITRUS WORLD	CO-GEN	-			-	0.000	0.000	-
ADJ		(1)			(1)			4.35
JEFFERSON POWER	CO-GEN	1,156			1,156	2.167	2.167	25,050.52
ADJ		-			-			(5,945.42)
LAKE COUNTY	CO-GEN	6,665			6,665	1.759	1.759	117,237.35
ADJ		-			-			(6,317.75)
LAKE ORDER COGEN LIMITED	CO-GEN	56,663			56,663	2.307	2.307	1,307,215.41
ADJ		-			-			35,150.15
METRO-DADE COUNTY	CO-GEN	25,108			25,108	2.060	2.060	517,318.16
ADJ		-			-			34,686.08
ORANGE COGEN	CO-GEN	40,660			40,660	1.937	1.937	788,033.04
ADJ		-			-			2,287.47
ORLANDO COGEN	CO-GEN	58,233			58,233	2.387	2.387	1,390,037.22
ADJ		-			-			(22,702.27)
PASCO COGEN LIMITED	CO-GEN	54,768			54,768	1.748	1.748	957,344.64
ADJ		-			-			138,775.73
PASCO COUNTY RESOURCE RECOVE	CO-GEN	17,776			17,776	1.765	1.765	313,746.40
ADJ		-			-			(20,861.91)
PCS PHOSPHATE	CO-GEN	180			180	2.799	2.799	5,034.51
ADJ		100			100			3,342.58
PERPETUAL ENERGY	CO-GEN	-			-	0.000	0.000	-
ADJ		-			-			-
PINELLAS COUNTY	CO-GEN	33,917			33,917	1.722	1.722	584,050.74
ADJ		-			-			(32,581.38)
POLK POWER - MULBERRY ENERGY	CO-GEN	34,444			34,444	1.498	1.498	515,972.17
ADJ		-			-			1,079,305.53
POLK POWER- ROYSTER ENERGY	CO-GEN	13,395			13,395	1.510	1.510	202,263.14
ADJ		-			-			421,229.52
ST. JOE PAPER	CO-GEN	-			-	0.000	0.000	-
ADJ		-			-			-
TIMBER ENERGY RESOURCES	CO-GEN	7,683			7,683	1.813	1.813	139,292.79
ADJ		-			-			(8,970.53)
U.S. AGRI-CHEMICALS	CO-GEN	4,247			4,247	2.292	2.292	97,341.24
ADJ		-			-			(3,916.78)
WHEELABRATOR RIDGE ENERGY	CO-GEN	15,175			15,175	2.780	2.780	421,865.00
ADJ		1			1			22,213.91
CURRENT MONTH TOTAL		467,053			467,053	2.387	2.387	11,147,505.70
DIFFERENCE		(94,778)			(94,778)	0.516	0.516	634,352.70
DIFFERENCE %		(16.9)			(16.9)	27.6	27.6	6.0
TIGER BAY STIPULATED PAYMENTS								
TIGER BAY - ECOPEAT	CO-GEN	18,519			18,519	2.061	2.061	381,729.23
TIGER BAY - GENERAL PEAT	CO-GEN	79,100			79,100	1.843	1.843	1,457,710.95
TIGER BAY - TIMBER 2	CO-GEN	2,785			2,785	1.841	1.841	51,276.61
TIGER BAY - STEAM SALES	CO-GEN	0			0	0.000	0.000	14,667.87
TOTAL QF ENERGY PAYMENTS INCLUDING TIGER BAY								
CURRENT MONTH TOTAL		567,457			567,457	2.300	2.300	13,052,890.00
DIFFERENCE		5,626			5,626	2.300	2.300	2,539,737.00
DIFFERENCE %		1.0			1.0	0.0	0.0	24.2
CUMULATIVE ACTUAL		6,566,409			6,566,409	2.109	2.109	138,522,240.00
CUMULATIVE ESTIMATED		6,707,728			6,707,728	1.983	1.983	133,022,647.00
CUMULATIVE DIFFERENCE		(139,319)			(139,319)	0.126	0.126	5,499,593.00
CUMULATIVE DIFFERENCE %		(2.1)			(2.1)	6.4	6.4	4.1

FLORIDA POWER CORPORATION
SCHEDULE A9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
FOR THE MONTH OF:
DEC 2000

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL KWH PURCHASED (000)	(4) ENERGY COST C/KWH	(5) TOTAL AMOUNT FOR FUEL ADJ $	(6) COST IF GENERATED C/KWH	(7) COST IF GENERATED $	(8) FUEL SAVINGS $
ESTIMATED		**25,244**	**2.228**	**562,470**	**2.228**	**562,470**	**0**
ACTUAL							
Oglethorpe Power Corporation	Service Schedule C - Economy	450	6.00	27,000.00	7.95	35,751.36	8,751.36
Subtotal - Energy Purchases (Broker)		**450**	**6.000**	**27,000**	**7.945**	**35,751**	**8,751**
Southeastern Power Admin.	Hydro	-	-		-	0.00	0.00
SEMINOLE	LOAD FOLLOWING	5,155	4.07	209,870.69	4.07	209,870.69	0.00
Aquila Energy Marketing Corporation	FERC Electric Rate Schedule	2,063	9.14	188,496.00	9.73	200,635.79	12,139.79
Cargill-Alliant, LLC	FERC Electric Tariff No. 8 (MR	49	8.00	3,920.00	15.00	7,350.00	3,430.00
City of Lakeland, FL	Service Schedule OS - Opport	530	11.81	62,600.00	10.55	55,908.80	(6,691.20)
City of Tallahassee, FL	Service Schedule OS - Opport	1,010	8.76	88,425.00	9.99	100,916.60	12,491.60
City of Tallahassee, FL	Transmission Purchase - Tran	-	-	2,146.68	-	0.00	(2,146.68)
Coral Power, L. L. C.	FERC Electric Rate Schedule	2,022	10.48	211,865.00	11.09	224,293.85	12,428.85
Duke Energy Trading & Marketing, L. L. C.	FERC Electric Rate Schedule	3,662	14.89	545,105.00	15.04	550,634.81	5,529.81
El Paso Merchant Energy, L.P.	FERC Electric Tariff No. 8 (MR	240	9.67	23,200.00	10.58	25,399.00	2,199.00
Enron Power Marketing, Inc.	FERC Electric Rate Schedule	1,926	10.16	195,590.00	11.26	216,824.02	21,234.02
Florida Power & Light Company	Service Schedule OS - Opport	23,525	7.51	1,767,150.00	8.70	2,046,636.00	279,486.00
Florida Power & Light Company	Transmission Purchase - Tran	-	-	15,171.96	-	0.00	(15,171.96)
Jacksonville Electric Authority	Transmission Purchase - Tran	-	-	126,294.08	-	0.00	(126,294.08)
Koch Energy Trading, Inc.	FERC Electric Rate Schedule	30	19.00	5,700.00	20.90	6,270.00	570.00
LG & E Energy Marketing, Inc.	FERC Electric Rate Schedule	1,890	9.97	188,410.00	12.00	226,750.76	38,340.76
Morgan Stanley Capital Group, Inc.	Service Schedule J - Negotiate	30	5.00	1,500.00	4.49	1,347.63	(152.37)
Oglethorpe Power Corporation	Schedule R - Replacement En	150	4.70	7,050.00	7.42	11,124.38	4,074.38
Orlando Utilities Commission	Service Schedule OS - Opport	5,435	29.16	1,585,025.00	32.13	1,746,209.50	161,184.50
Reedy Creek Improvement District	Service Schedule OS - Opport	13,454	4.96	666,990.00	8.51	1,145,419.18	478,429.18
Reliant Energy Services, Inc.	FERC Electric Rate Schedule	353	13.62	48,064.00	15.05	53,119.00	5,055.00
Seminole Electric Cooperative, Inc.	Transmission Purchase - Tran	-	-	23,388.20	-	0.00	(23,388.20)
Southern Company Energy Marketing, L. P	FERC Electric Rate Schedule	2,500	9.16	229,100.00	10.00	249,979.40	20,879.40
Southern Company Services, Inc.	FERC Electric Tariff No. 8 (MR	4,500	11.60	522,050.00	12.66	569,780.20	47,730.20
Southern Company Services, Inc.	Transmission Purchase - Tran	-	-	13,128.00	-	0.00	(13,128.00)
Tampa Electric Company	FERC Electric Tariff No. 8 (MR	285	6.88	19,620.00	8.52	24,284.85	4,664.85
Tampa Electric Company	Service Schedule J - Negotiate	3,155	13.02	410,650.00	15.04	474,447.35	63,797.35
The Energy Authority	Service Schedule OS - Opport	3,120	7.66	239,577.50	9.16	285,694.72	46,117.22
TXU Energy Trading Company	FERC Electric Rate Schedule	300	10.23	30,700.00	13.63	40,891.40	10,191.40
ADJUSTMENTS							
Jacksonville Electric Authority	Transmission Purchase - Tran	-	-	(10.14)	-		10.14
Subtotal - Energy Purchases (Non-Broker)		**76,384**		**7,430,777**		**8,473,788**	**1,043,011**
CURRENT MONTH TOTAL		75,834	9.834	7,457,777	11.221	8,509,539	1,051,762
DIFFERENCE		50,590	3.834	6,895,307	3.276	7,947,069	1,051,762
DIFFERENCE %		200.4	63.9	1,225.9	41.2	1,412.9	0.0
CUMULATIVE ACTUAL		847,477	7.003	59,349,042	8.360	70,852,726	11,503,684
CUMULATIVE ESTIMATED		490,000	4.461	21,860,475	4.461	21,860,475	
CUMULATIVE DIFFERENCE		357,477	2.542	37,488,567	3.899	48,992,251	11,503,684
CUMULATIVE DIFFERENCE %		73.0	57.0	171.5	87.4	224.1	

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

ESTIMATED/ACTUAL TRUE-UP AMOUNTS JANUARY THROUGH DECEMBER 2001

PART A - SALES FORECAST ASSUMPTIONS

SALES FORECAST ASSUMPTIONS

1. This forecast of customers, sales and peak demand utilizes the short-term load forecasting methodology developed for use in the 2002 budget and 2002 - 2006 Five Year Business Plan. This forecast was prepared in June 2001.

2. Normal weather conditions are assumed over the forecast horizon. For kiloWatt-hour sales projections normal weather is based on a historical twenty-five year average of service area weighted billing month degree-days. Seasonal peak demand projections are based on a twenty-five year historical average of system-weighted temperatures at time of seasonal peak.

3. The population projections produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida as published in "Florida Population Studies", Bulletin No. 128 (May 2001) provide the basis for development of the customer forecast. State and national economic assumptions produced by WEFA in their national and Florida forecasts (March 2001) are also incorporated.

4. Within the State of Florida the phosphate mining industry accounts for 75% of the U.S. phosphate supply and 35% of the global need. This energy intensive industry, which in the FPC service area consists of six major producers with either national and/or international influence upon the supply of phosphate-based fertilizers, consumed nearly 31% of industrial class kWh energy sales in 2000. Load and energy consumption at the FPC-served mining or chemical processing sites depend heavily on plant operations which are heavily influenced by both micro- and macroeconomic conditions. There is presently excess mining capacity in the industry due to weak farm commodity prices worldwide. Weak farm commodity prices lead to lower crop production, which results in less demand for fertilizer products. In addition, the export market for fertilizer has dried up since the Asian/Russian financial crisis. Going forward, energy consumption is expected to remain weak. Phosphate energy consumption – as a percentage of the total FPC Industrial class usage – is expected to fall to 27% in the 2001-2002 timeframe, the second lowest share ever seen. A return to even a 35% share – recorded just a year ago – is not expected in the short term.

5. Florida Power Corporation (FPC) supplies load and energy service to wholesale customers on a "full", "partial" and "supplemental" requirement basis. Full

requirements customers' demand and energy is assumed to grow at a rate that approximates their historical trend. Partial requirements customer load is assumed to reflect the current contractual obligations received by FPC as of May 31, 2001. The forecast of energy and demand to the partial requirements customers reflect the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. Contracts for partial requirements service included in this forecast are with FMPA, the cities of New Smyrna Beach, Tallahassee and Homestead, Reedy Creek Utilities, and Florida Power & Light. FPC's arrangement with Seminole Electric Cooperative, Inc. (SECI) is to serve "supplemental" service over and above stated levels they commit to supply themselves. SECI's projection of their system's requirements in the FPC control area has been incorporated into this forecast. This forecast also incorporates two firm bulk power contracts with SECI. The first is a multi-part contract to supply 605 MW for three years ending in December 2001. An option to extend one piece of this contract (150 MW) has been exercised by SECI and incorporated into the forecast. A second 3-year agreement with SECI to sell up to 300 MW of peaking power beginning in 2000 and going through 2002 has also been reflected in the forecast.

6. This forecast assumes that FPC will successfully renew all future franchise agreements.

7. This forecast incorporates demand and energy reductions from FPC'S dispatchable and non-dispatchable DSM programs required to meet the approved goals set by the Florida Public Service Commission.

8. Expected energy and demand reductions from self-service cogeneration are also included in this forecast. FPC will supply the supplemental load of self-service cogeneration customers. While FPC offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for standby power.

9. This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. The ability of wholesale customers to switch suppliers has ended the company's obligation to serve these customers beyond their contract life. As a result, the company does not plan for generation resources unless a long-term contract is in place. Current "all requirements" customers are assumed to not renew their contracts with FPC. Current "partial requirements" contracts are projected to terminate as terms reach their expiration date. Deviation from these assumptions can occur as information

from the Term Marketing department indicates that a wholesale customer has limited options in the marketplace to replace FPC capacity more economically.

10. The economic outlook for this forecast calls for a significant moderation of national and State economic growth compared to rates seen in the 1990's. Energy price escalation and the bursting of the stock market bubble have acted to deflate consumer confidence and effectively halt new capital investment in many industries nationwide. While no economic recession – two negative quarters of GDP growth – is incorporated in this forecast, the growth rate of the U.S. national economy has ground to a halt in early 2001. The current stretch of economic expansion – which has become the longest period of economic expansion in the history of our nation – is now in serious risk of stalling out.

    The assumption that the national economy will skirt a full-blown recession is based upon the belief that the U.S. Congress and the Federal Reserve Board (FRB) will enact an appropriate mixture of fiscal and monetary policy actions. Economic stimulus from a Federal tax cut, while marginal in the short term, has been enacted. Swift and significant reductions to government-controlled interest rates by the Federal Reserve Board during the first half of 2001 assures most economists that the economy will react (with a lag) and pick up by year end.

    Over-riding this, however, is the fear that a "reverse wealth-effect" will take hold of the economy and depress consumer demand. The "wealth-effect", caused by the record run-up in the U.S. stock market in the later 1990s, created a sizeable increase in consumer demand these past few years. Today, after a loss of several trillion dollars of wealth in the stock market and rising unemployment, the fear is that the consumer will rein in spending and pay down their record levels of debt.

    On a Statewide basis, interest rates and energy prices will continue to influence the pace of economic growth in Florida through their impacts on the construction and tourism industries. The Florida construction industry is expected to feel the impact of corporate mergers and consolidations with respect to commercial and industrial floor space requirements. The State has seen its fair share of corporate mergers in the banking, telecommunications and utility industries, and has not been immune to the impact of "DOT-com" failures. Office vacancy rates are reported to have risen dramatically of late. The tourism industry is reported to have performed well during the winter 2000-2001 but by mid-year hotel vacancy rates and theme park attendance have dropped precipitously. Looking forward, high consumer debt levels in a weak economic environment place an added risk on this industry's ability to avoid some economic pain.

Another Florida industry sector increasing in importance, export-related industries, is expected to stall in 2001 as Central and South American economies flounder. Florida has developed significant trade relations with its neighbors to the south and continues to attract a significant number of tourists from this area. Areas of Latin America are reeling from drought conditions and a serious electricity shortage, which are not helping economic matters.

Personal income growth is expected to continue growing but not at the torrid pace experienced in recent years. Employment growth will moderate resulting in slower growth in total wages. Slower growth in hourly earnings as well as transfer payments should also hold down income growth in the years ahead. The low interest rate environment also means lower returns on bank deposits – a significant part of retiree income.

Growth in energy consumption is directly tied to the levels of economic activity in the State, nation and around the world, but demographic forces play a major role as well. Factors that influence in-migration rates to Florida impact residential customer growth, especially since the difference between births and deaths contribute little to Florida's growing population. The University of Florida's latest projection (May 2001) shows a significant fall off in population growth for the 29 county area which Florida Power provides residential service. This is due to the characteristics of the age cohorts reaching retirement age this decade. Those now reaching retirement age were born during the Great Depression – a period of very low birth rates. This is expected to temporarily hold down Florida population growth by reducing the numbers of retirees entering the State.

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

ESTIMATED/ACTUAL TRUE-UP AMOUNTS JANUARY THROUGH DECEMBER 2001

PART B - FUEL PRICE FORECAST ASSUMPTIONS

FUEL PRICE FORECAST ASSUMPTIONS

A. Residual Oil and Light Oil

The oil price forecast is based on expectations of normal weather and no radical changes in world energy markets (OPEC actions, governmental rule changes, etc.). Prices are based on expected contract structures, specifications, and spot market purchases for 2001 & 2002.

FPC Residual Fuel Oil (#6) and Distillate Fuel Oil (#2) prices were derived from EIA forecasts, NYMEX, and current market information.

Transportation to the Tampa Bay area plus applicable environment taxes were added to the above prices (an adjustment was later made to transportation costs for individual plant locations).

B. Coal

Coal price projections are provided by Electric Fuels Corporation and represent an estimate of EFC's price to Florida Power for coal delivered to the plant sites in accordance with the delivery schedules projected. The forecast is consistent with the coal supply and transportation agreements which EFC has, or expects to have, in place during 2001 & 2002 and estimated spot purchase volumes and prices for the period. It assumes environmental restrictions on coal quality remain in effect as per current permits: 2.1 lbs. per million BTU sulfur dioxide limit for Crystal River Units 1 and 2, and 1.2 lbs. per million BTU sulfur dioxide limit for Crystal River Units 4 and 5.

C. Natural Gas

The natural gas price forecast is based on the expectation of normal weather, no material changes in energy markets, governmental rule changes, etc. Prices are based on expected contract structures and spot market purchases for 2001 & 2002. Gas supply prices were derived from EIA, NYMEX and current spot market information.

Transportation costs for Florida Gas Transmission pipeline firm transportation service is based on expected tariff rates. Interruptible transportation rates and availability are based on expected tariff rates and market conditions.

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

ESTIMATED/ACTUAL TRUE-UP AMOUNTS JANUARY THROUGH DECEMBER 2001

PART C - FUEL PRICE FORECAST

Florida Power Corporation
Docket No. 010001-EI
Witness: J. Portuondo
Exhibit No. _____
Part C
Sheet 1 of 4

FUEL PRICE FORECAST
#6 Fuel Oil

	1.0%		1.5%		2.5%	
Month	**$/barrel**	**$/MMBtu (1)**	**$/barrel**	**$/MMBtu (1)**	**$/barrel**	**$/MMBtu (1)**
Aug – Sept 2001	23.40	3.60	22.10	3.40	19.50	3.00
Oct – Dec 2001	26.00	4.00	24.05	3.70	20.15	3.10

(1) 6.5 mmbtu/bbl

Florida Power Corporation
Docket No. 010001-EI
Witness: J. Portuondo
Exhibit No. _____
Part C
Sheet 2 of 4

FUEL PRICE FORECAST
#2 Fuel Oil

Month	$/barrel	¢/gallon	$/MMBtu[1]
July – Sept 2001	34.80	82.90	6.00
Oct – Dec 2001	37.70	89.76	6.50

[1] 5.8 MMBtu/Bbl & 42 gallon/Bbl

Florida Power Corporation
Docket No. 010001-EI
Witness: J. Portuondo
Exhibit No. _____
Part C
Sheet 3 of 4

FUEL PRICE FORECAST
Coal

	Crystal River 1 & 2			Crystal River 4 & 5		
Month	**BTU/lb.**	**$/ton**	**$/MMBtu**	**BTU/lb.**	**$/ton**	**$/MMBtu**
Aug – 2001	12,659	43.15	1.704	12,451	60.57	2.432
Sep – 2001	12,696	43.03	1.695	12,438	59.57	2.395
Oct – 2001	12,632	43.26	1.712	12,450	60.90	2.446
Nov – 2001	12,686	43.16	1.701	12,436	59.09	2.376
Dec – 2001	12,647	43.11	1.704	12,454	60.53	2.430

Florida Power Corporation
Docket No. 000001-EI
Witness: J. Portuondo
Exhibit No. _____
Part C
Sheet 4 of 4

FUEL PRICE FORECAST
Natural Gas Supply

INTO FLORIDA GAS TRANSMISSION [1]	
Month	**$/MMBtu**
July - Sept 2001	4.00
Oct -Dec 2001	4.75

[1] Transport costs not included

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

ESTIMATED/ACTUAL TRUE-UP AMOUNTS JANUARY THROUGH DECEMBER 2001

PART D - CAPACITY COST RECOVERY CALCULATIONS

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED / ACTUAL TRUE-UP
For the Year 2001

Florida Power Corporation
Docket 010001-EI
Witness: Portuondo
Part D
Reprojected 8/01

		Actual Jan-01	Actual Feb-01	Actual Mar-01	Actual Apr-01	Actual May-01	Actual Jun-01	Actual Jul-01	Estimated Aug-01	Estimated Sep-01	Estimated Oct-01	Estimated Nov-01	Estimated Dec-01	Total 2001
	Base Production Level Capacity Charges:													
1	Payments to Qualifying Facilities	22,943,226	24,364,878	23,475,193	23,510,763	23,877,267	23,918,874	23,917,936	24,135,401	24,142,721	24,150,041	24,157,361	24,164,681	286,758,342
2	UPS Purchase (409 MW)	4,193,198	4,168,465	3,801,057	3,986,225	3,677,373	4,000,010	3,988,181	3,959,000	3,831,000	3,959,000	3,831,000	3,959,000	47,353,509
3	Other Power Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Subtotal - Base Level Capacity Charges	27,136,424	28,533,343	27,276,250	27,496,988	27,554,640	27,918,884	27,906,117	28,094,401	27,973,721	28,109,041	27,988,361	28,123,681	334,111,851
5	Base Production Jurisdictional %	97.232%	97.232%	97.232%	97.232%	97.560%	97.560%	97.560%	97.560%	97.560%	97.560%	97.560%	97.560%	
6	Base Level Jurisdictional Capacity Charges	26,385,288	27,743,540	26,521,243	26,735,871	26,882,307	27,237,663	27,225,208	27,408,898	27,291,162	27,423,180	27,305,445	27,437,463	325,597,289
	Intermediate Production Level Capacity Charges:													
7	TECO Power Purchase	565,567	565,567	565,567	565,567	565,567	565,567	565,567	566,000	566,000	566,000	566,000	566,000	6,788,969
8	Capacity Sales	(2,385)	(2,154)	(2,154)	(2,538)	(3,508)	(3,395)	(3,508)	0	0	0	0	0	(19,642)
9	FP&L, Reedy Creek	430,000	340,000	0	0	0	0	0	0	0	0	0	0	770,000
10	Subtotal - Intermediate Level Capacity Charges	993,182	903,413	563,413	563,029	562,059	562,172	562,059	566,000	566,000	566,000	566,000	566,000	7,539,327
11	Intermediate Production Jurisdictional %	70.241%	70.241%	70.241%	70.241%	71.248%	71.248%	71.248%	71.248%	71.248%	71.248%	71.248%	71.248%	
12	Intermediate Level Jurisdictional Capacity Charge	697,621	634,566	395,747	395,477	400,456	400,536	400,456	403,264	403,264	403,264	403,264	403,264	5,341,178
13	Sebring Base Rate Credits	(464,721)	(354,441)	(301,789)	(308,469)	(283,496)	(383,629)	(374,436)	(417,286)	(431,685)	(372,068)	(326,876)	(336,953)	(4,355,849)
14	Adjustments - Premium/Liquidating Damages	0	(13,988)	8,605	0	0	0							(5,383)
15	Retail Wheeling	(221,452)	(172,014)	(297,274)	(180,022)	(33,371)	(330,733)	(59,037)	(182,844)	(143,082)	(123,859)	(91,708)	(176,474)	(2,011,870)
16	Jurisdictional Capacity Payments (Lines 6 + 12 + 13 + 14 + 15)	26,396,736	27,837,663	26,326,532	26,642,858	26,965,896	26,923,838	27,192,191	27,212,031	27,119,659	27,330,517	27,290,125	27,327,300	324,565,344
17	Capacity Cost Recovery Revenues	31,348,684	23,847,120	20,977,423	22,806,403	23,073,364	29,620,723	29,823,480	31,181,283	32,588,968	28,469,322	24,598,487	24,234,758	322,570,015
18	Prior Period True-Up Provision	(11,934)	(11,934)	(11,934)	(11,934)	(11,934)	(11,934)	(11,934)	(11,934)	(11,934)	(11,934)	(11,934)	(1,414,479)	(1,545,753)
19	Current Period Capacity Revenues (Lines 17+18)	31,336,750	23,835,186	20,965,489	22,794,469	23,061,430	29,608,789	29,811,546	31,169,349	32,577,034	28,457,388	24,586,553	22,820,279	321,024,262
20	Current Period Over/(Under) Recovery (Lines 19+16	4,940,014	(4,002,477)	(5,361,043)	(3,848,389)	(3,904,466)	2,684,951	2,619,355	3,957,318	5,457,375	1,126,871	(2,703,572)	(4,507,021)	(3,541,082)
21	Interest Provision for Month	4,352	6,282	(13,740)	(30,634)	(40,655)	(40,015)	(30,758)	(20,459)	(5,657)	4,733	2,302	(6,801)	(171,050)
22	Current Cycle Balance	4,944,366	948,171	(4,426,613)	(8,305,635)	(12,250,755)	(9,605,818)	(7,017,221)	(3,080,362)	2,371,356	3,502,960	801,690	(3,712,132)	(3,712,132)
23	Plus: Prior Period Balance	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)
24	Plus: Cumulative True-Up Provision	11,934	23,868	35,802	47,736	59,670	71,604	83,538	95,472	107,406	119,340	131,274	1,545,753	1,545,753
25	End of Period Net True-Up (Lines 22+23+24)	3,410,547	(573,714)	(5,936,564)	(9,803,652)	(13,736,838)	(11,079,967)	(8,479,436)	(4,530,643)	933,009	2,076,547	(612,789)	(3,712,132)	(3,712,132)

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

ESTIMATED/ACTUAL TRUE-UP AMOUNTS JANUARY THROUGH DECEMBER 2001

SCHEDULES E1 THROUGH E9

FLORIDA POWER CORPORATION
CALCULATION OF ESTIMATED TRUE-UP
REPROJECTED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2001

	DESCRIPTION		ACTUALS Jan - Jul 01	ESTIMATED Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TOTAL PERIOD
	REVENUE								
1	Jurisdictional KWH Sales		20,778,246	3,497,471	3,655,365	3,193,282	2,759,107	2,718,309	36,601,780
2	Jurisdictional Fuel Factor (Pre-Tax)		2.638	2.878	2.878	2.878	2.878	2.878	
3	Total Jurisdictional Fuel Revenue		548,179,004	100,654,697	105,198,773	91,900,357	79,405,113	78,230,976	1,003,568,920
4	Less: True-Up Provision		(16,105,194)	(2,300,742)	(2,300,742)	(2,300,742)	(2,300,742)	(2,300,742)	(27,608,904)
5	Less: GPIF Provision		(1,273,454)	(181,922)	(181,922)	(181,922)	(181,922)	(181,922)	(2,183,064)
6	Less: Other		0	0	0	0	0	0	0
7	Net Fuel Revenue		530,800,356	98,172,033	102,716,109	89,417,693	76,922,449	75,748,312	973,776,952
	FUEL EXPENSE								
8	Total Cost of Generated Power		471,469,720	104,721,386	88,880,935	88,161,569	47,316,599	63,017,728	863,567,937
9	Total Cost of Purchased Power		158,539,121	24,530,833	41,552,665	22,589,809	19,458,063	21,652,140	288,322,631
10	Total Cost of Power Sales		(96,268,505)	(23,315,617)	(23,515,356)	(19,085,931)	(14,788,904)	(13,473,033)	(190,447,346)
11	Total Fuel and Net Power		533,740,336	105,936,602	106,918,244	91,665,447	51,985,758	71,196,835	961,443,222
12	Jurisdictional Percentage		97.40%	97.14%	97.15%	96.73%	96.79%	97.27%	97.31%
13	Jurisdictional Loss Multiplier		1.0022	1.0022	1.0022	1.0022	1.0022	1.0022	1.0022
14	Jurisdictional Fuel Cost		521,683,084	103,133,210	104,099,590	88,863,056	50,427,713	69,405,518	937,612,172
	COST RECOVERY								
15	Net Fuel Revenue Less Expense		9,117,272	(4,961,177)	(1,383,482)	554,636	26,494,736	6,342,793	
16	Interest Provision	(1)	(1,989,962)	(197,485)	(200,853)	(195,544)	(146,310)	(87,804)	
17	Current Cycle Balance		7,127,310	1,968,648	384,313	743,406	27,091,833	33,346,822	
18	Plus: Prior Period True-Up Balance		(84,596,026)	(84,596,026)	(84,596,026)	(84,596,026)	(84,596,026)	(84,596,026)	
19	Plus: Cumulative True-Up Provision		16,105,194	18,405,936	20,706,678	23,007,420	25,308,162	27,608,904	
20	Total Retail Balance		(61,363,522)	(64,221,442)	(63,505,035)	(60,845,200)	(32,196,031)	(23,640,300)	

(1) Interest for the August through December 2001 period calculated at the July 2001 monthly rate of .315%.

FLORIDA POWER CORPORATION
COMPARISON OF ACTUAL/REVISED ESTIMATE VS. ORIGINAL ESTIMATE
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2001

	DOLLARS				MWH				CENTS/KWH			
	Actual / Rev Estimate	Original Estimate	Difference Amount	Difference %	Actual / Rev Estimate	Original Estimate	Difference Amount	Difference %	Actual / Rev Estimate	Original Estimate	Difference Amount	Difference %
1. Fuel Cost of System Net Generation	879,893,649	868,919,614	10,974,035	1.3	33,292,509	33,887,979	(595,470)	(1.8)	2.6429	2.5641	0.0788	3.1
2. Spent Nuclear Fuel Disposal Cost	5,530,721	5,583,023	(52,302)	(0.9)	5,809,709 *	5,971,148 *	(161,439)	(2.7)	0.0952	0.0935	0.0017	1.8
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4. Adjustment to Fuel Cost	(21,856,433)	8,234,000	(30,090,433)	(365.4)	(796,954)	0	(796,954)	0.0	2.7425	0.0000	2.7425	0.0
5. TOTAL COST OF GENERATED POWER	863,567,937	882,736,637	(19,168,700)	(2.2)	32,495,555	33,887,979	(1,392,424)	(4.1)	2.6575	2.6049	0.0526	2.0
6. Energy Cost of P. P. (Excl. Econ & Cogens)	59,729,390	44,878,324	14,851,066	33.1	3,359,502	2,610,225	749,277	28.7	1.7779	1.7193	0.0586	3.4
7. Energy Cost Econ Purch (Broker)	1,305,326	0	1,305,326	0.0	20,378	0	20,378	0.0	6.4056	0.0000	6.4056	0.0
8. Energy Cost of Econ Purch (Non-Broker)	48,974,412	23,126,018	25,848,394	--	776,515	578,000	198,515	--	6.3069	4.0010	2.3059	57.6
9. Energy Cost of Schedule E Economy Purch	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
10. Capacity Cost of Economy Purchases	0	0	0	0.0	0 *	0 *	0	0.0	0.0000	0.0000	0.0000	0.0
11. Payments to Qualifying Facilities	178,313,503	149,783,042	28,530,461	19.0	6,679,118	7,184,410	(505,292)	(7.0)	2.6697	2.0848	0.5849	28.1
12. TOTAL COST OF PURCHASED POWER	288,322,631	217,787,384	70,535,247	32.4	10,835,513	10,372,635	462,878	4.5	2.6609	2.0996	0.5613	26.7
13. TOTAL AVAILABLE KWH					43,331,068	44,260,614	(929,546)	(2.1)	--	--	--	--
14. Fuel Cost of Economy Sales	(161,377)	0	(161,377)	0.0	(3,450)	0	(3,450)	0.0	4.6776	0.0000	4.6776	0.0
14a. Gain on Economy Sales - 80%	(3,072)	0	(3,072)	0.0	(3,450) *	0 *	(3,450)	0.0	0.0890	0.0000	0.0890	0.0
15. Fuel Cost of Other Power Sales	(35,673,484)	(50,746,119)	15,072,635	(29.7)	(1,068,005)	(1,307,000)	238,995	(18.3)	3.3402	3.8826	(0.5424)	(14.0)
15a. Gain on Other Power Sales	(11,184,809)	(12,067,824)	883,015	(7.3)	(1,068,005) *	(1,307,000) *	238,995	(18.3)	1.0473	0.9233	0.1239	13.4
16. Fuel Cost of Unit Power Sales	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
16a. Gain on Unit Power Sales	0	0	0	0.0	0 *	0 *	0	0.0	0.0000	0.0000	0.0000	0.0
17. Fuel Cost of Stratified Sales	(143,424,604)	(128,477,587)	(14,947,017)	11.6	(3,229,069)	(3,061,375)	(167,694)	5.5	4.4417	4.1967	0.2449	5.8
18. TOTAL FUEL COST & GAINS ON POWER SALES	(190,447,346)	(191,291,530)	844,184	(0.4)	(4,300,524)	(4,368,375)	67,851	(1.6)	4.4285	4.3790	0.0495	1.1
19. Net Inadvertent Interchange					(2,827)	0	(2,827)	0.0	--	--	--	--
20. TOTAL FUEL & NET POWER TRANSACTIONS	961,443,222	909,232,491	52,210,731	5.7	39,027,717	39,892,239	(864,522)	(2.2)	2.4635	2.2792	0.1843	8.1
21. Net Unbilled	(7,303,282) *	827,973 *	(8,131,255)	(982.1)	296,461	(36,327)	332,788	(916.1)	(0.0197)	0.0022	(0.0219)	(991.0)
22. Company Use	3,435,655 *	4,102,599 *	(666,944)	(16.3)	(139,463)	(180,000)	40,537	(22.5)	0.0093	0.0110	(0.0017)	(15.4)
23. T & D Losses	51,734,263 *	50,478,922 *	1,255,341	2.5	(2,100,041)	(2,214,744)	114,703	(5.2)	0.1395	0.1347	0.0048	3.5
24. Adjusted System KWH Sales	961,443,222	909,232,491	52,210,731	5.7	37,084,674	37,461,168	(376,494)	(1.0)	2.5926	2.4271	0.1654	6.8
25. Wholesale KWH Sales (Excl Suppl. Sales)	(25,886,171)	(23,154,556)	(2,731,615)	11.8	(1,026,267)	(959,483)	(66,784)	7.0	2.5224	2.4132	0.1091	4.5
26. Jurisdictional KWH Sales	935,557,051	886,077,935	49,479,116	5.6	36,058,407	36,501,685	(443,278)	(1.2)	2.5946	2.4275	0.1671	6.9
27. Jurisd KWH Sales Adj for Line Losses	937,605,059	889,356,423	48,248,636	5.4	36,058,407	36,501,685	(443,278)	(1.2)	2.6002	2.4365	0.1638	6.7
28. Prior Period True-Up **	27,608,904	27,608,904	0	0.0	36,058,407	36,501,685	(443,278)	(1.2)	0.0766	0.0756	0.0009	1.2
28a. Market Price True-Up **	0	0	0	0.0	36,058,407	36,501,685	(443,278)	(1.2)	0.0000	0.0000	0.0000	0.0
29. Total Jurisdictional Fuel Cost	965,213,963	916,965,327	48,248,636	5.3	36,058,407	36,501,685	(443,278)	(1.2)	2.6768	2.5121	0.1647	6.6
30. Revenue Tax Factor									1.00072	1.00072	0.0000	0.0
31. Fuel Factor Adjusted for Taxes									2.6787	2.5139	0.1648	6.6
32. GPIF **	2,183,064	2,183,064	0	0.0	36,058,407	36,501,685	(443,278)	(1.2)	0.0061	0.0060	0.0001	1.7
33. Fuel Factor Adjusted for Taxes & GPIF									2.6848	2.5199	0.1649	6.5
34. Total Fuel Cost Factor (Rounded)									2.685	2.520	0.165	6.5

FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD OF: AUGUST THROUGH DECEMBER 2001

			Aug-01	Sep-01	Oct-01	Nov-01	Dec-01		Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		25,258,812	21,669,548	19,612,503	12,188,075	23,252,409		101,981,349
2	LIGHT OIL		17,793,329	10,625,126	14,954,454	758,566	2,108,893		46,240,367
3	COAL		29,823,487	27,854,950	30,364,048	26,720,430	21,828,290		136,591,204
4	GAS		28,360,962	25,509,850	20,557,174	4,246,227	12,357,396		91,031,609
5	NUCLEAR		1,930,631	1,743,795	61,224	1,883,859	1,934,750		7,554,259
6	OTHER		0	0	0	0	0		0
7	TOTAL	$	103,167,221	87,403,270	85,549,402	45,797,157	61,481,738		383,398,788
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		751,470	636,127	569,061	329,995	674,082		2,960,735
9	LIGHT OIL		177,587	106,575	161,990	10,111	24,446		480,709
10	COAL		1,496,244	1,362,453	1,487,580	1,274,670	1,027,175		6,648,122
11	GAS		587,343	539,511	399,550	52,763	278,169		1,857,356
12	NUCLEAR		569,160	514,080	18,360	563,040	581,808		2,246,448
13	OTHER		0	0	0	0	0		0
14	TOTAL	MWH	3,581,804	3,158,746	2,636,541	2,230,599	2,585,680		14,193,370
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	1,170,730	992,030	884,461	546,941	1,033,694		4,627,858
16	LIGHT OIL	BBL	457,982	275,514	390,827	19,887	55,402		1,199,613
17	COAL	TON	570,243	519,902	560,690	479,736	385,693		2,516,265
18	GAS	MCF	5,101,067	5,436,133	3,960,442	597,040	2,306,561		18,401,243
19	NUCLEAR	MMBTU	5,850,396	5,284,228	185,528	5,708,663	5,862,879		22,891,694
20	OTHER	BBL	0	0	0	0	0		0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		7,609,747	6,448,198	5,748,996	3,555,119	6,719,013		30,081,074
22	LIGHT OIL		2,656,295	1,597,979	2,266,799	115,346	321,334		6,957,754
23	COAL		14,336,720	13,067,401	14,092,580	12,052,609	9,688,715		63,238,025
24	GAS		5,101,067	5,436,133	3,960,442	597,040	2,306,561		18,401,243
25	NUCLEAR		5,850,396	5,284,228	185,528	5,708,663	5,862,879		22,891,694
26	OTHER		0	0	0	0	0		0
27	TOTAL	MMBTU	36,554,226	31,833,939	26,254,345	22,028,777	24,898,503		141,569,790
	GENERATION MIX (% MWH)								
28	HEAVY OIL		20.98%	20.14%	21.58%	14.79%	26.07%		20.86%
29	LIGHT OIL		4.96%	3.37%	6.14%	0.45%	0.95%		3.39%
30	COAL		41.77%	43.13%	56.42%	57.15%	39.73%		46.84%
31	GAS		16.40%	17.08%	15.15%	2.37%	10.76%		13.09%
32	NUCLEAR		15.89%	16.28%	0.70%	25.24%	22.50%		15.83%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%		100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	21.58	21.84	22.17	22.28	22.49		22.04
36	LIGHT OIL	$/BBL	38.85	38.56	38.26	38.14	38.07		38.55
37	COAL	$/TON	52.30	53.58	54.15	55.70	56.59		54.28
38	GAS	$/MCF	4.65	4.69	5.19	7.11	5.36		4.95
39	NUCLEAR	$/MMBTU	0.33	0.33	0.33	0.33	0.33		0.33
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00		0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		3.32	3.36	3.41	3.43	3.46		3.39
42	LIGHT OIL		6.70	6.65	6.60	6.58	6.56		6.65
43	COAL		2.08	2.13	2.16	2.22	2.25		2.16
44	GAS		4.65	4.69	5.19	7.11	5.36		4.95
45	NUCLEAR		0.33	0.33	0.33	0.33	0.33		0.33
46	OTHER		0.00	0.00	0.00	0.00	0.00		0.00
47	TOTAL	$/MMBTU	2.82	2.75	3.26	2.08	2.47		2.71
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		10,126	10,137	10,103	10,773	9,968		10,160
49	LIGHT OIL		14,958	14,994	13,993	11,408	13,145		14,474
50	COAL		9,582	9,591	9,473	9,455	9,432		9,512
51	GAS		10,388	10,076	9,912	11,311	8,292		9,907
52	NUCLEAR		10,279	10,279	10,105	10,139	10,077		10,190
53	OTHER		0	0	0	0	0		0
54	TOTAL	BTU/KWH	10,206	10,078	9,958	9,876	9,629		9,974
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		3.36	3.41	3.45	3.69	3.45		3.44
56	LIGHT OIL		10.02	9.97	9.23	7.50	8.63		9.62
57	COAL		1.99	2.04	2.04	2.10	2.13		2.05
58	GAS		4.83	4.73	5.15	8.04	4.44		4.90
59	NUCLEAR		0.34	0.34	0.33	0.33	0.33		0.34
60	OTHER		0.00	0.00	0.00	0.00	0.00		0.00
61	TOTAL	C/KWH	2.88	2.77	3.24	2.05	2.38		2.70

SCHEDULE E4

Reprojected 8/01

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Aug-01

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	765	569,160	100.0	97.2	100.0	10,279 NUCLEAR	5,850,396 MMBTU	1.00	5,850,396	1,930,631	0.34
2	ANCLOTE	1	498	209,491	57.9	91.8	57.9	10,082 HEAVY OIL	324,937 BBLS	6.50	2,112,088	7,041,377	3.36
3	ANCLOTE	1		5,071				10,390 GAS	52,688 MCF	1.00	52,688	210,751	4.16
4	ANCLOTE	2	495	233,800	64.9	93.8	64.9	9,793 HEAVY OIL	352,247 BBLS	6.50	2,289,603	7,633,185	3.26
5	ANCLOTE	2		5,262				10,007 GAS	52,657 MCF	1.00	52,657	210,627	4.00
6	BARTOW	1	121	64,090	71.2	90.7	71.2	10,263 HEAVY OIL	101,193 BBLS	6.50	657,756	2,099,758	3.28
7	BARTOW	2	119	66,197	74.8	92.5	74.8	10,316 HEAVY OIL	105,060 BBLS	6.50	682,888	2,179,989	3.29
8	BARTOW	3	204	118,693	78.2	89.2	78.2	9,951 HEAVY OIL	181,710 BBLS	6.50	1,181,114	3,770,479	3.18
9	BARTOW	3		0				0 GAS	0 MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	379	272,192	96.5	83.7	96.5	9,755 COAL	105,366 TONS	25.20	2,655,233	4,591,867	1.69
11	CRYSTAL RIVER	1		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
12	CRYSTAL RIVER	2	486	345,155	95.5	78.7	95.5	9,560 COAL	130,940 TONS	25.20	3,299,682	5,706,354	1.65
13	CRYSTAL RIVER	2		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
14	CRYSTAL RIVER	4	720	420,173	78.4	95.5	84.6	9,555 COAL	159,950 TONS	25.10	4,014,753	9,352,295	2.23
15	CRYSTAL RIVER	4		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
16	CRYSTAL RIVER	5	717	458,724	86.0	94.3	86.0	9,520 COAL	173,986 TONS	25.10	4,367,052	10,172,970	2.22
17	SUWANNEE	1	32	12,341	51.8	98.8	52.3	12,210 HEAVY OIL	23,182 BBLS	6.50	150,684	556,370	4.51
18	SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
19	SUWANNEE	2	31	14,635	63.5	99.4	65.5	13,103 HEAVY OIL	29,502 BBLS	6.50	191,762	708,046	4.84
20	SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
21	SUWANNEE	3	80	32,223	54.1	88.5	70.8	10,671 HEAVY OIL	52,900 BBLS	6.50	343,852	1,269,606	3.94
22	SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
23	AVON PARK	1-2	52	1,174	3.0	100.0	66.4	18,826 LIGHT OIL	3,811 BBLS	5.80	22,102	147,739	12.58
24	BARTOW	1-4	187	13,823	21.5	100.0	52.5	17,069 LIGHT OIL	40,880 BBLS	5.80	235,945	1,574,728	11.39
25	BARTOW	1-4		16,108				16,304 GAS	262,625 MCF	1.00	262,625	1,050,499	6.52
26	BAYBORO	1-4	184	16,631	12.1	100.0	67.8	14,579 LIGHT OIL	41,804 BBLS	5.80	242,463	1,618,234	9.73
27	DEBARY	1-10	667	68,659	26.2	100.0	49.3	15,435 LIGHT OIL	182,716 BBLS	5.80	1,059,752	7,178,904	10.46
28	DEBARY	1-10		61,582				14,012 GAS	862,887 MCF	1.00	862,887	3,451,548	5.60
29	HIGGINS	1-4	122	5,669	15.3	100.0	69.5	17,855 LIGHT OIL	17,452 BBLS	5.80	101,220	664,387	11.72
30	HIGGINS	1-4		8,259				17,420 GAS	143,872 MCF	1.00	143,872	575,487	6.97
31	HINES	1	482	276,804	77.8	97.3	78.2	7,033 GAS	1,946,763 MCF	1.00	1,946,763	7,787,050	2.81
32	HINES	1		2,144				8,459 LIGHT OIL	3,127 BBLS	5.80	18,136	118,479	5.53
33	INT CITY	1-10,12-14	886	35,255	34.0	100.0	54.1	14,801 LIGHT OIL	89,967 BBLS	5.80	521,809	3,435,844	9.75
34	INT CITY	1-10,12-14		188,741				13,431 GAS	2,534,980 MCF	1.00	2,534,980	10,139,921	5.37
35	INT CITY	11	0	0	0.0	0.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
36	RIO PINAR	1	13	140	1.4	100.0	89.7	17,324 LIGHT OIL	418 BBLS	5.80	2,425	16,258	11.61
37	SUWANNEE	1-3	184	15,102	12.4	100.0	69.9	13,887 LIGHT OIL	36,159 BBLS	5.80	209,721	1,408,027	9.32
38	SUWANNEE	1-3		0				0 GAS	0 MCF	1.00	0	0	0.00
39	TURNER	1-4	154	8,245	7.2	100.0	67.8	16,602 LIGHT OIL	23,601 BBLS	5.80	136,883	923,256	11.20
40	UNIV OF FLA.	1	35	25,516	98.0	96.9	100.0	9,586 GAS	244,596 MCF	1.00	244,596	809,075	3.17
41	OTHER - START UP		-	10,745	-		-	9,850 LIGHT OIL	18,248 BBLS	5.80	105,838	707,474	6.58
42	OTHER - GAS TRANSP.		-	0	-	-	-	- GAS TRANSP.	-	-	-	4,126,003	-
43	TOTAL		7,593	3,581,804			10,206				36,554,226	103,167,221	2.88

SCHEDULE E4

Reprojected 8/01

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Sep-01

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	765	514,080	93.3	90.7	100.0	10,279	NUCLEAR	5,284,228 MMBTU	1.00	5,284,228	1,743,795	0.34
2 ANCLOTE	1	498	197,394	57.9	91.8	57.9	10,095	HEAVY OIL	306,568 BBLS	6.50	1,992,692	6,836,468	3.46
3 ANCLOTE	1		10,061				10,890	GAS	109,564 MCF	1.00	109,564	438,257	4.36
4 ANCLOTE	2	495	210,833	61.7	93.8	61.7	9,818	HEAVY OIL	318,455 BBLS	6.50	2,069,958	7,101,550	3.37
5 ANCLOTE	2		8,965				10,060	GAS	90,188 MCF	1.00	90,188	360,752	4.02
6 BARTOW	1	121	48,371	55.5	63.5	79.5	10,150	HEAVY OIL	75,533 BBLS	6.50	490,966	1,544,653	3.19
7 BARTOW	2	119	63,344	73.9	92.5	73.9	10,326	HEAVY OIL	100,629 BBLS	6.50	654,090	2,057,868	3.25
8 BARTOW	3	204	78,395	53.4	91.7	69.6	10,052	HEAVY OIL	121,235 BBLS	6.50	788,027	2,479,253	3.16
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	379	263,125	96.4	83.7	97.2	9,745	COAL	101,752 TONS	25.20	2,564,153	4,400,779	1.67
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	486	199,358	57.0	78.7	76.1	9,710	COAL	76,816 TONS	25.20	1,935,766	3,322,297	1.67
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	720	439,475	84.8	95.5	84.8	9,553	COAL	167,263 TONS	25.10	4,198,305	9,865,180	2.24
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	717	460,495	89.2	94.5	89.2	9,488	COAL	174,071 TONS	25.10	4,369,177	10,266,695	2.23
17 SUWANNEE	1	32	11,012	47.8	98.9	53.0	12,184	HEAVY OIL	20,659 BBLS	6.50	134,280	489,607	4.45
18 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
19 SUWANNEE	2	31	11,443	51.3	99.5	60.9	13,318	HEAVY OIL	23,446 BBLS	6.50	152,398	555,666	4.86
20 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
21 SUWANNEE	3	80	15,335	26.6	90.0	59.2	10,811	HEAVY OIL	25,506 BBLS	6.50	165,787	604,484	3.94
22 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
23 AVON PARK	1-2	52	1,310	3.5	100.0	63.0	18,441	LIGHT OIL	4,165 BBLS	5.80	24,158	160,441	12.25
24 BARTOW	1-4	187	9,501	11.6	100.0	52.1	17,284	LIGHT OIL	28,313 BBLS	5.80	164,215	1,088,917	11.46
25 BARTOW	1-4		6,162				15,709	GAS	96,799 MCF	1.00	96,799	387,195	6.28
26 BAYBORO	1-4	184	8,100	6.1	100.0	68.0	14,593	LIGHT OIL	20,380 BBLS	5.80	118,203	783,810	9.68
27 DEBARY	1-10	667	37,955	18.3	100.0	51.0	15,595	LIGHT OIL	102,053 BBLS	5.80	591,908	3,984,155	10.50
28 DEBARY	1-10		50,063				14,124	GAS	707,090 MCF	1.00	707,090	2,828,359	5.65
29 HIGGINS	1-4	122	4,495	9.3	100.0	67.9	17,954	LIGHT OIL	13,914 BBLS	5.80	80,703	526,241	11.71
30 HIGGINS	1-4		3,709				17,528	GAS	65,011 MCF	1.00	65,011	260,045	7.01
31 HINES	1	482	278,872	80.9	97.4	80.9	7,055	GAS	1,967,442 MCF	1.00	1,967,442	7,869,768	2.82
32 HINES	1		2,050				7,934	LIGHT OIL	2,804 BBLS	5.80	16,265	105,552	5.15
33 INT CITY	1-10,12-14	886	21,771	27.9	100.0	51.6	15,046	LIGHT OIL	56,477 BBLS	5.80	327,566	2,142,737	9.84
34 INT CITY	1-10,12-14		156,479				13,794	GAS	2,158,471 MCF	1.00	2,158,471	8,633,885	5.52
35 INT CITY	11	0	0	0.0	0.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
36 RIO PINAR	1	13	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
37 SUWANNEE	1-3	184	8,533	7.2	100.0	68.2	14,358	LIGHT OIL	21,124 BBLS	5.80	122,517	817,272	9.58
38 SUWANNEE	1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
39 TURNER	1-4	154	3,384	3.1	100.0	64.0	17,466	LIGHT OIL	10,191 BBLS	5.80	59,105	396,105	11.71
40 UNIV OF FLA.	1	35	25,200	100.0	97.6	100.0	9,586	GAS	241,567 MCF	1.00	241,567	792,790	3.15
41 OTHER - START UP		-	9,476	-	-	-	9,850	LIGHT OIL	16,093 BBLS	5.80	93,339	619,897	6.54
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	3,938,798	-
43 TOTAL		7,593	3,158,746				10,078				31,833,939	87,403,270	2.77

SCHEDULE E4

Reprojected 8/01

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Oct-01

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	765	18,360	3.2	3.1	100.0	10,105 NUCLEAR	185,528 MMBTU	1.00	185,528	61,224	0.33
2	ANCLOTE	1	498	160,117	45.1	93.4	58.1	10,019 HEAVY OIL	246,802 BBLS	6.50	1,604,212	5,701,123	3.56
3	ANCLOTE	1		6,808				10,990 GAS	74,820 MCF	1.00	74,820	355,395	5.22
4	ANCLOTE	2	495	166,957	47.1	95.2	60.8	9,849 HEAVY OIL	252,978 BBLS	6.50	1,644,359	5,843,801	3.50
5	ANCLOTE	2		6,512				10,740 GAS	69,939 MCF	1.00	69,939	332,210	5.10
6	BARTOW	1	121	19,074	21.2	29.3	65.7	10,267 HEAVY OIL	30,128 BBLS	6.50	195,833	610,094	3.20
7	BARTOW	2	119	65,521	74.0	92.5	74.0	10,206 HEAVY OIL	102,878 BBLS	6.50	668,707	2,083,281	3.18
8	BARTOW	3	204	109,842	72.4	90.6	82.7	9,835 HEAVY OIL	166,199 BBLS	6.50	1,080,296	3,365,538	3.06
9	BARTOW	3		0				0 GAS	0 MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	379	154,018	54.6	51.3	94.5	9,721 COAL	59,413 TONS	25.20	1,497,209	2,570,209	1.67
11	CRYSTAL RIVER	1		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
12	CRYSTAL RIVER	2	486	352,612	97.5	78.7	97.5	9,510 COAL	133,069 TONS	25.20	3,353,340	5,756,567	1.63
13	CRYSTAL RIVER	2		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
14	CRYSTAL RIVER	4	720	493,806	92.2	95.5	92.2	9,423 COAL	185,384 TONS	25.10	4,653,134	11,095,222	2.25
15	CRYSTAL RIVER	4		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
16	CRYSTAL RIVER	5	717	487,144	91.3	94.3	91.3	9,420 COAL	182,825 TONS	25.10	4,588,898	10,942,050	2.25
17	SUWANNEE	1	32	11,529	48.4	98.8	56.7	12,053 HEAVY OIL	21,378 BBLS	6.50	138,959	502,390	4.36
18	SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
19	SUWANNEE	2	31	10,931	47.4	99.5	61.6	13,215 HEAVY OIL	22,224 BBLS	6.50	144,453	522,254	4.78
20	SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
21	SUWANNEE	3	80	25,090	42.2	92.3	63.2	10,848 HEAVY OIL	41,873 BBLS	6.50	272,176	984,022	3.92
22	SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
23	AVON PARK	1-2	52	1,095	2.8	100.0	79.5	16,851 LIGHT OIL	3,181 BBLS	5.80	18,452	122,068	11.15
24	BARTOW	1-4	187	7,056	7.8	100.0	48.2	17,307 LIGHT OIL	21,055 BBLS	5.80	122,118	806,612	11.43
25	BARTOW	1-4		3,795				16,981 GAS	64,443 MCF	1.00	64,443	306,104	8.07
26	BAYBORO	1-4	184	11,874	8.7	100.0	65.7	14,755 LIGHT OIL	30,207 BBLS	5.80	175,201	1,157,232	9.75
27	DEBARY	1-10	667	42,356	13.6	100.0	46.8	15,111 LIGHT OIL	110,352 BBLS	5.80	640,042	4,291,589	10.13
28	DEBARY	1-10		25,044				14,716 GAS	368,548 MCF	1.00	368,548	1,750,601	6.99
29	HIGGINS	1-4	122	4,315	5.3	100.0	66.8	17,914 LIGHT OIL	13,327 BBLS	5.80	77,299	502,043	11.63
30	HIGGINS	1-4		511				17,256 GAS	8,818 MCF	1.00	8,818	41,885	8.20
31	HINES	1	482	229,054	64.9	97.5	69.3	7,086 GAS	1,623,077 MCF	1.00	1,623,077	7,709,614	3.37
32	HINES	1		3,550				8,054 LIGHT OIL	4,930 BBLS	5.80	28,592	184,811	5.21
33	INT CITY	1-10,12-14	886	31,963	20.1	100.0	45.3	14,985 LIGHT OIL	82,580 BBLS	5.80	478,966	3,120,708	9.76
34	INT CITY	1-10,12-14		100,667				14,554 GAS	1,465,108 MCF	1.00	1,465,108	6,959,261	6.91
35	INT CITY	11	143	38,328	36.0	100.0	83.5	11,483 LIGHT OIL	75,883 BBLS	5.80	440,120	2,867,612	7.48
36	RIO PINAR	1	13	262	2.7	100.0	91.8	17,178 LIGHT OIL	776 BBLS	5.80	4,501	29,859	11.40
37	SUWANNEE	1-3	164	6,252	9.5	100.0	70.6	13,903 LIGHT OIL	14,986 BBLS	5.80	86,922	577,579	9.24
38	SUWANNEE	1-3		5,319				14,351 GAS	76,333 MCF	1.00	76,333	362,582	6.82
39	TURNER	1-4	154	7,029	6.1	100.0	63.7	16,599 LIGHT OIL	20,116 BBLS	5.80	116,674	778,902	11.08
40	UNIV OF FLA.	1	35	21,840	83.9	97.4	100.0	9,586 GAS	209,358 MCF	1.00	209,358	785,984	3.60
41	OTHER - START UP		-	7,910	-	-	-	9,850 LIGHT OIL	13,433 BBLS	5.80	77,914	515,438	6.52
42	OTHER - GAS TRANSP.		-	0	-	-	-	- GAS TRANSP.	-	-	-	1,953,541	-
43	TOTAL		7,736	2,636,541				9,958			26,254,345	85,549,402	3.24

SCHEDULE E4

Reprojected 8/01

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Nov-01

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	782	563,040	100.0	97.2	100.0	10,139	NUCLEAR	5,708,663 MMBTU	1.00	5,708,663	1,883,859	0.33
2 ANCLOTE	1	522	45,332	13.0	94.5	19.4	12,093	HEAVY OIL	84,338 BBLS	6.50	548,200	2,053,641	4.53
3 ANCLOTE	1		3,685				12,595	GAS	46,413 MCF	1.00	46,413	220,460	5.98
4 ANCLOTE	2	522	89,503	25.8	93.8	25.8	11,292	HEAVY OIL	155,487 BBLS	6.50	1,010,668	3,786,117	4.23
5 ANCLOTE	2		7,519				11,896	GAS	89,446 MCF	1.00	89,446	424,869	5.65
6 BARTOW	1	123	58,942	66.6	90.7	66.6	10,261	HEAVY OIL	93,047 BBLS	6.50	604,804	1,912,111	3.24
7 BARTOW	2	121	53,458	61.4	92.5	61.4	10,365	HEAVY OIL	85,245 BBLS	6.50	554,092	1,751,784	3.28
8 BARTOW	3	208	76,409	51.0	91.8	67.5	9,988	HEAVY OIL	117,411 BBLS	6.50	763,173	2,412,801	3.16
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	383	19,504	7.1	17.3	48.0	10,683	COAL	8,268 TONS	25.20	208,361	357,108	1.83
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	491	273,449	77.4	72.3	85.9	9,585	COAL	104,008 TONS	25.20	2,621,009	4,492,118	1.64
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	735	492,948	93.1	95.5	93.1	9,397	COAL	184,551 TONS	25.10	4,632,232	10,984,481	2.23
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	732	488,769	92.7	94.3	92.7	9,393	COAL	182,909 TONS	25.10	4,591,007	10,886,723	2.23
17 SUWANNEE	1	33	1,112	4.7	99.9	45.5	12,277	HEAVY OIL	2,100 BBLS	6.50	13,652	49,987	4.50
18 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
19 SUWANNEE	2	32	888	3.9	99.9	48.7	13,890	HEAVY OIL	1,898 BBLS	6.50	12,334	45,163	5.09
20 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
21 SUWANNEE	3	81	4,351	7.5	0.0	49.7	11,077	HEAVY OIL	7,415 BBLS	6.50	48,196	176,472	4.06
22 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
23 AVON PARK	1-2	64	169	0.4	100.0	58.7	17,338	LIGHT OIL	505 BBLS	5.80	2,930	19,283	11.41
24 BARTOW	1-4	219	0	0.5	100.0	44.7	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
25 BARTOW	1-4		833				16,982	GAS	14,146 MCF	1.00	14,146	67,194	8.07
26 BAYBORO	1-4	232	84	0.1	100.0	48.3	15,127	LIGHT OIL	219 BBLS	5.80	1,271	8,349	9.94
27 DEBARY	1-10	762	1,290	0.7	100.0	38.6	16,373	LIGHT OIL	3,642 BBLS	5.80	21,121	140,893	10.92
28 DEBARY	1-10		2,448				15,237	GAS	37,300 MCF	1.00	37,300	177,176	7.24
29 HIGGINS	1-4	134	0	0.0	100.0	63.6	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 HIGGINS	1-4		682				17,539	GAS	11,962 MCF	1.00	11,962	56,818	8.33
31 HINES	1	529	0	0.0	0.0	0.0	0	GAS	0 MCF	1.00	0	0	0.00
32 HINES	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
33 INT CITY	1-10,12-14	1,024	611	1.1	100.0	70.5	14,627	LIGHT OIL	2,045 BBLS	5.80	11,862	76,881	9.48
34 INT CITY	1-10,12-14		7,352				15,050	GAS	110,648 MCF	1.00	110,648	525,576	7.15
35 INT CITY	11	170	1,065	0.9	100.0	69.6	11,498	LIGHT OIL	2,111 BBLS	5.80	12,245	79,363	7.45
36 RIO PINAR	1	16	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
37 SUWANNEE	1-3	201	0	0.0	100.0	61.7	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
38 SUWANNEE	1-3		744				14,025	GAS	10,435 MCF	1.00	10,435	49,564	6.66
39 TURNER	1-4	194	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
40 UNIV OF FLA.	1	41	29,520	100.0	96.9	100.0	9,373	GAS	276,691 MCF	1.00	276,691	1,088,852	3.69
41 OTHER - START UP		-	6,692	-	-	-	9,850	LIGHT OIL	11,365 BBLS	5.80	65,916	433,797	6.48
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	1,635,719	-
43 TOTAL		8,351	2,230,599				9,876				22,028,777	45,797,157	2.05

SCHEDULE E4

Reprojected 8/01

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Dec-01

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	782	581,808	100.0	97.2	100.0	10,077 NUCLEAR	5,862,879 MMBTU	1.00	5,862,879	1,934,750	0.33
2	ANCLOTE	1	522	178,618	48.3	91.8	48.3	10,089 HEAVY OIL	277,243 BBLS	6.50	1,802,077	6,667,685	3.73
3	ANCLOTE	1		8,806				10,490 GAS	92,375 MCF	1.00	92,375	438,781	4.98
4	ANCLOTE	2	522	200,400	54.5	93.8	54.5	9,837 HEAVY OIL	303,282 BBLS	6.50	1,971,335	7,293,939	3.64
5	ANCLOTE	2		11,284				10,780 GAS	121,642 MCF	1.00	121,642	577,797	5.12
6	BARTOW	1	123	65,532	71.6	92.5	87.8	9,938 HEAVY OIL	100,193 BBLS	6.50	651,257	2,028,916	3.10
7	BARTOW	2	121	74,051	82.3	92.5	82.3	10,093 HEAVY OIL	114,984 BBLS	6.50	747,397	2,328,428	3.14
8	BARTOW	3	208	135,269	87.4	89.2	87.4	9,749 HEAVY OIL	202,883 BBLS	6.50	1,318,737	4,108,374	3.04
9	BARTOW	3		0				0 GAS	0 MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	383	131,400	46.1	87.4	70.3	10,050 COAL	52,404 TONS	25.20	1,320,570	2,261,214	1.72
11	CRYSTAL RIVER	1		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
12	CRYSTAL RIVER	2	491	67,138	18.4	39.4	73.1	9,654 COAL	25,720 TONS	25.20	648,150	1,109,829	1.65
13	CRYSTAL RIVER	2		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
14	CRYSTAL RIVER	4	735	413,993	75.7	95.9	97.8	9,319 COAL	153,705 TONS	25.10	3,858,001	9,223,850	2.23
15	CRYSTAL RIVER	4		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
16	CRYSTAL RIVER	5	732	414,644	76.1	94.3	97.0	9,314 COAL	153,864 TONS	25.10	3,861,994	9,233,397	2.23
17	SUWANNEE	1	33	4,161	16.9	99.9	48.1	12,108 HEAVY OIL	7,751 BBLS	6.50	50,381	182,148	4.38
18	SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
19	SUWANNEE	2	32	2,292	9.6	99.9	54.3	13,402 HEAVY OIL	4,726 BBLS	6.50	30,717	111,055	4.85
20	SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
21	SUWANNEE	3	81	13,759	22.8	97.6	53.2	10,692 HEAVY OIL	22,632 BBLS	6.50	147,111	531,864	3.87
22	SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
23	AVON PARK	1-2	64	441	0.9	100.0	76.6	17,832 LIGHT OIL	1,356 BBLS	5.80	7,864	51,753	11.74
24	BARTOW	1-4	219	1,003	1.1	100.0	44.9	17,110 LIGHT OIL	2,959 BBLS	5.80	17,161	112,762	11.24
25	BARTOW	1-4		818				15,600 GAS	12,761 MCF	1.00	12,761	60,614	7.41
26	BAYBORO	1-4	232	1,502	0.9	100.0	58.9	16,418 LIGHT OIL	4,251 BBLS	5.80	24,657	162,012	10.79
27	DEBARY	1-10	762	4,098	1.6	100.0	49.5	14,220 LIGHT OIL	10,047 BBLS	5.80	58,274	388,725	9.49
28	DEBARY	1-10		5,152				14,463 GAS	74,513 MCF	1.00	74,513	353,939	6.87
29	HIGGINS	1-4	134	505	1.2	100.0	63.9	17,673 LIGHT OIL	1,539 BBLS	5.80	8,925	57,658	11.42
30	HIGGINS	1-4		672				17,392 GAS	11,687 MCF	1.00	11,687	55,515	8.26
31	HINES	1	529	206,097	52.4	98.2	62.7	7,154 GAS	1,474,418 MCF	1.00	1,474,418	7,003,485	3.40
32	HINES	1		127				7,909 LIGHT OIL	173 BBLS	5.80	1,004	6,458	5.08
33	INT CITY	1-10,12-14	1,024	4,988	3.1	100.0	38.7	15,086 LIGHT OIL	12,974 BBLS	5.80	75,249	487,691	9.78
34	INT CITY	1-10,12-14		18,566				14,445 GAS	268,186 MCF	1.00	268,186	1,273,883	6.86
35	INT CITY	11	170	2,639	2.1	100.0	73.9	11,230 LIGHT OIL	5,110 BBLS	5.80	29,636	192,072	7.28
36	RIO PINAR	1	16	53	0.4	100.0	82.8	17,330 LIGHT OIL	158 BBLS	5.80	918	6,062	11.44
37	SUWANNEE	1-3	201	438	0.3	100.0	72.6	13,956 LIGHT OIL	1,054 BBLS	5.80	6,113	40,407	9.23
38	SUWANNEE	1-3		0				0 GAS	0 MCF	1.00	0	0	0.00
39	TURNER	1-4	194	895	0.6	100.0	49.4	16,901 LIGHT OIL	2,608 BBLS	5.80	15,126	100,460	11.22
40	UNIV OF FLA.	1	41	26,774	87.8	96.9	100.0	9,374 GAS	250,979 MCF	1.00	250,979	961,059	3.59
41	OTHER - START UP		-	7,757	-	-	-	9,850 LIGHT OIL	13,174 BBLS	5.80	76,406	502,833	6.48
42	OTHER - GAS TRANSP.		-	0	-	-	-	- GAS TRANSP.	-	-	-	1,632,323	-
43	TOTAL		8,351	2,585,680			9,629				24,898,503	61,481,738	2.38

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD OF: Aug-01 THROUGH Dec-01

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	774	2,246,448	79.1	77.1	100.0	10,190	NUCLEAR	22,891,694 MMBTU	1.00	22,891,894	7,554,259	0.34
2 ANCLOTE	1	510	790,952	44.1	92.7	49.2	10,189	HEAVY OIL	1,239,888 BBLS	6.50	8,059,270	28,300,295	3.58
3 ANCLOTE	1		34,431				10,916	GAS	375,859 MCF	1.00	375,859	1,663,643	4.83
4 ANCLOTE	2	509	901,493	50.4	94.1	52.6	9,968	HEAVY OIL	1,382,450 BBLS	6.50	8,985,924	31,658,592	3.51
5 ANCLOTE	2		39,542				10,720	GAS	423,871 MCF	1.00	423,871	1,906,254	4.82
6 BARTOW	1	122	256,009	57.1	73.3	74.6	10,158	HEAVY OIL	400,095 BBLS	6.50	2,600,615	8,195,533	3.20
7 BARTOW	2	120	322,571	73.2	92.5	73.2	10,253	HEAVY OIL	508,796 BBLS	6.50	3,307,175	10,401,350	3.22
8 BARTOW	3	206	518,608	68.6	90.5	77.8	9,894	HEAVY OIL	789,438 BBLS	6.50	5,131,347	16,136,445	3.11
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	381	840,239	60.1	64.7	88.9	9,813	COAL	327,203 TONS	25.20	8,245,526	14,181,177	1.69
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	489	1,237,712	69.0	69.6	88.5	9,581	COAL	470,553 TONS	25.20	11,857,947	20,387,165	1.65
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	728	2,260,395	84.6	95.6	90.1	9,448	COAL	850,854 TONS	25.10	21,356,425	50,521,027	2.24
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	725	2,309,776	66.8	94.3	90.6	9,429	COAL	867,654 TONS	25.10	21,778,127	51,501,835	2.23
17 SUWANNEE	1	33	40,155	33.6	99.3	52.4	12,152	HEAVY OIL	75,070 BBLS	6.50	487,956	1,780,503	4.43
18 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
19 SUWANNEE	2	32	40,189	34.7	99.6	61.1	13,229	HEAVY OIL	81,795 BBLS	6.50	531,665	1,942,183	4.83
20 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
21 SUWANNEE	3	81	90,758	30.7	73.7	62.1	10,766	HEAVY OIL	150,326 BBLS	6.50	977,122	3,566,447	3.93
22 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
23 AVON PARK	1-2	58	4,189	2.0	100.0	63.4	18,025	LIGHT OIL	13,018 BBLS	5.80	75,505	501,284	11.97
24 BARTOW	1-4	203	31,383	7.9	100.0	47.5	17,189	LIGHT OIL	93,007 BBLS	5.80	539,440	3,583,019	11.42
25 BARTOW	1-4		27,716				16,264	GAS	450,773 MCF	1.00	450,773	1,671,606	6.75
26 BAYBORO	1-4	208	38,191	5.0	100.0	59.6	14,710	LIGHT OIL	96,861 BBLS	5.80	561,795	3,729,638	9.77
27 DEBARY	1-10	715	154,358	11.4	100.0	46.0	15,361	LIGHT OIL	408,810 BBLS	5.80	2,371,096	15,984,265	10.36
28 DEBARY	1-10		144,289				14,210	GAS	2,050,338 MCF	1.00	2,050,338	8,561,622	5.93
29 HIGGINS	1-4	128	14,984	6.1	100.0	65.4	17,896	LIGHT OIL	48,232 BBLS	5.80	268,147	1,750,329	11.68
30 HIGGINS	1-4		13,633				17,447	GAS	241,350 MCF	1.00	241,350	989,750	7.15
31 HINES	1	506	990,827	53.6	78.1	71.1	7,077	GAS	7,011,699 MCF	1.00	7,011,699	30,369,917	3.07
32 HINES	1		7,871				8,131	LIGHT OIL	11,034 BBLS	5.80	63,997	415,300	5.28
33 INT CITY	1-10,12-14	955	94,788	16.2	100.0	47.2	14,933	LIGHT OIL	244,044 BBLS	5.80	1,415,453	9,263,861	9.77
34 INT CITY	1-10,12-14		471,805				13,856	GAS	6,537,393 MCF	1.00	6,537,393	27,532,526	5.84
35 INT CITY	11	109	42,032	10.5	60.0	110.0	11,467	LIGHT OIL	83,104 BBLS	5.80	482,002	3,139,047	7.47
36 RIO PINAR	1	15	455	0.9	100.0	82.6	17,241	LIGHT OIL	1,352 BBLS	5.80	7,844	52,180	11.47
37 SUWANNEE	1-3	183	30,325	5.4	100.0	62.9	14,024	LIGHT OIL	73,323 BBLS	5.80	425,273	2,843,284	9.38
38 SUWANNEE	1-3		6,063				14,311	GAS	86,768 MCF	1.00	86,768	412,146	6.80
39 TURNER	1-4	174	19,553	3.1	100.0	57.8	16,764	LIGHT OIL	58,515 BBLS	5.80	327,789	2,198,723	11.24
40 UNIV OF FLA.	1	38	128,850	92.3	97.1	98.4	9,493	GAS	1,223,192 MCF	1.00	1,223,192	4,437,759	3.44
41 OTHER - START UP		-	42,580	-	-	-	9,650	LIGHT OIL	72,313 BBLS	5.80	419,413	2,779,439	6.53
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	13,286,385	-
43 TOTAL		7,996	14,193,370				9,974				141,569,790	383,398,788	2.70

SCHEDULE E5
Reprojected 8/01

FLORIDA POWER CORPORATION
INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD OF: AUGUST THROUGH DECEMBER 2001

	HEAVY OIL		Aug-01	Sep-01	Oct-01	Nov-01	Dec-01		Subtotal
1	PURCHASES:								
2	UNITS	BBL	1,170,730	992,030	884,461	546,941	1,033,694		4,627,858
3	UNIT COST	$/BBL	21.67	22.30	23.10	24.35	24.05		22.93
4	AMOUNT	$	25,369,727	22,122,279	20,431,049	13,318,024	24,860,348		106,101,427
5	BURNED:								
6	UNITS	BBL	1,170,730	992,030	884,461	546,941	1,033,694		4,627,858
7	UNIT COST	$/BBL	21.58	21.84	22.17	22.28	22.49		22.04
8	AMOUNT	$	25,258,812	21,669,548	19,612,503	12,188,075	23,252,409		101,981,349
9	ENDING INVENTORY:								
10	UNITS	BBL	800,000	800,000	800,000	800,000	800,000		
11	UNIT COST	$/BBL	21.67	22.02	22.59	23.30	23.72		
12	AMOUNT	$	17,336,000	17,615,004	18,069,188	18,642,065	18,979,134		
13	DAYS SUPPLY:		21	24	28	44	24		
	LIGHT OIL								
14	PURCHASES:								
15	UNITS	BBL	457,982	275,514	390,827	19,887	55,402		1,199,613
16	UNIT COST	$/BBL	38.80	38.55	38.40	38.20	38.20		38.57
17	AMOUNT	$	17,769,701	10,621,052	15,007,773	759,693	2,116,372		46,274,590
18	BURNED:								
19	UNITS	BBL	457,982	275,514	390,827	19,887	55,402		1,199,613
20	UNIT COST	$/BBL	38.86	38.56	38.26	38.14	38.07		38.55
21	AMOUNT	$	17,793,329	10,625,126	14,954,454	758,566	2,108,893		46,240,367
22	ENDING INVENTORY:								
23	UNITS	BBL	550,000	550,000	550,000	550,000	550,000		
24	UNIT COST	$/BBL	38.62	38.60	38.51	38.50	38.48		
25	AMOUNT	$	21,241,000	21,228,151	21,183,224	21,177,179	21,161,880		
26	DAYS SUPPLY:		37	60	44	830	308		
	COAL								
27	PURCHASES:								
28	UNITS	TON	447,000	542,000	532,000	526,000	557,000		2,604,000
29	UNIT COST	$/TON	53.22	54.14	55.32	53.39	55.13		54.28
30	AMOUNT	$	23,789,340	29,343,880	29,430,240	28,083,140	30,707,410		141,354,010
31	BURNED:								
32	UNITS	TON	570,243	519,902	560,690	479,736	385,693		2,516,265
33	UNIT COST	$/TON	52.30	53.58	54.15	55.70	56.59		54.28
34	AMOUNT	$	29,823,487	27,854,950	30,364,048	26,720,430	21,828,290		136,591,204
35	ENDING INVENTORY:								
36	UNITS	TON	550,000	572,098	543,407	589,671	760,978		
37	UNIT COST	$/TON	52.30	53.21	54.23	53.82	54.45		
38	AMOUNT	$	28,764,780	30,443,077	29,468,042	31,733,712	41,438,477		
39	DAYS SUPPLY:		38	32	32	34	42		
	GAS								
40	BURNED:								
41	UNITS	MCF	6,101,067	5,436,133	3,960,442	597,040	2,306,561		18,401,243
42	UNIT COST	$/MCF	4.65	4.69	5.19	7.11	5.36		4.95
43	AMOUNT	$	28,360,962	25,509,850	20,557,174	4,246,227	12,357,396		91,031,609
	NUCLEAR								
44	BURNED:								
45	UNITS	MMBTU	5,850,396	5,284,228	185,528	5,708,663	5,862,879		22,891,694
46	UNIT COST	$/MMBTU	0.33	0.33	0.33	0.33	0.33		0.33
47	AMOUNT	$	1,930,631	1,743,795	61,224	1,883,859	1,934,750		7,554,259

FLORIDA POWER CORPORATION
FUEL COST OF POWER SOLD
ESTIMATED FOR THE PERIOD OF: AUGUST THROUGH DECEMBER 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				KWH		C/KWH				REFUNDABLE
MONTH	SOLD TO	TYPE & SCHED	TOTAL KWH SOLD	WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	GAIN ON POWER SALES $
Aug-01	ECONSALE	--	97,942,100		97,942,100	4.129	5.129	4,044,364	5,023,290	978,926
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	412,269,000		412,269,000	4.437	4.437	18,292,327	18,292,327	0
	TOTAL		510,211,100		510,211,100	4.378	4.570	22,336,691	23,315,617	978,926
Sep-01	ECONSALE	--	76,642,700		76,642,700	4.379	5.533	3,356,237	4,240,934	884,697
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	428,743,000		428,743,000	4.496	4.496	19,274,422	19,274,422	0
	TOTAL		505,385,700		505,385,700	4.478	4.653	22,630,659	23,515,356	884,697
Oct-01	ECONSALE	--	66,346,200		66,346,200	4.760	5.229	3,158,397	3,469,485	311,088
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	348,550,000		348,550,000	4.480	4.480	15,616,446	15,616,446	0
	TOTAL		414,896,200		414,896,200	4.525	4.600	18,774,843	19,085,931	311,088
Nov-01	ECONSALE	--	49,124,300		49,124,300	4.793	5.218	2,354,743	2,563,220	208,477
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	309,588,000		309,588,000	3.949	3.949	12,225,684	12,225,684	0
	TOTAL		358,712,300		358,712,300	4.065	4.123	14,580,427	14,788,904	208,477
Dec-01	ECONSALE	--	94,529,600		94,529,600	4.821	5.151	4,556,810	4,869,628	312,817
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	203,288,000		203,288,000	4.232	4.232	8,603,406	8,603,406	0
	TOTAL		297,817,600		297,817,600	4.419	4.524	13,160,216	13,473,034	312,817

FLORIDA POWER CORPORATION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGEN PURCHASES)
ESTIMATED FOR THE PERIOD OF: AUGUST THROUGH DECEMBER 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Aug-01	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	31,346,200			31,346,200	3.200	3.200	1,003,078
	UPS PURCHASE	UPS	251,855,000			251,855,000	1.568	1.568	3,949,086
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		283,201,200	0	0	283,201,200	1.749	1.749	4,952,164
Sep-01	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	30,957,500			30,957,500	3.200	3.200	990,640
	UPS PURCHASE	UPS	244,064,500			244,064,500	1.568	1.568	3,826,932
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		275,022,000	0	0	275,022,000	1.752	1.752	4,817,572
Oct-01	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	35,377,800			35,377,800	3.200	3.200	1,132,090
	UPS PURCHASE	UPS	252,464,000			252,464,000	1.568	1.568	3,958,636
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		287,841,800	0	0	287,841,800	1.769	1.769	5,090,726
Nov-01	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	27,073,300			27,073,300	3.202	3.202	866,986
	UPS PURCHASE	UPS	244,320,000			244,320,000	1.568	1.568	3,830,938
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		271,393,300	0	0	271,393,300	1.731	1.731	4,697,924
Dec-01	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	39,638,600			39,638,600	3.200	3.200	1,268,435
	UPS PURCHASE	UPS	252,264,000			252,264,000	1.568	1.568	3,955,500
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		291,902,600	0	0	291,902,600	1.790	1.790	5,223,935

SCHEDULE E8

Reprojected 8/01

FLORIDA POWER CORPORATION
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD OF: AUGUST THROUGH DECEMBER 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	C/KWH (A) ENERGY COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(A)
Aug-01	QUAL. FACILITIES	COGEN	623,126,500			623,126,500	2.470	6.722	15,393,233
Sep-01	QUAL. FACILITIES	COGEN	565,586,400			565,586,400	6.011	10.262	33,998,478
Oct-01	QUAL. FACILITIES	COGEN	544,957,300			544,957,300	2.495	6.746	13,596,208
Nov-01	QUAL. FACILITIES	COGEN	503,213,700			503,213,700	2.421	6.672	12,183,293
Dec-01	QUAL. FACILITIES	COGEN	603,488,900			603,488,900	2.439	6.690	14,719,926

SCHEDULE E9

Reprojected 8/01

FLORIDA POWER CORPORATION
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD OF: AUGUST THROUGH DECEMBER 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL KWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Aug-01	ECONPURCH	--	104,635,900	4.000	4.000	4,185,436	4.700	4,917,887	732,451
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		104,635,900	4.000	4.000	4,185,436	4.700	4,917,887	732,451
Sep-01	ECONPURCH	--	66,746,700	4.100	4.100	2,736,615	4.700	3,137,095	400,480
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		66,746,700	4.100	4.100	2,736,615	4.700	3,137,095	400,480
Oct-01	ECONPURCH	--	84,845,100	4.600	4.600	3,902,875	5.100	4,327,100	424,226
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		84,845,100	4.600	4.600	3,902,875	5.100	4,327,100	424,226
Nov-01	ECONPURCH	--	56,018,400	4.600	4.600	2,576,846	5.100	2,856,938	280,092
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		56,018,400	4.600	4.600	2,576,846	5.100	2,856,938	280,092
Dec-01	ECONPURCH	--	37,136,500	4.600	4.600	1,708,279	5.100	1,893,962	185,683
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		37,136,500	4.600	4.600	1,708,279	5.100	1,893,962	185,683

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

LEVELIZED FUEL AND CAPACITY COST RECOVERY FACTORS JANUARY THROUGH DECEMBER 2002

PART A - SALES FORECAST ASSUMPTIONS

SALES FORECAST ASSUMPTIONS

1. This forecast of customers, sales and peak demand utilizes the short-term load forecasting methodology developed for use in the 2002 budget and 2002 - 2006 Five Year Business Plan. This forecast was prepared in June 2001.

2. Normal weather conditions are assumed over the forecast horizon. For kiloWatt-hour sales projections normal weather is based on a historical twenty-five year average of service area weighted billing month degree-days. Seasonal peak demand projections are based on a twenty-five year historical average of system-weighted temperatures at time of seasonal peak.

3. The population projections produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida as published in "Florida Population Studies", Bulletin No. 128 (May 2001) provide the basis for development of the customer forecast. State and national economic assumptions produced by WEFA in their national and Florida forecasts (March 2001) are also incorporated.

4. Within the State of Florida the phosphate mining industry accounts for 75% of the U.S. phosphate supply and 35% of the global need. This energy intensive industry, which in the FPC service area consists of six major producers with either national and/or international influence upon the supply of phosphate-based fertilizers, consumed nearly 31% of industrial class kWh energy sales in 2000. Load and energy consumption at the FPC-served mining or chemical processing sites depend heavily on plant operations which are heavily influenced by both micro- and macroeconomic conditions. There is presently excess mining capacity in the industry due to weak farm commodity prices worldwide. Weak farm commodity prices lead to lower crop production, which results in less demand for fertilizer products. In addition, the export market for fertilizer has dried up since the Asian/Russian financial crisis. Going forward, energy consumption is expected to remain weak. Phosphate energy consumption – as a percentage of the total FPC Industrial class usage – is expected to fall to 27% in the 2001-2002 timeframe, the second lowest share ever seen. A return to even a 35% share – recorded just a year ago – is not expected in the short term.

5. Florida Power Corporation (FPC) supplies load and energy service to wholesale customers on a "full", "partial" and "supplemental" requirement basis. Full requirements customers' demand and energy is assumed to grow at a rate that

approximates their historical trend. Partial requirements customer load is assumed to reflect the current contractual obligations received by FPC as of May 31, 2001. The forecast of energy and demand to the partial requirements customers reflect the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. Contracts for partial requirements service included in this forecast are with FMPA, the cities of New Smyrna Beach, Tallahassee and Homestead, Reedy Creek Utilities, and Florida Power & Light. FPC's arrangement with Seminole Electric Cooperative, Inc. (SECI) is to serve "supplemental" service over and above stated levels they commit to supply themselves. SECI's projection of their system's requirements in the FPC control area has been incorporated into this forecast. This forecast also incorporates two firm bulk power contracts with SECI. The first is a multi-part contract to supply 605 MW for three years ending in December 2001. An option to extend one piece of this contract (150 MW) has been exercised by SECI and incorporated into the forecast. A second 3-year agreement with SECI to sell up to 300 MW of peaking power beginning in 2000 and going through 2002 has also been reflected in the forecast.

6. This forecast assumes that FPC will successfully renew all future franchise agreements.

7. This forecast incorporates demand and energy reductions from FPC'S dispatchable and non-dispatchable DSM programs required to meet the approved goals set by the Florida Public Service Commission.

8. Expected energy and demand reductions from self-service cogeneration are also included in this forecast. FPC will supply the supplemental load of self-service cogeneration customers. While FPC offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for standby power.

9. This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. The ability of wholesale customers to switch suppliers has ended the company's obligation to serve these customers beyond their contract life. As a result, the company does not plan for generation resources unless a long-term contract is in place. Current "all requirements" customers are assumed to not renew their contracts with FPC. Current "partial requirements" contracts are projected to terminate as terms reach their expiration date. Deviation from these assumptions can occur as information from the Term Marketing department indicates that a wholesale customer has limited options in the marketplace to replace FPC capacity more economically.

10. The economic outlook for this forecast calls for a significant moderation of national and State economic growth compared to rates seen in the 1990's. Energy price escalation and the bursting of the stock market bubble have acted to deflate consumer confidence and effectively halt new capital investment in many industries nationwide. While no economic recession – two negative quarters of GDP growth – is incorporated in this forecast, the growth rate of the U.S. national economy has ground to a halt in early 2001. The current stretch of economic expansion – which has become the longest period of economic expansion in the history of our nation – is now in serious risk of stalling out.

    The assumption that the national economy will skirt a full-blown recession is based upon the belief that the U.S. Congress and the Federal Reserve Board (FRB) will enact an appropriate mixture of fiscal and monetary policy actions. Economic stimulus from a Federal tax cut, while marginal in the short term, has been enacted. Swift and significant reductions to government-controlled interest rates by the Federal Reserve Board during the first half of 2001 assures most economists that the economy will react (with a lag) and pick up by year end.

    Over-riding this, however, is the fear that a "reverse wealth-effect" will take hold of the economy and depress consumer demand. The "wealth-effect", caused by the record run-up in the U.S. stock market in the later 1990s, created a sizeable increase in consumer demand these past few years. Today, after a loss of several trillion dollars of wealth in the stock market and rising unemployment, the fear is that the consumer will rein in spending and pay down their record levels of debt.

    On a Statewide basis, interest rates and energy prices will continue to influence the pace of economic growth in Florida through their impacts on the construction and tourism industries. The Florida construction industry is expected to feel the impact of corporate mergers and consolidations with respect to commercial and industrial floor space requirements. The State has seen its fair share of corporate mergers in the banking, telecommunications and utility industries, and has not been immune to the impact of "DOT-com" failures. Office vacancy rates are reported to have risen dramatically of late. The tourism industry is reported to have performed well during the winter 2000-2001 but by mid-year hotel vacancy rates and theme park attendance have dropped precipitously. Looking forward, high consumer debt levels in a weak economic environment place an added risk on this industry's ability to avoid some economic pain.

    Another Florida industry sector increasing in importance, export-related industries, is expected to stall in 2001 as Central and South American economies flounder. Florida has developed significant trade relations with its neighbors to the south and

continues to attract a significant number of tourists from this area. Areas of Latin America are reeling from drought conditions and a serious electricity shortage, which are not helping economic matters.

Personal income growth is expected to continue growing but not at the torrid pace experienced in recent years. Employment growth will moderate resulting in slower growth in total wages. Slower growth in hourly earnings as well as transfer payments should also hold down income growth in the years ahead. The low interest rate environment also means lower returns on bank deposits – a significant part of retiree income.

Growth in energy consumption is directly tied to the levels of economic activity in the State, nation and around the world, but demographic forces play a major role as well. Factors that influence in-migration rates to Florida impact residential customer growth, especially since the difference between births and deaths contribute little to Florida's growing population. The University of Florida's latest projection (May 2001) shows a significant fall off in population growth for the 29 county area which Florida Power provides residential service. This is due to the characteristics of the age cohorts reaching retirement age this decade. Those now reaching retirement age were born during the Great Depression – a period of very low birth rates. This is expected to temporarily hold down Florida population growth by reducing the numbers of retirees entering the State.

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

LEVELIZED FUEL AND CAPACITY COST RECOVERY FACTORS JANUARY THROUGH DECEMBER 2002

PART B - FUEL PRICE FORECAST ASSUMPTIONS

FUEL PRICE FORECAST ASSUMPTIONS

A. Residual Oil and Light Oil

The oil price forecast is based on expectations of normal weather and no radical changes in world energy markets (OPEC actions, governmental rule changes, etc.). Prices are based on expected contract structures, specifications, and spot market purchases for 2001 & 2002.

FPC Residual Fuel Oil (#6) and Distillate Fuel Oil (#2) prices were derived from EIA forecasts, NYMEX, and current market information.

Transportation to the Tampa Bay area plus applicable environment taxes were added to the above prices (an adjustment was later made to transportation costs for individual plant locations).

B. Coal

Coal price projections are provided by Electric Fuels Corporation and represent an estimate of EFC's price to Florida Power for coal delivered to the plant sites in accordance with the delivery schedules projected. The forecast is consistent with the coal supply and transportation agreements which EFC has, or expects to have, in place during 2001 & 2002 and estimated spot purchase volumes and prices for the period. It assumes environmental restrictions on coal quality remain in effect as per current permits: 2.1 lbs. per million BTU sulfur dioxide limit for Crystal River Units 1 and 2, and 1.2 lbs. per million BTU sulfur dioxide limit for Crystal River Units 4 and 5.

C. Natural Gas

The natural gas price forecast is based on the expectation of normal weather, no material changes in energy markets, governmental rule changes, etc. Prices are based on expected contract structures and spot market purchases for 2001 & 2002. Gas supply prices were derived from EIA, NYMEX and current spot market information.

Transportation costs for Florida Gas Transmission pipeline firm transportation service is based on expected tariff rates. Interruptible transportation rates and availability are based on expected tariff rates and market conditions.

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

LEVELIZED FUEL AND CAPACITY COST RECOVERY FACTORS JANUARY THROUGH DECEMBER 2002

PART C - FUEL PRICE FORECAST

Florida Power Corporation
Docket No. 010001-EI
Witness: J. Portuondo
Part C
Sheet 1 of 4

FUEL PRICE FORECAST
#6 Fuel Oil

	1.0%		1.5%		2.5%	
Month	**$/barrel**	**$/MMBtu (1)**	**$/barrel**	**$/MMBtu (1)**	**$/barrel**	**$/MMBtu (1)**
Jan – Feb 2002	26.00	4.00	24.05	3.70	19.50	3.00
Mar - Sept 2002	22.75	3.50	21.45	3.30	18.85	2.90
Oct – Dec 2002	24.70	3.80	22.75	3.50	19.50	3.00

(1) 6.5 mmbtu/bbl

FUEL PRICE FORECAST
#2 Fuel Oil

Month	$/barrel	¢/gallon	$/MMBtu[1]
Jan – Mar 2002	37.70	89.76	6.50
Apr - Sept 2002	31.90	75.95	5.50
Oct - Dec 2002	34.80	82.90	6.00

[1] 5.8 MMBtu/Bbl & 42 gallon/Bbl

Florida Power Corporation
Docket No. 010001-EI
Witness: J. Portuondo
Part C
Sheet 3 of 4

FUEL PRICE FORECAST
Coal

	Crystal River 1 & 2			Crystal River 4 & 5		
Month	**BTU/lb.**	**$/ton**	**$/MMBtu**	**BTU/lb.**	**$/ton**	**$/MMBtu**
Jan 2002	12,415	52.04	2.096	12,424	69.27	2.788
Feb 2002	12,415	52.07	2.097	12,428	69.49	2.796
Mar 2002	12,415	52.02	2.095	12,428	69.40	2.792
Apr 2002	12,387	51.66	2.085	12,428	69.61	2.801
May 2002	12,415	52.02	2.095	12,430	69.22	2.784
Jun 2002	12,393	51.69	2.085	12,431	69.53	2.797
Jul 2002	12,500	53.92	2.157	12,383	69.26	2.797
Aug 2002	12,500	53.96	2.158	12,375	69.59	2.812
Sep 2002	12,500	53.90	2.156	12,383	69.25	2.796
Oct 2002	12,500	54.06	2.163	12,380	69.49	2.807
Nov 2002	12,500	53.92	2.157	12,406	69.22	2.790
Dec 2002	12,500	53.96	2.158	12,386	69.27	2.796

FUEL PRICE FORECAST
Natural Gas Supply

INTO FLORIDA GAS TRANSMISSION [1]	
Month	**$/MMBtu**
Jan – Feb 2002	5.50
Mar – Sep 2002	4.10
Oct - Dec 2002	4.50

[1] Transport costs not included

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

LEVELIZED FUEL AND CAPACITY COST RECOVERY FACTORS JANUARY THROUGH DECEMBER 2002

PART D - CAPACITY COST RECOVERY CALCULATIONS

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
PROJECTED CAPACITY PAYMENTS
For the Year 2002

Florida Power Corporation
Docket 010001-EI
Witness: J. Portuondo
Part D
Sheet 1 of 5

	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Total
Base Production Level Capacity Charges:													
1 Payments to Qualifying Facilities	25,283,882	25,283,882	25,283,882	24,953,412	25,303,412	25,303,412	25,303,412	25,303,412	25,303,412	25,303,412	25,303,412	25,303,412	303,232,354
2 UPS Purchase (409 MW)	3,894,000	3,517,000	3,894,000	3,768,000	3,894,000	3,768,000	3,894,000	3,894,000	3,768,000	3,894,000	3,768,000	3,894,000	45,847,000
3 Other Power Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
4 Subtotal - Base Level Capacity Charges	29,177,882	28,800,882	29,177,882	28,721,412	29,197,412	29,071,412	29,197,412	29,197,412	29,071,412	29,197,412	29,071,412	29,197,412	349,079,354
5 Base Production Jurisdictional %	97.560%	97.560%	97.560%	97.560%	97.560%	97.560%	97.560%	97.560%	97.560%	97.560%	97.560%	97.560%	
6 Base Jurisdictional Capacity Charges	28,465,942	28,098,140	28,465,942	28,020,610	28,484,995	28,362,070	28,484,995	28,484,995	28,362,070	28,484,995	28,362,070	28,484,995	340,561,818
Intermediate Production Level Capacity Charges:													
7 TECO Power Purchase	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	6,792,000
8 Other Power Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Subtotal - Intermediate Level Capacity Charges	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	6,792,000
10 Intermediate Production Jurisdictional %	71.248%	71.248%	71.248%	71.248%	71.248%	71.248%	71.248%	71.248%	71.248%	71.248%	71.248%	71.248%	
11 Intermediate Jurisdictional Capacity Charges	403,264	403,264	403,264	403,264	403,264	403,264	403,264	403,264	403,264	403,264	403,264	403,264	4,839,164
Peaking Production Level Capacity Charges:													
12 Peaking Purchases - Yearly	0	0	0	0	0	0	0	0	0	0	0	0	0
13 Peaking Purchases - *Summer Peak*	0	0	0	0	0	0	0	0	0	0	0	0	0
14 Peaking Purchases - Winter Peak	0	0	0	0	0	0	0	0	0	0	0	0	0
15 Subtotal - Peaking Level Capacity Charges	0	0	0	0	0	0	0	0	0	0	0	0	0
16 Peaking Production Jurisdictional %	76.267%	76.267%	76.267%	76.267%	76.267%	76.267%	76.267%	76.267%	76.267%	76.267%	76.267%	76.267%	
17 Peaking Jurisdictional Capacity Charges	0	0	0	0	0	0	0	0	0	0	0	0	0
18 Sebring Base Rate Credits	(384,812)	(363,985)	(328,851)	(305,538)	(309,767)	(387,735)	(404,542)	(432,316)	(435,475)	(380,428)	(332,380)	(346,454)	(4,412,283)
19 Transmission Revenues from Economy Sales	(202,061)	(140,263)	(217,734)	(107,475)	(84,390)	(145,501)	(225,965)	(197,958)	(171,234)	(135,665)	(136,869)	(187,285)	(1,932,200)
20 Jurisdictional Capacity Payments (Lines 6 + 11 + 17 + 18 + 19)	28,282,332	27,997,156	28,322,620	28,010,860	28,514,102	28,232,097	28,257,752	28,257,985	28,158,624	28,372,186	28,296,284	28,354,520	339,056,499
21 Estimated/Actual True-Up Provision for the Period January through December 2001													3,712,132
22 Total (Sum of lines 19 & 20)													342,768,631
23 Revenue Tax Multiplier													1.00072
24 Total Recoverable Capacity Payments													343,015,424

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED / ACTUAL *TRUE-UP*
For the Year 2001

Florida Power Corporation
Docket 010001-EI
Witness: J. Portuondo
Part D
Sheet 2 of 5

		Actual Jan-01	Actual Feb-01	Actual Mar-01	Actual Apr-01	Actual May-01	Actual Jun-01	Actual Jul-01	Estimated Aug-01	Estimated Sep-01	Estimated Oct-01	Estimated Nov-01	Estimated Dec-01	Total 2001
	Base Production Level Capacity Charges:													
	Bay County Qualifying Facility	183,260	194,700	194,700	194,700	194,700	194,700	194,700	194,700	194,700	194,700	194,700	194,700	2,324,960
	Eco Peat Qualifying Facility	1,103,732	1,103,732	1,103,732	1,103,732	1,103,732	1,103,732	1,103,732	1,103,732	1,103,732	1,103,732	1,103,732	1,103,732	13,244,784
	General Peat Qualifying Facility	3,979,404	3,979,404	3,979,404	3,979,404	3,979,404	3,979,404	3,979,404	3,979,404	3,979,404	3,979,404	3,979,404	3,979,404	47,752,848
	Auburndale LFC Qualifying Facility	554,320	577,780	72,690	394,230	394,230	394,230	394,230	394,230	394,230	394,230	394,230	394,230	4,752,860
	Dade County Qualifying Facility	638,601	620,438	642,913	659,655	630,318	616,183	631,800	742,560	749,880	757,200	764,520	771,840	8,225,908
	Lake County Qualifying Facility	347,565	369,623	369,623	369,623	369,623	369,623	369,623	369,495	369,495	369,495	369,495	369,495	4,412,778
	Pasco County Qualifying Facility	626,980	666,540	666,540	666,540	666,540	666,540	666,540	666,540	666,540	666,540	666,540	666,540	7,958,920
	Pinellas County 1&2 Qualifying Facility	1,492,485	1,586,655	1,586,655	1,586,655	1,586,655	1,586,655	1,586,655	1,586,655	1,586,655	1,586,655	1,586,655	1,586,655	18,945,690
	El Dorado Qualifying Facility	1,891,454	1,987,798	1,987,798	1,987,798	1,987,798	1,987,798	1,987,798	1,987,798	1,987,798	1,987,798	1,987,798	1,987,798	23,757,232
	Lake Cogen Qualifying Facility	1,998,699	2,099,277	2,099,277	2,099,277	2,098,077	2,099,277	2,099,277	2,087,859	2,099,277	2,099,277	2,099,277	2,099,277	25,074,128
	El Paso Qualifying Facility	4,512,625	4,707,940	4,702,434	4,726,810	4,721,356	4,769,684	4,765,688	4,857,001	4,857,001	4,857,001	4,857,001	4,857,001	57,191,522
	Orlando Cogen Qualifying Facility	1,508,138	1,584,957	1,584,957	1,584,957	1,584,957	1,584,957	1,584,957	1,584,957	1,584,957	1,584,957	1,584,957	1,584,957	18,942,685
	Pasco Cogen Qualifying Facility	2,466,683	3,211,250	2,860,882	2,863,196	2,863,196	2,863,196	2,863,196	2,863,196	2,863,196	2,863,196	2,863,196	2,863,196	34,307,379
	Ridge Generating Station Qualifying Facility	777,908	789,404	795,766	792,952	790,571	798,481	800,946	800,946	800,946	800,946	800,946	800,946	9,550,758
	Timber Energy 1 Qualifying Facility	361,250	361,250	361,250	361,250	380,780	380,780	380,780	380,780	380,780	380,780	380,780	380,780	4,491,240
	Timber Energy 2 Qualifying Facility	139,140	139,140	139,140	139,140	139,140	139,140	139,140	139,140	139,140	139,140	139,140	139,140	1,669,680
	Cargill Fertilizer Qualifying Facility	391,950	412,050	354,692	381,104	412,050	412,050	412,050	412,050	412,050	412,050	412,050	412,050	4,836,196
	US Agrichem Qualifying Facility	37,699	39,607	39,607	39,607	39,607	39,131	35,505	39,607	39,607	39,607	39,607	39,607	468,798
	Tiger Bay (Eco Peat Lease Credit)	(66,667)	(66,667)	(66,667)	(416,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(1,150,004)
1	Payments to Qualifying Facilities	22,943,226	24,364,878	23,475,193	23,510,763	23,877,267	23,918,874	23,917,936	24,135,401	24,142,721	24,150,041	24,157,361	24,164,681	288,758,342
2	UPS Purchase (409 MW)	4,193,198	4,168,465	3,801,057	3,986,225	3,677,373	4,000,010	3,988,181	3,959,000	3,831,000	3,959,000	3,831,000	3,959,000	47,353,509
3	Other Power Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Subtotal - Base Level Capacity Charges	27,136,424	28,533,343	27,276,250	27,496,988	27,554,640	27,918,884	27,906,117	28,094,401	27,973,721	28,109,041	27,988,361	28,123,681	334,111,851
5	Base Production Jurisdictional %	97.232%	97.232%	97.232%	97.232%	97.560%	97.560%	97.560%	97.560%	97.560%	97.560%	97.560%	97.560%	
6	Base Level Jurisdictional Capacity Charges	26,385,288	27,743,540	26,521,243	26,735,871	26,882,307	27,237,663	27,225,208	27,408,898	27,291,162	27,423,180	27,305,445	27,437,463	325,597,269
	Intermediate Production Level Capacity Charges:													
7	TECO Power Purchase	565,567	565,567	565,567	565,567	565,567	565,567	565,567	566,000	566,000	566,000	566,000	566,000	6,788,969
8	Capacity Sales	(2,385)	(2,154)	(2,154)	(2,536)	(3,508)	(3,395)	(3,508)	0	0	0	0	0	(19,642)
9	FP&L, Reedy Creek	430,000	340,000	0	0	0	0	0	0	0	0	0	0	770,000
10	Subtotal - Intermediate Level Capacity Charges	993,182	903,413	563,413	563,028	562,059	562,172	562,059	566,000	566,000	566,000	566,000	566,000	7,539,327
11	Intermediate Production Jurisdictional %	70.241%	70.241%	70.241%	70.241%	71.248%	71.248%	71.248%	71.248%	71.248%	71.248%	71.248%	71.248%	
12	Intermediate Level Jurisdictional Capacity Charge	697,621	634,566	395,747	395,477	400,456	400,536	400,456	403,264	403,264	403,264	403,264	403,264	5,341,178
13	Sebring Base Rate Credits	(464,721)	(354,441)	(301,789)	(308,469)	(283,496)	(383,629)	(374,436)	(417,286)	(431,685)	(372,088)	(326,876)	(336,953)	(4,355,849)
14	Adjustments - Premium/Liquidating Damages	0	(13,968)	8,605	0	0	0							(5,383)
15	Retail Wheeling	(221,452)	(172,014)	(297,274)	(180,022)	(33,371)	(330,733)	(59,037)	(182,844)	(143,082)	(123,859)	(91,708)	(176,474)	(2,011,870)
16	Jurisdictional Capacity Payments (Lines 6 + 12 + 13 + 14 + 15)	26,396,736	27,837,663	26,326,532	26,642,858	26,965,896	26,823,838	27,192,191	27,212,031	27,119,659	27,330,517	27,290,125	27,327,300	324,565,344
17	Capacity Cost Recovery Revenues	31,348,684	23,847,120	20,977,423	22,806,403	23,073,364	29,820,723	29,823,480	31,181,283	32,588,968	28,469,322	24,598,487	24,234,758	322,570,015
18	Prior Period True-Up Provision	(11,934)	(11,934)	(11,934)	(11,934)	(11,934)	(11,934)	(11,934)	(11,934)	(11,934)	(11,934)	(11,934)	(1,414,479)	(1,545,753)
19	Current Period Capacity Revenues (Lines 17+18)	31,336,750	23,835,186	20,965,489	22,794,469	23,061,430	29,808,789	29,811,546	31,169,349	32,577,034	28,457,388	24,586,553	22,820,279	321,024,262
20	Current Period Over/(Under) Recovery (Lines 19+16	4,940,014	(4,002,477)	(5,361,043)	(3,848,389)	(3,904,466)	2,984,951	2,619,355	3,957,318	5,457,375	1,126,871	(2,703,572)	(4,507,021)	(3,541,082)
21	Interest Provision for Month	4,352	6,262	(13,740)	(30,634)	(40,655)	(40,015)	(30,758)	(20,459)	(5,657)	4,733	2,302	(6,801)	(171,050)
22	Current Cycle Balance	4,944,366	948,171	(4,426,613)	(8,305,635)	(12,250,755)	(9,605,818)	(7,017,221)	(3,080,362)	2,371,356	3,502,960	801,690	(3,712,132)	(3,712,132)
23	Plus: Prior Period Balance	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)	(1,545,753)
24	Plus: Cumulative True-Up Provision	11,934	23,868	35,802	47,736	59,670	71,604	83,538	95,472	107,406	119,340	131,274	1,545,753	1,545,753
25	End of Period Net True-Up (Lines 22+23+24)	3,410,547	(573,714)	(5,936,564)	(9,803,652)	(13,736,838)	(11,079,967)	(8,479,436)	(4,530,843)	933,009	2,076,547	(612,789)	(3,712,132)	(3,712,132)

FLORIDA POWER CORPORATION
DEVELOPMENT OF JURISDICTIONAL DELIVERY LOSS MULTIPLIERS
BASED ON ACTUAL CALENDAR YEAR 2000 DATA
FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Energy Delivered				Energy Required @ Source			
Class Loads	Sales Mwh	Unbilled Mwh	Total Mwh	% of Total	Delivery Efficiency	Mwh (3) / (5)	% of Total	Jurisdictional Loss Multiplier
I. CLASS LOADS:								
A. RETAIL								
1. Transmission	646,503	4,269	650,772		0.9779000	665,479		
2. Distribution Primary	4,618,696	30,491	4,649,187		0.9679000	4,803,375		
3. Distribution Secondary	29,566,766	195,187	29,761,953		0.9377499	31,737,623		
Total Retail	34,831,965	229,947	35,061,912	90.41%	0.9423604	37,206,477	90.87%	1.0051
B. WHOLESALE								
1. Source Level	2,789,617	105,705	2,895,322		1.0000000	2,895,322		
2. Transmission	714,800	6,858	721,658		0.9779000	737,967		
3. Distribution Primary	99,860	1,274	101,134		0.9679000	104,488		
4. Distribution Secondary	0	0	0		0.9377499	0		
Total Wholesale	3,604,277	113,837	3,718,114	9.59%	0.9947390	3,737,777	9.13%	0.9522
Total Class Loads	38,436,242	343,784	38,780,026	100.00%	0.9471421	40,944,254	100.00%	1.0000
II. NON-CLASS LOADS								
1. Company Use	125,909	0	125,909		0.9377499	134,267		
2. Seminole Electric	0	0	0		1.0000000	0		
3. Kissimmee	0	0	0		0.9779000	0		
4. St. Cloud	0	0	0		0.9779000	0		
5. Interchange	1,477,064	0	1,477,064		0.9779000	1,510,445		
6. SEPA	127,759	0	127,759		0.9779000	130,646		
Total Non-Class Loads	1,730,732	0	1,730,732		0.9748637	1,775,358		
Total System	40,166,974	343,784	40,510,758		0.9482941	42,719,612		

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF AVERAGE 12 CP AND ANNUAL AVERAGE DEMAND
For the Year 2002

Rate Class	(1) Mwh Sales @ Meter Level	(2) 12 CP Load Factor	(3) Average CP MW @ Meter Level (1)/8760hrs/(2)	(4) Delivery Efficiency Factor	(5) Average CP MW @ Source Level (3)/(4)	(6) Mwh Sales @ Meter Level	(7) Delivery Efficiency Factor	(8) Source Level Mwh (6)/(7)	(9) Annual Average Demand (8)/8760hrs
I. Residential Service	18,636,202	0.517	4,114.93	0.9377499	4,388.09	18,636,202	0.9377499	19,873,318	2,268.64
II. General Service Non-Demand									
Transmission	3,180	0.705	0.51	0.9779000	0.52	3,180	0.9779000	3,252	0.37
Primary	6,688	0.705	1.08	0.9679000	1.12	6,688	0.9679000	6,910	0.79
Secondary	1,163,499	0.705	188.40	0.9377499	200.91	1,163,499	0.9377499	1,240,735	141.64
Total Gen Serv Non-Demand	1,173,367		189.99		202.55	1,173,367		1,250,897	142.80
III. GS - 100% L.F.	76,820	1.000	8.77	0.9377499	9.35	76,820	0.9377499	81,919	9.35
IV. General Service Demand									
SS-1 - Transmission	6,190	0.888	0.80			6,190			
GSD-1 - Transmission	6,879	0.820	0.96			6,879			
Total Transmission	13,069		1.76	0.9779000	1.80	13,069	0.9779000	13,364	1.53
SS-1 - Primary	0	0.888	0.00			0			
GSD-1 - Primary	2,709,317	0.820	377.17			2,709,317			
Total Primary	2,709,317		377.17	0.9679000	389.68	2,709,317	0.9679000	2,799,170	319.54
GSD - Secondary	11,615,025	0.820	1,616.97	0.9377499	1,724.31	11,615,025	0.9377499	12,386,058	1,413.93
Total Gen Serv Demand	14,337,411		1,995.90		2,115.79	14,337,411		15,198,592	1,735.00
V. Curtailable Service									
CS - Primary	181,162	1.169	17.69			181,162			
SS-3 - Primary	1,437	N/A	0.00			1,437			
Total Primary	182,599		17.69	0.9679000	18.28	182,599	0.9679000	188,655	21.54
CS - Secondary	649	1.169	0.06	0.9377499	0.06	649	0.9377499	692	0.08
Total Curtailable Service	183,248		17.75		18.34	183,248		189,347	21.62
VI. Interruptible Service									
IS - Transmission	450,738	0.975	52.77			450,738			
SS-2 - Transmission	143,766	1.196	13.72			143,766			
Total Transmission	594,504		66.49	0.9779000	67.99	594,504	0.9779000	607,939	69.40
IS - Primary	1,672,975	0.975	195.88			1,672,975			
SS-2 - Primary	72,804	1.196	6.95			72,804			
Total Primary	1,745,779		202.83	0.9679000	209.56	1,745,779	0.9679000	1,803,677	205.90
IS - Secondary	91,326	0.975	10.69	0.9377499	11.40	91,326	0.9377499	97,388	11.12
Total Interruptible Service	2,431,609		280.01		288.95	2,431,609		2,509,004	286.42
VII. Lighting Service	277,451	5.042	6.28	0.9377499	6.70	277,451	0.9377499	295,869	33.78
Total Retail	**37,116,108**				**7,029.77**	**37,116,108**		**39,398,946**	**4,497.61**

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF CAPACITY COST RECOVERY FACTOR
For the Year 2002

	(1) Average 12 CP Demand Mw	(2) Average 12 CP Demand %	(3) Annual Average Demand Mw	(4) Annual Average Demand %	(5) 12/13 of 12 CP 12/13 * (2)	(6) 1/13 of Annual Demand 1/13 * (4)	(7) Demand Allocation (5) + (6)	(8) Dollar Allocation (7) * Total	(9) Effective Mwh's @ Secondary Level Year 2002	(10) Capacity Cost Recovery Factor (c/Kwh)
I. Residential Service	4,388.09	62.422%	2,268.64	50.441%	57.620%	3.880%	61.500%	210,954,486	18,636,202	**1.132**
II. General Service Non-Demand										
Transmission									3,116	**0.832**
Primary									6,621	**0.840**
Secondary									1,163,499	**0.849**
Total Gen Serv Non-Demand	202.55	2.881%	142.80	3.175%	2.659%	0.244%	2.903%	9,957,738	1,173,236	
III. GS - 100% L.F.	9.35	0.133%	9.35	0.208%	0.123%	0.016%	0.139%	476,791	76,820	**0.621**
IV. General Service Demand										
Transmission									12,808	**0.722**
Primary									2,682,224	**0.730**
Secondary									11,615,025	**0.737**
Total Gen Service Demand	2,115.79	30.098%	1,735.00	38.576%	27.783%	2.967%	30.750%	105,477,243	14,310,057	
V. Curtailable Service										
Transmission									0	**0.515**
Primary									180,773	**0.520**
Secondary									649	**0.526**
Total Curtailable Service	18.34	0.261%	21.62	0.481%	0.241%	0.037%	0.278%	953,583	181,422	
VI. Interruptible Service										
Transmission									582,614	**0.599**
Primary									1,728,321	**0.606**
Secondary									91,326	**0.612**
Total Interruptible Service	288.95	4.110%	286.42	6.368%	3.794%	0.490%	4.284%	14,694,781	2,402,261	
VII. Lighting Service	6.70	0.095%	33.78	0.751%	0.088%	0.058%	0.146%	500,802	277,451	**0.181**
Total Retail	**7,029.77**	**100.000%**	**4,497.61**	**100.000%**	**92.308%**	**7.692%**	**100.000%**	**343,015,424**	**37,057,449**	**0.92417**

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

LEVELIZED FUEL AND CAPACITY COST RECOVERY FACTORS JANUARY THROUGH DECEMBER 2002

SCHEDULES E1 THROUGH E10 AND H1

FLORIDA POWER CORPORATION
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

			DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation		848,829,151	32,645,940	2.60011
2.	Spent Nuclear Fuel Disposal Cost		6,164,383	6,592,923 *	0.09350
3.	Coal Car Investment		0	0	0.00000
4.	Adjustment to Fuel Cost		10,962,000	0	0.00000
5.	TOTAL COST OF GENERATED POWER		865,955,534	32,645,940	2.65257
6.	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)		59,300,216	3,319,365	1.78649
7.	Energy Cost of Sch. C,X Economy Purchases (Broker) (E9)		0	0	0.00000
8.	Energy Cost of Economy Purchases (Non-Broker) (E9)		20,107,161	678,000	2.96566
9.	Energy Cost of Schedule E Economy Purchases (E9)		0	0	0.00000
10.	Capacity Cost of Economy Purchases (E9)		0	0 *	0.00000
11.	Payments to Qualifying Facilities (E8)		158,644,508	6,510,148	2.43688
12.	TOTAL COST OF PURCHASED POWER		238,051,885	10,507,513	2.26554
13.	TOTAL AVAILABLE KWH			43,153,453	
14.	Fuel Cost of Economy Sales	(E6)	0	0	0.00000
14a.	Gain on Economy Sales - 80%	(E6)	0	0 *	0.00000
15.	Fuel Cost of Other Power Sales	(E6)	(34,059,150)	(1,035,000)	3.29074
15a.	Gain on Other Power Sales	(E6)	(4,765,728)	(1,035,000) *	0.46046
16.	Fuel Cost of Unit Power Sales	(E6)	0	0	0.00000
16a.	Gain on Unit Power Sales	(E6)	0	0	0.00000
17.	Fuel Cost of Stratified Sales	(E6)	(71,009,729)	(1,800,987)	3.94282
18.	TOTAL FUEL COST AND GAINS ON POWER SALES		(109,834,607)	(2,835,987)	3.87289
19.	Net Inadvertent Interchange			0	
20.	TOTAL FUEL AND NET POWER TRANSACTIONS		994,172,812	40,317,466	2.46586
21.	Net Unbilled		(3,456,275)	140,165	(0.00910)
22.	Company Use		3,550,840	(144,000)	0.00930
23.	T & D Losses		53,830,888	(2,183,046)	0.14118
24.	Adjusted System KWH Sales		994,172,812	38,130,585	2.60724
25.	Wholesale KWH Sales (Excluding Supplemental Sales)		(26,252,741)	(1,014,477)	2.58781
26.	Jurisdictional KWH Sales		967,920,071	37,116,108	2.60782
27.	Jurisdictional KWH Sales Adjusted for Line Losses x	1.0051	972,856,464	37,116,108	2.62112
28.	Prior Period True-Up (E1-B, Sheet 1)		23,640,300	37,116,108	0.06369
29.	Total Jurisdictional Fuel Cost		996,496,764	37,116,108	2.68481
30.	Revenue Tax Factor				1.00072
31.	Fuel Cost Adjusted for Taxes		997,214,241	37,116,108	2.68674
32.	GPIF		266,919	37,116,108	0.00072
33.	Fuel Factor Adjusted for taxes including GPIF		997,481,160	37,116,108	2.68746
34.	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)				2.687

* For Informational Purposes Only

FLORIDA POWER CORPORATION
CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

1.	ACTUAL OVER/(UNDER) RECOVERY JANUARY - DECEMBER 2000 (Schedule E1-B, Line 18 - Dec '01)	$	(84,596,026)
2.	50% OF PROJECTED 2000 UNDERRECOVERY, PLUS INTEREST, **DEFERRED** TO 2002 FOR RECOVERY. (Mid-Course, Schedule E1-D, Line 2)		29,671,241
3.	50% OF PROJECTED 2000 UNDERRECOVERY **COLLECTED** IN 2001. (Schedule E1-B, Line 19 - Dec '01)		27,608,904
4.	2001 CURRENT PERIOD ESTIMATED OVER/(UNDER)RECOVERY (Schedule E1-B, Line 17, Dec '01)		33,346,822
5.	OVER/(UNDER) RECOVERY VARIANCE FROM MID-COURSE FILING (Total Lines 1 through 4)	$	6,030,941
6.	50% OF PROJECTED 2000 UNDERRECOVERY, PLUS INTEREST, **DEFERRED** TO 2002 FOR RECOVERY. (Mid-Course, Schedule E1-D, Line 2)		(29,671,241)
7.	TOTAL 2001 PROJECTED OVER/(UNDER) RECOVERY (Total Lines 5 and 6)	$	(23,640,300)
8.	JURISDICTIONAL MWH SALES (Projected Period)		37,116,108 Mwh
9.	TRUE-UP FACTOR (Line 7 / Line 8 / 10)		0.06369 Cents/kwh

FLORIDA POWER CORPORATION
CALCULATION OF ESTIMATED TRUE-UP
REPROJECTED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2001

DESCRIPTION		ACTUALS Jan - Jul 01	ESTIMATED Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TOTAL PERIOD
REVENUE								
1 Jurisdictional KWH Sales		20,778,246	3,497,471	3,655,365	3,193,282	2,759,107	2,718,309	36,601,780
2 Jurisdictional Fuel Factor (Pre-Tax)		2.638	2.878	2.878	2.878	2.878	2.878	
3 Total Jurisdictional Fuel Revenue		548,179,004	100,654,697	105,198,773	91,900,357	79,405,113	78,230,976	1,003,568,920
4 Less: True-Up Provision		(16,105,194)	(2,300,742)	(2,300,742)	(2,300,742)	(2,300,742)	(2,300,742)	(27,608,904)
5 Less: GPIF Provision		(1,273,454)	(181,922)	(181,922)	(181,922)	(181,922)	(181,922)	(2,183,064)
6 Less: Other		0	0	0	0	0	0	0
7 Net Fuel Revenue		530,800,356	98,172,033	102,716,109	89,417,693	76,922,449	75,748,312	973,776,952
FUEL EXPENSE								
8 Total Cost of Generated Power		471,469,720	104,721,386	88,880,935	88,161,569	47,316,599	63,017,728	863,567,937
9 Total Cost of Purchased Power		158,539,121	24,530,833	41,552,665	22,589,809	19,458,063	21,652,140	288,322,631
10 Total Cost of Power Sales		(96,268,505)	(23,315,617)	(23,515,356)	(19,085,931)	(14,788,904)	(13,473,033)	(190,447,346)
11 Total Fuel and Net Power		533,740,336	105,936,602	106,918,244	91,665,447	51,985,758	71,196,835	961,443,222
12 Jurisdictional Percentage		97.40%	97.14%	97.15%	96.73%	96.79%	97.27%	97.31%
13 Jurisdictional Loss Multiplier		1.0022	1.0022	1.0022	1.0022	1.0022	1.0022	1.0022
14 Jurisdictional Fuel Cost		521,683,084	103,133,210	104,099,590	88,863,056	50,427,713	69,405,518	937,612,172
COST RECOVERY								
15 Net Fuel Revenue Less Expense		9,117,272	(4,961,177)	(1,383,482)	554,636	26,494,736	6,342,793	
16 Interest Provision	(1)	(1,989,962)	(197,485)	(200,853)	(195,544)	(146,310)	(87,804)	
17 Current Cycle Balance		7,127,310	1,968,648	384,313	743,406	27,091,833	33,346,822	
18 Plus: Prior Period True-Up Balance		(84,596,026)	(84,596,026)	(84,596,026)	(84,596,026)	(84,596,026)	(84,596,026)	
19 Plus: Cumulative True-Up Provision		16,105,194	18,405,936	20,706,678	23,007,420	25,308,162	27,608,904	
20 Total Retail Balance		(61,363,522)	(64,221,442)	(63,505,035)	(60,845,200)	(32,196,031)	(23,640,300)	

(1) Interest for the August through December 2001 period calculated at the July 2001 monthly rate of .315%.

FLORIDA POWER CORPORATION
CALCULATION OF GENERATING PERFORMANCE INCENTIVE AND TRUE-UP ADJUSTMENT FACTORS
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward / (Penalty)	$ 266,919	
	B. True-Up (Over) / Under Recovery	$ 23,640,300	
2.	JURISDICTIONAL MWH SALES	37,116,108	Mwh
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor	0.00072	Cents/kwh
	B. True-Up Factor	0.06369	Cents/kwh

FLORIDA POWER CORPORATION
CALCULATION OF LEVELIZED FUEL ADJUSTMENT FACTORS
(PROJECTED PERIOD)
FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

1.	Period Jurisdictional Fuel Cost (E1, line 27)	$ 972,856,464	
2.	Prior Period True-Up (E1, line 28)	23,640,300	
3.	Other Adjustments	0	
4.	Regulatory Assessment Fee (E1, line 30)	717,477	
5.	Generating Performance Incentive Factor (GPIF) (E1, line 32)	266,919	
6.	Total Jurisdictional Fuel Cost (E1, line 33)	$ 997,481,160	
7.	Jurisdictional Sales (E1, line 26)	37,116,108	Mwh
8.	Jurisdictional Cost per Kwh Sold (Line 6 / Line 7 / 10)	2.687	Cents/kwh
9.	Effective Jurisdictional Sales (See Below)	37,057,449	Mwh

LEVELIZED FUEL FACTORS:

10.	Fuel Factor at Secondary Metering (Line 6 / Line 9 / 10)	**2.692**	Cents/kwh
11.	Fuel Factor at Primary Metering (Line 10 * 99%)	**2.665**	Cents/kwh
12.	Fuel Factor at Transmission Metering (Line 10 * 98%)	**2.638**	Cents/kwh

	JURISDICTIONAL SALES (MWH)	
METERING VOLTAGE:	METER	SECONDARY
Distribution Secondary	31,860,972	31,860,972
Distribution Primary	4,644,383	4,597,939
Transmission	610,753	596,538
Total	37,116,108	37,057,449

FLORIDA POWER CORPORATION
CALCULATION OF FINAL FUEL COST FACTORS
FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

Line:	Metering Voltage	(1) Levelized Factors Cents/Kwh	(2) Time of Use On-Peak Multiplier 1.216	(3) Time of Use Off-Peak Multiplier 0.907
1.	Distribution Secondary	2.692	3.273	2.442
2.	Distribution Primary	2.665	3.241	2.417
3.	Transmission	2.638	3.208	2.393
4.	Lighting Service	2.597	--	--

Line 4 Calculated as secondary rate 2.692 * (18.7% * On-Peak Multiplier 1.216 + 81.3% * Off-Peak Multiplier 0.907).

DEVELOPMENT OF TIME OF USE MULTIPLIERS

	ON-PEAK PERIOD			OFF-PEAK PERIOD			TOTAL		
Mo/Yr	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)
1/02	862,303	25,601,776	2.969	2,408,235	63,529,245	2.638	3,270,538	89,131,021	2.725
2/02	773,257	27,326,902	3.534	2,144,531	55,972,262	2.610	2,917,788	83,299,164	2.855
3/02	748,806	22,666,358	3.027	2,339,185	65,380,226	2.795	3,087,991	88,046,584	2.851
4/02	954,408	33,127,502	3.471	2,032,111	55,842,410	2.748	2,986,519	88,969,912	2.979
5/02	1,283,867	46,411,796	3.615	2,371,694	60,905,107	2.568	3,655,561	107,316,903	2.936
6/02	1,221,144	53,559,376	4.386	2,683,963	77,298,137	2.880	3,905,107	130,857,513	3.351
7/02	1,464,421	61,564,259	4.204	2,763,914	78,854,469	2.853	4,228,335	140,418,728	3.321
8/02	1,444,225	64,889,029	4.493	2,939,940	86,845,828	2.954	4,384,165	151,734,857	3.461
9/02	1,249,412	53,087,520	4.249	2,663,244	80,909,356	3.038	3,912,656	133,996,876	3.425
10/02	1,134,480	48,283,469	4.256	2,281,399	69,628,301	3.052	3,415,879	117,911,770	3.452
11/02	740,440	22,457,548	3.033	2,258,165	67,812,695	3.003	2,998,605	90,270,243	3.010
12/02	829,881	26,954,535	3.248	2,524,637	76,016,826	3.011	3,354,518	102,971,361	3.070
TOTAL	12,706,644	485,930,070	3.824	29,411,019	838,994,862	2.853	42,117,664	1,324,924,932	3.146

	ON-PEAK	OFF-PEAK	AVERAGE
MARGINAL FUEL COST			
WEIGHTING MULTIPLIER	1.216	0.907	1.000

FLORIDA POWER CORPORATION
DEVELOPMENT OF JURISDICTIONAL DELIVERY LOSS MULTIPLIERS
BASED ON ACTUAL CALENDAR YEAR 2000 DATA
FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Energy Delivered				Energy Required @ Source			
Class Loads	Sales Mwh	Unbilled Mwh	Total Mwh	% of Total	Delivery Efficiency	Mwh (3) / (5)	% of Total	*Jurisdictional* Loss Multiplier
I. CLASS LOADS:								
A. RETAIL								
1. Transmission	646,503	4,269	650,772		0.9779000	665,479		
2. Distribution Primary	4,618,696	30,491	4,649,187		0.9679000	4,803,375		
3. Distribution Secondary	29,566,766	195,187	29,761,953		0.9377499	31,737,623		
Total Retail	34,831,965	229,947	35,061,912	90.41%	0.9423604	37,206,477	90.87%	1.0051
B. WHOLESALE								
1. Source Level	2,789,617	105,705	2,895,322		1.0000000	2,895,322		
2. Transmission	714,800	6,858	721,658		0.9779000	737,967		
3. Distribution Primary	99,860	1,274	101,134		0.9679000	104,488		
4. Distribution Secondary	0	0	0		0.9377499	0		
Total Wholesale	3,604,277	113,837	3,718,114	9.59%	0.9947390	3,737,777	9.13%	0.9522
Total Class Loads	38,436,242	343,784	38,780,026	100.00%	0.9471421	40,944,254	100.00%	1.0000
II. NON-CLASS LOADS								
1. Company Use	125,909	0	125,909		0.9377499	134,267		
2. Seminole Electric	0	0	0		1.0000000	0		
3. Kissimmee	0	0	0		0.9779000	0		
4. St. Cloud	0	0	0		0.9779000	0		
5. Interchange	1,477,064	0	1,477,064		0.9779000	1,510,445		
6. SEPA	127,759	0	127,759		0.9779000	130,646		
Total Non-Class Loads	1,730,732	0	1,730,732		0.9748637	1,775,358		
Total System	40,166,974	343,784	40,510,758		0.9482941	42,719,612		

FLORIDA POWER CORPORATION
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

	DESCRIPTION		Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	TOTAL
1	Fuel Cost of System Net Generation		$56,867,186	$52,180,695	$52,186,479	$50,450,359	$68,979,541	$89,185,350	$93,611,844	$102,448,425	$88,733,188	$75,186,869	$55,129,894	$63,869,321	$848,829,151
1a	*Nuclear Fuel Disposal Cost*		543,990	491,346	543,990	526,442	532,165	466,359	532,165	532,165	514,998	487,102	449,670	543,990	6,164,383
1b	Adjustments to Fuel Cost		874,000	463,000	521,000	494,000	842,000	1,078,000	1,173,000	1,332,000	980,000	2,199,000	272,000	734,000	10,962,000
2	Fuel Cost of Power Sold		(3,905,067)	(2,762,922)	(3,924,854)	(1,785,410)	(1,077,192)	(2,399,096)	(3,593,235)	(3,254,617)	(2,951,015)	(2,423,377)	(2,551,419)	(3,430,946)	(34,059,150)
2a	Fuel Cost of Stratified Sales		(14,509,640)	(8,376,805)	(5,090,701)	(3,808,637)	(2,582,545)	(4,082,464)	(6,732,871)	(7,662,639)	(8,292,681)	(5,855,665)	(3,508,205)	(2,507,076)	(71,009,729)
2b	Gains on Power Sales		(267,832)	(215,377)	(348,573)	(173,563)	(147,656)	(575,655)	(781,011)	(773,897)	(783,485)	(237,077)	(226,921)	(234,681)	(4,765,728)
3	Energy Cost of Purchased Power		4,779,604	4,257,007	5,162,105	4,977,835	4,977,209	4,868,917	5,065,536	5,074,745	4,952,811	5,169,979	4,897,099	5,117,369	59,300,216
3a	Capacity Cost of Economy Purchases		-	-	-	-	-	-	-	-	-	-	-	-	-
3b	Payments to Qualifying Facilities		14,209,639	11,954,307	13,071,156	12,447,640	13,651,516	13,718,548	15,134,214	13,237,619	13,299,093	12,329,435	13,234,218	12,357,123	158,644,508
4	Energy Cost of Economy Purchases		1,017,382	202,536	355,840	526,907	1,559,794	2,790,322	3,501,064	3,146,808	2,357,642	1,957,056	1,343,360	1,348,448	20,107,161
5	Total Fuel & Net Power Transactions		$59,609,262	$60,193,969	$62,476,442	$63,655,573	$86,734,832	$105,050,281	$107,910,706	$114,080,609	$98,810,551	$88,813,322	$69,039,696	$77,797,548	$994,172,812
6	Adjusted System Sales	MWH	3,000,472	2,854,127	2,724,029	2,706,316	2,822,169	3,463,087	3,597,346	3,803,882	3,863,844	3,433,177	2,944,550	2,917,586	38,130,585
7	System Cost per KWH Sold	c/kwh	1.9867	2.1091	2.2935	2.3521	3.0733	3.0333	2.9998	2.9991	2.5573	2.5869	2.3446	2.6664	2.6072
7a	Jurisdictional Loss Multiplier	x	1.0051	1.0051	1.0051	1.0051	1.0051	1.0051	1.0051	1.0051	1.0051	1.0051	1.0051	1.0051	1.0051
7b	Jurisdictional Cost per KWH Sold	c/kwh	1.9968	2.1198	2.3052	2.3641	3.0890	3.0489	3.0150	3.0144	2.5704	2.6001	2.3566	2.6801	2.6211
8	Prior Period True-Up	c/kwh	0.0676	0.0712	0.0743	0.0747	0.0715	0.0583	0.0562	0.0532	0.0524	0.0591	0.0689	0.0692	0.0637
9	Total Jurisdictional Fuel Expense	c/kwh	2.0644	2.1910	2.3795	2.4388	3.1606	3.1072	3.0713	3.0675	2.6227	2.6592	2.4255	2.7493	2.6848
10	Revenue Tax Multiplier	x	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
11	Fuel Cost Factor Adjusted for Taxes	c/kwh	2.0659	2.1926	2.3812	2.4406	3.1628	3.1094	3.0735	3.0697	2.6246	2.6611	2.4272	2.7513	2.6867
12	GPIF	c/kwh	0.0008	0.0008	0.0008	0.0008	0.0008	0.0007	0.0008	0.0008	0.0008	0.0007	0.0008	0.0008	0.0007
13	Total Fuel Cost Factor (rounded .001)	c/kwh	2.067	2.193	2.382	2.441	3.164	3.110	3.074	3.070	2.625	2.662	2.428	2.752	2.687

FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

			Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		11,221,695	11,291,366	14,917,818	16,576,625	19,307,081	19,674,175	92,988,760
2	LIGHT OIL		3,422,524	2,639,676	1,228,082	2,323,651	2,947,114	10,326,940	22,887,990
3	COAL		34,674,349	29,069,029	23,655,286	21,482,584	28,857,075	32,481,403	170,219,725
4	GAS		5,574,124	7,397,208	10,410,800	8,144,064	15,930,315	24,977,523	72,434,034
5	NUCLEAR		1,974,493	1,783,413	1,974,493	1,923,435	1,937,956	1,725,310	11,319,101
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	56,867,186	52,180,695	52,186,479	50,450,359	68,979,541	89,185,350	369,849,609
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		310,886	315,480	456,641	517,829	595,395	606,997	2,803,228
9	LIGHT OIL		38,457	29,893	14,810	32,840	39,575	122,576	278,151
10	COAL		1,469,440	1,244,334	1,039,274	933,701	1,231,559	1,344,115	7,262,423
11	GAS		90,204	126,507	286,039	189,293	357,932	482,835	1,532,810
12	NUCLEAR		581,808	525,504	581,808	563,040	569,160	498,780	3,320,100
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	2,490,795	2,241,718	2,378,572	2,236,703	2,793,621	3,055,303	15,196,712
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	513,024	509,971	715,683	807,555	934,360	951,942	4,432,534
16	LIGHT OIL	BBL	88,191	67,924	31,541	70,607	89,476	310,896	658,635
17	COAL	TON	555,906	471,962	392,259	354,650	468,337	512,793	2,755,906
18	GAS	MCF	883,350	1,200,376	2,363,621	1,798,588	3,460,201	5,207,081	14,913,218
19	NUCLEAR	MMBTU	5,983,313	5,404,283	5,983,313	5,828,590	5,872,593	5,228,212	34,300,305
20	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		3,334,654	3,314,813	4,651,940	5,249,106	6,073,337	6,187,621	28,811,472
22	LIGHT OIL		511,509	393,959	182,936	409,519	518,963	1,803,197	3,820,083
23	COAL		13,975,478	11,967,637	9,866,219	8,919,564	11,775,958	12,888,901	69,293,758
24	GAS		883,350	1,200,376	2,363,621	1,798,588	3,460,201	5,207,081	14,913,218
25	NUCLEAR		5,983,313	5,404,283	5,983,313	5,828,590	5,872,593	5,228,212	34,300,305
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	24,688,306	22,181,069	23,048,029	22,205,367	27,701,052	31,315,013	151,138,836
	GENERATION MIX (% MWH)								
28	HEAVY OIL		12.48%	14.07%	19.20%	23.15%	21.31%	19.87%	18.45%
29	LIGHT OIL		1.54%	1.33%	0.62%	1.47%	1.42%	4.01%	1.83%
30	COAL		59.00%	55.51%	43.69%	41.75%	44.09%	43.99%	47.79%
31	GAS		3.62%	5.64%	12.03%	8.46%	12.81%	15.80%	10.09%
32	NUCLEAR		23.36%	23.44%	24.46%	26.17%	20.37%	16.33%	21.85%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	21.87	22.14	20.84	20.53	20.66	20.67	20.98
36	LIGHT OIL	$/BBL	38.81	38.86	38.94	32.91	32.94	33.22	34.75
37	COAL	$/TON	62.37	61.59	60.31	60.57	61.62	63.34	61.77
38	GAS	$/MCF	6.31	6.16	4.40	4.53	4.60	4.80	4.86
39	NUCLEAR	$/MMBTU	0.33	0.33	0.33	0.33	0.33	0.33	0.33
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		3.37	3.41	3.21	3.16	3.18	3.18	3.23
42	LIGHT OIL		6.69	6.70	6.71	5.67	5.68	5.73	5.99
43	COAL		2.48	2.45	2.40	2.41	2.45	2.52	2.46
44	GAS		6.31	6.16	4.41	4.53	4.60	4.80	4.86
45	NUCLEAR		0.33	0.33	0.33	0.33	0.33	0.33	0.33
46	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL	$/MMBTU	2.30	2.35	2.26	2.27	2.49	2.85	2.45
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		10,726	10,507	10,187	10,137	10,201	10,194	10,278
49	LIGHT OIL		13,301	13,179	12,352	12,470	13,113	14,711	13,734
50	COAL		9,511	9,537	9,493	9,553	9,562	9,589	9,541
51	GAS		9,793	9,489	8,263	9,502	9,667	10,784	9,729
52	NUCLEAR		10,284	10,284	10,284	10,352	10,318	10,492	10,331
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	9,912	9,895	9,690	9,928	9,916	10,249	9,945
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		3.61	3.58	3.27	3.20	3.24	3.24	3.32
56	LIGHT OIL		8.90	8.83	8.29	7.08	7.45	8.42	8.23
57	COAL		2.36	2.34	2.28	2.30	2.34	2.42	2.34
58	GAS		6.18	5.85	3.64	4.30	4.45	5.17	4.73
59	NUCLEAR		0.34	0.34	0.34	0.34	0.34	0.35	0.34
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	2.28	2.33	2.19	2.26	2.47	2.92	2.43

FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

			Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		24,118,099	23,697,371	21,676,040	16,635,279	13,346,780	18,002,172	210,464,502
2	LIGHT OIL		7,472,573	10,085,054	7,745,126	5,660,008	1,174,679	1,029,831	56,055,262
3	COAL		33,591,334	37,507,845	31,400,476	29,015,939	28,966,537	29,945,320	360,647,175
4	GAS		26,458,449	29,186,766	26,003,751	22,095,428	9,998,964	12,917,122	199,094,513
5	NUCLEAR		1,971,388	1,971,388	1,907,795	1,780,216	1,642,934	1,974,877	22,567,699
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	93,611,844	102,448,425	88,733,188	75,186,869	55,129,894	63,869,321	848,829,151
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		742,799	726,809	665,889	489,261	394,349	528,959	6,351,294
9	LIGHT OIL		85,890	117,127	90,412	67,955	15,390	15,698	670,623
10	COAL		1,373,440	1,560,216	1,275,298	1,150,773	1,156,853	1,253,794	15,032,797
11	GAS		548,278	577,589	516,153	412,893	168,376	242,204	3,998,303
12	NUCLEAR		569,160	569,160	550,800	520,965	480,930	581,808	6,592,923
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	3,319,567	3,550,901	3,098,552	2,641,847	2,215,898	2,622,463	32,645,940
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	1,159,732	1,133,551	1,036,665	769,691	631,057	831,353	9,994,583
16	LIGHT OIL	BBL	224,406	303,165	233,136	157,414	32,710	28,703	1,638,170
17	COAL	TON	523,001	592,965	484,800	435,900	437,568	473,398	5,703,538
18	GAS	MCF	5,517,951	6,157,918	5,421,894	4,302,678	1,690,406	2,335,657	40,339,722
19	NUCLEAR	MMBTU	5,973,903	5,973,903	5,781,197	5,394,593	4,978,587	5,984,477	68,386,966
20	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		7,536,256	7,368,082	6,736,321	5,002,989	4,101,872	5,403,794	64,964,787
22	LIGHT OIL		1,301,556	1,758,360	1,352,188	913,004	189,716	166,479	9,501,385
23	COAL		13,144,492	14,907,444	12,182,618	10,949,350	10,991,590	11,900,894	143,370,147
24	GAS		5,517,951	6,157,918	5,421,894	4,302,678	1,690,406	2,335,657	40,339,722
25	NUCLEAR		5,973,903	5,973,903	5,781,197	5,394,593	4,978,587	5,984,477	68,386,966
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	33,476,159	36,165,707	31,476,218	26,562,614	21,952,170	25,791,302	326,563,006
	GENERATION MIX (% MWH)								
28	HEAVY OIL		22.38%	20.47%	21.49%	18.52%	17.80%	20.17%	19.46%
29	LIGHT OIL		2.59%	3.30%	2.92%	2.57%	0.70%	0.60%	2.05%
30	COAL		41.37%	43.94%	41.16%	43.56%	52.21%	47.81%	46.05%
31	GAS		16.52%	16.27%	16.66%	15.63%	7.60%	9.24%	12.25%
32	NUCLEAR		17.15%	16.03%	17.78%	19.72%	21.70%	22.19%	20.20%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	20.80	20.91	20.91	21.61	21.15	21.65	21.06
36	LIGHT OIL	$/BBL	33.30	33.27	33.22	35.96	35.91	35.88	34.22
37	COAL	$/TON	64.23	63.25	64.77	66.57	66.20	63.26	63.23
38	GAS	$/MCF	4.80	4.74	4.80	5.14	5.92	5.53	4.94
39	NUCLEAR	$/MMBTU	0.33	0.33	0.33	0.33	0.33	0.33	0.33
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		3.20	3.22	3.22	3.33	3.25	3.33	3.24
42	LIGHT OIL		5.74	5.74	5.73	6.20	6.19	6.19	5.90
43	COAL		2.56	2.52	2.58	2.65	2.64	2.52	2.52
44	GAS		4.80	4.74	4.80	5.14	5.92	5.53	4.94
45	NUCLEAR		0.33	0.33	0.33	0.33	0.33	0.33	0.33
46	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL	$/MMBTU	2.80	2.83	2.82	2.83	2.51	2.48	2.60
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		10,148	10,138	10,119	10,226	10,402	10,216	10,229
49	LIGHT OIL		15,154	15,012	14,956	13,435	12,327	10,605	14,168
50	COAL		9,570	9,555	9,553	9,515	9,501	9,492	9,537
51	GAS		10,064	10,661	10,504	10,421	10,039	9,643	10,089
52	NUCLEAR		10,496	10,496	10,496	10,355	10,352	10,286	10,373
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	10,084	10,185	10,158	10,056	9,907	9,835	10,003
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		3.25	3.26	3.26	3.40	3.38	3.40	3.31
56	LIGHT OIL		8.70	8.61	8.57	8.33	7.63	6.56	8.36
57	COAL		2.45	2.40	2.46	2.52	2.50	2.39	2.40
58	GAS		4.83	5.05	5.04	5.35	5.94	5.33	4.98
59	NUCLEAR		0.35	0.35	0.35	0.34	0.34	0.34	0.34
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	2.82	2.89	2.86	2.85	2.49	2.44	2.60

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Jan-02

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	782	581,808	100.0	97.2	100.0	10,284	NUCLEAR	5,983,313 MMBTU	1.00	5,983,313	1,974,493	0.34
2 ANCLOTE	1	522	83,226	17.0	94.4	24.9	11,260	HEAVY OIL	109,527 BBLS	6.50	711,925	2,634,122	4.17
3 ANCLOTE	1		2,634				11,485	GAS	30,251 MCF	1.00	30,251	166,383	6.32
4 ANCLOTE	2	522	73,373	19.7	95.8	28.8	10,973	HEAVY OIL	123,865 BBLS	6.50	805,122	2,978,951	4.06
5 ANCLOTE	2		3,057				11,192	GAS	34,214 MCF	1.00	34,214	188,177	6.16
6 BARTOW	1	123	51,777	56.6	91.1	58.5	10,348	HEAVY OIL	82,429 BBLS	6.50	535,788	1,607,365	3.10
7 BARTOW	2	121	51,219	56.9	92.5	56.9	10,355	HEAVY OIL	81,598 BBLS	6.50	530,373	1,591,118	3.11
8 BARTOW	3	208	59,483	38.4	91.7	50.3	10,405	HEAVY OIL	95,219 BBLS	6.50	618,921	1,856,762	3.12
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	383	222,712	78.2	86.3	93.0	9,759	COAL	86,248 TONS	25.20	2,173,446	4,488,339	2.02
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	491	361,587	99.0	78.7	99.0	9,494	COAL	136,226 TONS	25.20	3,432,907	7,089,225	1.96
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	735	434,991	79.5	95.5	79.5	9,477	COAL	164,239 TONS	25.10	4,122,410	11,378,865	2.62
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	732	450,150	82.7	94.3	82.7	9,434	COAL	169,192 TONS	25.10	4,246,715	11,719,919	2.60
17 SUWANNEE	1	33	1,895	7.7	99.8	49.9	12,075	HEAVY OIL	3,520 BBLS	6.50	22,882	80,087	4.23
18 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
19 SUWANNEE	2	32	1,542	6.5	99.9	61.8	13,040	HEAVY OIL	3,093 BBLS	6.50	20,108	70,377	4.56
20 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
21 SUWANNEE	3	81	8,371	13.9	97.0	53.8	10,696	HEAVY OIL	13,775 BBLS	6.50	89,536	402,913	4.81
22 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
23 AVON PARK	1-2	64	538	1.1	100.0	84.1	16,350	LIGHT OIL	1,517 BBLS	5.80	8,796	59,026	10.97
24 BARTOW	1-4	219	1,278	1.4	100.0	45.4	16,141	LIGHT OIL	3,557 BBLS	5.80	20,628	138,209	10.81
25 BARTOW	1-4		933				16,585	GAS	15,474 MCF	1.00	15,474	85,106	9.12
26 BAYBORO	1-4	232	1,405	0.8	100.0	65.5	15,604	LIGHT OIL	3,780 BBLS	5.80	21,924	146,868	10.45
27 DEBARY	1-10	762	7,814	2.1	100.0	47.3	14,471	LIGHT OIL	19,496 BBLS	5.80	113,076	768,919	9.84
28 DEBARY	1-10		3,972				14,666	GAS	58,253 MCF	1.00	58,253	320,393	8.07
29 HIGGINS	1-4	134	694	0.7	100.0	64.7	17,491	LIGHT OIL	2,093 BBLS	5.80	12,139	79,990	11.53
30 HIGGINS	1-4		0				0	GAS	0 MCF	1.00	0	0	0.00
31 HINES	1	529	37,177	9.4	99.3	40.9	7,766	GAS	288,717 MCF	1.00	288,717	1,587,941	4.27
32 HINES	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
33 INT CITY	1-10,12-14	1,024	8,853	2.7	100.0	41.9	14,763	LIGHT OIL	22,534 BBLS	5.80	130,697	863,951	9.76
34 INT CITY	1-10,12-14		11,927				14,295	GAS	170,496 MCF	1.00	170,496	937,731	7.86
35 INT CITY	11	170	6,646	5.3	100.0	72.4	11,256	LIGHT OIL	12,900 BBLS	5.80	74,821	494,590	7.44
36 RIO PINAR	1	16	84	0.7	100.0	65.6	19,388	LIGHT OIL	281 BBLS	5.80	1,629	10,959	13.05
37 SUWANNEE	1-3	201	2,023	1.4	100.0	70.2	13,728	LIGHT OIL	4,788 BBLS	5.80	27,768	187,145	9.25
38 SUWANNEE	1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
39 TURNER	1-4	194	1,650	1.1	100.0	50.0	16,020	LIGHT OIL	4,557 BBLS	5.80	26,433	178,970	10.85
40 UNIV OF FLA.	1	41	30,504	100.0	96.9	100.0	9,374	GAS	285,944 MCF	1.00	285,944	1,181,468	3.87
41 OTHER - START UP		-	7,472	-		-	9,850	LIGHT OIL	12,890 BBLS	5.80	73,599	493,878	6.61
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	1,106,925	-
43 TOTAL		8,351	2,490,795				9,912				24,688,306	58,867,186	2.28

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Feb-02

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	782	525,504	100.0	97.2	100.0	10,284	NUCLEAR	5,404,283 MMBTU	1.00	5,404,283	1,783,413	0.34
2 ANCLOTE	1	522	59,135	17.6	96.3	39.3	10,401	HEAVY OIL	94,625 BBLS	6.50	615,063	2,275,734	3.85
3 ANCLOTE	1		2,464				10,609	GAS	26,141 MCF	1.00	26,141	143,773	5.83
4 ANCLOTE	2	522	82,097	24.4	95.5	33.4	10,664	HEAVY OIL	134,690 BBLS	6.50	875,482	3,239,285	3.95
5 ANCLOTE	2		3,421				10,877	GAS	37,210 MCF	1.00	37,210	204,656	5.98
6 BARTOW	1	123	45,040	54.5	91.4	58.3	10,393	HEAVY OIL	72,015 BBLS	6.50	468,101	1,404,302	3.12
7 BARTOW	2	121	29,313	36.1	72.9	47.9	10,526	HEAVY OIL	47,469 BBLS	6.50	308,549	925,646	3.16
8 BARTOW	3	208	78,656	56.3	89.2	56.3	10,282	HEAVY OIL	124,422 BBLS	6.50	808,741	2,426,223	3.08
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	383	248,711	95.9	83.7	95.9	9,742	COAL	95,375 TONS	25.20	2,403,459	4,966,194	2.01
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	491	314,524	95.3	78.7	95.3	9,503	COAL	118,608 TONS	25.20	2,988,922	6,175,919	1.96
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	735	393,720	79.7	95.5	79.7	9,475	COAL	148,625 TONS	25.10	3,730,497	10,327,978	2.62
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	732	289,379	58.8	95.6	77.2	9,485	COAL	109,353 TONS	25.10	2,744,760	7,596,939	2.63
17 SUWANNEE	1	33	590	2.7	28.5	52.6	12,025	HEAVY OIL	1,092 BBLS	6.50	7,095	24,832	4.21
18 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
19 SUWANNEE	2	32	3,507	16.3	99.8	51.0	13,595	HEAVY OIL	7,335 BBLS	6.50	47,678	186,872	4.76
20 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
21 SUWANNEE	3	81	17,142	31.5	92.8	50.5	10,740	HEAVY OIL	28,324 BBLS	6.50	184,105	828,473	4.83
22 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
23 AVON PARK	1-2	64	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
24 BARTOW	1-4	219	828	0.9	100.0	41.1	17,158	LIGHT OIL	2,444 BBLS	5.80	14,173	94,956	11.50
25 BARTOW	1-4		501				14,914	GAS	7,472 MCF	1.00	7,472	41,096	8.20
26 BAYBORO	1-4	232	372	0.2	100.0	71.3	14,596	LIGHT OIL	936 BBLS	5.80	5,430	36,379	9.78
27 DEBARY	1-10	762	8,401	2.6	100.0	43.5	15,093	LIGHT OIL	21,861 BBLS	5.80	126,796	862,215	10.26
28 DEBARY	1-10		5,746				14,250	GAS	81,881 MCF	1.00	81,881	450,343	7.84
29 HIGGINS	1-4	134	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 HIGGINS	1-4		0				0	GAS	0 MCF	1.00	0	0	0.00
31 HINES	1	528	67,566	19.1	98.6	38.1	7,691	GAS	519,665 MCF	1.00	519,665	2,858,160	4.23
32 HINES	1		169				7,912	LIGHT OIL	231 BBLS	5.80	1,337	8,770	5.19
33 INT CITY	1-10,12-14	1,024	5,452	3.6	100.0	40.2	15,450	LIGHT OIL	14,523 BBLS	5.80	84,233	556,812	10.21
34 INT CITY	1-10,12-14		19,255				14,010	GAS	269,763 MCF	1.00	269,763	1,483,694	7.71
35 INT CITY	11	170	6,558	5.7	100.0	70.1	11,309	LIGHT OIL	12,787 BBLS	5.80	74,164	490,252	7.48
36 RIO PINAR	1	18	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
37 SUWANNEE	1-3	201	778	0.6	100.0	61.1	14,410	LIGHT OIL	1,933 BBLS	5.80	11,211	75,558	9.71
38 SUWANNEE	1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
39 TURNER	1-4	194	612	0.5	100.0	55.7	16,950	LIGHT OIL	1,789 BBLS	5.80	10,373	70,235	11.48
40 UNIV OF FLA.	1	41	27,552	100.0	96.9	100.0	9,373	GAS	258,245 MCF	1.00	258,245	1,087,455	3.95
41 OTHER - START UP		-	6,725	-	-	-	9,850	LIGHT OIL	11,421 BBLS	5.80	66,241	444,502	6.61
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	1,128,031	-
43 TOTAL		8,351	2,241,718				9,895				22,181,069	52,180,695	2.33

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Mar-02

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	782	581,808	100.0	97.2	100.0	10,284 NUCLEAR	5,983,313 MMBTU	1.00	5,983,313	1,974,493	0.34
2	ANCLOTE	1	522	135,393	36.3	92.6	40.6	10,299 HEAVY OIL	214,525 BBLS	6.50	1,394,413	4,601,561	3.40
3	ANCLOTE	1		5,841				10,505 GAS	59,259 MCF	1.00	59,259	242,961	4.31
4	ANCLOTE	2	522	172,252	46.2	93.8	46.2	10,049 HEAVY OIL	266,302 BBLS	6.50	1,730,960	5,712,169	3.32
5	ANCLOTE	2		7,177				10,250 GAS	73,564 MCF	1.00	73,564	301,613	4.20
6	BARTOW	1	123	74,147	81.0	90.7	81.0	10,006 HEAVY OIL	114,141 BBLS	6.50	741,915	2,151,553	2.90
7	BARTOW	2	121	55,392	61.5	89.6	64.6	10,244 HEAVY OIL	87,298 BBLS	6.50	567,436	1,645,563	2.97
8	BARTOW	3	208	2,472	1.6	2.9	54.0	10,271 HEAVY OIL	3,906 BBLS	6.50	25,390	73,631	2.98
9	BARTOW	3		0				0 GAS	0 MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	383	203,113	71.3	87.4	92.1	9,753 COAL	78,610 TONS	25.20	1,980,961	4,089,270	2.01
11	CRYSTAL RIVER	1		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
12	CRYSTAL RIVER	2	491	335,012	91.7	78.7	91.7	9,527 COAL	126,653 TONS	25.20	3,191,659	6,588,497	1.97
13	CRYSTAL RIVER	2		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
14	CRYSTAL RIVER	4	735	16,266	3.0	3.1	92.3	9,356 COAL	6,071 TONS	25.10	152,391	421,351	2.59
15	CRYSTAL RIVER	4		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
16	CRYSTAL RIVER	5	732	484,861	89.0	94.4	90.2	9,366 COAL	180,925 TONS	25.10	4,541,208	12,556,169	2.59
17	SUWANNEE	1	33	2,941	12.0	96.4	43.9	12,213 HEAVY OIL	5,526 BBLS	6.50	35,918	122,123	4.15
18	SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
19	SUWANNEE	2	32	1,494	6.3	99.9	47.2	13,852 HEAVY OIL	3,184 BBLS	6.50	20,695	70,363	4.71
20	SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
21	SUWANNEE	3	81	12,550	20.8	95.0	46.1	10,774 HEAVY OIL	20,802 BBLS	6.50	135,214	540,855	4.31
22	SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
23	AVON PARK	1-2	84	261	0.5	100.0	58.3	16,841 LIGHT OIL	749 BBLS	5.80	4,343	29,145	11.17
24	BARTOW	1-4	219	546	1.0	100.0	46.4	15,983 LIGHT OIL	1,505 BBLS	5.80	8,727	58,469	10.71
25	BARTOW	1-4		1,106				16,595 GAS	18,354 MCF	1.00	18,354	75,252	6.80
26	BAYBORO	1-4	232	503	0.3	100.0	57.8	14,376 LIGHT OIL	1,247 BBLS	5.80	7,231	48,449	9.63
27	DEBARY	1-10	762	3,280	1.1	100.0	43.1	15,170 LIGHT OIL	8,579 BBLS	5.80	49,758	336,352	10.32
28	DEBARY	1-10		3,189				14,728 GAS	46,968 MCF	1.00	46,968	192,567	6.04
29	HIGGINS	1-4	134	71	1.0	100.0	58.5	19,155 LIGHT OIL	234 BBLS	5.80	1,360	8,962	12.62
30	HIGGINS	1-4		890				17,660 GAS	15,717 MCF	1.00	15,717	64,441	7.24
31	HINES	1	529	218,856	55.7	97.4	59.6	7,217 GAS	1,579,484 MCF	1.00	1,579,484	6,475,883	2.96
32	HINES	1		447				7,909 LIGHT OIL	810 BBLS	5.80	3,535	23,187	5.19
33	INT CITY	1-10,12-14	1,024	2,236	2.6	100.0	37.0	14,757 LIGHT OIL	5,689 BBLS	5.80	32,997	218,119	9.75
34	INT CITY	1-10,12-14		17,628				15,285 GAS	269,444 MCF	1.00	269,444	1,104,720	6.27
35	INT CITY	11	170	0	0.0	100.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
36	RIO PINAR	1	16	0	0.0	100.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
37	SUWANNEE	1-3	201	136	0.6	100.0	59.0	14,050 LIGHT OIL	329 BBLS	5.80	1,911	12,878	9.47
38	SUWANNEE	1-3		1,049				14,229 GAS	14,926 MCF	1.00	14,926	61,198	5.83
39	TURNER	1-4	194	194	0.1	0.0	100.0	14,354 LIGHT OIL	480 BBLS	5.80	2,785	18,854	9.72
40	UNIV OF FLA.	1	41	30,503	100.0	96.9	100.0	9,373 GAS	285,905 MCF	1.00	285,905	819,127	2.69
41	OTHER - START UP		-	7,136	-	-	-	9,850 LIGHT OIL	12,119 BBLS	5.80	70,290	471,867	6.61
42	OTHER - GAS TRANSP.		-	0	-	-	-	- GAS TRANSP.	-	-	-	1,073,037	-
43	TOTAL		8,351	2,378,572			9,690				23,048,029	52,186,479	2.19

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Apr-02

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	782	563,040	100.0	97.2	100.0	10,352	NUCLEAR	5,828,590 MMBTU	1.00	5,828,590	1,923,435	0.34
2 ANCLOTE	1	522	138,444	38.4	92.9	44.3	10,213	HEAVY OIL	217,527 BBLS	6.50	1,413,929	4,665,964	3.37
3 ANCLOTE	1		5,768				10,417	GAS	60,085 MCF	1.00	60,085	246,350	4.27
4 ANCLOTE	2	522	180,285	50.0	93.8	50.0	9,973	HEAVY OIL	276,613 BBLS	6.50	1,797,982	5,933,342	3.29
5 ANCLOTE	2		7,512				10,172	GAS	76,412 MCF	1.00	76,412	313,289	4.17
6 BARTOW	1	123	73,210	82.7	90.7	82.7	10,024	HEAVY OIL	112,901 BBLS	6.50	733,857	2,128,185	2.91
7 BARTOW	2	121	56,522	64.9	92.5	64.9	10,309	HEAVY OIL	89,644 BBLS	6.50	582,685	1,689,787	2.99
8 BARTOW	3	208	60,290	40.3	54.5	79.2	10,079	HEAVY OIL	93,487 BBLS	6.50	607,663	1,762,222	2.92
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	383	258,080	93.6	83.7	93.6	9,791	COAL	100,272 TONS	25.20	2,526,861	5,160,066	2.01
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	491	206,737	58.5	86.4	91.3	9,539	COAL	78,257 TONS	25.20	1,972,064	4,042,732	1.96
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	735	0	0.0	0.0	0.0	0	COAL	0 TONS	25.10	0	0	0.00
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	732	468,884	89.0	94.3	89.0	9,428	COAL	176,121 TONS	25.10	4,420,638	12,259,786	2.61
17 SUWANNEE	1	33	3,816	16.1	99.6	49.4	12,180	HEAVY OIL	7,151 BBLS	6.50	46,479	158,028	4.14
18 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
19 SUWANNEE	2	32	3,324	14.4	99.8	54.4	13,512	HEAVY OIL	6,910 BBLS	6.50	44,914	152,707	4.59
20 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
21 SUWANNEE	3	81	1,938	3.3	39.2	46.9	11,144	HEAVY OIL	3,323 BBLS	6.50	21,597	86,388	4.46
22 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
23 AVON PARK	1-2	64	105	0.2	100.0	46.9	19,357	LIGHT OIL	350 BBLS	5.80	2,032	11,606	11.05
24 BARTOW	1-4	219	1,527	1.1	100.0	44.5	17,054	LIGHT OIL	4,490 BBLS	5.80	26,041	148,436	9.72
25 BARTOW	1-4		179				16,001	GAS	2,864 MCF	1.00	2,864	11,743	6.56
26 BAYBORO	1-4	232	616	0.4	100.0	48.3	15,091	LIGHT OIL	1,603 BBLS	5.80	9,296	52,988	8.60
27 DEBARY	1-10	762	6,426	2.8	100.0	48.8	15,088	LIGHT OIL	16,716 BBLS	5.80	96,955	562,342	8.75
28 DEBARY	1-10		7,784				14,265	GAS	111,039 MCF	1.00	111,039	455,259	5.85
29 HIGGINS	1-4	134	400	0.4	100.0	59.7	18,015	LIGHT OIL	1,242 BBLS	5.80	7,206	40,279	10.07
30 HIGGINS	1-4		0				0	GAS	0 MCF	1.00	0	0	0.00
31 HINES	1	529	101,277	28.1	52.1	61.7	7,168	GAS	725,954 MCF	1.00	725,954	2,976,409	2.94
32 HINES	1		5,699				7,793	LIGHT OIL	7,657 BBLS	5.80	44,412	246,871	4.33
33 INT CITY	1-10,12-14	1,024	6,523	6.1	100.0	42.0	15,582	LIGHT OIL	17,524 BBLS	5.80	101,641	570,243	8.74
34 INT CITY	1-10,12-14		38,587				14,289	GAS	551,370 MCF	1.00	551,370	2,260,616	5.86
35 INT CITY	11	170	4,732	3.9	100.0	69.6	11,497	LIGHT OIL	9,380 BBLS	5.80	54,404	305,224	6.45
36 RIO PINAR	1	16	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
37 SUWANNEE	1-3	201	102	1.2	100.0	69.4	14,084	LIGHT OIL	248 BBLS	5.80	1,437	8,245	8.08
38 SUWANNEE	1-3		1,618				13,500	GAS	21,843 MCF	1.00	21,843	89,556	5.54
39 TURNER	1-4	194	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
40 UNIV OF FLA.	1	41	26,568	90.0	97.2	100.0	9,373	GAS	249,022 MCF	1.00	249,022	696,358	2.62
41 OTHER - START UP		-	6,710	-	-	-	9,850	LIGHT OIL	11,395 BBLS	5.80	66,094	377,417	5.62
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	- -	-	-	1,094,484	-
43 TOTAL		8,351	2,236,703				9,928				22,205,367	50,450,359	2.26

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: May-02

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)		FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	765	569,160	100.0	97.2	100.0	10,318	NUCLEAR	5,872,593	MMBTU	1.00	5,872,593	1,937,956	0.34
2 ANCLOTE	1	498	186,131	46.7	91.8	46.7	10,225	HEAVY OIL	261,337	BBLS	6.50	1,698,689	5,605,675	3.37
3 ANCLOTE	1		6,922				10,430	GAS	72,196	MCF	1.00	72,196	298,005	4.28
4 ANCLOTE	2	495	187,334	53.0	93.8	53.0	10,024	HEAVY OIL	288,898	BBLS	6.50	1,877,836	6,196,859	3.31
5 ANCLOTE	2		7,806				10,224	GAS	79,809	MCF	1.00	79,809	327,215	4.19
6 BARTOW	1	121	50,917	56.6	92.8	73.1	10,134	HEAVY OIL	79,384	BBLS	6.50	515,993	1,496,379	2.94
7 BARTOW	2	119	55,684	62.9	92.6	63.6	10,333	HEAVY OIL	88,520	BBLS	6.50	575,383	1,868,610	3.00
8 BARTOW	3	204	109,574	72.2	89.2	72.2	10,108	HEAVY OIL	170,396	BBLS	6.50	1,107,574	3,211,965	2.93
9 BARTOW	3		0				0	GAS	0	MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	379	214,309	76.0	87.0	95.7	9,720	COAL	82,662	TONS	25.20	2,083,083	4,300,079	2.01
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	486	328,597	90.9	79.0	92.2	9,539	COAL	124,384	TONS	25.20	3,134,487	6,470,476	1.97
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	720	243,915	45.5	55.4	78.4	9,570	COAL	92,999	TONS	25.10	2,334,267	6,437,368	2.64
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	717	444,738	83.4	94.3	83.4	9,498	COAL	166,292	TONS	25.10	4,224,122	11,649,151	2.62
17 SUWANNEE	1	32	6,238	26.2	99.2	46.1	12,297	HEAVY OIL	11,801	BBLS	6.50	76,709	260,810	4.18
18 SUWANNEE	1		0				0	GAS	0	MCF	1.00	0	0	0.00
19 SUWANNEE	2	31	2,175	9.4	32.2	53.6	13,662	HEAVY OIL	4,572	BBLS	6.50	29,715	101,030	4.65
20 SUWANNEE	2		0				0	GAS	0	MCF	1.00	0	0	0.00
21 SUWANNEE	3	80	17,342	29.1	83.8	51.9	11,039	HEAVY OIL	29,452	BBLS	6.50	191,438	765,753	4.42
22 SUWANNEE	3		0				0	GAS	0	MCF	1.00	0	0	0.00
23 AVON PARK	1-2	52	210	0.5	100.0	57.7	19,490	LIGHT OIL	706	BBLS	5.80	4,093	23,372	11.13
24 BARTOW	1-4	187	1,888	2.8	100.0	46.0	17,575	LIGHT OIL	5,721	BBLS	5.80	33,182	188,135	10.02
25 BARTOW	1-4		2,030				17,919	GAS	36,376	MCF	1.00	36,376	149,140	7.35
26 BAYBORO	1-4	184	1,190	0.9	100.0	68.1	14,620	LIGHT OIL	3,000	BBLS	5.80	17,398	99,167	8.33
27 DEBARY	1-10	667	6,651	4.4	100.0	43.5	16,237	LIGHT OIL	18,619	BBLS	5.80	107,992	626,355	9.42
28 DEBARY	1-10		15,302				15,678	GAS	239,905	MCF	1.00	239,905	983,609	6.43
29 HIGGINS	1-4	122	801	1.7	100.0	67.1	18,017	LIGHT OIL	2,488	BBLS	5.80	14,432	80,868	10.07
30 HIGGINS	1-4		714		100.0		17,835	GAS	12,734	MCF	1.00	12,734	52,210	7.31
31 HINES	1	482	219,907	61.6	97.5	66.8	7,192	GAS	1,581,571	MCF	1.00	1,581,571	6,484,442	2.95
32 HINES	1		872				9,302	LIGHT OIL	1,399	BBLS	5.80	8,111	45,088	5.17
33 INT CITY	1-10,12-14	886	5,493	12.2	100.0	41.7	15,451	LIGHT OIL	14,633	BBLS	5.80	84,872	476,163	8.67
34 INT CITY	1-10,12-14		75,031				15,012	GAS	1,126,365	MCF	1.00	1,126,365	4,618,098	6.15
35 INT CITY	11	143	12,895	12.1	100.0	82.7	11,497	LIGHT OIL	25,561	BBLS	5.80	148,254	831,755	6.45
36 RIO PINAR	1	13	0	0.0	100.0	0.0	0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
37 SUWANNEE	1-3	184	720	4.0	100.0	65.0	13,757	LIGHT OIL	1,708	BBLS	5.80	9,905	56,852	7.90
38 SUWANNEE	1-3		4,180				14,743	GAS	61,626	MCF	1.00	61,626	252,666	6.04
39 TURNER	1-4	154	474	0.4	100.0	66.0	17,239	LIGHT OIL	1,409	BBLS	5.80	8,171	47,154	9.95
40 UNIV OF FLA.	1	35	26,040	100.0	98.9	100.0	9,586	GAS	249,619	MCF	1.00	249,619	709,861	2.73
41 OTHER - START UP		-	8,381	-	-	-	9,850	LIGHT OIL	14,233	BBLS	5.80	82,553	471,405	5.62
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	-	2,057,069	-
43 TOTAL		7,736	2,793,621				9,918					27,701,052	68,979,541	2.47

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Jun-02

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	785	498,780	90.6	97.5	100.0	10,482	NUCLEAR	5,228,212 MMBTU	1.00	5,228,212	1,725,310	0.35
2 ANCLOTE	1	498	153,972	44.7	93.7	58.8	10,057	HEAVY OIL	238,230 BBLS	6.50	1,548,496	5,110,038	3.32
3 ANCLOTE	1		6,415				10,258	GAS	65,805 MCF	1.00	65,805	269,801	4.21
4 ANCLOTE	2	495	169,547	49.6	94.9	60.4	9,852	HEAVY OIL	256,981 BBLS	6.50	1,670,377	5,512,244	3.25
5 ANCLOTE	2		7,064				10,049	GAS	70,986 MCF	1.00	70,986	291,043	4.12
6 BARTOW	1	121	61,401	70.5	90.7	70.5	10,283	HEAVY OIL	97,136 BBLS	6.50	631,386	1,831,021	2.98
7 BARTOW	2	119	63,827	74.3	92.5	74.3	10,315	HEAVY OIL	100,971 BBLS	6.50	656,313	1,903,306	2.99
8 BARTOW	3	204	111,254	75.7	89.2	75.7	10,158	HEAVY OIL	173,864 BBLS	6.50	1,130,118	3,277,343	2.95
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	379	222,949	81.7	85.3	90.8	9,808	COAL	86,773 TONS	25.20	2,186,684	4,485,305	2.01
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	486	239,617	68.5	83.9	90.8	9,580	COAL	91,092 TONS	25.20	2,295,531	4,708,571	1.97
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	720	430,679	83.1	95.5	83.1	9,569	COAL	164,190 TONS	25.10	4,121,167	11,416,126	2.65
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	717	450,870	87.3	94.3	87.3	9,505	COAL	170,738 TONS	25.10	4,285,519	11,871,401	2.63
17 SUWANNEE	1	32	9,320	40.5	99.0	54.8	12,153	HEAVY OIL	17,426 BBLS	6.50	113,266	385,104	4.13
18 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
19 SUWANNEE	2	31	11,985	53.7	99.5	61.5	13,286	HEAVY OIL	24,497 BBLS	6.50	159,233	541,391	4.52
20 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
21 SUWANNEE	3	80	25,891	44.9	91.9	63.8	10,754	HEAVY OIL	42,836 BBLS	6.50	278,432	1,113,727	4.30
22 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
23 AVON PARK	1-2	52	1,066	2.8	100.0	73.2	17,286	LIGHT OIL	3,177 BBLS	5.80	18,429	105,236	9.87
24 BARTOW	1-4	187	8,720	14.8	100.0	53.8	16,724	LIGHT OIL	25,144 BBLS	5.80	145,833	831,250	9.53
25 BARTOW	1-4		11,256				16,236	GAS	182,752 MCF	1.00	182,752	749,285	6.66
26 BAYBORO	1-4	184	13,155	9.9	100.0	69.2	14,493	LIGHT OIL	32,872 BBLS	5.80	190,655	1,086,736	8.26
27 DEBARY	1-10	667	45,304	18.7	100.0	46.5	15,423	LIGHT OIL	120,470 BBLS	5.80	698,724	4,052,597	8.95
28 DEBARY	1-10		44,408				14,330	GAS	636,367 MCF	1.00	636,367	2,609,103	5.88
29 HIGGINS	1-4	122	1,289	9.3	100.0	72.9	17,912	LIGHT OIL	3,981 BBLS	5.80	23,089	129,057	10.01
30 HIGGINS	1-4		6,890				17,189	GAS	118,432 MCF	1.00	118,432	485,572	7.05
31 HINES	1	482	229,865	66.6	97.3	66.6	7,198	GAS	1,654,568 MCF	1.00	1,654,568	6,783,730	2.95
32 HINES	1		1,319				7,983	LIGHT OIL	1,815 BBLS	5.80	10,530	58,530	4.44
33 INT CITY	1-10,12-14	886	24,747	27.7	100.0	49.8	14,505	LIGHT OIL	61,889 BBLS	5.80	358,955	2,013,863	8.14
34 INT CITY	1-10,12-14		151,737				14,740	GAS	2,236,603 MCF	1.00	2,236,603	9,170,074	6.04
35 INT CITY	11	0	0	0.0	0.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
36 RIO PINAR	1	13	109	1.2	100.0	93.2	17,051	LIGHT OIL	320 BBLS	5.80	1,859	10,648	9.77
37 SUWANNEE	1-3	164	11,268	9.5	100.0	70.8	13,837	LIGHT OIL	26,882 BBLS	5.80	155,915	894,900	7.94
38 SUWANNEE	1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
39 TURNER	1-4	154	6,433	5.6	100.0	65.6	16,932	LIGHT OIL	18,780 BBLS	5.80	108,924	628,564	9.77
40 UNIV OF FLA.	1	35	25,200	100.0	96.9	100.0	9,586	GAS	241,587 MCF	1.00	241,587	650,837	2.58
41 OTHER - START UP		-	9,166	-	-	-	9,850	LIGHT OIL	15,566 BBLS	5.80	90,285	515,559	5.62
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	3,968,078	-
43 TOTAL		7,593	3,055,303				10,249				31,315,013	89,185,350	2.92

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Jul-02

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	765	569,160	100.0	97.2	100.0	10,496	NUCLEAR	5,973,903 MMBTU	1.00	5,973,903	1,971,388	0.35
2 ANCLOTE	1	498	210,360	59.1	91.8	59.1	10,060	HEAVY OIL	325,573 BBLS	6.50	2,116,222	6,983,531	3.32
3 ANCLOTE	1		8,765				10,261	GAS	89,938 MCF	1.00	89,938	368,744	4.21
4 ANCLOTE	2	495	224,670	63.5	93.8	63.5	9,802	HEAVY OIL	338,802 BBLS	6.50	2,202,215	7,267,311	3.23
5 ANCLOTE	2		9,361				9,998	GAS	93,591 MCF	1.00	93,591	383,724	4.10
6 BARTOW	1	121	70,502	78.3	90.7	78.3	10,167	HEAVY OIL	110,276 BBLS	6.50	716,794	2,078,702	2.95
7 BARTOW	2	119	67,022	75.7	92.5	75.7	10,305	HEAVY OIL	106,256 BBLS	6.50	690,662	2,002,919	2.99
8 BARTOW	3	204	114,413	75.4	89.2	75.4	10,168	HEAVY OIL	178,977 BBLS	6.50	1,163,351	3,373,719	2.95
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	379	201,982	71.6	87.4	92.5	9,776	COAL	78,356 TONS	25.20	1,974,576	4,224,966	2.09
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	486	245,199	67.8	84.2	91.2	9,579	COAL	93,205 TONS	25.20	2,348,761	5,025,803	2.05
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	720	453,895	84.7	95.5	84.7	9,553	COAL	172,751 TONS	25.10	4,336,059	11,964,759	2.64
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	717	472,364	88.5	94.3	88.5	9,495	COAL	178,689 TONS	25.10	4,485,096	12,376,006	2.62
17 SUWANNEE	1	32	11,942	50.2	98.7	54.7	12,157	HEAVY OIL	22,335 BBLS	6.50	145,179	493,608	4.13
18 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
19 SUWANNEE	2	31	12,141	52.6	99.5	60.9	13,319	HEAVY OIL	24,878 BBLS	6.50	161,706	549,800	4.53
20 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
21 SUWANNEE	3	80	31,749	53.3	90.0	61.7	10,776	HEAVY OIL	52,635 BBLS	6.50	342,127	1,368,509	4.31
22 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
23 AVON PARK	1-2	52	946	2.4	100.0	66.2	17,986	LIGHT OIL	2,934 BBLS	5.80	17,015	97,160	10.27
24 BARTOW	1-4	187	6,551	15.5	100.0	52.3	17,591	LIGHT OIL	19,869 BBLS	5.80	115,239	656,860	10.03
25 BARTOW	1-4		15,078				16,335	GAS	246,299 MCF	1.00	246,299	1,009,826	6.70
26 BAYBORO	1-4	184	4,436	3.2	100.0	63.0	15,081	LIGHT OIL	11,534 BBLS	5.80	66,899	381,326	8.60
27 DEBARY	1-10	667	37,222	19.2	100.0	46.3	16,161	LIGHT OIL	103,715 BBLS	5.80	601,545	3,488,960	9.37
28 DEBARY	1-10		57,983				14,639	GAS	848,813 MCF	1.00	848,813	3,480,134	6.00
29 HIGGINS	1-4	122	1,045	9.7	100.0	70.5	18,034	LIGHT OIL	3,249 BBLS	5.80	18,846	105,340	10.08
30 HIGGINS	1-4		7,733				17,437	GAS	134,840 MCF	1.00	134,840	552,845	7.15
31 HINES	1	482	262,543	73.2	97.4	73.8	7,127	GAS	1,871,144 MCF	1.00	1,871,144	7,671,890	2.92
32 HINES	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
33 INT CITY	1-10,12-14	886	11,500	26.1	100.0	50.2	14,743	LIGHT OIL	29,232 BBLS	5.80	169,545	951,203	8.27
34 INT CITY	1-10,12-14		160,775				13,891	GAS	2,233,326 MCF	1.00	2,233,326	9,156,635	5.70
35 INT CITY	11	0	0	0.0	0.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
36 RIO PINAR	1	13	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
37 SUWANNEE	1-3	164	12,221	10.0	100.0	63.5	14,545	LIGHT OIL	30,647 BBLS	5.80	177,754	1,020,249	8.35
38 SUWANNEE	1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
39 TURNER	1-4	154	2,010	1.8	100.0	56.4	18,218	LIGHT OIL	6,313 BBLS	5.80	36,616	211,312	10.51
40 UNIV OF FLA.	1	35	26,040	100.0	96.9	100.0	0	GAS	0 MCF	1.00	0	-144,642	-0.56
41 OTHER - START UP		-	9,959	-	-	-	9,850	LIGHT OIL	16,913 BBLS	5.80	98,096	560,163	5.62
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	3,979,492	-
43 TOTAL		7,593	3,319,567				10,084				33,476,159	93,611,844	2.82

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Aug-02

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	765	569,160	100.0	97.2	100.0	10,496	NUCLEAR	5,973,903 MMBTU	1.00	5,973,903	1,971,388	0.35
2 ANCLOTE	1	498	221,139	62.2	91.8	62.2	10,022	HEAVY OIL	340,962 BBLS	6.50	2,216,255	7,313,842	3.31
3 ANCLOTE	1		9,214				10,222	GAS	94,186 MCF	1.00	94,186	386,161	4.19
4 ANCLOTE	2	495	225,584	63.8	93.8	63.8	9,802	HEAVY OIL	340,181 BBLS	6.50	2,211,174	7,296,875	3.23
5 ANCLOTE	2		9,399				9,996	GAS	93,971 MCF	1.00	93,971	385,282	4.10
6 BARTOW	1	121	68,006	75.5	90.7	75.5	10,192	HEAVY OIL	106,633 BBLS	6.50	693,117	2,010,040	2.96
7 BARTOW	2	119	67,180	75.9	92.5	75.9	10,303	HEAVY OIL	106,485 BBLS	6.50	692,156	2,007,251	2.99
8 BARTOW	3	204	85,437	56.3	92.2	77.8	10,163	HEAVY OIL	133,584 BBLS	6.50	868,296	2,518,059	2.95
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	379	275,837	97.8	83.7	97.8	9,741	COAL	106,624 TONS	25.20	2,686,928	5,753,438	2.09
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	486	352,886	97.6	78.7	97.6	9,549	COAL	133,719 TONS	25.20	3,369,708	7,215,455	2.04
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	720	447,456	83.5	95.6	86.3	9,535	COAL	169,980 TONS	25.10	4,266,493	11,828,894	2.64
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	717	484,037	90.7	94.3	90.7	9,471	COAL	182,642 TONS	25.10	4,584,314	12,710,057	2.63
17 SUWANNEE	1	32	13,122	55.1	96.7	55.9	12,131	HEAVY OIL	24,490 BBLS	6.50	159,183	541,222	4.12
18 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
19 SUWANNEE	2	31	12,824	55.6	99.5	64.0	13,168	HEAVY OIL	25,979 BBLS	6.50	168,866	574,148	4.48
20 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
21 SUWANNEE	3	80	33,517	56.3	90.3	66.9	10,712	HEAVY OIL	55,236 BBLS	6.50	359,034	1,436,136	4.28
22 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
23 AVON PARK	1-2	52	1,042	2.7	100.0	70.3	17,825	LIGHT OIL	3,202 BBLS	5.80	18,574	106,062	10.18
24 BARTOW	1-4	187	8,776	20.6	100.0	56.5	16,675	LIGHT OIL	25,231 BBLS	5.80	146,340	834,137	9.50
25 BARTOW	1-4		19,878				15,963	GAS	317,313 MCF	1.00	317,313	1,300,981	6.54
26 BAYBORO	1-4	184	11,663	8.5	100.0	67.1	14,660	LIGHT OIL	29,479 BBLS	5.80	170,980	974,584	8.36
27 DEBARY	1-10	667	48,678	20.6	100.0	46.5	15,744	LIGHT OIL	132,136 BBLS	5.80	766,386	4,445,041	9.13
28 DEBARY	1-10		53,634				14,491	GAS	777,210 MCF	1.00	777,210	3,186,562	5.94
29 HIGGINS	1-4	122	1,574	10.7	100.0	73.9	18,050	LIGHT OIL	4,898 BBLS	5.80	28,411	158,806	10.09
30 HIGGINS	1-4		8,147				17,063	GAS	139,012 MCF	1.00	139,012	569,950	7.00
31 HINES	1	482	264,236	73.7	97.3	73.7	7,163	GAS	1,892,722 MCF	1.00	1,892,722	7,760,162	2.94
32 HINES	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
33 INT CITY	1-10,12-14	686	19,343	31.3	100.0	52.5	14,654	LIGHT OIL	48,871 BBLS	5.80	283,452	1,590,265	8.22
34 INT CITY	1-10,12-14		187,041				13,868	GAS	2,593,885 MCF	1.00	2,593,885	10,834,927	5.69
35 INT CITY	11	0	0	0.0	0.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
36 RIO PINAR	1	13	52	0.5	100.0	100.0	16,546	LIGHT OIL	148 BBLS	5.80	860	4,929	9.48
37 SUWANNEE	1-3	164	8,796	7.2	100.0	67.9	14,082	LIGHT OIL	21,356 BBLS	5.80	123,865	710,944	8.08
38 SUWANNEE	1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
39 TURNER	1-4	154	6,550	5.7	100.0	62.2	17,490	LIGHT OIL	19,752 BBLS	5.80	114,560	661,087	10.09
40 UNIV OF FLA.	1	35	26,040	100.0	96.9	100.0	9,586	GAS	249,619 MCF	1.00	249,619	835,947	3.21
41 OTHER - START UP		-	10,653	-	-	-	9,850	LIGHT OIL	18,092 BBLS	5.80	104,932	599,198	5.62
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	4,126,794	-
43 TOTAL		7,593	3,550,901				10,185				36,165,707	102,448,425	2.89

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Sep-02

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	785	550,800	100.0	97.2	100.0	10,498	NUCLEAR	5,781,197 MMBTU	1.00	5,781,197	1,907,795	0.35
2 ANCLOTE	1	498	208,114	60.5	91.8	60.5	10,041	HEAVY OIL	321,488 BBLS	6.50	2,089,673	6,895,920	3.31
3 ANCLOTE	1		8,671				10,242	GAS	88,808 MCF	1.00	88,808	364,114	4.20
4 ANCLOTE	2	495	216,364	63.2	93.8	63.2	9,789	HEAVY OIL	325,844 BBLS	6.50	2,117,987	6,989,358	3.23
5 ANCLOTE	2		9,015				9,985	GAS	90,015 MCF	1.00	90,015	369,061	4.09
6 BARTOW	1	121	31,538	36.2	39.3	83.5	10,098	HEAVY OIL	48,995 BBLS	6.50	318,471	923,565	2.93
7 BARTOW	2	119	65,996	77.0	92.5	77.0	10,289	HEAVY OIL	104,467 BBLS	6.50	679,033	1,969,195	2.98
8 BARTOW	3	204	94,444	64.3	91.1	78.5	10,147	HEAVY OIL	147,434 BBLS	6.50	958,323	2,779,137	2.94
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	379	257,390	94.3	83.7	94.3	9,788	COAL	99,974 TONS	25.20	2,519,333	5,388,574	2.09
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	486	107,850	30.8	81.2	75.0	9,701	COAL	41,518 TONS	25.20	1,046,253	2,237,819	2.07
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	720	484,757	89.7	95.5	89.7	9,499	COAL	175,866 TONS	25.10	4,414,727	12,180,073	2.62
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	717	445,301	86.3	94.8	94.4	9,437	COAL	167,423 TONS	25.10	4,202,306	11,594,010	2.60
17 SUWANNEE	1	32	11,740	51.0	98.8	59.4	12,067	HEAVY OIL	21,795 BBLS	6.50	141,667	481,666	4.10
18 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
19 SUWANNEE	2	31	12,105	54.2	99.5	84.5	13,145	HEAVY OIL	24,480 BBLS	6.50	159,120	541,009	4.47
20 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
21 SUWANNEE	3	80	25,568	44.4	92.3	66.9	10,710	HEAVY OIL	42,161 BBLS	6.50	274,047	1,096,190	4.28
22 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
23 AVON PARK	1-2	52	756	2.0	100.0	70.9	17,396	LIGHT OIL	2,267 BBLS	5.80	13,151	75,099	9.93
24 BARTOW	1-4	187	8,551	15.9	100.0	52.4	17,451	LIGHT OIL	25,726 BBLS	5.80	149,224	850,574	9.95
25 BARTOW	1-4		12,820				16,149	GAS	207,030 MCF	1.00	207,030	848,824	6.62
26 BAYBORO	1-4	184	7,595	5.7	100.0	64.0	14,902	LIGHT OIL	19,514 BBLS	5.80	113,181	645,130	8.49
27 DEBARY	1-10	667	29,856	18.3	100.0	51.5	15,766	LIGHT OIL	80,619 BBLS	5.80	467,588	2,712,011	9.14
28 DEBARY	1-10		58,383				14,277	GAS	833,534 MCF	1.00	833,534	3,417,490	5.85
29 HIGGINS	1-4	122	1,718	6.5	100.0	69.5	18,008	LIGHT OIL	5,334 BBLS	5.80	30,938	172,931	10.07
30 HIGGINS	1-4		3,964				17,449	GAS	69,168 MCF	1.00	69,168	283,588	7.15
31 HINES	1	482	255,288	73.8	97.3	73.8	7,158	GAS	1,827,352 MCF	1.00	1,827,352	7,492,141	2.93
32 HINES	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
33 INT CITY	1-10,12-14	866	14,734	26.0	100.0	52.4	14,674	LIGHT OIL	37,277 BBLS	5.80	216,207	1,212,994	8.23
34 INT CITY	1-10,12-14		151,212				14,185	GAS	2,144,942 MCF	1.00	2,144,942	8,794,263	5.82
35 INT CITY	11	0	0	0.0	0.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
36 RIO PINAR	1	13	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
37 SUWANNEE	1-3	164	14,692	12.4	100.0	67.0	14,254	LIGHT OIL	36,107 BBLS	5.80	209,420	1,201,997	8.18
38 SUWANNEE	1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
39 TURNER	1-4	154	3,412	3.1	100.0	60.4	17,853	LIGHT OIL	10,502 BBLS	5.80	60,914	351,518	10.30
40 UNIV OF FLA.	1	35	16,800	66.7	97.9	100.0	9,586	GAS	161,045 MCF	1.00	161,045	466,193	2.77
41 OTHER - START UP		-	9,296	-	-	-	9,850	LIGHT OIL	15,787 BBLS	5.80	91,566	522,871	5.62
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	- -	-	-	3,968,078	-
43 TOTAL		7,593	3,098,552				10,158				31,476,218	88,733,188	2.86

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Oct-02

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	785	520,965	91.5	97.5	100.0	10,355	NUCLEAR	5,394,593 MMBTU	1.00	5,394,593	1,780,216	0.34
2 ANCLOTE	1	498	124,582	35.0	94.3	50.6	10,155	HEAVY OIL	194,635 BBLS	6.50	1,265,130	4,427,956	3.55
3 ANCLOTE	1		5,191				10,358	GAS	53,768 MCF	1.00	53,768	241,958	4.66
4 ANCLOTE	2	495	114,273	32.3	54.5	55.7	9,937	HEAVY OIL	174,697 BBLS	6.50	1,135,531	3,974,358	3.48
5 ANCLOTE	2		4,761				10,136	GAS	48,257 MCF	1.00	48,257	217,159	4.56
6 BARTOW	1	121	37,992	42.2	58.6	66.2	10,262	HEAVY OIL	59,981 BBLS	6.50	389,874	1,169,622	3.08
7 BARTOW	2	119	53,508	60.4	94.1	76.6	10,203	HEAVY OIL	83,991 BBLS	6.50	545,942	1,637,826	3.06
8 BARTOW	3	204	117,678	77.5	89.2	77.5	10,054	HEAVY OIL	182,021 BBLS	6.50	1,183,135	3,549,404	3.02
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	379	214,540	76.1	87.4	98.3	9,704	COAL	82,615 TONS	25.20	2,081,896	4,466,163	2.08
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	486	0	0.0	0.0	0.0	0	COAL	0 TONS	25.20	0	0	0.00
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	720	453,434	84.6	95.5	84.6	9,507	COAL	171,745 TONS	25.10	4,310,797	11,934,553	2.63
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	717	482,799	90.5	94.3	90.5	9,438	COAL	181,540 TONS	25.10	4,556,657	12,615,223	2.61
17 SUWANNEE	1	32	10,314	43.3	98.9	56.4	12,069	HEAVY OIL	19,151 BBLS	6.50	124,480	435,679	4.22
18 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
19 SUWANNEE	2	31	9,649	41.8	99.6	59.7	13,321	HEAVY OIL	19,775 BBLS	6.50	128,534	449,870	4.66
20 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
21 SUWANNEE	3	80	21,265	35.7	93.4	62.4	10,833	HEAVY OIL	35,441 BBLS	6.50	230,364	990,564	4.66
22 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
23 AVON PARK	1-2	52	404	1.0	100.0	64.7	18,282	LIGHT OIL	1,273 BBLS	5.80	7,386	45,869	11.35
24 BARTOW	1-4	187	2,681	8.6	100.0	50.2	17,601	LIGHT OIL	8,136 BBLS	5.80	47,188	292,567	10.91
25 BARTOW	1-4		9,344				16,932	GAS	158,213 MCF	1.00	158,213	711,957	7.62
26 BAYBORO	1-4	184	2,594	1.9	100.0	65.6	14,867	LIGHT OIL	6,649 BBLS	5.80	38,565	239,103	9.22
27 DEBARY	1-10	667	20,239	11.5	100.0	46.2	16,081	LIGHT OIL	56,114 BBLS	5.80	325,463	2,050,419	10.13
28 DEBARY	1-10		36,881				14,844	GAS	547,462 MCF	1.00	547,462	2,463,577	6.68
29 HIGGINS	1-4	122	419	3.6	100.0	68.2	18,009	LIGHT OIL	1,301 BBLS	5.80	7,546	45,951	10.97
30 HIGGINS	1-4		2,827				17,791	GAS	50,295 MCF	1.00	50,295	226,328	8.01
31 HINES	1	482	223,031	62.2	97.5	67.2	7,179	GAS	1,601,140 MCF	1.00	1,601,140	7,205,128	3.23
32 HINES	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
33 INT CITY	1-10,12-14	886	5,391	19.4	100.0	83.5	14,653	LIGHT OIL	13,620 BBLS	5.80	78,994	482,683	8.95
34 INT CITY	1-10,12-14		122,442				14,250	GAS	1,744,799 MCF	1.00	1,744,799	7,851,593	6.41
35 INT CITY	11	143	26,381	24.8	100.0	82.7	11,494	LIGHT OIL	52,280 BBLS	5.80	303,223	1,852,798	7.02
36 RIO PINAR	1	13	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
37 SUWANNEE	1-3	164	1,920	4.5	100.0	66.3	13,837	LIGHT OIL	4,581 BBLS	5.80	26,587	165,769	8.63
38 SUWANNEE	1-3		3,516				14,725	GAS	51,773 MCF	1.00	51,773	232,979	6.63
39 TURNER	1-4	154	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
40 UNIV OF FLA.	1	35	4,900	18.8	99.4	100.0	9,586	GAS	46,971 MCF	1.00	46,971	268	0.01
41 OTHER - START UP		-	7,926	-	-	-	9,850	LIGHT OIL	13,461 BBLS	5.80	78,071	484,848	6.12
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	- -	-	-	2,944,481	-
43 TOTAL		7,736	2,641,847				10,055				26,562,614	75,186,869	2.85

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Nov-02

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	782	480,930	85.4	97.6	100.0	10,352	NUCLEAR	4,978,587 MMBTU	1.00	4,978,587	1,642,934	0.34
2 ANCLOTE	1	522	137,298	38.1	91.8	38.1	10,501	HEAVY OIL	221,810 BBLS	6.50	1,441,786	5,046,182	3.68
3 ANCLOTE	1		5,721				10,711	GAS	61,278 MCF	1.00	61,278	275,749	4.82
4 ANCLOTE	2	522	0	0.0	0.0	0.0	0	HEAVY OIL	0 BBLS	6.50	0	0	0.00
5 ANCLOTE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	123	84,936	73.3	90.7	73.3	10,148	HEAVY OIL	101,380 BBLS	6.50	658,971	1,976,912	3.04
7 BARTOW	2	121	57,120	65.6	92.9	69.1	10,271	HEAVY OIL	90,258 BBLS	6.50	586,680	1,760,039	3.08
8 BARTOW	3	208	105,890	70.7	89.2	70.7	10,106	HEAVY OIL	164,635 BBLS	6.50	1,070,124	3,210,373	3.03
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	383	218,775	79.3	83.6	79.3	9,952	COAL	86,399 TONS	25.20	2,177,249	4,658,621	2.13
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	491	0	0.0	0.0	0.0	0	COAL	0 TONS	25.20	0	0	0.00
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	735	497,124	93.9	95.5	93.9	9,391	COAL	185,996 TONS	25.10	4,668,491	12,874,621	2.59
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	732	440,954	83.7	94.8	91.5	9,402	COAL	165,173 TONS	25.10	4,145,850	11,433,295	2.59
17 SUWANNEE	1	33	6,469	27.2	99.2	47.7	12,219	HEAVY OIL	12,161 BBLS	6.50	79,045	276,656	4.28
18 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
19 SUWANNEE	2	32	5,794	25.1	99.7	49.5	13,832	HEAVY OIL	12,330 BBLS	6.50	80,143	280,499	4.84
20 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
21 SUWANNEE	3	81	16,842	28.9	93.8	54.1	10,993	HEAVY OIL	28,484 BBLS	6.50	185,144	796,120	4.73
22 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
23 AVON PARK	1-2	64	355	0.8	100.0	61.6	17,090	LIGHT OIL	1,046 BBLS	5.80	6,067	37,678	10.61
24 BARTOW	1-4	219	0	2.3	100.0	50.9	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
25 BARTOW	1-4		3,621				16,111	GAS	58,338 MCF	1.00	58,338	262,521	7.25
26 BAYBORO	1-4	232	1,348	0.8	100.0	50.5	14,860	LIGHT OIL	3,454 BBLS	5.80	20,031	124,194	9.21
27 DEBARY	1-10	762	2,114	2.4	100.0	44.3	16,219	LIGHT OIL	5,912 BBLS	5.80	34,287	216,008	10.22
28 DEBARY	1-10		10,844				14,984	GAS	162,486 MCF	1.00	162,486	731,189	6.74
29 HIGGINS	1-4	134	0	0.0	100.0	62.1	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 HIGGINS	1-4		707				17,718	GAS	12,527 MCF	1.00	12,527	56,370	7.97
31 HINES	1	529	84,609	22.2	52.1	51.1	7,220	GAS	610,877 MCF	1.00	610,877	2,748,946	3.25
32 HINES	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
33 INT CITY	1-10,12-14	1,024	2,204	4.9	100.0	38.8	14,770	LIGHT OIL	5,613 BBLS	5.80	32,553	198,911	9.02
34 INT CITY	1-10,12-14		34,130				14,823	GAS	505,909 MCF	1.00	505,909	2,276,590	6.67
35 INT CITY	11	170	2,721	2.2	100.0	69.6	11,501	LIGHT OIL	5,396 BBLS	5.80	31,294	191,218	7.03
36 RIO PINAR	1	16	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
37 SUWANNEE	1-3	201	0	0.0	100.0	60.1	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
38 SUWANNEE	1-3		2,012				14,118	GAS	28,405 MCF	1.00	28,405	127,824	6.35
39 TURNER	1-4	194	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
40 UNIV OF FLA.	1	41	26,732	90.6	97.2	100.0	9,374	GAS	250,586 MCF	1.00	250,586	928,602	3.47
41 OTHER - START UP		-	6,648	-	-	-	9,850	LIGHT OIL	11,290 BBLS	5.80	65,483	406,671	6.12
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	- -	-	-	2,591,171	-
43 TOTAL		8,351	2,215,898				9,907				21,952,170	55,129,894	2.49

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Dec-02

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	782	561,808	100.0	97.2	100.0	10,286	NUCLEAR	5,984,477 MMBTU	1.00	5,984,477	1,974,877	0.34
2 ANCLOTE	1	522	155,098	41.6	92.2	44.1	10,254	HEAVY OIL	244,673 BBLS	6.50	1,590,375	5,566,312	3.59
3 ANCLOTE	1		6,462				10,459	GAS	67,586 MCF	1.00	67,586	304,137	4.71
4 ANCLOTE	2	522	138,537	37.2	78.7	44.3	10,105	HEAVY OIL	215,372 BBLS	6.50	1,399,916	4,899,707	3.54
5 ANCLOTE	2		5,772				10,307	GAS	59,492 MCF	1.00	59,492	267,714	4.64
6 BARTOW	1	123	53,599	58.6	92.8	75.7	10,031	HEAVY OIL	82,716 BBLS	6.50	537,652	1,612,955	3.01
7 BARTOW	2	121	47,996	53.3	93.8	64.7	10,219	HEAVY OIL	75,457 BBLS	6.50	490,471	1,471,413	3.07
8 BARTOW	3	208	105,130	67.9	90.0	73.3	10,067	HEAVY OIL	162,822 BBLS	6.50	1,058,344	3,175,031	3.02
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	383	260,021	91.3	84.8	98.4	9,752	COAL	100,624 TONS	25.20	2,535,725	5,429,671	2.09
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	491	226,497	62.0	51.0	97.9	9,494	COAL	85,332 TONS	25.20	2,150,363	4,604,506	2.03
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	735	369,811	67.6	96.5	87.7	9,399	COAL	138,480 TONS	25.10	3,475,854	9,592,525	2.59
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	732	397,465	73.0	95.1	85.1	9,407	COAL	148,962 TONS	25.10	3,738,953	10,318,617	2.60
17 SUWANNEE	1	33	6,999	28.5	99.3	57.3	11,950	HEAVY OIL	12,867 BBLS	6.50	83,638	292,733	4.18
18 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
19 SUWANNEE	2	32	6,009	25.2	99.8	62.4	13,021	HEAVY OIL	12,037 BBLS	6.50	78,243	273,851	4.56
20 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
21 SUWANNEE	3	81	15,591	25.9	95.2	62.5	10,593	HEAVY OIL	25,409 BBLS	6.50	165,155	710,168	4.55
22 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
23 AVON PARK	1-2	64	184	0.4	100.0	57.5	18,160	LIGHT OIL	576 BBLS	5.80	3,341	20,751	11.28
24 BARTOW	1-4	219	1,525	0.9	100.0	63.3	14,790	LIGHT OIL	3,889 BBLS	5.80	22,555	139,839	9.17
25 BARTOW	1-4		0				0	GAS	0 MCF	1.00	0	0	0.00
26 BAYBORO	1-4	232	224	0.1	100.0	48.3	18,662	LIGHT OIL	721 BBLS	5.80	4,180	25,918	11.57
27 DEBARY	1-10	782	1,504	2.3	100.0	39.7	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
28 DEBARY	1-10		11,625				15,773	GAS	183,361 MCF	1.00	183,361	825,125	7.10
29 HIGGINS	1-4	134	0	0.0	100.0	59.7	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 HIGGINS	1-4		360				18,012	GAS	6,484 MCF	1.00	6,484	29,179	8.11
31 HINES	1	529	136,866	34.8	98.5	63.1	7,193	GAS	984,477 MCF	1.00	984,477	4,430,147	3.24
32 HINES	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
33 INT CITY	1-10,12-14	1,024	1,217	6.8	100.0	37.3	15,654	LIGHT OIL	3,285 BBLS	5.80	19,051	116,408	9.57
34 INT CITY	1-10,12-14		50,615				14,785	GAS	748,343 MCF	1.00	748,343	3,367,542	6.65
35 INT CITY	11	170	2,129	1.7	100.0	69.6	11,324	LIGHT OIL	4,157 BBLS	5.80	24,109	147,313	6.92
36 RIO PINAR	1	16	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
37 SUWANNEE	1-3	201	748	0.5	100.0	50.7	14,890	LIGHT OIL	1,920 BBLS	5.80	11,138	69,496	9.29
38 SUWANNEE	1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
39 TURNER	1-4	194	180	0.1	100.0	46.4	19,071	LIGHT OIL	592 BBLS	5.80	3,433	21,526	11.96
40 UNIV OF FLA.	1	41	30,504	100.0	96.9	100.0	9,373	GAS	285,914 MCF	1.00	285,914	1,052,701	3.45
41 OTHER - START UP		-	7,987	-	-	-	9,850	LIGHT OIL	13,564 BBLS	5.80	78,672	488,580	6.12
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	2,640,576	-
43 TOTAL		8,351	2,622,483				9,835				25,791,302	63,869,321	2.44

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD OF: Jan-02 THROUGH Dec-02

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	774	6,592,923	97.3	97.3	100.0	10,373	NUCLEAR	68,386,966 MMBTU	1.00	68,386,966	22,587,699	0.34
2 ANCLOTE	1	510	1,772,892	41.3	93.0	48.1	10,210	HEAVY OIL	2,784,913 BBLS	6.50	18,101,936	61,126,637	3.45
3 ANCLOTE	1		73,868				10,415	GAS	769,301 MCF	1.00	769,301	3,306,137	4.48
4 ANCLOTE	2	509	1,784,316	41.7	81.9	51.8	9,990	HEAVY OIL	2,742,244 BBLS	6.50	17,824,584	60,000,459	3.36
5 ANCLOTE	2		74,345				10,189	GAS	757,522 MCF	1.00	757,522	3,248,933	4.37
6 BARTOW	1	122	683,065	63.9	84.2	72.9	10,163	HEAVY OIL	1,067,987 BBLS	6.50	6,941,918	20,390,601	2.99
7 BARTOW	2	120	670,579	63.8	90.9	67.9	10,298	HEAVY OIL	1,062,412 BBLS	6.50	6,905,680	20,272,675	3.02
8 BARTOW	3	206	1,044,721	57.9	79.8	71.2	10,146	HEAVY OIL	1,630,766 BBLS	6.50	10,599,980	31,213,869	2.99
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	381	2,796,419	83.8	85.3	93.4	9,773	COAL	1,084,532 TONS	25.20	27,330,202	57,430,686	2.05
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	489	2,718,506	63.5	65.0	93.4	9,539	COAL	1,028,994 TONS	25.20	25,930,655	54,158,803	1.99
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	728	4,208,070	66.0	76.6	84.8	9,494	COAL	1,590,962 TONS	25.10	39,933,152	110,355,112	2.62
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	725	5,311,602	83.7	94.6	87.7	9,446	COAL	1,999,049 TONS	25.10	50,176,138	138,702,573	2.61
17 SUWANNEE	1	33	85,386	30.0	93.0	53.3	12,128	HEAVY OIL	159,314 BBLS	6.50	1,035,540	3,552,549	4.16
18 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
19 SUWANNEE	2	32	82,549	29.9	94.1	59.2	13,313	HEAVY OIL	169,070 BBLS	6.50	1,099,954	3,771,918	4.57
20 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
21 SUWANNEE	3	81	227,786	32.3	87.9	59.3	10,783	HEAVY OIL	377,876 BBLS	6.50	2,456,194	10,135,797	4.45
22 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
23 AVON PARK	1-2	58	5,867	1.2	100.0	64.0	17,595	LIGHT OIL	17,798 BBLS	5.80	103,228	611,005	10.41
24 BARTOW	1-4	203	42,869	6.7	100.0	49.2	17,008	LIGHT OIL	125,712 BBLS	5.80	729,129	4,234,433	9.88
25 BARTOW	1-4		76,746				16,294	GAS	1,250,484 MCF	1.00	1,250,484	5,245,730	6.84
26 BAYBORO	1-4	208	45,101	2.5	100.0	59.3	14,762	LIGHT OIL	114,788 BBLS	5.80	665,770	3,860,861	8.56
27 DEBARY	1-10	715	217,291	8.4	100.0	44.8	15,595	LIGHT OIL	584,236 BBLS	5.80	3,388,571	20,123,218	9.26
28 DEBARY	1-10		309,751				14,616	GAS	4,527,278 MCF	1.00	4,527,278	19,115,352	6.17
29 HIGGINS	1-4	128	8,011	3.6	100.0	67.7	17,971	LIGHT OIL	24,821 BBLS	5.80	143,965	821,985	10.26
30 HIGGINS	1-4		32,232				17,350	GAS	559,210 MCF	1.00	559,210	2,320,485	7.20
31 HINES	1	506	2,101,223	47.6	90.2	63.7	7,204	GAS	15,137,670 MCF	1.00	15,137,670	64,474,781	3.07
32 HINES	1		8,506				7,986	LIGHT OIL	11,711 BBLS	5.80	67,926	382,446	4.50
33 INT CITY	1-10,12-14	955	107,693	13.5	100.0	62.1	14,794	LIGHT OIL	274,689 BBLS	5.80	1,593,198	9,251,815	8.59
34 INT CITY	1-10,12-14		1,020,380				14,304	GAS	14,595,244 MCF	1.00	14,595,244	61,656,483	6.04
35 INT CITY	11	183	62,062	4.3	66.7	72.8	11,445	LIGHT OIL	122,460 BBLS	5.80	710,268	4,313,152	6.95
36 RIO PINAR	1	15	245	0.2	100.0	80.5	17,745	LIGHT OIL	750 BBLS	5.80	4,348	26,537	10.83
37 SUWANNEE	1-3	183	53,404	4.1	100.0	61.1	14,173	LIGHT OIL	130,498 BBLS	5.80	756,891	4,404,033	8.25
38 SUWANNEE	1-3		12,375				14,430	GAS	178,573 MCF	1.00	178,573	764,223	6.18
39 TURNER	1-4	174	21,515	1.4	91.7	55.9	17,300	LIGHT OIL	64,174 BBLS	5.80	372,211	2,189,221	10.18
40 UNIV OF FLA.	1	38	297,383	89.3	97.2	100.0	8,623	GAS	2,564,438 MCF	1.00	2,564,438	8,284,173	2.79
41 OTHER - START UP		-	98,059	-	-	-	9,850	LIGHT OIL	166,531 BBLS	5.80	965,881	5,836,757	5.95
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	30,678,217	-
43 TOTAL		8,050	32,645,940				10,003				326,563,006	848,829,151	2.60

FLORIDA POWER CORPORATION
INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

	HEAVY OIL		Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Subtotal
1	PURCHASES:								
2	UNITS	BBL	513,024	509,971	715,683	807,555	934,360	951,942	4,432,534
3	UNIT COST	$/BBL	21.78	21.78	20.15	20.15	20.15	20.15	20.53
4	AMOUNT	$	11,171,092	11,104,625	14,421,015	16,272,228	18,827,345	19,181,625	90,977,931
5	BURNED:								
6	UNITS	BBL	513,024	509,971	715,683	807,555	934,360	951,942	4,432,534
7	UNIT COST	$/BBL	21.87	22.14	20.84	20.53	20.66	20.67	20.98
8	AMOUNT	$	11,221,695	11,291,366	14,917,818	16,576,625	19,307,081	19,674,175	92,988,760
9	ENDING INVENTORY:								
10	UNITS	BBL	800,000	800,000	800,000	800,000	800,000	800,000	
11	UNIT COST	$/BBL	23.10	22.58	21.43	20.79	20.44	20.28	
12	AMOUNT	$	18,480,000	18,067,342	17,147,836	16,631,503	16,355,939	16,227,738	
13	DAYS SUPPLY:		48	44	35	30	27	25	
	LIGHT OIL								
14	PURCHASES:								
15	UNITS	BBL	88,191	67,924	31,541	70,607	89,476	310,896	658,635
16	UNIT COST	$/BBL	38.95	38.95	38.95	33.15	33.15	33.15	34.80
17	AMOUNT	$	3,435,049	2,645,639	1,228,509	2,340,613	2,966,141	10,306,205	22,922,156
18	BURNED:								
19	UNITS	BBL	88,191	67,924	31,541	70,607	89,476	310,896	658,635
20	UNIT COST	$/BBL	38.81	38.86	38.94	32.91	32.94	33.22	34.75
21	AMOUNT	$	3,422,524	2,639,678	1,228,082	2,323,651	2,947,114	10,326,940	22,887,990
22	ENDING INVENTORY:								
23	UNITS	BBL	550,000	550,000	550,000	550,000	550,000	550,000	
24	UNIT COST	$/BBL	38.65	38.68	38.70	38.07	37.38	35.85	
25	AMOUNT	$	21,257,500	21,276,637	21,283,603	20,936,477	20,558,133	19,718,275	
26	DAYS SUPPLY:		193	227	541	234	191	53	
	COAL								
27	PURCHASES:								
28	UNITS	TON	493,000	484,000	509,000	484,000	519,000	485,000	2,974,000
29	UNIT COST	$/TON	63.16	63.18	63.43	63.11	63.42	63.09	63.24
30	AMOUNT	$	31,137,880	30,579,120	32,285,870	30,545,240	32,914,980	30,598,650	188,061,740
31	BURNED:								
32	UNITS	TON	555,906	471,962	392,259	354,650	468,337	512,793	2,755,906
33	UNIT COST	$/TON	62.37	61.59	60.31	60.57	61.62	63.34	61.77
34	AMOUNT	$	34,674,349	29,069,029	23,655,286	21,482,584	28,857,075	32,481,403	170,219,725
35	ENDING INVENTORY:								
36	UNITS	TON	550,000	562,038	678,780	808,130	858,793	831,000	
37	UNIT COST	$/TON	62.37	62.75	63.07	63.09	63.22	63.17	
38	AMOUNT	$	34,305,975	35,268,770	42,813,327	50,984,075	54,291,540	52,495,966	
39	DAYS SUPPLY:		35	33	41	50	51	51	
	GAS								
40	BURNED:								
41	UNITS	MCF	883,350	1,200,376	2,363,621	1,798,588	3,460,201	5,207,081	14,913,218
42	UNIT COST	$/MCF	6.31	6.16	4.40	4.53	4.60	4.80	4.86
43	AMOUNT	$	5,574,124	7,397,208	10,410,800	8,144,064	15,930,315	24,977,523	72,434,034
	NUCLEAR								
44	BURNED:								
45	UNITS	MMBTU	5,983,313	5,404,283	5,983,313	5,828,590	5,872,593	5,228,212	34,300,305
46	UNIT COST	$/MMBTU	0.33	0.33	0.33	0.33	0.33	0.33	0.33
47	AMOUNT	$	1,974,493	1,783,413	1,974,493	1,923,435	1,937,956	1,725,310	11,319,101

FLORIDA POWER CORPORATION
INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

	HEAVY OIL		Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Total
1	PURCHASES:								
2	UNITS	BBL	1,159,732	1,133,551	1,036,665	769,691	631,057	831,353	9,994,583
3	UNIT COST	$/BBL	20.15	20.15	20.15	21.13	21.13	21.13	20.53
4	AMOUNT	$	23,368,593	22,841,054	20,888,795	16,259,716	13,331,084	17,562,332	205,229,505
5	BURNED:								
6	UNITS	BBL	1,159,732	1,133,551	1,036,665	769,691	631,057	831,353	9,994,583
7	UNIT COST	$/BBL	20.80	20.91	20.91	21.61	21.15	21.65	21.06
8	AMOUNT	$	24,118,099	23,697,371	21,676,040	16,635,279	13,346,780	18,002,172	210,464,502
9	ENDING INVENTORY:								
10	UNITS	BBL	800,000	800,000	800,000	800,000	800,000	800,000	
11	UNIT COST	$/BBL	20.20	20.17	20.16	20.63	20.85	20.99	
12	AMOUNT	$	16,163,981	16,138,197	16,127,926	16,506,509	16,680,028	16,792,128	
13	DAYS SUPPLY:		21	22	23	32	38	30	
	LIGHT OIL								
14	PURCHASES:								
15	UNITS	BBL	224,406	303,165	233,136	157,414	32,710	28,703	1,638,170
16	UNIT COST	$/BBL	33.15	33.15	33.15	36.05	36.05	36.05	34.20
17	AMOUNT	$	7,439,067	10,049,935	7,728,453	5,674,792	1,179,179	1,034,751	56,028,333
18	BURNED:								
19	UNITS	BBL	224,406	303,165	233,136	157,414	32,710	28,703	1,638,170
20	UNIT COST	$/BBL	33.30	33.27	33.22	35.96	35.91	35.88	34.22
21	AMOUNT	$	7,472,573	10,085,054	7,745,126	5,660,008	1,174,679	1,029,831	56,055,262
22	ENDING INVENTORY:								
23	UNITS	BBL	550,000	550,000	550,000	550,000	550,000	550,000	
24	UNIT COST	$/BBL	35.07	34.39	34.02	34.47	34.56	34.63	
25	AMOUNT	$	19,287,730	18,912,762	18,710,251	18,958,863	19,007,622	19,048,288	
26	DAYS SUPPLY:		76	66	71	108	504	594	
	COAL								
27	PURCHASES:								
28	UNITS	TON	499,000	464,000	500,000	473,000	510,000	480,000	5,900,000
29	UNIT COST	$/TON	63.89	63.69	63.88	63.79	63.97	63.69	63.53
30	AMOUNT	$	31,881,110	29,552,160	31,940,000	30,172,670	32,624,700	30,571,200	374,803,580
31	BURNED:								
32	UNITS	TON	523,001	592,965	484,800	435,900	437,568	473,398	5,703,538
33	UNIT COST	$/TON	64.23	63.25	64.77	66.57	66.20	63.26	63.23
34	AMOUNT	$	33,591,334	37,507,845	31,400,476	29,015,939	28,966,537	29,945,320	360,647,175
35	ENDING INVENTORY:								
36	UNITS	TON	806,998	678,034	693,234	730,334	802,766	809,368	
37	UNIT COST	$/TON	63.44	63.53	63.68	63.72	63.83	63.77	
38	AMOUNT	$	51,197,116	43,076,949	44,145,007	46,540,172	51,236,918	51,617,251	
39	DAYS SUPPLY:		50	45	42	48	47	52	
	GAS								
40	BURNED:								
41	UNITS	MCF	5,517,951	6,157,918	5,421,894	4,302,678	1,690,406	2,335,657	40,339,722
42	UNIT COST	$/MCF	4.80	4.74	4.80	5.14	5.92	5.53	4.94
43	AMOUNT	$	26,458,449	29,186,766	26,003,751	22,095,428	9,998,964	12,917,122	199,094,513
	NUCLEAR								
44	BURNED:								
45	UNITS	MMBTU	5,973,903	5,973,903	5,781,197	5,394,593	4,978,587	5,984,477	68,386,966
46	UNIT COST	$/MMBTU	0.33	0.33	0.33	0.33	0.33	0.33	0.33
47	AMOUNT	$	1,971,388	1,971,388	1,907,795	1,780,216	1,642,934	1,974,877	22,567,699

FLORIDA POWER CORPORATION
FUEL COST OF POWER SOLD
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
						C/KWH				
MONTH	SOLD TO	TYPE & SCHED	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	REFUNDABLE GAIN ON POWER SALES $
Jan-02	ECONSALE	--	108,236,000		108,236,000	3.608	3.855	3,905,067	4,172,899	267,832
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	299,333,000		299,333,000	4.847	4.847	14,509,640	14,509,640	0
	TOTAL		407,569,000		407,569,000	4.518	4.584	18,414,707	18,682,539	267,832
Feb-02	ECONSALE	--	75,133,000		75,133,000	3.677	3.964	2,762,922	2,978,299	215,377
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	138,986,000		138,986,000	4.588	4.588	6,376,605	6,376,605	0
	TOTAL		214,119,000		214,119,000	4.268	4.369	9,139,527	9,354,904	215,377
Mar-02	ECONSALE	--	116,631,000		116,631,000	3.365	3.664	3,924,854	4,273,427	348,573
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	109,740,000		109,740,000	4.639	4.639	5,090,701	5,090,701	0
	TOTAL		226,371,000		226,371,000	3.983	4.137	9,015,555	9,364,128	348,573
Apr-02	ECONSALE	--	57,570,000		57,570,000	3.101	3.403	1,785,410	1,958,973	173,563
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	117,939,000		117,939,000	3.229	3.229	3,808,637	3,808,637	0
	TOTAL		175,509,000		175,509,000	3.187	3.286	5,594,047	5,767,610	173,563
May-02	ECONSALE	--	34,491,000		34,491,000	3.123	3.551	1,077,192	1,224,848	147,656
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	104,589,000		104,589,000	2.469	2.469	2,582,545	2,582,545	0
	TOTAL		139,080,000		139,080,000	2.631	2.738	3,659,737	3,807,393	147,656
Jun-02	ECONSALE	--	77,939,000		77,939,000	3.078	3.817	2,399,096	2,974,751	575,655
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	124,251,000		124,251,000	3.286	3.286	4,082,464	4,082,464	0
	TOTAL		202,190,000		202,190,000	3.206	3.490	6,481,560	7,057,215	575,655

FLORIDA POWER CORPORATION
FUEL COST OF POWER SOLD
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
						C/KWH				
MONTH	SOLD TO	TYPE & SCHED	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	REFUNDABLE GAIN ON POWER SALES $
Jul-02	ECONSALE	--	121,040,000		121,040,000	2.969	3.614	3,593,235	4,374,246	781,011
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	162,284,000		162,284,000	4.149	4.149	6,732,871	6,732,871	0
	TOTAL		283,324,000		283,324,000	3.645	3.920	10,326,106	11,107,117	781,011
Aug-02	ECONSALE	--	106,038,000		106,038,000	3.069	3.799	3,254,617	4,028,514	773,897
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	181,923,000		181,923,000	4.212	4.212	7,662,639	7,662,639	0
	TOTAL		287,961,000		287,961,000	3.791	4.060	10,917,256	11,691,153	773,897
Sep-02	ECONSALE	--	91,723,000		91,723,000	3.217	4.071	2,951,015	3,734,500	783,485
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	195,345,000		195,345,000	4.245	4.245	8,292,681	8,292,681	0
	TOTAL		287,068,000		287,068,000	3.917	4.190	11,243,696	12,027,181	783,485
Oct-02	ECONSALE	--	72,670,000		72,670,000	3.335	3.661	2,423,377	2,660,454	237,077
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	150,316,000		150,316,000	3.896	3.896	5,855,665	5,855,665	0
	TOTAL		222,986,000		222,986,000	3.713	3.819	8,279,042	8,516,119	237,077
Nov-02	ECONSALE	--	73,208,000		73,208,000	3.485	3.795	2,551,419	2,778,340	226,921
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	123,399,000		123,399,000	2.843	2.843	3,508,205	3,508,205	0
	TOTAL		196,607,000		196,607,000	3.082	3.198	6,059,624	6,286,545	226,921
Dec-02	ECONSALE	--	100,321,000		100,321,000	3.420	3.654	3,430,946	3,665,627	234,681
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	92,882,000		92,882,000	2.699	2.699	2,507,076	2,507,076	0
	TOTAL		193,203,000		193,203,000	3.073	3.195	5,938,022	6,172,703	234,681
Jan-02	ECONSALE	--	1,035,000,000		1,035,000,000	3.291	3.751	34,059,150	38,824,878	4,765,728
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-02	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	1,800,987,000		1,800,987,000	3.943	3.943	71,009,729	71,009,729	0
	TOTAL		2,835,987,000		2,835,987,000	3.705	3.873	105,068,879	109,834,607	4,765,728

FLORIDA POWER CORPORATION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGEN PURCHASES)
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jan-02	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	21,879,000			21,879,000	3.200	3.200	700,128
	UPS PURCHASE	UPS	251,664,000			251,664,000	1.621	1.621	4,079,473
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		273,543,000	0	0	273,543,000	1.747	1.747	4,779,601
Feb-02	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	17,519,000			17,519,000	3.200	3.200	560,608
	UPS PURCHASE	UPS	228,032,000			228,032,000	1.621	1.621	3,696,399
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		245,551,000	0	0	245,551,000	1.734	1.734	4,257,007
Mar-02	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	33,427,000			33,427,000	3.200	3.200	1,069,664
	UPS PURCHASE	UPS	252,464,000			252,464,000	1.621	1.621	4,092,441
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		285,891,000	0	0	285,891,000	1.806	1.806	5,162,105
Apr-02	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	31,794,000			31,794,000	3.200	3.200	1,017,408
	UPS PURCHASE	UPS	244,320,000			244,320,000	1.621	1.621	3,960,427
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		276,114,000	0	0	276,114,000	1.803	1.803	4,977,835
May-02	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	27,649,000			27,649,000	3.200	3.200	884,768
	UPS PURCHASE	UPS	252,464,000			252,464,000	1.621	1.621	4,092,441
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		280,113,000	0	0	280,113,000	1.777	1.777	4,977,209
Jun-02	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	28,405,000			28,405,000	3.200	3.200	908,960
	UPS PURCHASE	UPS	244,291,000			244,291,000	1.621	1.621	3,959,957
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		272,696,000	0	0	272,696,000	1.785	1.785	4,868,917

FLORIDA POWER CORPORATION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGEN PURCHASES)
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jul-02	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	30,509,000			30,509,000	3.200	3.200	976,288
	UPS PURCHASE	UPS	252,267,000			252,267,000	1.621	1.621	4,089,248
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		282,776,000	0	0	282,776,000	1.791	1.791	5,065,536
Aug-02	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	30,697,000			30,697,000	3.200	3.200	982,304
	UPS PURCHASE	UPS	252,464,000			252,464,000	1.621	1.621	4,092,441
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		283,161,000	0	0	283,161,000	1.792	1.792	5,074,745
Sep-02	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	31,012,000			31,012,000	3.200	3.200	992,384
	UPS PURCHASE	UPS	244,320,000			244,320,000	1.621	1.621	3,960,427
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		275,332,000	0	0	275,332,000	1.799	1.799	4,952,811
Oct-02	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	33,707,000			33,707,000	3.200	3.200	1,078,624
	UPS PURCHASE	UPS	252,397,000			252,397,000	1.621	1.621	4,091,355
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		286,104,000	0	0	286,104,000	1.807	1.807	5,169,979
Nov-02	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	29,271,000			29,271,000	3.200	3.200	936,672
	UPS PURCHASE	UPS	244,320,000			244,320,000	1.621	1.621	3,960,427
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		273,591,000	0	0	273,591,000	1.790	1.790	4,897,099
Dec-02	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	32,029,000			32,029,000	3.200	3.200	1,024,928
	UPS PURCHASE	UPS	252,464,000			252,464,000	1.621	1.621	4,092,441
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		284,493,000	0	0	284,493,000	1.799	1.799	5,117,369
Jan-02	EMERGENCY	A&B	0			0	0.000	0.000	0
THRU	TECO	--	347,898,000			347,898,000	3.200	3.200	11,132,736
Dec-02	UPS PURCHASE	UPS	2,971,467,000			2,971,467,000	1.621	1.621	48,167,480
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		3,319,365,000	0	0	3,319,365,000	1.786	1.786	59,300,216

SCHEDULE E8

FLORIDA POWER CORPORATION
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	C/KWH (A) ENERGY COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(A)
Jan-02	QUAL. FACILITIES	COGEN	586,539,600			586,539,600	2.423	7.080	14,209,639
Feb-02	QUAL. FACILITIES	COGEN	499,699,100			499,699,100	2.392	7.050	11,954,307
Mar-02	QUAL. FACILITIES	COGEN	529,038,300			529,038,300	2.471	7.129	13,071,156
Apr-02	QUAL. FACILITIES	COGEN	514,275,400			514,275,400	2.420	7.078	12,447,640
May-02	QUAL. FACILITIES	COGEN	562,522,500			562,522,500	2.427	7.085	13,651,516
Jun-02	QUAL. FACILITIES	COGEN	558,219,400			558,219,400	2.458	7.115	13,718,548
Jul-02	QUAL. FACILITIES	COGEN	621,966,600			621,966,600	2.433	7.091	15,134,214
Aug-02	QUAL. FACILITIES	COGEN	543,208,100			543,208,100	2.437	7.095	13,237,619
Sep-02	QUAL. FACILITIES	COGEN	549,179,400			549,179,400	2.422	7.079	13,299,093
Oct-02	QUAL. FACILITIES	COGEN	499,425,500			499,425,500	2.469	7.127	12,329,435
Nov-02	QUAL. FACILITIES	COGEN	540,334,400			540,334,400	2.449	7.107	13,234,218
Dec-02	QUAL. FACILITIES	COGEN	505,740,000			505,740,000	2.443	7.101	12,357,123
TOTAL	QUAL. FACILITIES	COGEN	6,510,148,300			6,510,148,300	2.437	7.095	158,644,508

FLORIDA POWER CORPORATION
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL KWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jan-02	ECONPURCH	--	29,923,000	3.400	3.400	1,017,382	4.100	1,226,843	209,461
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		29,923,000	3.400	3.400	1,017,382	4.100	1,226,843	209,461
Feb-02	ECONPURCH	--	5,957,000	3.400	3.400	202,538	4.100	244,237	41,699
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		5,957,000	3.400	3.400	202,538	4.100	244,237	41,699
Mar-02	ECONPURCH	--	11,120,000	3.200	3.200	355,840	3.700	411,440	55,600
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		11,120,000	3.200	3.200	355,840	3.700	411,440	55,600
Apr-02	ECONPURCH	--	16,997,000	3.100	3.100	526,907	3.600	611,892	84,985
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		16,997,000	3.100	3.100	526,907	3.600	611,892	84,985
May-02	ECONPURCH	--	53,786,000	2.900	2.900	1,559,794	3.600	1,936,296	376,502
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		53,786,000	2.900	2.900	1,559,794	3.600	1,936,296	376,502
Jun-02	ECONPURCH	--	96,218,000	2.900	2.900	2,790,322	3.600	3,463,848	673,526
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		96,218,000	2.900	2.900	2,790,322	3.600	3,463,848	673,526

FLORIDA POWER CORPORATION
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL KWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jul-02	ECONPURCH	--	125,038,000	2.800	2.800	3,501,064	3.600	4,501,368	1,000,304
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		125,038,000	2.800	2.800	3,501,064	3.600	4,501,368	1,000,304
Aug-02	ECONPURCH	--	112,386,000	2.800	2.800	3,146,808	3.600	4,045,896	899,088
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	1
	TOTAL		112,386,000	2.800	2.800	3,146,808	3.600	4,045,896	899,089
Sep-02	ECONPURCH	--	81,298,000	2.900	2.900	2,357,642	3.600	2,926,728	569,086
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		81,298,000	2.900	2.900	2,357,642	3.600	2,926,728	569,086
Oct-02	ECONPURCH	--	61,158,000	3.200	3.200	1,957,056	3.900	2,385,162	428,106
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		61,158,000	3.200	3.200	1,957,056	3.900	2,385,162	428,106
Nov-02	ECONPURCH	--	41,980,000	3.200	3.200	1,343,360	3.900	1,637,220	293,860
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		41,980,000	3.200	3.200	1,343,360	3.900	1,637,220	293,860
Dec-02	ECONPURCH	--	42,139,000	3.200	3.200	1,348,448	3.900	1,643,421	294,973
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		42,139,000	3.200	3.200	1,348,448	3.900	1,643,421	294,973
Jan-02	ECONPURCH	--	678,000,000	2.966	2.966	20,107,161	3.692	25,034,351	4,927,190
THRU	OTHER	--	0	0.000	0.000	0	0.000	0	0
Dec-02	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		678,000,000	2.966	2.966	20,107,161	3.692	25,034,351	4,927,190

SCHEDULE E10

FLORIDA POWER CORPORATION
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2002

	DESCRIPTION		Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Period Average	Prior Residential Bill *	Jan-02 vs. Prior
1	Base Rate Revenues	($)	49.05	49.05	49.05	49.05	49.05	49.05	49.05	49.05	49.05	49.05	49.05	49.05	49.05	49.05	0.00
2	Fuel Recovery Factor	(c/kwh)	2.687	2.687	2.687	2.687	2.687	2.687	2.687	2.687	2.687	2.687	2.687	2.687	2.687	2.880	
3	Fuel Cost Recovery Revenues	($)	26.92	26.92	26.92	26.92	26.92	26.92	26.92	26.92	26.92	26.92	26.92	26.92	26.92	28.85	-1.93
4	Capacity Cost Recovery Revenues	($)	11.32	11.32	11.32	11.32	11.32	11.32	11.32	11.32	11.32	11.32	11.32	11.32	11.32	11.08	0.24
5	Energy Conservation Cost Revenues	($)	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.09	-0.02
6	Gross Receipt Taxes	($)	2.29	2.29	2.29	2.29	2.29	2.29	2.29	2.29	2.29	2.29	2.29	2.29	2.29	2.34	-0.05
7	Total Revenues	($)	91.65	91.65	91.65	91.65	91.65	91.65	91.65	91.65	91.65	91.65	91.65	91.65	91.65	93.41	-1.76

* Actual Residential Billing for Dec-01

SCHEDULE H1

FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

			1999	2000	2001	2002	2000 vs. 1999	2001 vs. 2000	2002 vs. 2001
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		136,029,905	206,541,419	237,485,432	210,464,502	51.8%	15.0%	-11.4%
2	LIGHT OIL		35,800,703	63,600,189	81,027,761	56,055,262	77.7%	27.4%	-30.8%
3	COAL		253,061,882	254,102,210	301,829,381	360,647,175	0.4%	18.8%	19.5%
4	GAS		153,504,135	237,565,411	239,485,705	199,094,513	54.8%	0.8%	-16.9%
5	NUCLEAR		18,014,523	23,654,659	20,065,370	22,567,699	31.3%	-15.2%	12.5%
6	OTHER		0	0	0	0	0.0%	0.0%	0.0%
7	TOTAL	$	596,411,148	785,463,888	879,893,649	848,829,151	31.7%	12.0%	-3.5%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		6,299,200	5,394,486	6,618,431	6,351,284	-14.4%	22.7%	-4.0%
9	LIGHT OIL		700,971	824,503	891,694	670,623	17.6%	8.1%	-24.8%
10	COAL		14,149,438	14,427,374	15,077,765	15,032,797	2.0%	4.5%	-0.3%
11	GAS		5,221,193	6,086,880	4,786,044	3,998,303	16.6%	-21.4%	-16.5%
12	NUCLEAR		5,769,375	6,606,870	5,918,575	6,592,923	14.5%	-10.4%	11.4%
13	OTHER		0	0	0	0	0.0%	0.0%	0.0%
14	TOTAL	MWH	32,140,177	33,340,113	33,292,509	32,645,940	3.7%	-0.1%	-1.9%
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	9,886,884	8,412,339	10,459,932	9,994,583	-14.9%	24.3%	-4.4%
16	LIGHT OIL	BBL	1,618,464	1,868,092	2,107,549	1,638,170	15.4%	12.8%	-22.3%
17	COAL	TON	5,389,190	5,493,064	5,752,573	5,703,538	1.9%	4.7%	-0.9%
18	GAS	MCF	46,388,707	53,169,726	43,578,374	40,339,722	14.6%	-18.0%	-7.4%
19	NUCLEAR	MMBTU	59,161,373	67,768,561	60,663,764	68,386,966	14.5%	-10.5%	12.7%
20	OTHER	BBL	0	0	0	0	0.0%	0.0%	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		64,103,123	55,082,394	67,609,334	64,964,787	-14.1%	22.7%	-3.9%
22	LIGHT OIL		9,431,247	10,866,191	12,227,375	9,501,385	15.2%	12.5%	-22.3%
23	COAL		136,357,695	136,896,531	143,289,238	143,370,147	0.4%	4.7%	0.1%
24	GAS		48,135,764	54,885,584	44,864,528	40,339,722	14.0%	-18.3%	-10.1%
25	NUCLEAR		59,161,373	67,768,561	60,663,764	68,386,966	14.5%	-10.5%	12.7%
26	OTHER		0	0	0	0	0.0%	0.0%	0.0%
27	TOTAL	MMBTU	317,189,202	325,499,261	328,654,239	326,563,007	2.6%	1.0%	-0.6%
	GENERATION MIX (% MWH)								
28	HEAVY OIL		19.60%	16.18%	19.88%	19.46%	-17.3%	22.9%	-2.0%
29	LIGHT OIL		2.18%	2.47%	2.68%	2.05%	13.8%	8.1%	-22.4%
30	COAL		44.02%	43.27%	45.29%	46.05%	-1.8%	4.6%	1.8%
31	GAS		16.25%	18.26%	14.38%	12.25%	12.3%	-21.4%	-14.6%
32	NUCLEAR		17.95%	19.82%	17.78%	20.20%	10.6%	-10.1%	13.5%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.0%	0.0%	0.0%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	0.0%	0.0%	0.0%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	13.76	24.55	22.70	21.06	78.5%	-7.5%	-7.2%
36	LIGHT OIL	$/BBL	22.12	34.05	38.45	34.22	53.9%	12.9%	-11.0%
37	COAL	$/TON	46.96	46.26	52.47	63.23	-1.5%	13.4%	20.5%
38	GAS	$/MCF	3.31	4.47	5.50	4.94	35.0%	23.0%	-10.2%
39	NUCLEAR	$/MMBTU	0.30	0.35	0.33	0.33	14.8%	-5.2%	-0.3%
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		2.12	3.75	3.51	3.24	76.7%	-6.3%	-7.8%
42	LIGHT OIL		3.80	5.85	6.63	5.90	54.2%	13.2%	-11.0%
43	COAL		1.86	1.86	2.11	2.52	0.0%	13.5%	19.4%
44	GAS		3.19	4.33	5.34	4.94	35.7%	23.3%	-7.5%
45	NUCLEAR		0.30	0.35	0.33	0.33	14.8%	-5.2%	-0.3%
46	OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
47	TOTAL	$/MMBTU	1.88	2.41	2.68	2.60	28.4%	10.9%	-2.9%
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		10,176	10,211	10,215	10,229	0.3%	0.0%	0.1%
49	LIGHT OIL		13,455	13,179	13,713	14,168	-2.0%	4.0%	3.3%
50	COAL		9,637	9,489	9,503	9,537	-1.5%	0.2%	0.4%
51	GAS		9,219	9,017	9,374	10,089	-2.2%	4.0%	7.6%
52	NUCLEAR		10,254	10,257	10,250	10,373	0.0%	-0.1%	1.2%
53	OTHER		0	0	0	0	0.0%	0.0%	0.0%
54	TOTAL	BTU/KWH	9,869	9,763	9,872	10,003	-1.1%	1.1%	1.3%
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		2.16	3.83	3.59	3.31	77.3%	-6.3%	-7.7%
56	LIGHT OIL		5.11	7.71	9.09	8.36	51.0%	17.8%	-8.0%
57	COAL		1.79	1.76	2.00	2.40	-1.5%	13.7%	19.8%
58	GAS		2.94	3.90	5.00	4.98	32.8%	28.2%	-0.5%
59	NUCLEAR		0.31	0.36	0.34	0.34	14.7%	-5.3%	0.9%
60	OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61	TOTAL	C/KWH	1.86	2.36	2.64	2.60	26.9%	12.2%	-1.6%

Florida Public Service Commission
Docket No. 010001-EI
GULF POWER COMPANY
Witness: T. A. Davis
Exhibit No. _____ (TAD-1)
Schedule 1

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
January 2000 - December 2000

1.	Estimated over/(under) - recovery for the period January 2000 - December 2000 (Schedule E1-A approved in Order No. PSC-00-2385-FOF-EI dated December 12, 2000)	$(8,668,391)
2.	Actual over/(under)-recovery for the period January 2000 - December 2000 (DECEMBER 2000 Schedule A-2, Pg. 2 of 3, "Period-to-Date", Lines 7 and 8)	(1,760,470)
3.	Amount to be refunded/(recovered) in the JANUARY 2002 - DECEMBER 2002 projection period (Line 2 - Line 1)	$ 6,907,921

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 13
COMPANY/ WITNESS. Davis
DATE: 10-20 & 21-01

Florida Public Service Commission
Docket No. 010001-EI
GULF POWER COMPANY
Witness: T. A. Davis
Exhibit No. ____ (TAD -1)
SCHEDULE CCA-1

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
JANUARY 2000 - DECEMBER 2000

1.	Estimated over/(under)-recovery for the period JANUARY 2000 - DECEMBER 2000 (Schedule CCE-1a approved in Order No. PSC-00-2385-FOF-EI dated December 12, 2000)	$(331,059)
2.	Actual over/(under)-recovery for the period JANUARY 2000 - DECEMBER 2000 (Schedule CCA-2 Line 12+13 in the Total column)	9,797
3.	Amount to be refunded/(recovered) in the JANUARY 2002 - DECEMBER 2002 projection period (Line 2 - Line 1)	$ 340,856

SCHEDULE CCA-2

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP AND INTEREST PROVISION
FOR THE PERIOD JANUARY 2000 - DECEMBER 2000

	ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ACTUAL JUNE	ACTUAL JULY	ACTUAL AUGUST	ACTUAL SEPTEMBEF	ACTUAL OCTOBER	ACTUAL NOVEMBER	ACTUAL DECEMBER	ACTUAL TOTAL
1. IIC Payments / (Receipts) ($)	731,509	455,463	188,112	228,081	487,164	1,266,921	2,973,922	3,830,155	1,801,298	377,075	325,240	464,836	13,129,776
2. Transmission Revenue ($)	(5,211)	(4,261)	(7,733)	(8,882)	(9,417)	(22,848)	(11,604)	(25,900)	(26,710)	(21,202)	(31,377)	(18,324)	(193,469)
3. Capacity Payments to Solutia ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	(566,892)	(116,489)	61,237	62,202	62,202	(62,326)
4. Total Capacity Payments/(Receipts) (Line 1 + 2 + 3) ($)	788,500	513,404	242,581	281,401	539,949	1,306,275	3,024,520	3,237,363	1,658,099	417,110	356,065	508,714	12,873,981
5. Jurisdictional %	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271
6. Jurisdictional Capacity Payments / (Receipts) (Line 3 x 4) ($)	760,766	495,346	234,049	271,503	520,958	1,260,330	2,918,139	3,123,495	1,599,779	402,439	343,541	490,821	12,421,166
7. Amount Included in Retail Base Rate Revenues ($)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,666)	(137,666)	(137,666)	(137,666)	(1,652,000)
8. Total Jurisdictional Recovery Amount (Line 5 - 6) ($)	898,433	633,013	371,716	409,170	658,625	1,397,997	3,055,806	3,261,162	1,737,445	540,105	481,207	628,487	14,073,166
9. Jurisdictional Capacity Cost Recovery Revenue Net of Taxes ($)	1,016,053	918,265	899,406	884,800	1,227,379	1,336,303	1,525,248	1,474,279	1,230,666	1,070,223	1,003,672	1,358,372	13,944,667
10. True-Up Provision ($)	5,682	5,682	5,682	5,682	5,682	5,682	5,682	5,682	5,682	5,682	5,681	5,681	68,182
11. Jurisdictional Capacity Cost Recovery Revenue (Line 9 + 10) ($)	1,021,735	923,947	905,088	890,482	1,233,061	1,341,985	1,530,930	1,479,961	1,236,348	1,075,905	1,009,353	1,364,053	14,012,849
12. Over/(Under) Recovery (Line 11 - 8) ($)	123,302	290,934	533,372	481,312	574,436	(56,012)	(1,524,876)	(1,781,201)	(501,097)	535,800	528,146	735,566	(60,318)
13. Interest Provision ($)	4,805	5,886	8,063	10,923	14,201	16,113	11,776	2,779	(3,408)	(3,366)	(542)	2,885	70,115
14. Beginning Balance True-Up & Interest Provision ($)	952,804	1,075,229	1,366,367	1,902,120	2,388,673	2,971,629	2,926,048	1,407,266	(376,838)	(887,025)	(360,273)	161,650	952,804
15. True-Up Collected/(Refunded) ($)	(5,682)	(5,682)	(5,682)	(5,682)	(5,682)	(5,682)	(5,682)	(5,682)	(5,682)	(5,682)	(5,681)	(5,681)	(68,182)
16. End Of Period Total Net True-Up (Lines 12 + 13 + 14 + 15) ($)	1,075,229	1,366,367	1,902,120	2,388,673	2,971,629	2,926,048	1,407,266	(376,838)	(887,025)	(360,273)	161,650	894,420	

SCHEDULE CCA-3

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD JANUARY 2000 - DECEMBER 2000

	ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ACTUAL JUNE	ACTUAL JULY	ACTUAL AUGUST	ACTUAL SEPTEMBER	ACTUAL OCTOBER	ACTUAL NOVEMBER	ACTUAL DECEMBER	TOTAL
1. Beginning True-Up Amount ($)	952,804	1,075,229	1,366,367	1,902,120	2,388,673	2,971,629	2,926,048	1,407,266	(376,838)	(887,025)	(360,273)	161,650	
2. Ending True-Up Amount Before Interest ($)	1,070,424	1,360,481	1,894,057	2,377,750	2,957,428	2,909,935	1,395,490	(379,617)	(883,617)	(356,907)	162,192	891,535	
3. Total Beginning & Ending True-Up Amount ($) (Lines 1 + 2)	2,023,228	2,435,710	3,260,424	4,279,870	5,346,101	5,881,564	4,321,538	1,027,649	(1,260,455)	(1,243,932)	(198,081)	1,053,185	
4. Average True-Up Amount ($)	1,011,614	1,217,855	1,630,212	2,139,935	2,673,051	2,940,782	2,160,769	513,825	(630,228)	(621,966)	(99,041)	526,593	
5. Interest Rate - First Day of Reporting Business Month	0.056000	0.058000	0.058000	0.060700	0.061800	0.065700	0.065800	0.065000	0.064800	0.065000	0.064900	0.066500	
6. Interest Rate - First Day of Subsequent Business Month	0.058000	0.058000	0.060700	0.061800	0.065700	0.065800	0.065000	0.064800	0.065000	0.064900	0.066500	0.065000	
7. Total Interest Rate (Lines 5 + 6)	0.114000	0.116000	0.118700	0.122500	0.127500	0.131500	0.130800	0.129800	0.129800	0.129900	0.131400	0.131500	
8. Average Interest Rate	0.057000	0.058000	0.059350	0.061250	0.063750	0.065750	0.065400	0.064900	0.064900	0.064950	0.065700	0.065750	
9. Monthly Average Interest Rate (1/12 Of Line 8)	0.004750	0.004833	0.004946	0.005104	0.005313	0.005479	0.005450	0.005408	0.005408	0.005413	0.005475	0.005479	
10. Interest Provision For the Month (Lines 4 X 9) ($)	4,805	5,886	8,063	10,923	14,201	16,113	11,776	2,779	(3,408)	(3,366)	(542)	2,885	70,115

SCHEDULE E-1A

FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002

1.	Estimated over/(under)-recovery, JANUARY - DECEMBER 2001 (Sch. E-1B, page 2, line 9)	($17,686,821)
2.	Final over/(under)-recovery JANUARY - DECEMBER 2000 (EXHIBIT No.____(TAD-1), filed April 2, 2001	6,907,921
3.	Total over/(under)-recovery (Lines 1 + 2) To be included in JANUARY 2002 - DECEMBER 2002 (Schedule E1, Line 28)	($10,778,900)
4.	Jurisdictional KWH sales FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002	10,265,886,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢ / KWH)	0.1050

SCHEDULE E-1B
Page 1 of 2

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2001 - DECEMBER 2001

			JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	TOTAL SIX MONTHS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation	17,220,440.71	13,308,480.72	17,836,808.64	16,982,064.30	15,328,649.56	19,652,728.07	$100,329,172.00
	2	Fuel Cost of Power Sold	(6,474,959.86)	(3,008,624.95)	(6,143,978.07)	(7,081,089.12)	(3,560,969.36)	(4,656,149.50)	($30,925,770.86)
	3	Fuel Cost of Purchased Power	7,918,888.63	4,470,531.66	1,591,190.32	2,656,470.72	4,924,364.87	6,894,977.20	28,456,423.40
	3a	Demand & Non-Fuel Cost Of Purchased Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	3b	Energy Payments to Qualified Facilities	411,227.00	148,148.00	55,503.00	252,742.00	177,840.00	155,670.00	1,201,130.00
	4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	5	Other Generation	(555.71)	(423.57)	5,150.00	53,000.89	62,488.76	104,995.51	224,655.88
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A5)	$19,075,040.77	$14,918,111.86	$13,344,673.89	$12,863,188.79	$16,932,373.83	$22,152,221.28	$99,285,610.42
B	1	Jurisdictional KWH Sales	894,601,648	665,415,950	740,704,306	753,771,220	876,985,519	984,069,572	4,915,548,215
	2	Non-Jurisdictional KWH Sales	32,771,393	22,728,026	25,019,926	24,522,286	29,172,685	31,745,515	165,959,831
	3	TOTAL SALES (Lines B1 + B2)	927,373,041	688,143,976	765,724,232	778,293,506	906,158,204	1,015,815,087	5,081,508,046
	4	Jurisdictional % Of Total Sales (Line B1/B3)	96.4662%	96.6972%	96.7325%	96.8492%	96.7806%	96.8749%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	$16,024,786.04	$11,867,985.57	$13,211,480.84	$13,480,270.48	$15,715,545.27	$17,632,644.48	$87,932,712.68
	2	True-Up Provision	(387,727.50)	(387,727.50)	(387,727.50)	(387,727.50)	(387,727.50)	(387,727.50)	(2,326,365.00)
	2a	Incentive Provision	(15,079.33)	(15,079.33)	(15,079.33)	(15,079.33)	(15,079.33)	(15,079.33)	(90,475.98)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$15,621,979.21	$11,465,178.74	$12,808,674.01	$13,077,463.65	$15,312,738.44	$17,229,837.65	$85,515,871.70
	4	Fuel & Net Power Transactions (Line A6)	$19,075,040.77	$14,918,111.86	$13,344,673.89	$12,863,188.79	$16,932,373.83	$22,152,221.28	$99,285,610.42
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A6 x Line B4 x 1.0014)	18,426,728.33	14,445,592.02	12,926,708.76	12,475,336.49	16,410,195.14	21,489,986.13	$96,174,546.87
	6	Over/(Under) Recovery (Line C3-C5)	(2,804,749.12)	(2,980,413.28)	(118,034.75)	602,127.16	(1,097,456.70)	(4,260,148.48)	($10,658,675.17)
	7	Interest Provision	5,255.37	(6,477.12)	(11,083.76)	(7,816.60)	(6,475.66)	(12,724.32)	($39,322.09)
	8	2000 Revenue sharing Refund True-Up					221,981.86		$221,981.86
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2001 - JUNE 2001**							($10,476,015.40)

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2001 - DECEMBER 2001

				JULY ACTUAL	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL PERIOD
				(a)	(b)	(c)				(d)
A	1	Fuel Cost of System Generation		18,948,433.07	20,816,613.00	17,785,196.00	16,303,905.00	15,701,505.00	15,421,025.00	$205,305,849.07
	2	Fuel Cost of Power Sold		(3,611,315.29)	(6,310,000.00)	(5,463,000.00)	(6,662,000.00)	(6,051,000.00)	(3,865,000.00)	($62,888,086.15)
	3	Fuel Cost of Purchased Power		10,044,590.38	9,180,000.00	3,766,000.00	2,608,000.00	1,349,000.00	1,953,000.00	$57,357,013.78
	3a	Demand & Non-Fuel Cost Of Purchased Power		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facilities		261,868.00	36,142.00	18,559.00	977.00	3,576.00	0.00	$1,522,252.00
	4	Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation		139,042.84	152,512.00	147,434.00	152,512.00	147,434.00	152,513.00	$1,116,103.72
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A5)		$25,782,619.00	$23,875,267.00	$16,254,189.00	$12,403,394.00	$11,150,515.00	$13,661,538.00	$202,413,132.42
B	1	Jurisdictional KWH Sales		1,065,436,221	1,087,159,000	910,120,000	746,881,000	690,615,000	818,601,000	10,234,360,436
	2	Non-Jurisdictional KWH Sales		35,933,844	36,338,000	31,078,000	26,466,000	25,796,000	29,600,000	351,171,675
	3	TOTAL SALES (Lines B1 + B2)		1,101,370,065	1,123,497,000	941,198,000	773,347,000	716,411,000	848,201,000	10,585,532,111
	4	Jurisdictional % Of Total Sales (Line B1/B3)		96.7374%	96.7656%	96.6980%	96.5777%	96.3993%	96.5103%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	$19,129,576.68	$19,459,058.94	$16,290,237.88	$13,368,423.02	$12,361,317.89	$14,652,139.30	$183,193,466.38
	2	True-Up Provision		(387,727.50)	(387,727.50)	(387,727.50)	(387,727.50)	(387,727.50)	(387,727.50)	($4,652,730.00)
	2a	Incentive Provision		(15,079.33)	(15,079.33)	(15,079.33)	(15,079.33)	(15,079.33)	(15,079.56)	($180,952.19)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		$18,726,769.85	$19,056,252.11	$15,887,431.05	$12,965,616.19	$11,958,511.06	$14,249,332.24	$178,359,784.19
	4	Fuel & Net Power Transactions (Line A6)		$25,782,619.00	$23,875,267.00	$16,254,189.00	$12,403,394.00	$11,150,515.00	$13,661,538.00	$202,413,132.42
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A6 x Line B4 x 1.0014)		24,976,353.28	23,135,389.63	15,739,480.15	11,995,683.12	10,764,067.03	13,203,250.02	$195,988,769.10
	6	Over/(Under) Recovery (Line C3-C5)		(6,249,583.43)	(4,079,137.52)	147,950.90	969,933.07	1,194,444.03	1,046,082.22	($17,628,986.90)
	7	Interest Provision	(2)	(27,764.67)	(42,879.31)	(47,978.17)	(45,150.89)	(40,668.58)	(36,052.38)	($279,816.09)
	8	2000 Revenue Sharing Refund True-Up								$221,981.86
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2001 - DECEMBER 2001**								($17,686,821.13)

Note 1: Estimated Revenues based on the 2001 Fuel Factor excluding revenue taxes of 1.7899 ¢/KWH
Note 2: Interest Calculated for August through December at July's rate of 0.3146

SCHEDULE E-1B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2001 - DECEMBER 2001

		DOLLARS				KWH				¢/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ACTUAL	EST.	DIFFERENCE AMT.	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	205,305,849	198,152,168	7,153,681	3.61	12,471,840,000	12,567,070,000	(95,230,000)	(0.76)	1.6462	1.5768	0.0694	4.40
2	Nuclear Fuel Disposal Costs	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Other Generation	1,116,104	1,795,125	(679,021)	(37.83)	63,471,000	102,520,000	(39,049,000)	(38.09)	1.7584	1.751	0.0074	0.42
5	TOTAL COST OF GENERATED POWER	206,421,953	199,947,293	6,474,660	3.24	12,535,311,000	12,669,590,000	(134,279,000)	(1.06)	1.6467	1.5782	0.0685	4.34
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
7	Energy Cost of Schedule C&X Econ. Purchases (Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Other Economy Purchases (Nonbroker) (A9)	57,357,014	53,410,000	3,947,014	7.39	1,848,477,147	1,609,687,000	238,790,147	14.83	3.1029	3.318	(0.2151)	(6.48)
9	Energy Cost of Schedule E Economy Purchases (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Energy Payments to Qualifying Facilities (A9a)	1,522,252	210,570	1,311,682	622.92	35,112,392	8,940,000	26,172,392	292.76	4.3354	2.3554	1.9800	84.06
12	TOTAL COST OF PURCHASED POWER	58,879,266	53,620,570	5,258,696	9.81	1,883,589,539	1,618,627,000	264,962,539	16.37	3.1259	3.3127	(0.1868)	(5.64)
13	Total Available KWH (Lines 4 + Line 12)	265,301,219	253,567,863	11,733,356	4.63	14,418,900,539	14,288,217,000	130,683,539	0.91				
14	Fuel Cost of Economy Sales (A6)	(5,828,811)	(4,815,000)	(1,013,811)	(21.06)	(227,987,895)	(193,085,000)	(34,902,895)	(18.08)	(2.5566)	(2.4937)	(0.0629)	(2.52)
15	Gain on Economy Sales (A6)	(1,570,574)	(1,047,000)	(523,574)	(50.01)			0	#N/A	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Unit Power Sales (A6)	(25,045,544)	(21,464,000)	(3,581,544)	(16.69)	(1,279,864,901)	(1,045,364,000)	(234,500,901)	(22.43)	(1.9569)	(2.0533)	0.0964	4.69
17	Fuel Cost of Other Power Sales (A6)	(30,443,157)	(43,126,000)	12,682,843	29.41	(1,650,073,976)	(1,863,676,000)	213,602,024	11.46	(1.8450)	(2.3140)	0.4690	20.27
18	TOTAL FUEL COST AND GAINS ON POWER SALES (LINES 14+15+16+17)	(62,888,086)	(70,452,000)	7,563,914	10.74	(3,157,926,772)	(3,102,125,000)	(55,801,772)	(1.80)	(1.9914)	(2.2711)	0.2797	12.32
19	Net Inadvertent Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
20	**TOTAL FUEL & NET POWER TRANSACTIONS** (LINES 5+12+18+19)	202,413,133	183,115,863	19,297,270	10.54	11,260,973,767	11,186,092,000	74,881,767	0.67	1.7975	1.637	0.1605	9.80
21	Net Unbilled Sales	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
22	Company Use *	409,270	351,267	58,002	16.51	22,768,825	21,458,000	1,310,825	6.11	1.7975	1.637	0.1605	9.80
23	T & D Losses *	11,731,794	10,656,019	1,075,775	10.10	652,672,831	650,948,000	1,724,831	0.26	1.7975	1.637	0.1605	9.80
24	TERRITORIAL (SYSTEM) SALES	202,413,133	183,115,863	19,297,270	10.54	10,585,532,111	10,513,686,000	71,846,111	0.68	1.9122	1.7417	0.1705	9.79
25	Wholesale Sales	6,698,365	6,202,438	495,927	8.00	351,171,675	356,114,000	(4,942,325)	(1.39)	1.9074	1.7417	0.1657	9.51
26	Jurisdictional Sales	195,714,768	176,913,425	18,801,343	10.63	10,234,360,436	10,157,572,000	76,788,436	0.76	1.9123	1.7417	0.1706	9.80
26a	Jurisdictional Loss Multiplier	1.0014	1.0014										
27	Jurisdictional Sales Adj. for Line Losses (Line 26 x 1.0014)	195,988,769	177,161,104	18,827,665	10.63	10,234,360,436	10,157,572,000	76,788,436	0.76	1.915	1.7441	0.1709	9.80
28	TRUE-UP **	4,652,730	4,652,730	0	0.00	10,234,360,436	10,157,572,000	76,788,436	0.76	0.0455	0.0458	(0.0003)	(0.66)
29	TOTAL JURISDICTIONAL FUEL COST	200,641,499	181,813,834	18,827,665	10.36	10,234,360,436	10,157,572,000	76,788,436	0.76	1.9605	1.7899	0.1706	9.53
30	Revenue Tax Factor									1.01609	1.01597		
31	Fuel Factor Adjusted for Revenue Taxes									1.9920	1.8185	0.1736	9.55
32	GPIF Reward / (Penalty) **	183,842	183,842	0	0.00	10,234,360,436	10,157,572,000	76,788,436	0.76	0.0018	0.0018	0.0000	0.00
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									1.9938	1.8203	0.1735	9.53
34	**FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)**									1.994	1.820	0.174	9.56

* Included for Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

Note: Amounts Included in the Estimated/Actual Column represent 7 months actual and 5 months estimate. Amounts Included in the Estimated Original Column represent amounts originally projected.

Schedule CCE-1a

Purchased Power Capacity Cost Recovery Clause
Calculation of True-up
Gulf Power Company
January 2002 - December 2002

1	Estimated over/(under)-recovery, January 2001 - December 2001 (Schedule CCE-1b-1, Line 18)	$1,515,391
2	Final True-Up, January 2000 - December 2000 (Exhibit No.____(TAD-1), filed April 2, 2001	340,856
3	Total Over/(Under)-Recovery (Line 1 & 2) (To be included in January 2002 - December 2002)	$1,856,247
4	Jurisdictional KWH sales, January 2002 - December 2002	10,265,886,000
5	True-up Factor (Line 3 / Line 4) x 100 (Cents/KWH)	(0.0181)

Schedule CCE-1b

Purchased Power Capacity Cost Recovery Clause
Calculation of Estimated True-Up Amount
Gulf Power Company
For the Period January 2001 - December 2001

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1	IIC Payments/(Receipts) ($)	756,739	478,834	435,604	416,580	449,533	1,656,328	3,291,404	820,247	910,482	81,203	(25,603)	93,860	9,365,211
2	Projected Capacity Payments to Monsanto ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
3	Transmission Revenue ($)	(35,910)	(11,404)	(39,862)	(13,748)	(14,826)	(52,093)	(5,068)	(23,000)	(25,000)	(81,000)	(91,000)	(38,000)	(430,911)
4	Projected Market Capacity Payments								3,373,375	1,606,063	344,400	344,400	344,400	6,012,638
5	Total Capacity Payments/(Receipts) (Line 1 + 2 + 3 + 4) ($)	783,031	529,632	457,944	465,034	496,909	1,666,437	3,348,538	4,232,824	2,553,747	406,805	289,999	462,462	15,693,362
6	Jurisdictional %	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
7	Jurisdictional Capacity Payments/(Receipts) (Line 5 x Line 6) ($)	755,683	511,134	441,950	448,793	479,554	1,608,236	3,231,589	4,084,991	2,464,557	392,597	279,871	446,310	15,145,265
8	Amount Included in Retail Base Rate Revenues ($)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,666)	(137,666)	(137,666)	(137,666)	(1,652,000)
9	Total Jurisdictional Recovery Amount (Line 7 - Line 8) ($)	893,350	648,801	579,617	586,460	617,221	1,745,903	3,369,256	4,222,658	2,602,223	530,263	417,537	583,976	16,797,265
10	Retail KWH Sales								1,087,159,000	910,120,000	746,881,000	690,615,000	818,601,000	
11	Purchased Power Capacity Cost Recovery Factor (¢/KWH)								0.176	0.176	0.176	0.176	0.176	
12	Capacity Cost Recovery Revenues (Line 10 x Line 11/100) ($)	1,612,108	1,149,770	1,266,208	1,292,654	1,510,924	1,740,018	1,897,050	1,913,400	1,601,811	1,314,511	1,215,482	1,440,738	17,954,673
13	Revenue Taxes (Line 12 x .01572) ($)	25,342	18,074	19,905	20,321	23,752	27,353	29,822	30,079	25,180	20,664	19,107	22,648	282,247
14	True-Up Provision ($)	46,130	46,130	46,130	46,131	46,130	46,130	46,130	46,131	46,130	46,130	46,130	46,131	553,563
15	Capacity Cost Recovery Revenues net of Revenue Taxes (Line 12 - Line 13 + Line 14) ($)	1,632,896	1,177,826	1,292,433	1,318,464	1,533,302	1,758,795	1,913,358	1,929,452	1,622,761	1,339,977	1,242,505	1,464,221	18,225,990
16	Over/(Under) Recovery (Line 15 - Line 9) ($)	739,546	529,025	712,816	732,004	916,081	12,892	(1,455,898)	(2,293,206)	(979,462)	809,714	824,968	880,245	1,428,725
17	Interest Provision ($)	6,231	8,183	10,228	12,122	13,487	13,954	11,241	5,234	(42)	(455)	1,970	4,513	86,666
18	Total Estimated True-Up for the Period January 2001 - December 2001 (Line 16 + Line 17) ($)													1,515,391

NOTE: Interest is Calculated for Aug - Dec at July's rate of 0.3146 %
Actual IIC Payments for January through July include Market Capacity Payments

SCHEDULE E-1A
Revised 9/20/01

FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002

1.	Estimated over/(under)-recovery, JANUARY - DECEMBER 2001 (Sch. E-1B, page 2, line 9)	($17,609,612)
2.	Final over/(under)-recovery JANUARY - DECEMBER 2000 (EXHIBIT No.____(TAD-1), filed April 2, 2001	6,907,921
3.	Total over/(under)-recovery (Lines 1 + 2) To be included in JANUARY 2002 - DECEMBER 2002 (Schedule E1, Line 28)	($10,701,691)
4.	Jurisdictional KWH sales FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002	10,265,886,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢ / KWH)	0.1042

SCHEDULE E-1B
Revised 9/20/01 Page 1 of 2

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2001 - DECEMBER 2001

			JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	TOTAL SIX MONTHS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation	17,220,440.71	13,308,480.72	17,836,808.64	16,982,064.30	15,328,649.56	19,652,728.07	$100,329,172.00
	2	Fuel Cost of Power Sold	(6,474,959.86)	(3,008,624.95)	(6,143,978.07)	(7,081,089.12)	(3,560,969.36)	(4,656,149.50)	($30,925,770.86)
	3	Fuel Cost of Purchased Power	7,918,888.63	4,470,531.66	1,591,190.32	2,656,470.72	4,924,364.87	6,894,977.20	28,456,423.40
	3a	Demand & Non-Fuel Cost Of Purchased Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	3b	Energy Payments to Qualified Facilities	411,227.00	148,148.00	55,503.00	252,742.00	177,840.00	155,670.00	1,201,130.00
	4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	5	Other Generation	(555.71)	(423.57)	5,150.00	53,000.89	62,488.76	104,995.51	224,655.88
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A5)	$19,075,040.77	$14,918,111.86	$13,344,673.89	$12,863,188.79	$16,932,373.83	$22,152,221.28	$99,285,610.42
B	1	Jurisdictional KWH Sales	894,601,648	665,415,950	740,704,306	753,771,220	876,985,519	984,069,572	4,915,548,215
	2	Non-Jurisdictional KWH Sales	32,771,393	22,728,026	25,019,926	24,522,286	29,172,685	31,745,515	165,959,831
	3	TOTAL SALES (Lines B1 + B2)	927,373,041	688,143,976	765,724,232	778,293,506	906,158,204	1,015,815,087	5,081,508,046
	4	Jurisdictional % Of Total Sales (Line B1/B3)	96.4662%	96.6972%	96.7325%	96.8492%	96.7806%	96.8749%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	$16,024,786.04	$11,867,985.57	$13,211,480.84	$13,480,270.48	$15,715,545.27	$17,632,644.48	$87,932,712.68
	2	True-Up Provision	(387,727.50)	(387,727.50)	(387,727.50)	(387,727.50)	(387,727.50)	(387,727.50)	(2,326,365.00)
	2a	Incentive Provision	(15,079.33)	(15,079.33)	(15,079.33)	(15,079.33)	(15,079.33)	(15,079.33)	(90,475.98)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$15,621,979.21	$11,465,178.74	$12,808,674.01	$13,077,463.65	$15,312,738.44	$17,229,837.65	$85,515,871.70
	4	Fuel & Net Power Transactions (Line A6)	$19,075,040.77	$14,918,111.86	$13,344,673.89	$12,863,188.79	$16,932,373.83	$22,152,221.28	$99,285,610.42
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A6 x Line B4 x 1.0014)	18,426,728.33	14,445,592.02	12,926,708.76	12,475,336.49	16,410,195.14	21,489,986.13	$96,174,546.87
	6	Over/(Under) Recovery (Line C3-C5)	(2,804,749.12)	(2,980,413.28)	(118,034.75)	602,127.16	(1,097,456.70)	(4,260,148.48)	($10,658,675.17)
	7	Interest Provision	5,255.37	(6,477.12)	(11,083.76)	(7,816.60)	(6,475.66)	(12,724.32)	($39,322.09)
	8	2000 Revenue sharing Refund True-Up					221,981.86		$221,981.86
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2001 - JUNE 2001**							($10,476,015.40)

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2001 - DECEMBER 2001

				JULY ACTUAL	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL PERIOD
				(a)	(b)	(c)				(d)
A	1	Fuel Cost of System Generation		18,948,433.07	20,816,613.00	17,785,196.00	16,303,905.00	15,701,505.00	15,421,025.00	$205,305,849.07
	2	Fuel Cost of Power Sold		(3,611,315.29)	(6,310,000.00)	(5,463,000.00)	(6,662,000.00)	(6,051,000.00)	(3,865,000.00)	($62,888,086.15)
	3	Fuel Cost of Purchased Power		10,044,590.38	9,180,000.00	3,766,000.00	2,608,000.00	1,349,000.00	1,953,000.00	$57,357,013.78
	3a	Demand & Non-Fuel Cost Of Purchased Power		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facilities		261,868.00	36,142.00	18,559.00	977.00	3,576.00	0.00	$1,522,252.00
	4	Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation		139,042.84	152,512.00	147,434.00	152,512.00	147,434.00	152,512.00	$1,116,102.72
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A5)		$25,782,619.00	$23,875,267.00	$16,254,189.00	$12,403,394.00	$11,150,515.00	$13,661,537.00	$202,413,131.42
B	1	Jurisdictional KWH Sales		1,065,436,221	1,087,159,000	910,120,000	746,881,000	690,615,000	818,601,000	10,234,360,436
	2	Non-Jurisdictional KWH Sales		35,933,844	36,338,000	31,078,000	26,466,000	25,796,000	29,600,000	351,171,675
	3	TOTAL SALES (Lines B1 + B2)		1,101,370,065	1,123,497,000	941,198,000	773,347,000	716,411,000	848,201,000	10,585,532,111
	4	Jurisdictional % Of Total Sales (Line B1/B3)		96.7374%	96.7656%	96.6980%	96.5777%	96.3993%	96.5103%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	$19,129,576.68	$19,478,627.80	$16,306,620.04	$13,381,866.88	$12,373,748.96	$14,666,874.12	$183,270,027.15
	2	True-Up Provision		(387,727.50)	(387,727.50)	(387,727.50)	(387,727.50)	(387,727.50)	(387,727.50)	($4,652,730.00)
	2a	Incentive Provision		(15,079.33)	(15,079.33)	(15,079.33)	(15,079.33)	(15,079.33)	(15,079.56)	($180,952.19)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		$18,726,769.85	$19,075,820.97	$15,903,813.21	$12,979,060.05	$11,970,942.13	$14,264,067.06	$178,436,344.96
	4	Fuel & Net Power Transactions (Line A6)		$25,782,619.00	$23,875,267.00	$16,254,189.00	$12,403,394.00	$11,150,515.00	$13,661,537.00	$202,413,131.42
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A6 x Line B4 x 1.0014)		24,976,353.28	23,135,389.63	15,739,480.15	11,995,683.12	10,764,067.03	13,203,249.05	$195,988,768.13
	6	Over/(Under) Recovery (Line C3-C5)		(6,249,583.43)	(4,059,568.66)	164,333.06	983,376.93	1,206,875.10	1,060,818.01	($17,552,425.16)
	7	Interest Provision	(2)	(27,764.67)	(42,848.53)	(47,890.74)	(45,016.27)	(40,492.83)	(35,833.35)	($279,168.48)
	8	2000 Revenue Sharing Refund True-Up								$221,981.86
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2001 - DECEMBER 2001**								($17,609,611.78)

Note 1: Estimated Revenues based on the 2001 Fuel Factor excluding revenue taxes of 1.7917 ¢/KWH
Note 2: Interest Calculated for August through December at July's rate of 0.3146

SCHEDULE E-1B-1
Revised 9/20/01

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2001 - DECEMBER 2001

		DOLLARS				KWH				¢/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ACTUAL	EST.	DIFFERENCE AMT.	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	205,305,849	198,152,168	7,153,681	3.61	12,471,840,000	12,567,070,000	(95,230,000)	(0.76)	1.6462	1.5768	0.0694	4.40
2	Nuclear Fuel Disposal Costs	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Other Generation	1,116,103	1,795,125	(679,022)	(37.83)	63,471,000	102,520,000	(39,049,000)	(38.09)	1.7584	1.751	0.0074	0.42
5	TOTAL COST OF GENERATED POWER	206,421,952	199,947,293	6,474,659	3.24	12,535,311,000	12,669,590,000	(134,279,000)	(1.06)	1.6467	1.5782	0.0685	4.34
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
7	Energy Cost of Schedule C&X Econ. Purchases (Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Other Economy Purchases (Nonbroker) (A9)	57,357,014	53,410,000	3,947,014	7.39	1,848,477,147	1,609,687,000	238,790,147	14.83	3.1029	3.318	(0.2151)	(6.48)
9	Energy Cost of Schedule E Economy Purchases (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Energy Payments to Qualifying Facilities (A9a)	1,522,252	210,570	1,311,682	622.92	35,112,392	8,940,000	26,172,392	292.76	4.3354	2.3554	1.9800	84.06
12	TOTAL COST OF PURCHASED POWER	58,879,266	53,620,570	5,258,696	9.81	1,883,589,539	1,618,627,000	264,962,539	16.37	3.1259	3.3127	(0.1868)	(5.64)
13	Total Available KWH (Lines 4 + Line 12)	265,301,218	253,567,863	11,733,355	4.63	14,418,900,539	14,288,217,000	130,683,539	0.91				
14	Fuel Cost of Economy Sales (A6)	(5,828,811)	(4,815,000)	(1,013,811)	(21.06)	(227,987,895)	(193,085,000)	(34,902,895)	(18.08)	(2.5566)	(2.4937)	(0.0629)	(2.52)
15	Gain on Economy Sales (A6)	(1,570,574)	(1,047,000)	(523,574)	(50.01)			0	#N/A	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Unit Power Sales (A6)	(25,045,544)	(21,464,000)	(3,581,544)	(16.69)	(1,279,864,901)	(1,045,364,000)	(234,500,901)	(22.43)	(1.9569)	(2.0533)	0.0964	4.69
17	Fuel Cost of Other Power Sales (A6)	(30,443,157)	(43,126,000)	12,682,843	29.41	(1,650,073,976)	(1,863,676,000)	213,602,024	11.46	(1.8450)	(2.3140)	0.4690	20.27
18	TOTAL FUEL COST AND GAINS ON POWER SALES (LINES 14+15+16+17)	(62,888,086)	(70,452,000)	7,563,914	10.74	(3,157,926,772)	(3,102,125,000)	(55,801,772)	(1.80)	(1.9914)	(2.2711)	0.2797	12.32
19	Net Inadvertent Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
20	**TOTAL FUEL & NET POWER TRANSACTIONS** (LINES 5+12+18+19)	202,413,132	183,115,863	19,297,269	10.54	11,260,973,767	11,186,092,000	74,881,767	0.67	1.7975	1.637	0.1605	9.80
21	Net Unbilled Sales	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
22	Company Use *	409,270	351,267	58,002	16.51	22,768,825	21,458,000	1,310,825	6.11	1.7975	1.637	0.1605	9.80
23	T & D Losses *	11,731,794	10,656,019	1,075,775	10.10	652,672,831	650,948,000	1,724,831	0.26	1.7975	1.637	0.1605	9.80
24	TERRITORIAL (SYSTEM) SALES	202,413,132	183,115,863	19,297,269	10.54	10,585,532,111	10,513,686,000	71,846,111	0.68	1.9122	1.7417	0.1705	9.79
25	Wholesale Sales	6,698,365	6,202,438	495,927	8.00	351,171,675	356,114,000	(4,942,325)	(1.39)	1.9074	1.7417	0.1657	9.51
26	Jurisdictional Sales	195,714,767	176,913,425	18,801,342	10.63	10,234,360,436	10,157,572,000	76,788,436	0.76	1.9123	1.7417	0.1706	9.80
26a	Jurisdictional Loss Multiplier	1.0014	1.0014										
27	Jurisdictional Sales Adj. for Line Losses (Line 26 x 1.0014)	195,988,768	177,161,104	18,827,664	10.63	10,234,360,436	10,157,572,000	76,788,436	0.76	1.915	1.7441	0.1709	9.80
28	TRUE-UP **	4,652,730	4,652,730	0	0.00	10,234,360,436	10,157,572,000	76,788,436	0.76	0.0455	0.0458	(0.0003)	(0.66)
29	TOTAL JURISDICTIONAL FUEL COST	200,641,498	181,813,834	18,827,664	10.36	10,234,360,436	10,157,572,000	76,788,436	0.76	1.9605	1.7899	0.1706	9.53
30	Revenue Tax Factor									1.01609	1.01597		
31	Fuel Factor Adjusted for Revenue Taxes									1.9920	1.8185	0.1736	9.55
32	GPIF Reward / (Penalty) **	183,842	183,842	0	0.00	10,234,360,436	10,157,572,000	76,788,436	0.76	0.0018	0.0018	0.0000	0.00
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									1.9938	1.8203	0.1735	9.53
34	**FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)**									1.994	1.820	0.174	9.56

* Included for Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

Note: Amounts Included in the Estimated/Actual Column represent 7 months actual and 5 months estimate. Amounts Included in the Estimated Original Column represent amounts originally projected.

Schedule CCE-1a

Purchased Power Capacity Cost Recovery Clause
Calculation of True-up
Gulf Power Company
January 2002 - December 2002

1	Estimated over/(under)-recovery, January 2001 - December 2001 (Schedule CCE-1b-1, Line 18)	$1,515,391
2	Final True-Up, January 2000 - December 2000 (Exhibit No.____(TAD-1), filed April 2, 2001	340,856
3	Total Over/(Under)-Recovery (Line 1 & 2) (To be included in January 2002 - December 2002)	$1,856,247
4	Jurisdictional KWH sales, January 2002 - December 2002	10,265,886,000
5	True-up Factor (Line 3 / Line 4) x 100 (Cents/KWH)	(0.0181)

Schedule CCE-1b

Purchased Power Capacity Cost Recovery Clause
Calculation of Estimated True-Up Amount
Gulf Power Company
For the Period January 2001 - December 2001

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1	IIC Payments/(Receipts) ($)	756,739	478,834	435,604	416,580	449,533	1,656,328	3,291,404	820,247	910,482	81,203	(25,603)	93,860	9,365,211
2	Projected Capacity Payments to Monsanto ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
3	Transmission Revenue ($)	(35,910)	(11,404)	(39,862)	(13,748)	(14,826)	(52,093)	(5,068)	(23,000)	(25,000)	(81,000)	(91,000)	(38,000)	(430,911)
4	Projected Market Capacity Payments								3,373,375	1,606,063	344,400	344,400	344,400	6,012,638
5	Total Capacity Payments/(Receipts) (Line 1 + 2 + 3 + 4) ($)	783,031	529,632	457,944	465,034	496,909	1,666,437	3,348,538	4,232,824	2,553,747	406,805	289,999	462,462	15,693,362
6	Jurisdictional %	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
7	Jurisdictional Capacity Payments/(Receipts) (Line 5 x Line 6) ($)	755,683	511,134	441,950	448,793	479,554	1,608,236	3,231,589	4,084,991	2,464,557	392,597	279,871	446,310	15,145,265
8	Amount Included in Retail Base Rate Revenues ($)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,666)	(137,666)	(137,666)	(137,666)	(1,652,000)
9	Total Jurisdictional Recovery Amount (Line 7 - Line 8) ($)	893,350	648,801	579,617	586,460	617,221	1,745,903	3,369,256	4,222,658	2,602,223	530,263	417,537	583,976	16,797,265
10	Retail KWH Sales								1,087,159,000	910,120,000	746,881,000	690,615,000	818,601,000	
11	Purchased Power Capacity Cost Recovery Factor (¢/KWH)								0.176	0.176	0.176	0.176	0.176	
12	Capacity Cost Recovery Revenues (Line 10 x Line 11/100) ($)	1,612,108	1,149,770	1,266,208	1,292,654	1,510,924	1,740,018	1,897,050	1,913,400	1,601,811	1,314,511	1,215,482	1,440,738	17,954,673
13	Revenue Taxes (Line 12 x .01572) ($)	25,342	18,074	19,905	20,321	23,752	27,353	29,822	30,079	25,180	20,664	19,107	22,648	282,247
14	True-Up Provision ($)	46,130	46,130	46,130	46,131	46,130	46,130	46,130	46,131	46,130	46,130	46,130	46,131	553,563
15	Capacity Cost Recovery Revenues net of Revenue Taxes (Line 12 - Line 13 + Line 14) ($)	1,632,896	1,177,826	1,292,433	1,318,464	1,533,302	1,758,795	1,913,358	1,929,452	1,622,761	1,339,977	1,242,505	1,464,221	18,225,990
16	Over/(Under) Recovery (Line 15 - Line 9) ($)	739,546	529,025	712,816	732,004	916,081	12,892	(1,455,898)	(2,293,206)	(979,462)	809,714	824,968	880,245	1,428,725
17	Interest Provision ($)	6,231	8,183	10,228	12,122	13,487	13,954	11,241	5,234	(42)	(455)	1,970	4,513	86,666
18	Total Estimated True-Up for the Period January 2001 - December 2001 (Line 16 + Line 17) ($)													1,515,391

NOTE: Interest is Calculated for Aug - Dec at July's rate of 0.3146 %
Actual IIC Payments for January through July include Market Capacity Payments

SCHEDULE E-1

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002

Line				(a) $	(b) KWH	(c) ¢ / KWH
1	Fuel Cost of System Net Generation		E-3	303,530,586	14,995,670,000	2.0241
2	Nuclear Fuel Disposal Costs		E-2	0	0	#N/A
3	Coal Car Investment			0	0	#N/A
4	Other Generation			217,158	10,200,000	2.1290
5	**Total Cost of Generated Power**	(Line 1 - 4)		303,747,744	15,005,870,000	2.0242
6	Fuel Cost of Purchased Power (Exclusive of Economy)		E-7			#N/A
7	Energy Cost of Schedule C & X Econ. Purch.		E-9			#N/A
8	Energy Cost of Other Econ. Purch. (Nonbroker)		E-9	21,398,000	740,869,000	2.8882
9	Energy Cost of Schedule E Economy Purch.		E-9	0	0	#N/A
10	Capacity Cost of Schedule E Economy Purchases		E-2	0	0	#N/A
11	Energy Payments to Qualifying Facilities		E-8	312,832	14,780,000	2.1166
12	**Total Cost of Purchased Power**	(Line 6 - 11)		21,710,832	755,649,000	2.8731
13	**Total Available KWH**	(Line 5 + 12)			15,761,519,000	
14	Fuel Cost of Economy Sales		E-6	(2,414,000)	(38,134,000)	6.3303
15	Gain on Economy Sales		E-6	(449,000)		#N/A
16	Fuel Cost of Unit Power Sales		E-6	(27,262,000)	(1,324,756,000)	2.0579
17	Fuel Cost of Other Power Sales			(75,793,000)	(3,093,280,000)	2.4502
18	**Total Fuel Cost & Gains on Power Sales**	(Line 14 -17)		(105,918,000)	(4,456,170,000)	2.3769
19	Net Inadvertant Interchange			0	0	#N/A
20	**Total Fuel & Net Power Trans.**	(Line 5+12+18+19)		219,540,576	11,305,349,000	1.9419
21	Net Unbilled Sales *			0	0	#N/A
22	Company Use *			419,276	21,591,000	1.9419
23	T & D Losses *			12,836,483	661,027,000	1.9419
24	**System KWH Sales**			219,540,576	10,622,731,000	2.0667
25	Wholesale KWH Sales			7,374,916	356,845,000	2.0667
26	Jurisdictional KWH Sales			212,165,660	10,265,886,000	2.0667
26a	Jurisdictional Line Loss Multiplier			1.0014		1.0014
27	Jurisdictional KWH Sales Adjusted for Line Losses			212,462,692	10,265,886,000	2.0696
28	**True-Up ****			10,701,691	10,265,886,000	0.1042
29	**Total Jurisdictional Fuel Cost**			223,164,383	10,265,886,000	2.1738
30	Revenue Tax Factor					1.01597
31	Fuel Factor Adjusted For Revenue Taxes					2.2085
32	GPIF Reward/(Penalty) **			379,732	10,265,886,000	0.0037
33	Fuel Factor Adjusted for GPIF					2.2122
34	**Fuel Factor Rounded to Nearest .001(¢ / KWH)**					**2.212**

*For informational purposes only

** Calculation Based on Jurisdictional KWH Sales

SCHEDULE E-1A
Revised 9/20/01

FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002

1.	Estimated over/(under)-recovery, JANUARY - DECEMBER 2001 (Sch. E-1B, page 2, line 9)	($17,609,612)
2.	Final over/(under)-recovery JANUARY - DECEMBER 2000 (EXHIBIT No.____(TAD-1), filed April 2, 2001	6,907,921
3.	Total over/(under)-recovery (Lines 1 + 2) To be included in JANUARY 2002 - DECEMBER 2002 (Schedule E1, Line 28)	($10,701,691)
4.	Jurisdictional KWH sales FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002	10,265,886,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢ / KWH)	0.1042

SCHEDULE E-1B
Revised 9/20/01 Page 1 of 2

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2001 - DECEMBER 2001

			JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	TOTAL SIX MONTHS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation	17,220,440.71	13,308,480.72	17,836,808.64	16,982,064.30	15,328,649.56	19,652,728.07	$100,329,172.00
	2	Fuel Cost of Power Sold	(6,474,959.86)	(3,008,624.95)	(6,143,978.07)	(7,081,089.12)	(3,560,969.36)	(4,656,149.50)	($30,925,770.86)
	3	Fuel Cost of Purchased Power	7,918,888.63	4,470,531.66	1,591,190.32	2,656,470.72	4,924,364.87	6,894,977.20	28,456,423.40
	3a	Demand & Non-Fuel Cost Of Purchased Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	3b	Energy Payments to Qualified Facilities	411,227.00	148,148.00	55,503.00	252,742.00	177,840.00	155,670.00	1,201,130.00
	4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	5	Other Generation	(555.71)	(423.57)	5,150.00	53,000.89	62,488.76	104,995.51	224,655.88
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A5)	$19,075,040.77	$14,918,111.86	$13,344,673.89	$12,863,188.79	$16,932,373.83	$22,152,221.28	$99,285,610.42
B	1	Jurisdictional KWH Sales	894,601,648	665,415,950	740,704,306	753,771,220	876,985,519	984,069,572	4,915,548,215
	2	Non-Jurisdictional KWH Sales	32,771,393	22,728,026	25,019,926	24,522,286	29,172,685	31,745,515	165,959,831
	3	TOTAL SALES (Lines B1 + B2)	927,373,041	688,143,976	765,724,232	778,293,506	906,158,204	1,015,815,087	5,081,508,046
	4	Jurisdictional % Of Total Sales (Line B1/B3)	96.4662%	96.6972%	96.7325%	96.8492%	96.7806%	96.8749%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	$16,024,786.04	$11,867,985.57	$13,211,480.84	$13,480,270.48	$15,715,545.27	$17,632,644.48	$87,932,712.68
	2	True-Up Provision	(387,727.50)	(387,727.50)	(387,727.50)	(387,727.50)	(387,727.50)	(387,727.50)	(2,326,365.00)
	2a	Incentive Provision	(15,079.33)	(15,079.33)	(15,079.33)	(15,079.33)	(15,079.33)	(15,079.33)	(90,475.98)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$15,621,979.21	$11,465,178.74	$12,808,674.01	$13,077,463.65	$15,312,738.44	$17,229,837.65	$85,515,871.70
	4	Fuel & Net Power Transactions (Line A6)	$19,075,040.77	$14,918,111.86	$13,344,673.89	$12,863,188.79	$16,932,373.83	$22,152,221.28	$99,285,610.42
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A6 x Line B4 x 1.0014)	18,426,728.33	14,445,592.02	12,926,708.76	12,475,336.49	16,410,195.14	21,489,986.13	$96,174,546.87
	6	Over/(Under) Recovery (Line C3-C5)	(2,804,749.12)	(2,980,413.28)	(118,034.75)	602,127.16	(1,097,456.70)	(4,260,148.48)	($10,658,675.17)
	7	Interest Provision	5,255.37	(6,477.12)	(11,083.76)	(7,816.60)	(6,475.66)	(12,724.32)	($39,322.09)
	8	2000 Revenue sharing Refund True-Up					221,981.86		$221,981.86
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2001 - JUNE 2001**							($10,476,015.40)

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2001 - DECEMBER 2001

				JULY ACTUAL	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL PERIOD
				(a)	(b)	(c)				(d)
A	1	Fuel Cost of System Generation		18,948,433.07	20,816,613.00	17,785,196.00	16,303,905.00	15,701,505.00	15,421,025.00	$205,305,849.07
	2	Fuel Cost of Power Sold		(3,611,315.29)	(6,310,000.00)	(5,463,000.00)	(6,662,000.00)	(6,051,000.00)	(3,865,000.00)	($62,888,086.15)
	3	Fuel Cost of Purchased Power		10,044,590.38	9,180,000.00	3,766,000.00	2,608,000.00	1,349,000.00	1,953,000.00	$57,357,013.78
	3a	Demand & Non-Fuel Cost Of Purchased Power		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facilities		261,868.00	36,142.00	18,559.00	977.00	3,576.00	0.00	$1,522,252.00
	4	Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation		139,042.84	152,512.00	147,434.00	152,512.00	147,434.00	152,512.00	$1,116,102.72
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A5)		$25,782,619.00	$23,875,267.00	$16,254,189.00	$12,403,394.00	$11,150,515.00	$13,661,537.00	$202,413,131.42
B	1	Jurisdictional KWH Sales		1,065,436,221	1,087,159,000	910,120,000	746,881,000	690,615,000	818,601,000	10,234,360,436
	2	Non-Jurisdictional KWH Sales		35,933,844	36,338,000	31,078,000	26,466,000	25,796,000	29,600,000	351,171,675
	3	TOTAL SALES (Lines B1 + B2)		1,101,370,065	1,123,497,000	941,198,000	773,347,000	716,411,000	848,201,000	10,585,532,111
	4	Jurisdictional % Of Total Sales (Line B1/B3)		96.7374%	96.7656%	96.6980%	96.5777%	96.3993%	96.5103%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	$19,129,576.68	$19,478,627.80	$16,306,620.04	$13,381,866.88	$12,373,748.96	$14,666,874.12	$183,270,027.15
	2	True-Up Provision		(387,727.50)	(387,727.50)	(387,727.50)	(387,727.50)	(387,727.50)	(387,727.50)	($4,652,730.00)
	2a	Incentive Provision		(15,079.33)	(15,079.33)	(15,079.33)	(15,079.33)	(15,079.33)	(15,079.56)	($180,952.19)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		$18,726,769.85	$19,075,820.97	$15,903,813.21	$12,979,060.05	$11,970,942.13	$14,264,067.06	$178,436,344.96
	4	Fuel & Net Power Transactions (Line A6)		$25,782,619.00	$23,875,267.00	$16,254,189.00	$12,403,394.00	$11,150,515.00	$13,661,537.00	$202,413,131.42
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A6 x Line B4 x 1.0014)		24,976,353.28	23,135,389.63	15,739,480.15	11,995,683.12	10,764,067.03	13,203,249.05	$195,988,768.13
	6	Over/(Under) Recovery (Line C3-C5)		(6,249,583.43)	(4,059,568.66)	164,333.06	983,376.93	1,206,875.10	1,060,818.01	($17,552,425.16)
	7	Interest Provision	(2)	(27,764.67)	(42,848.53)	(47,890.74)	(45,016.27)	(40,492.83)	(35,833.35)	($279,168.48)
	8	2000 Revenue Sharing Refund True-Up								$221,981.86
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2001 - DECEMBER 2001**								($17,609,611.78)

Note 1: Estimated Revenues based on the 2001 Fuel Factor excluding revenue taxes of 1.7917 ¢/KWH
Note 2: Interest Calculated for August through December at July's rate of 0.3146

SCHEDULE E-1B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2001 - DECEMBER 2001

		DOLLARS				KWH				¢/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ACTUAL	EST.	DIFFERENCE AMT.	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	205,305,849	198,152,168	7,153,681	3.61	12,471,840,000	12,567,070,000	(95,230,000)	(0.76)	1.6462	1.5768	0.0694	4.40
2	Nuclear Fuel Disposal Costs	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Other Generation	1,116,104	1,795,125	(679,021)	(37.83)	63,471,000	102,520,000	(39,049,000)	(38.09)	1.7584	1.751	0.0074	0.42
5	TOTAL COST OF GENERATED POWER	206,421,953	199,947,293	6,474,660	3.24	12,535,311,000	12,669,590,000	(134,279,000)	(1.06)	1.6467	1.5782	0.0685	4.34
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
7	Energy Cost of Schedule C&X Econ. Purchases (Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Other Economy Purchases (Nonbroker) (A9)	57,357,014	53,410,000	3,947,014	7.39	1,848,477,147	1,609,687,000	238,790,147	14.83	3.1029	3.318	(0.2151)	(6.48)
9	Energy Cost of Schedule E Economy Purchases (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Energy Payments to Qualifying Facilities (A9a)	1,522,252	210,570	1,311,682	622.92	35,112,392	8,940,000	26,172,392	292.76	4.3354	2.3554	1.9800	84.06
12	TOTAL COST OF PURCHASED POWER	58,879,266	53,620,570	5,258,696	9.81	1,883,589,539	1,618,627,000	264,962,539	16.37	3.1259	3.3127	(0.1868)	(5.64)
13	Total Available KWH (Lines 4 + Line 12)	265,301,219	253,567,863	11,733,356	4.63	14,418,900,539	14,288,217,000	130,683,539	0.91				
14	Fuel Cost of Economy Sales (A6)	(5,828,811)	(4,815,000)	(1,013,811)	(21.06)	(227,987,895)	(193,085,000)	(34,902,895)	(18.08)	(2.5566)	(2.4937)	(0.0629)	(2.52)
15	Gain on Economy Sales (A6)	(1,570,574)	(1,047,000)	(523,574)	(50.01)			0	#N/A	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Unit Power Sales (A6)	(25,045,544)	(21,464,000)	(3,581,544)	(16.69)	(1,279,864,901)	(1,045,364,000)	(234,500,901)	(22.43)	(1.9569)	(2.0533)	0.0964	4.69
17	Fuel Cost of Other Power Sales (A6)	(30,443,157)	(43,126,000)	12,682,843	29.41	(1,650,073,976)	(1,863,676,000)	213,602,024	11.46	(1.8450)	(2.3140)	0.4690	20.27
18	TOTAL FUEL COST AND GAINS ON POWER SALES (LINES 14+15+16+17)	(62,888,086)	(70,452,000)	7,563,914	10.74	(3,157,926,772)	(3,102,125,000)	(55,801,772)	(1.80)	(1.9914)	(2.2711)	0.2797	12.32
19	Net Inadvertent Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
20	**TOTAL FUEL & NET POWER TRANSACTIONS** (LINES 5+12+18+19)	202,413,133	183,115,863	19,297,270	10.54	11,260,973,767	11,186,092,000	74,881,767	0.67	1.7975	1.637	0.1605	9.80
21	Net Unbilled Sales	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
22	Company Use *	409,270	351,267	58,002	16.51	22,768,825	21,458,000	1,310,825	6.11	1.7975	1.637	0.1605	9.80
23	T & D Losses *	11,731,794	10,656,019	1,075,775	10.10	652,672,831	650,948,000	1,724,831	0.26	1.7975	1.637	0.1605	9.80
24	TERRITORIAL (SYSTEM) SALES	202,413,133	183,115,863	19,297,270	10.54	10,585,532,111	10,513,686,000	71,846,111	0.68	1.9122	1.7417	0.1705	9.79
25	Wholesale Sales	6,698,366	6,202,438	495,928	8.00	351,171,675	356,114,000	(4,942,325)	(1.39)	1.9074	1.7417	0.1657	9.51
26	Jurisdictional Sales	195,714,767	176,913,425	18,801,342	10.63	10,234,360,436	10,157,572,000	76,788,436	0.76	1.9123	1.7417	0.1706	9.80
26a	Jurisdictional Loss Multiplier	1.0014	1.0014										
27	Jurisdictional Sales Adj. for Line Losses (Line 26 x 1.0014)	195,988,768	177,161,104	18,827,664	10.63	10,234,360,436	10,157,572,000	76,788,436	0.76	1.915	1.7441	0.1709	9.80
28	TRUE-UP **	4,652,730	4,652,730	0	0.00	10,234,360,436	10,157,572,000	76,788,436	0.76	0.0455	0.0458	(0.0003)	(0.66)
29	TOTAL JURISDICTIONAL FUEL COST	200,641,498	181,813,834	18,827,664	10.36	10,234,360,436	10,157,572,000	76,788,436	0.76	1.9605	1.7899	0.1706	9.53
30	Revenue Tax Factor									1.01609	1.01597		
31	Fuel Factor Adjusted for Revenue Taxes									1.9920	1.8185	0.1736	9.55
32	GPIF Reward / (Penalty) **	183,842	183,842	0	0.00	10,234,360,436	10,157,572,000	76,788,436	0.76	0.0018	0.0018	0.0000	0.00
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									1.9938	1.8203	0.1735	9.53
34	**FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)**									1.994	1.820	0.174	9.56

* Included for Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

Note: Amounts Included in the Estimated/Actual Column represent 7 months actual and 5 months estimate. Amounts Included in the Estimated Original Column represent amounts originally projected.

SCHEDULE E-1C

CALCULATION OF GENERATING PERFORMANCE INCENTIVE FACTOR AND TRUE-UP FACTOR GULF POWER COMPANY FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward/(Penalty)	$	379,732
	B. True-Up (Over)/Under Recovered	$	10,701,691
2.	TOTAL SALES (KWH)		10,265,886,000
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor		0.0037
	B. True-Up Factor		0.1042

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002

		NET ENERGY FOR LOAD %
	On-Peak	29.83
	Off-Peak	70.17
		100.00

	AVERAGE	ON-PEAK	OFF-PEAK
Cost per KWH Sold	2.0667	2.5263	1.8713
Jurisdictional Loss Factor	1.0014	1.0014	1.0014
Jurisdictional Fuel Factor	2.0696	2.5298	1.8739
GPIF	0.0037	0.0037	0.0037
True-Up	0.1042	0.1042	0.1042
TOTAL	2.1775	2.6377	1.9818
Revenue Tax Factor	1.01597	1.01597	1.01597
Recovery Factor	2.2122	2.6798	2.0134
Recovery Factor Rounded to the Nearest .001 ¢/KWH	2.212	2.680	2.013

HOURS:	ON-PEAK	25.21%
	OFF-PEAK	74.79%
		100.00%

SCHEDULE E-1E

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002

Group	Rate Schedules	Average Factor	Fuel Recovery Loss Multipliers	Standard Fuel Recovery Factor
A	RS, GS, GSD, OSIII, OSIV, SBS (1)	2.212	1.01228	2.239
B	LP, SBS (2)	2.212	0.98106	2.170
C	PX, RTP, SBS (3)	2.212	0.96230	2.129
D	OSI, OSII	2.212	1.01228	2.208 *

		TOU
A	On-Peak	2.713
	Off-Peak	2.038
B	On-Peak	2.629
	Off-Peak	1.975
C	On-Peak	2.579
	Off-Peak	1.938
D	On-Peak	N/A
	Off-Peak	N/A

Group D Calculation

* D	On-Peak	2.680 ¢ / KWH	x	0.2521	=	0.675 ¢ / KWH
	Off-Peak	2.013 ¢ / KWH	x	0.7479	=	1.506 ¢ / KWH
						2.181 ¢ / KWH
			Line Loss Multiplier		x	1.01228
						2.208 ¢ / KWH

(1) Includes SBS customers with a Contract Demand in the range of 100 to 499 KW
(2) Includes SBS customers with a Contract Demand in the range of 500 to 7,499 KW
(3) Includes SBS customers with a Contract Demand over 7,499 KW

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2002 - DECEMBER 2002

LINE	LINE DESCRIPTION	(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) JULY	(h) AUGUST	(i) SEPTEMBER	(j) OCTOBER	(k) NOVEMBER	(l) DECEMBER	(m) TOTAL
	$													
1	Fuel Cost of System Generation	21,031,867	15,943,905	14,525,017	13,359,012	18,912,752	33,457,474	39,389,110	40,658,499	30,906,782	27,276,477	24,387,321	23,682,370	303,530,586
1a	Other Generation	15,755	35,767	24,058	10,432	8,516	21,503	52,799	19,374	13,626	5,961	8,942	425	217,158
2	Fuel Cost of Power Sold	(7,153,000)	(5,125,000)	(3,301,000)	(3,090,000)	(4,656,000)	(11,240,000)	(15,900,000)	(16,668,000)	(10,827,000)	(10,795,000)	(10,162,000)	(7,001,000)	(105,918,000)
3	Fuel Cost of Purchased Power	1,623,000	3,405,000	3,487,000	3,710,000	3,040,000	812,000	1,669,000	1,330,000	546,000	575,000	632,000	569,000	21,398,000
3a	Demand & Non-Fuel Cost of Pur Power													0
3b	Qualifying Facilities	21,831	25,407	27,477	21,090	13,542	31,302	90,354	38,406	25,752	5,106	12,565	0	312,832
4	Energy Cost of Economy Purchases													0
5	**Total Fuel & Net Power Trans.** (Sum of Lines 1 -4)	15,539,453	14,285,079	14,762,552	14,010,534	17,318,810	23,082,279	25,301,263	25,378,279	20,665,160	17,067,544	14,878,828	17,250,795	219,540,576
6	System KWH Sold	887,726,000	751,730,000	761,354,000	715,862,000	925,909,000	1,053,537,000	1,094,029,000	1,120,905,000	946,898,000	774,974,000	724,011,000	865,796,000	10,622,731,000
6a	Jurisdictional % of Total Sales	96.5415	96.6081	96.6461	96.5428	96.7636	96.7868	96.5984	96.7452	96.6497	96.5670	96.5184	96.6148	96.6407
7	Cost per KWH Sold (¢/KWH)	1.7505	1.9003	1.9390	1.9572	1.8705	2.1909	2.3127	2.2641	2.1824	2.2023	2.0551	1.9925	2.0667
7a	Jurisdictional Loss Multiplier	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014
7b	Jurisdictional Cost (¢/KWH)	1.7530	1.9030	1.9417	1.9599	1.8731	2.1940	2.3159	2.2673	2.1855	2.2054	2.0580	1.9953	2.0696
8	GPIF (¢ / KWH) *	0.0037	0.0044	0.0043	0.0046	0.0035	0.0031	0.0030	0.0029	0.0035	0.0042	0.0045	0.0038	0.0037
9	True-Up (¢/KWH) *	0.1041	0.1228	0.1212	0.1290	0.0995	0.0875	0.0844	0.0822	0.0974	0.1192	0.1276	0.1066	0.1042
10	TOTAL	1.8608	2.0302	2.0672	2.0935	1.9761	2.2846	2.4033	2.3524	2.2864	2.3288	2.1901	2.1057	2.1775
11	Revenue Tax Factor	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597
12	Recovery Factor Adjusted for Taxes	1.8905	2.0626	2.1002	2.1269	2.0077	2.3211	2.4417	2.3900	2.3229	2.3660	2.2251	2.1393	2.2123
13	**Recovery Factor Rounded to the Nearest .001 ¢/KWH**	1.891	2.063	2.100	2.127	2.008	2.321	2.442	2.390	2.323	2.366	2.225	2.139	2.212

* CALCULATIONS BASED ON JURISDICTIONAL KWH SALES

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	FUEL COST - NET GEN. ($)													
2	LIGHTER OIL	52,684	46,689	39,025	48,752	51,479	51,307	51,157	51,027	50,918	50,825	50,744	50,673	595,280
3	COAL excluding Scherer	18,233,116	13,147,122	11,855,545	11,091,073	16,666,685	19,004,069	20,085,831	20,521,197	18,361,015	16,961,852	16,434,721	18,170,327	200,532,553
3a	COAL at Scherer	2,213,991	2,222,569	2,307,750	2,012,587	1,984,314	2,134,370	2,266,957	2,354,184	2,211,063	1,610,414	1,874,019	1,676,775	24,868,993
4	GAS	281,518	273,779	233,467	169,383	150,881	12,217,556	16,671,099	17,466,653	10,233,827	8,623,881	5,980,440	3,743,910	76,046,394
4a	GAS (B.L.)	40,685	36,033	26,968	14,190	29,505	29,505	40,403	40,403	29,505	29,505	36,033	40,685	393,420
6	OTHER - C.T.	209,873	217,713	62,262	23,027	29,888	20,667	273,663	225,035	20,454	0	11,364	0	1,093,946
6a	OTHER GENERATION	15,755	35,767	24,058	10,432	8,516	21,503	52,799	19,374	13,626	5,961	8,942	425	217,158
7	TOTAL ($)	21,047,622	15,979,672	14,549,075	13,369,444	18,921,268	33,478,977	39,441,909	40,677,873	30,920,408	27,282,438	24,396,263	23,682,795	303,747,744
	SYSTEM NET GEN. (MWH)													
9	LIGHTER OIL													0
10	COAL	1,179,030	889,790	818,670	745,930	1,087,550	1,239,430	1,297,060	1,335,460	1,204,830	1,091,200	1,079,650	1,173,170	13,141,770
11	GAS	3,040	3,270	2,640	2,340	2,050	327,790	336,520	359,800	303,660	256,410	161,580	79,590	1,838,690
13	OTHER - C.T.	2,850	3,010	860	320	420	290	3,840	3,170	290	-	160	-	15,210
13a	OTHER GENERATION	740	1,680	1,130	490	400	1,010	2,480	910	640	280	420	20	10,200
14	TOTAL (MWH)	1,185,660	897,750	823,300	749,080	1,090,420	1,568,520	1,639,900	1,699,340	1,509,420	1,347,890	1,241,810	1,252,780	15,005,870
	UNITS OF FUEL BURNED													
16	LIGHTER OIL (BBL)	1,688	1,509	1,272	1,594	1,688	1,687	1,687	1,687	1,687	1,687	1,687	1,687	19,560
17	COAL excl. Scherer (TON)	450,621	326,180	297,893	274,551	420,951	479,661	507,778	518,539	464,064	429,185	416,645	458,532	5,044,600
18	GAS-all (MCF)	62,140	67,311	55,948	46,726	45,830	2,743,842	2,897,815	3,055,417	2,177,827	1,726,574	1,142,897	571,781	14,594,108
20	OTHER - C.T. (BBL)	6,786	7,166	2,058	762	991	686	9,146	7,545	686	0	381	0	36,207
	BTU'S BURNED (MMBTU)													
22	LIGHTER OIL	0	0	0	0	0	0	0	0	0	0	0	0	0
23	COAL + GAS B.L. + OIL B.L.	12,042,721	9,042,582	8,351,859	7,592,661	11,104,134	12,661,103	13,433,576	13,774,829	12,368,270	11,171,184	11,014,911	11,921,903	134,479,733
24	GAS-Generation	55,463	60,790	51,234	44,020	38,664	2,817,616	2,976,208	3,138,538	2,234,620	1,769,830	1,168,643	580,394	14,936,020
26	OTHER - C.T.	40,061	42,312	12,153	4,501	5,852	4,051	54,015	44,562	4,051	0	2,251	0	213,809
27	TOTAL (MMBTU)	12,138,245	9,145,684	8,415,246	7,641,182	11,148,650	15,482,770	16,463,799	16,957,929	14,606,941	12,941,014	12,185,805	12,502,297	149,629,562

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	GENERATION MIX (% MWH)													
29	LIGHTER OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	COAL	99.44	99.11	99.44	99.58	99.73	79.02	79.10	78.59	79.82	80.96	86.95	93.65	87.58
31	GAS-Generation	0.26	0.36	0.32	0.31	0.19	20.90	20.52	21.17	20.12	19.02	13.01	6.35	12.25
33	OTHER - C.T.	0.24	0.34	0.10	0.04	0.04	0.02	0.23	0.19	0.02	0.00	0.01	0.00	0.10
33a	OTHER GENERATION	0.06	0.19	0.14	0.07	0.04	0.06	0.15	0.05	0.04	0.02	0.03	0.00	0.07
34	TOTAL (% MWH)	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
	FUEL COST $ / UNIT													
36	LIGHTER OIL ($/BBL)	31.21	30.94	30.68	30.58	30.50	30.41	30.32	30.25	30.18	30.13	30.08	30.04	30.43
37	COAL ($/TON)	40.46	40.31	39.80	40.40	39.59	39.62	39.56	39.58	39.57	39.52	39.45	39.63	39.75
38	GAS + B.L. ($/MCF)	5.19	4.60	4.65	3.93	3.94	4.46	5.77	5.73	4.71	5.01	5.26	6.62	5.24
40	OTHER - C.T.	30.93	30.38	30.25	30.22	30.16	30.13	29.92	29.83	29.82	#N/A	29.83	#N/A	30.21
	FUEL COST $ / MMBTU													
42	LIGHTER OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
43	COAL + GAS B.L. + OIL B.L.	1.70	1.70	1.70	1.73	1.68	1.67	1.67	1.66	1.67	1.67	1.67	1.67	1.68
44	GAS-Generation	5.08	4.50	4.56	3.85	3.90	4.34	5.60	5.57	4.58	4.87	5.12	6.45	5.09
46	OTHER - C.T.	5.24	5.15	5.12	5.12	5.11	5.10	5.07	5.05	5.05	#N/A	5.05	#N/A	5.12
47	TOTAL ($/MMBTU)	1.73	1.75	1.73	1.75	1.70	2.16	2.40	2.40	2.12	2.11	2.00	1.89	2.03
	BTU BURNED BTU / KWH													
49	LIGHTER OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
50	COAL + GAS B.L. + OIL B.L.	10,214	10,163	10,202	10,179	10,210	10,215	10,357	10,315	10,266	10,238	10,202	10,162	10,233
51	GAS-Generation	18,244	18,590	19,407	18,812	18,860	8,596	8,844	8,723	7,359	6,902	7,233	7,292	8,123
53	OTHER - C.T.	14,056	14,057	14,131	14,066	13,933	13,969	14,066	14,057	13,969	#N/A	14,069	#N/A	14,057
	TOTAL (BTU/KWH)	10,244	10,206	10,235	10,207	10,228	9,877	10,055	9,984	9,681	9,603	9,816	9,980	9,978
	FUEL COST CENTS / KWH													
56	LIGHTER OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
57	COAL + GAS B.L. + OIL B.L.	1.74	1.74	1.74	1.77	1.72	1.71	1.73	1.72	1.71	1.71	1.70	1.70	1.72
58	GAS-Generation	9.26	8.37	8.84	7.24	7.36	3.73	4.95	4.85	3.37	3.36	3.70	4.70	4.14
60	OTHER - C.T.	7.36	7.23	7.24	7.20	7.12	7.13	7.13	7.10	7.05	#N/A	7.10	#N/A	7.19
60a	OTHER GENERATION	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.12	2.13
61	TOTAL (¢/KWH)	1.78	1.78	1.77	1.78	1.74	2.13	2.41	2.39	2.05	2.02	1.96	1.89	2.02

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JANUARY 2002

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	690	3.9	96.5	4.0	19,651	Gas - G	13,164	1,030	13,559	69,784	10.11	5.30
2	1							Oil - G						
3	Crist 2	24.0	710	4.0	96.5	4.1	18,983	Gas - G	13,085	1,030	13,478	69,393	9.77	5.30
4	2							Oil - G						
5	Crist 3	35.0	1,640	6.3	96.5	6.5	17,333	Gas - G	27,599	1,030	28,426	142,341	8.68	5.16
6	3							Oil - G						
7	Crist 4	78.0	37,680	64.9	92.2	70.4	10,195	Coal	15,802	12,155	384,147	623,045	1.65	39.43
8	4							Gas - G						
9	Crist 5	80.0	44,640	75.0	95.7	78.4	10,309	Coal	18,930	12,155	460,188	746,429	1.67	39.43
10	5							Gas - G						
11	Crist 6	302.0	176,150	78.4	89.8	87.3	10,522	Coal	76,246	12,155	1,853,380	3,006,377	1.71	39.43
12	6							Gas - G						
13	Crist 7	477.0	300,040	84.5	85.6	98.8	10,138	Coal	125,128	12,155	3,041,863	4,933,809	1.64	39.43
14	7							Gas - G						
15	Scherer 3 (2)	210.3	116,000	74.2	96.5	76.8	9,933	Coal			1,152,275	2,213,991	1.91	#N/A
16	Scholz 1	46.0	16,520	48.3	92.7	52.1	12,739	Coal	8,331	12,630	210,446	353,918	2.14	42.48
17	Scholz 2	46.0	18,680	54.6	95.8	57.0	12,553	Coal	9,283	12,630	234,490	394,325	2.11	42.48
18	Smith 1	162.0	108,070	89.7	92.2	97.2	10,072	Coal	45,353	12,000	1,088,494	1,947,024	1.80	42.93
19	Smith 2	189.0	133,450	94.9	97.8	97.0	9,912	Coal	55,115	12,000	1,322,760	2,366,067	1.77	42.93
20	Smith 3							Gas - G			0			
21	Smith A (CT)	32.0	2,850	12.0	91.7	13.1	14,056	Oil - G	6,786	140,566	40,061	209,873	7.36	30.93
22	Other Generation		740									15,755	2.13	#N/A
23	Daniel 1 (1)	253.5	129,210	68.5	74.7	91.7	10,168	Coal	55,661	11,802	1,313,794	2,229,194	1.73	40.05
24	Daniel 2 (1)	255.0	98,590	52.0	53.8	96.6	9,761	Coal	40,772	11,802	962,382	1,632,928	1.66	40.05
25	Gas,BL							Gas	8,292	1,030	8,541	40,685	#N/A	4.91
26	Ltr. Oil							Oil	1,688	140,490	9,961	52,684	#N/A	31.21
27		2,213.8	1,185,660	72.0	85.3	84.4	10,244				12,138,245	21,047,622	1.78	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : FEBRUARY 2002

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	620	3.8	96.4	4.0	20,108	Gas - G	12,104	1,030	12,467	57,791	9.32	4.77
2	1							Oil - G						
3	Crist 2	24.0	740	4.6	96.4	4.8	19,795	Gas - G	14,221	1,030	14,648	66,992	9.05	4.71
4	2							Oil - G						
5	Crist 3	35.0	1,910	8.1	96.4	8.4	17,631	Gas - G	32,694	1,030	33,675	148,996	7.80	4.56
6	3							Oil - G						
7	Crist 4	78.0	34,930	66.6	87.5	76.2	10,362	Coal	14,834	12,200	361,950	579,277	1.66	39.05
8	4							Gas - G						
9	Crist 5	80.0	38,210	71.1	95.7	74.3	10,254	Coal	16,057	12,200	391,791	627,022	1.64	39.05
10	5							Gas - G						
11	Crist 6	302.0	49,870	24.6	27.2	90.3	10,502	Coal	21,465	12,200	523,746	838,193	1.68	39.05
12	6							Gas - G						
13	Crist 7	477.0	291,890	91.1	91.5	99.5	10,135	Coal	121,245	12,200	2,958,284	4,734,627	1.62	39.05
14	7							Gas - G						
15	Scherer 3 (2)	210.3	113,640	80.4	94.5	85.1	10,018	Coal			1,138,438	2,222,569	1.96	#N/A
16	Scholz 1	46.0	15,370	49.7	92.9	53.5	12,684	Coal	7,701	12,658	194,959	320,978	2.09	41.68
17	Scholz 2	46.0	10,240	33.1	97.2	34.1	12,455	Coal	5,038	12,658	127,537	209,984	2.05	41.68
18	Smith 1	162.0	105,720	97.1	98.2	98.9	9,957	Coal	43,861	12,000	1,052,688	1,884,282	1.78	42.96
19	Smith 2	189.0	113,280	89.2	90.5	98.6	9,865	Coal	46,563	12,000	1,117,512	2,000,333	1.77	42.96
20	Smith 3													
21	Smith A (CT)	32.0	3,010	14.0	91.7	15.3	14,057	Oil - G	7,166	140,591	42,312	217,713	7.23	30.38
22	Other Generation		1,680									35,767	2.13	#N/A
23	Daniel 1 (1)	253.5	116,640	68.5	72.8	94.1	9,930	Coal	49,416	11,719	1,158,233	1,952,426	1.67	39.51
24	Daniel 2 (1)	255.0	0	0.0	0.0	#DIV/0!	#N/A	Coal	0	11,719	0	0	#N/A	#N/A
25	Gas,BL							Gas	8,292	1,030	8,541	36,033	#N/A	4.35
26	Ltr. Oil							Oil	1,509	140,497	8,903	46,689	#N/A	30.94
27		2,213.8	897,750	60.3	71.1	84.9	10,206				9,145,684	15,979,672	1.78	

Notes:

(1) Represents Gulf's 50% Ownership

(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : MARCH 2002

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	610	3.4	96.5	3.5	20,664	Gas - G	12,238	1,030	12,605	58,374	9.57	4.77
2	1							Oil - G						
3	Crist 2	24.0	1,180	6.6	96.5	6.8	20,014	Gas - G	22,928	1,030	23,616	104,829	8.88	4.57
4	2							Oil - G						
5	Crist 3	35.0	850	3.3	96.5	3.4	17,662	Gas - G	14,576	1,030	15,013	70,264	8.27	4.82
6	3							Oil - G						
7	Crist 4	78.0	48,610	83.8	98.1	85.4	10,376	Coal	20,713	12,175	504,362	802,021	1.65	38.72
8	4							Gas - G						
9	Crist 5	80.0	43,910	73.8	95.7	77.1	10,304	Coal	18,581	12,175	452,447	719,439	1.64	38.72
10	5							Gas - G						
11	Crist 6	302.0	0	0.0	0.0	#N/A	#N/A	Coal	0	12,175	0	0	#N/A	#N/A
12	6							Gas - G						
13	Crist 7	477.0	302,540	85.2	85.2	100.1	10,135	Coal	125,918	12,175	3,066,260	4,875,549	1.61	38.72
14	7							Gas - G						
15	Scherer 3 (2)	210.3	116,390	74.4	96.5	77.1	9,993	Coal			1,163,061	2,307,750	1.98	#N/A
16	Scholz 1	46.0	7,100	20.7	94.9	21.9	12,878	Coal	3,607	12,675	91,432	148,528	2.09	41.18
17	Scholz 2	46.0	13,270	38.8	95.8	40.5	12,508	Coal	6,548	12,675	165,987	269,655	2.03	41.18
18	Smith 1	162.0	117,330	97.3	98.3	99.0	10,068	Coal	49,220	12,000	1,181,280	2,156,309	1.84	43.81
19	Smith 2	189.0	4,370	3.1	3.2	97.1	9,870	Coal	1,797	12,000	43,132	78,746	1.80	43.82
20	Smith 3													
21	Smith A (CT)	32.0	860	3.6	91.7	3.9	14,131	Oil - G	2,058	140,596	12,153	62,262	7.24	30.25
22	Other Generation		1,130									24,058	2.13	#N/A
23	Daniel 1 (1)	253.5	165,150	87.6	92.2	95.0	10,112	Coal	71,509	11,677	1,669,998	2,805,298	1.70	39.23
24	Daniel 2 (1)	255.0	0	0.0	0.0	#DIV/0!	#N/A	Coal	0	11,677	0	0	#N/A	#N/A
25	Gas,BL							Gas	6,206	1,030	6,392	26,968	#N/A	4.35
26	Ltr. Oil							Oil	1,272	140,523	7,508	39,025	#N/A	30.68
27		2,213.8	823,300	50.0	61.4	81.5	10,235				8,415,246	14,549,075	1.77	

Notes:

(1) Represents Gulf's 50% Ownership

(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : APRIL 2002

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	300	1.7	96.4	1.8	20,280	Gas - G	5,906	1,030	6,084	26,208	8.74	4.44
2	1							Oil - G						
3	Crist 2	24.0	770	4.5	96.4	4.6	20,058	Gas - G	14,995	1,030	15,445	58,550	7.60	3.90
4	2							Oil - G						
5	Crist 3	35.0	1,270	5.0	96.4	5.2	17,709	Gas - G	21,837	1,030	22,491	84,625	6.66	3.88
6	3							Oil - G						
7	Crist 4	78.0	35,820	63.8	98.6	64.7	10,461	Coal	15,440	12,134	374,698	593,833	1.66	38.46
8	4							Gas - G						
9	Crist 5	80.0	29,670	51.5	95.7	53.8	10,387	Coal	12,699	12,134	308,179	488,401	1.65	38.46
10	5							Gas - G						
11	Crist 6	302.0	124,860	57.4	73.7	77.9	10,245	Coal	52,712	12,134	1,279,171	2,027,295	1.62	38.46
12	6							Gas - G						
13	Crist 7	477.0	0	0.0	0.0	#DIV/0!	#N/A	Coal	0	12,134	0	0	#N/A	#N/A
14	7							Gas - G						
15	Scherer 3 (2)	210.3	104,210	68.8	96.5	71.3	9,833	Coal			1,024,694	2,012,587	1.93	#N/A
16	Scholz 1	46.0	3,770	11.4	92.8	12.3	12,995	Coal	1,931	12,685	48,993	78,998	2.10	40.91
17	Scholz 2	46.0	11,080	33.5	95.8	34.9	12,646	Coal	5,523	12,685	140,119	226,020	2.04	40.92
18	Smith 1	162.0	93,420	80.1	85.4	93.8	10,082	Coal	39,245	12,000	941,875	1,705,991	1.83	43.47
19	Smith 2	189.0	123,900	91.0	97.9	93.0	10,003	Coal	51,640	12,000	1,239,360	2,244,780	1.81	43.47
20	Smith 3													
21	Smith A (CT)	32.0	320	1.4	91.7	1.5	14,066	Oil - G	762	140,599	4,501	23,027	7.20	30.22
22	Other Generation		490									10,432	2.13	#N/A
23	Daniel 1 (1)	253.5	124,850	68.4	80.3	85.2	10,284	Coal	55,104	11,651	1,283,989	2,152,908	1.72	39.07
24	Daniel 2 (1)	255.0	94,350	51.4	59.1	87.0	9,942	Coal	40,257	11,651	938,069	1,572,847	1.67	39.07
25	Gas,BL							Gas	3,988	1,030	4,108	14,190	#N/A	3.56
26	Ltr. Oil							Oil	1,594	140,537	9,406	48,752	#N/A	30.58
27		2,213.8	749,080	47.0	65.6	71.6	10,207				7,641,182	13,369,444	1.78	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : MAY 2002

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	290	1.6	96.5	1.7	20,455	Gas - G	5,759	1,030	5,932	25,687	8.86	4.46
2	1							Oil - G						
3	Crist 2	24.0	720	4.0	96.5	4.2	19,915	Gas - G	13,921	1,030	14,339	54,729	7.60	3.93
4	2							Oil - G						
5	Crist 3	35.0	1,040	4.0	96.5	4.1	17,686	Gas - G	17,857	1,030	18,393	70,465	6.78	3.95
6	3							Oil - G						
7	Crist 4	78.0	46,750	80.6	98.5	81.8	10,460	Coal	20,154	12,132	489,017	773,102	1.65	38.36
8	4							Gas - G						
9	Crist 5	80.0	19,160	32.2	95.7	33.6	10,388	Coal	8,203	12,132	199,038	314,678	1.64	38.36
10	5							Gas - G						
11	Crist 6	302.0	162,990	72.5	89.8	80.8	10,579	Coal	71,062	12,132	1,724,248	2,725,923	1.67	38.36
12	6							Gas - G						
13	Crist 7	477.0	233,470	65.8	67.3	97.8	10,051	Coal	96,709	12,132	2,346,700	3,709,767	1.59	38.36
14	7							Gas - G						
15	Scherer 3 (2)	210.3	103,890	66.4	96.5	68.8	9,847	Coal			1,022,954	1,984,314	1.91	#N/A
16	Scholz 1	46.0	4,580	13.4	92.7	14.4	13,204	Coal	2,383	12,689	60,476	97,459	2.13	40.90
17	Scholz 2	46.0	6,550	19.1	95.8	20.0	12,729	Coal	3,286	12,689	83,377	134,403	2.05	40.90
18	Smith 1	162.0	68,370	56.7	60.5	93.8	9,997	Coal	28,480	12,000	683,521	1,236,907	1.81	43.43
19	Smith 2	189.0	129,990	92.4	97.8	94.5	10,098	Coal	54,695	12,000	1,312,680	2,375,383	1.83	43.43
20	Smith 3													
21	Smith A (CT)	32.0	420	1.8	91.7	1.9	13,933	Oil - G	991	140,602	5,852	29,888	7.12	30.16
22	Other Generation		400									8,516	2.13	#N/A
23	Daniel 1 (1)	253.5	152,680	81.0	92.2	87.8	10,247	Coal	67,245	11,633	1,564,456	2,620,513	1.72	38.97
24	Daniel 2 (1)	255.0	159,120	83.9	93.0	90.2	10,050	Coal	68,734	11,633	1,599,165	2,678,550	1.68	38.97
25	Gas,BL							Gas	8,292	1,030	8,541	29,505	#N/A	3.56
26	Ltr. Oil							Oil	1,688	140,541	9,961	51,479	#N/A	30.50
27		2,213.8	1,090,420	66.2	85.8	77.2	10,228				11,148,650	18,921,268	1.74	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JUNE 2002

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	14,310	82.8	89.4	92.6	16,500	Gas - G	229,238	1,030	236,115	822,603	5.75	3.59
2	1							Oil - G						
3	Crist 2	24.0	15,460	89.5	89.4	100.1	15,931	Gas - G	239,125	1,030	246,299	857,785	5.55	3.59
4	2							Oil - G						
5	Crist 3	35.0	21,870	86.8	93.5	92.8	15,572	Gas - G	330,646	1,030	340,565	1,185,742	5.42	3.59
6	3							Oil - G						
7	Crist 4	78.0	39,780	70.8	98.6	71.8	10,682	Coal	17,407	12,206	424,940	670,172	1.68	38.50
8	4							Gas - G						
9	Crist 5	80.0	36,000	62.5	95.1	65.7	10,344	Coal	15,254	12,206	372,381	587,277	1.63	38.50
10	5							Gas - G						
11	Crist 6	302.0	174,310	80.2	96.0	83.5	10,681	Coal	76,266	12,206	1,861,806	2,936,242	1.68	38.50
12	6							Gas - G						
13	Crist 7	477.0	308,040	89.7	91.5	98.0	10,141	Coal	127,962	12,206	3,123,817	4,926,536	1.60	38.50
14	7							Gas - G						
15	Scherer 3 (2)	210.3	112,640	74.4	97.1	76.6	9,888	Coal			1,113,757	2,134,370	1.89	#N/A
16	Scholz 1	46.0	12,130	36.6	93.9	39.0	12,988	Coal	6,206	12,693	157,544	253,385	2.09	40.83
17	Scholz 2	46.0	14,820	44.7	94.9	47.2	12,518	Coal	7,308	12,693	185,521	298,392	2.01	40.83
18	Smith 1	162.0	109,230	93.6	98.6	95.0	10,080	Coal	45,874	12,000	1,100,987	1,977,158	1.81	43.10
19	Smith 2	189.0	125,970	92.6	97.9	94.6	10,098	Coal	53,000	12,000	1,272,000	2,284,311	1.81	43.10
20	Smith 3	574.0	276,150	66.8	90.7	73.7	7,223	Gas	1,936,541	1,030	1,994,637	9,351,426	3.39	4.83
21	Smith A (CT)	32.0	290	1.3	95.7	1.3	13,969	Oil - G	686	140,601	4,051	20,667	7.13	30.13
22	Other Generation		1,010									21,503	2.13	#N/A
23	Daniel 1 (1)	253.5	150,350	82.4	92.6	89.0	9,917	Coal	64,163	11,619	1,491,020	2,495,275	1.66	38.89
24	Daniel 2 (1)	255.0	156,160	85.1	93.2	91.3	9,854	Coal	66,221	11,619	1,538,828	2,575,321	1.65	38.89
25	Gas,BL							Gas	8,292	1,030	8,541	29,505	#N/A	3.56
26	Ltr. Oil							Oil	1,687	140,551	9,961	51,307	#N/A	30.41
27		2,787.8	1,568,520	78.1	75.1	104.0	9,877				15,482,770	33,478,977	2.13	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JULY 2002

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	15,970	89.4	89.5	99.9	16,507	Gas - G	255,935	1,030	263,614	1,253,972	7.85	4.90
2	1							Oil - G						
3	Crist 2	24.0	14,580	81.7	89.5	91.2	15,934	Gas - G	225,552	1,030	232,318	1,105,929	7.59	4.90
4	2							Oil - G						
5	Crist 3	35.0	24,340	93.5	93.4	100.1	15,569	Gas - G	367,924	1,030	378,961	1,801,950	7.40	4.90
6	3							Oil - G						
7	Crist 4	78.0	47,700	82.2	98.5	83.4	10,787	Coal	21,031	12,233	514,544	810,518	1.70	38.54
8	4							Gas - G						
9	Crist 5	80.0	45,890	77.1	95.2	81.0	10,306	Coal	19,330	12,233	472,928	744,965	1.62	38.54
10	5							Gas - G						
11	Crist 6	302.0	180,540	80.4	96.0	83.7	10,552	Coal	77,863	12,233	1,904,996	3,000,858	1.66	38.54
12	6							Gas - G						
13	Crist 7	477.0	312,660	88.1	91.5	96.3	10,330	Coal	132,007	12,233	3,229,782	5,087,562	1.63	38.54
14	7							Gas - G						
15	Scherer 3 (2)	210.3	120,470	77.0	97.0	79.4	9,905	Coal			1,193,272	2,266,957	1.88	#N/A
16	Scholz 1	46.0	16,340	47.7	93.8	50.9	12,591	Coal	8,101	12,698	205,733	329,641	2.02	40.69
17	Scholz 2	46.0	21,800	63.7	94.9	67.1	12,442	Coal	10,681	12,698	271,243	434,599	1.99	40.69
18	Smith 1	162.0	111,280	92.3	98.7	93.5	10,083	Coal	46,751	12,000	1,122,027	2,004,680	1.80	42.88
19	Smith 2	189.0	128,960	91.7	97.8	93.8	10,104	Coal	54,290	12,000	1,302,960	2,327,958	1.81	42.88
20	Smith 3	574.0	281,630		90.7				2,040,112	1,030	2,101,315	12,509,248		
21	Smith A (CT)	32.0	3,840	16.1	95.7	16.9	14,066	Oil - G	9,146	140,612	54,015	273,663	7.13	29.92
22	Other Generation		2,480									52,799	2.13	#N/A
23	Daniel 1 (1)	253.5	152,140	80.7	92.6	87.1	10,493	Coal	68,758	11,609	1,596,423	2,668,478	1.75	38.81
24	Daniel 2 (1)	255.0	159,280	84.0	93.3	90.0	10,053	Coal	68,966	11,609	1,601,166	2,676,572	1.68	38.81
25	Gas,BL							Gas	8,292	1,030	8,541	40,403	#N/A	4.87
26	Ltr. Oil							Oil	1,687	140,563	9,961	51,157	#N/A	30.32
27		2,787.8	1,639,900	79.1	75.1	105.3	10,055				16,463,799	39,441,909	2.41	

Notes:

(1) Represents Gulf's 50% Ownership

(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : AUGUST 2002

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	15,970	89.4	89.5	99.9	16,507	Gas - G	255,938	1,030	263,616	1,253,987	7.85	4.90
2	1							Oil - G						
3	Crist 2	24.0	15,970	89.4	89.5	99.9	15,936	Gas - G	247,083	1,030	254,495	1,210,839	7.58	4.90
4	2							Oil - G						
5	Crist 3	35.0	24,340	93.5	93.4	100.1	15,570	Gas - G	367,924	1,030	378,962	1,801,950	7.40	4.90
6	3							Oil - G						
7	Crist 4	78.0	45,000	77.5	98.5	78.7	10,783	Coal	19,751	12,284	485,243	763,755	1.70	38.67
8	4							Gas - G						
9	Crist 5	80.0	45,820	77.0	95.2	80.9	10,262	Coal	19,139	12,284	470,207	740,105	1.62	38.67
10	5							Gas - G						
11	Crist 6	302.0	188,270	83.8	96.0	87.3	10,522	Coal	80,630	12,284	1,980,918	3,117,964	1.66	38.67
12	6							Gas - G						
13	Crist 7	477.0	318,510	89.7	91.5	98.1	10,285	Coal	133,337	12,284	3,275,839	5,156,156	1.62	38.67
14	7							Gas - G						
15	Scherer 3 (2)	210.3	125,730	80.4	97.0	82.9	9,944	Coal			1,250,208	2,354,184	1.87	#N/A
16	Scholz 1	46.0	22,030	64.4	93.8	68.6	12,597	Coal	10,924	12,702	277,512	443,058	2.01	40.56
17	Scholz 2	46.0	21,620	63.2	94.9	66.6	12,391	Coal	10,545	12,702	267,885	427,725	1.98	40.56
18	Smith 1	162.0	114,110	94.7	98.7	95.9	10,076	Coal	47,909	12,000	1,149,811	2,047,132	1.79	42.73
19	Smith 2	189.0	131,440	93.5	97.8	95.6	10,091	Coal	55,264	12,000	1,326,336	2,361,450	1.80	42.73
20	Smith 3	574.0	303,520		90.7				2,176,180	1,030	2,241,465	13,199,877		
21	Smith A (CT)	32.0	3,170	13.3	95.7	13.9	14,057	Oil - G	7,545	140,616	44,562	225,035	7.10	29.83
22	Other Generation		910									19,374	2.13	#N/A
23	Daniel 1 (1)	253.5	159,130	84.4	92.6	91.1	10,179	Coal	69,815	11,601	1,619,806	2,704,618	1.70	38.74
24	Daniel 2 (1)	255.0	163,800	86.3	93.3	92.5	10,089	Coal	71,225	11,601	1,652,562	2,759,234	1.68	38.74
25	Gas,BL							Gas	8,292	1,030	8,541	40,403	#N/A	4.87
26	Ltr. Oil							Oil	1,687	140,571	9,961	51,027	#N/A	30.25
27		2,787.8	1,699,340	81.9	75.1	109.1	9,984				16,957,929	40,677,873	2.39	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : SEPTEMBER 2002

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	580	3.4	89.4	3.8	16,390	Gas - G	9,229	1,030	9,506	39,768	6.86	4.31
2	1							Oil - G						
3	Crist 2	24.0	1,060	6.1	89.4	6.9	19,079	Gas - G	19,635	1,030	20,224	76,794	7.24	3.91
4	2							Oil - G						
5	Crist 3	35.0	1,450	5.8	93.5	6.2	16,506	Gas - G	23,238	1,030	23,934	91,923	6.34	3.96
6	3							Oil - G						
7	Crist 4	78.0	46,750	83.2	98.6	84.4	10,400	Coal	19,810	12,272	486,217	764,861	1.64	38.61
8	4							Gas - G						
9	Crist 5	80.0	40,650	70.6	95.1	74.2	10,296	Coal	17,053	12,272	418,549	658,454	1.62	38.61
10	5							Gas - G						
11	Crist 6	302.0	165,650	76.2	89.6	85.0	10,540	Coal	71,145	12,272	1,745,985	2,746,892	1.66	38.61
12	6							Gas - G						
13	Crist 7	477.0	276,360	80.5	82.4	97.7	10,338	Coal	116,409	12,272	2,857,143	4,494,533	1.63	38.61
14	7							Gas - G						
15	Scherer 3 (2)	210.3	118,320	78.2	97.1	80.5	9,929	Coal			1,174,822	2,211,063	1.87	#N/A
16	Scholz 1	46.0	11,520	34.8	93.9	37.0	12,869	Coal	5,835	12,704	148,256	236,686	2.05	40.56
17	Scholz 2	46.0	14,920	45.0	94.9	47.5	12,417	Coal	7,291	12,704	185,258	295,705	1.98	40.56
18	Smith 1	162.0	109,790	94.1	98.2	95.9	10,077	Coal	46,099	12,000	1,106,381	1,968,427	1.79	42.70
19	Smith 2	189.0	126,700	93.1	97.9	95.1	10,094	Coal	53,286	12,000	1,278,864	2,275,313	1.80	42.70
	Smith 3	574.0	300,570		90.7				2,117,433	1,030	2,180,956	10,025,342		
20	Smith A (CT)	32.0	290	1.3	95.7	1.3	13,969	Oil - G	686	140,616	4,051	20,454	7.05	29.82
21	Other Generation		640									13,626	2.13	#N/A
22	Daniel 1 (1)	253.5	151,750	83.1	92.6	89.8	10,204	Coal	66,773	11,595	1,548,467	2,584,100	1.70	38.70
23	Daniel 2 (1)	255.0	142,420	77.6	83.9	92.5	9,829	Coal	60,363	11,595	1,399,826	2,336,044	1.64	38.70
24	Gas,BL							Gas	8,292	1,030	8,541	29,505	#N/A	3.56
25	Ltr. Oil							Oil	1,687	140,577	9,961	50,918	#N/A	30.18
26		2,787.8	1,509,420	75.2	72.0	104.5	9,681				14,606,941	30,920,408	2.05	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : OCTOBER 2002

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	290	1.6	96.5	1.7	20,455	Gas - G	5,759	1,030	5,932	27,422	9.46	4.76
2	1							Oil - G						
3	Crist 2	24.0	170	1.0	96.5	1.0	20,265	Gas - G	3,345	1,030	3,445	18,830	11.08	5.63
4	2							Oil - G						
5	Crist 3	35.0	0	0.0	96.5	#N/A	#N/A	Gas - G	0	1,030	0	9,238	#N/A	#N/A
6	3							Oil - G						
7	Crist 4	78.0	5,650	9.7	25.4	38.3	10,494	Coal	2,417	12,265	59,289	93,306	1.65	38.60
8	4							Gas - G						
9	Crist 5	80.0	10,070	16.9	95.7	17.7	10,436	Coal	4,284	12,265	105,087	165,317	1.64	38.59
10	5							Gas - G						
11	Crist 6	302.0	157,020	69.9	89.8	77.8	10,609	Coal	67,912	12,265	1,665,778	2,620,709	1.67	38.59
12	6							Gas - G						
13	Crist 7	477.0	310,630	87.5	91.5	95.7	10,282	Coal	130,205	12,265	3,193,929	5,024,595	1.62	38.59
14	7							Gas - G						
15	Scherer 3 (2)	210.3	86,360	55.2	96.5	57.2	9,845	Coal			850,233	1,610,414	1.86	#N/A
16	Scholz 1	46.0	1,790	5.2	92.8	5.6	13,473	Coal	949	12,706	24,116	38,597	2.16	40.67
17	Scholz 2	46.0	680	2.0	97.0	2.0	13,040	Coal	349	12,706	8,867	14,167	2.08	40.59
18	Smith 1	162.0	88,660	73.6	79.6	92.4	10,087	Coal	37,265	12,000	894,354	1,595,688	1.80	42.82
19	Smith 2	189.0	126,790	90.2	97.9	92.1	10,117	Coal	53,447	12,000	1,282,728	2,288,600	1.81	42.82
20	Smith 3	574.0	255,950		91.8				1,709,178	1,030	1,760,453	8,568,391		
21	Smith A (CT)	32.0	0	0.0	91.7	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
22	Other Generation		280									5,961	2.13	#N/A
23	Daniel 1 (1)	253.5	148,220	78.6	92.6	84.9	10,295	Coal	65,822	11,591	1,525,887	2,546,633	1.72	38.69
24	Daniel 2 (1)	255.0	155,330	81.9	93.3	87.8	9,930	Coal	66,535	11,591	1,542,414	2,574,240	1.66	38.69
25	Gas,BL							Gas	8,292	1,030	8,541	29,505	#N/A	3.56
26	Ltr. Oil							Oil	1,687	140,585	9,961	50,825	#N/A	30.13
27		2,787.8	1,347,890	65.0	71.4	91.0	9,603				12,941,014	27,282,438	2.02	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : NOVEMBER, 2002

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	0	0.0	96.4	#N/A	#N/A	Gas - G	0	1,030	0	6,929	#N/A	#N/A
2	1							Oil - G						
3	Crist 2	24.0	580	3.4	96.4	3.5	19,888	Gas - G	11,199	1,030	11,535	55,594	9.59	4.96
4	2							Oil - G						
5	Crist 3	35.0	0	0.0	96.4	#N/A	#N/A	Gas - G	0	1,030	0	9,238	#N/A	#N/A
6	3							Oil - G						
7	Crist 4	78.0	43,290	77.1	98.3	78.4	10,460	Coal	18,501	12,237	452,793	712,476	1.65	38.51
8	4							Gas - G						
9	Crist 5	80.0	1,400	2.4	98.9	2.5	10,226	Coal	585	12,237	14,317	22,525	1.61	38.50
10	5							Gas - G						
11	Crist 6	302.0	150,230	69.1	86.4	80.0	10,587	Coal	64,988	12,237	1,590,514	2,502,687	1.67	38.51
12	6							Gas - G						
13	Crist 7	477.0	284,090	82.7	85.4	96.9	10,147	Coal	117,784	12,237	2,882,646	4,535,864	1.60	38.51
14	7							Gas - G						
15	Scherer 3 (2)	210.3	100,730	66.5	96.5	#N/A	9,844	Coal			991,632	1,874,019	1.86	#N/A
16	Scholz 1	46.0	10,260	31.0	92.8	33.4	13,086	Coal	5,283	12,708	134,258	214,294	2.09	40.56
17	Scholz 2	46.0	13,280	40.1	95.8	41.9	12,670	Coal	6,620	12,708	168,254	268,492	2.02	40.56
18	Smith 1	162.0	90,070	77.2	82.2	93.9	9,961	Coal	37,383	12,000	897,196	1,616,060	1.79	43.23
19	Smith 2	189.0	83,970	61.7	65.0	94.9	10,098	Coal	35,331	12,000	847,944	1,527,366	1.82	43.23
20	Smith 3	574.0	161,000		90.1				1,123,406	1,030	1,157,108	5,908,679		
21	Smith A (CT)	32.0	160	0.7	91.7	0.8	14,069	Oil - G	381	140,617	2,251	11,364	7.10	29.83
22	Other Generation		420									8,942	2.13	#N/A
23	Daniel 1 (1)	253.5	146,820	80.4	92.6	86.9	10,258	Coal	64,983	11,588	1,506,081	2,513,519	1.71	38.68
24	Daniel 2 (1)	255.0	155,510	84.7	93.2	90.9	9,715	Coal	65,187	11,588	1,510,774	2,521,438	1.62	38.68
25	Gas,BL							Gas	8,292	1,030	8,541	36,033	#N/A	4.35
26	Ltr. Oil							Oil	1,687	140,589	9,961	50,744	#N/A	30.08
27		2,787.8	1,241,810	61.9	70.0	88.4	9,816				12,185,805	24,396,263	1.96	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : DECEMBER 2002

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned MMBTU	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	0	0.0	96.5	0.0	#N/A	Gas - G	0	1,030	0	6,929	#N/A	#N/A
2	1							Oil - G						
3	Crist 2	24.0	290	1.6	96.5	1.7	19,890	Gas - G	5,601	1,030	5,768	34,405	11.86	6.14
4	2							Oil - G						
5	Crist 3	35.0	0	0.0	96.5	0.0	#N/A	Gas - G	0	1,030	0	9,238	#N/A	#N/A
6	3							Oil - G						
7	Crist 4	78.0	21,370	36.8	98.5	37.4	10,383	Coal	9,042	12,270	221,891	349,048	1.63	38.60
8	4							Gas - G						
9	Crist 5	80.0	7,160	12.0	95.8	12.6	10,217	Coal	2,981	12,270	73,155	115,072	1.61	38.60
10	5							Gas - G						
11	Crist 6	302.0	166,840	74.3	89.8	82.7	10,561	Coal	71,803	12,270	1,762,047	2,771,583	1.66	38.60
12	6							Gas - G						
13	Crist 7	477.0	322,260	90.8	91.5	99.2	10,136	Coal	133,107	12,270	3,266,446	5,137,911	1.59	38.60
14	7							Gas - G						
15	Scherer 3 (2)	210.3	89,230	57.0	96.5	59.1	9,912	Coal			884,457	1,676,775	1.88	#N/A
16	Scholz 1	46.0	1,580	4.6	94.9	4.9	12,853	Coal	799	12,708	20,307	32,447	2.05	40.61
17	Scholz 2	46.0	7,440	21.7	95.8	22.7	12,625	Coal	3,696	12,708	93,933	150,050	2.02	40.60
18	Smith 1	162.0	116,240	96.4	98.7	97.7	10,071	Coal	48,776	12,000	1,170,627	2,092,477	1.80	42.90
19	Smith 2	189.0	133,860	95.2	97.8	97.3	10,078	Coal	56,208	12,000	1,348,992	2,411,337	1.80	42.90
20	Smith 3	574.0	79,300		90.2				557,889	1,030	574,626	3,693,338		
21	Smith A (CT)	32.0	0	0.0	91.7	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
22	Other Generation		20									425	2.13	#N/A
23	Daniel 1 (1)	253.5	149,560	79.3	86.6	91.6	10,169	Coal	65,631	11,586	1,520,864	2,538,607	1.70	38.68
24	Daniel 2 (1)	255.0	157,630	83.1	87.2	95.3	9,774	Coal	66,489	11,586	1,540,683	2,571,795	1.63	38.68
25	Gas,BL							Gas	8,292	1,030	8,541	40,685	#N/A	4.91
26	Ltr. Oil							Oil	1,687	140,595	9,961	50,673	#N/A	30.04
27		2,787.8	1,252,780	60.4	73.5	82.2	9,980				12,502,298	23,682,795	1.89	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD : JANUARY 2002 - DECEMBER 2002

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	49,630	23.6	94.1	25.1	16,712	Gas - G	805,270	1,030	829,430	3,649,454	7.35	4.53
2	1							Oil - G	0		0			
3	Crist 2	24.0	52,230	24.8	94.1	26.4	16,382	Gas - G	830,690	1,030	855,610	3,714,669	7.11	4.47
4	2							Oil - G	0		0			
5	Crist 3	35.0	78,710	25.7	95.5	26.9	15,759	Gas - G	1,204,295	1,030	1,240,420	5,425,970	6.89	4.51
6	3							Oil - G	0		0			
7	Crist 4	78.0	453,330	66.3	90.9	73.0	10,498	Coal	194,902	12,209	4,759,091	7,535,414	1.66	38.66
8	4							Gas - G	0		0			
9	Crist 5	80.0	362,580	51.7	95.8	54.0	10,310	Coal	153,096	12,209	3,738,267	5,929,684	1.64	38.73
10	5							Gas - G	0		0			
11	Crist 6	302.0	1,696,730	64.1	77.3	83.0	10,545	Coal	732,092	12,220	17,892,589	28,294,723	1.67	38.65
12	6							Gas - G	0		0	0		
13	Crist 7	477.0	3,260,490	78.0	79.7	97.9	10,196	Coal	1,359,811	12,223	33,242,709	52,616,909	1.61	38.69
14	7							Gas - G	0		0			
15	Scherer 3 (2)	210.3	1,307,610	71.0	96.5	73.6	9,911	Coal			12,959,803	24,868,993	1.90	#N/A
16	Scholz 1	46.0	122,990	30.5	93.5	32.6	12,798	Coal	62,050	12,684	1,574,032	2,547,989	2.07	41.06
17	Scholz 2	46.0	154,380	38.3	95.7	40.0	12,518	Coal	76,168	12,686	1,932,471	3,123,517	2.02	41.01
18	Smith 1	162.0	1,232,290	86.8	90.7	95.7	10,054	Coal	516,216	12,000	12,389,241	22,232,135	1.80	43.07
19	Smith 2	189.0	1,362,680	82.3	86.6	95.0	10,050	Coal	570,636	12,000	13,695,268	24,541,644	1.80	43.01
20	Smith 3	574.0	1,658,120	33.0	94.6	34.9	7,243	Gas - G	11,660,739	1,030	12,010,560	63,256,301	3.81	5.42
21	Smith A (CT)	32.0	15,210	5.4	93.0	5.8	14,057	Oil - G	36,207	140,599	213,809	1,093,946	7.19	30.21
22	Other Generation		10,200									217,158	2.13	#N/A
23	Daniel 1 (1)	253.5	1,746,500	78.6	88.0	89.4	10,191	Coal	764,880	11,635	17,799,018	29,811,569	1.71	38.98
24	Daniel 2 (1)	255.0	1,442,190	64.6	70.7	91.3	9,906	Coal	614,749	11,635	14,285,869	23,898,969	1.66	38.88
25	Gas,BL							Gas	93,114	1,030	95,910	393,420	#N/A	4.23
26	Ltr. Oil							Oil	19,560	140,553	115,466	595,280	#N/A	30.43
27		2,787.8	15,005,870	61.4	67.2	91.4	9,978				149,629,562	303,747,744	2.02	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2002 - DECEMBER 2002

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	LIGHT OIL													
1	*PURCHASES :*													
2	UNITS (BBL)	1,703	1,507	1,287	1,608	1,702	1,702	1,702	1,702	1,702	1,702	1,702	1,701	19,720
3	UNIT COST ($/BBL)	29.80	29.81	29.82	29.81	29.80	29.80	29.77	29.77	29.77	29.77	29.77	29.78	29.79
4	AMOUNT ($)	50,747	44,928	38,383	47,931	50,725	50,726	50,667	50,669	50,662	50,664	50,661	50,657	587,420
5	*BURNED :*													
6	UNITS (BBL)	1,688	1,509	1,272	1,594	1,688	1,687	1,687	1,687	1,687	1,687	1,687	1,687	19,560
7	UNIT COST ($/BBL)	31.21	30.94	30.68	30.58	30.50	30.41	30.32	30.25	30.18	30.13	30.08	30.04	30.43
8	AMOUNT ($)	52,684	46,689	39,025	48,752	51,479	51,307	51,157	51,027	50,918	50,825	50,744	50,673	595,280
9	*ENDING INVENTORY :*													
10	UNITS (BBL)	8,803	8,801	8,816	8,830	8,844	8,859	8,874	8,889	8,904	8,919	8,934	8,948	
11	UNIT COST ($/BBL)	31.62	31.43	31.30	31.16	31.03	30.91	30.80	30.71	30.63	30.56	30.50	30.45	
12	AMOUNT ($)	278,370	276,609	275,967	275,146	274,392	273,811	273,321	272,963	272,707	272,546	272,463	272,447	
13	DAYS SUPPLY:	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
	COAL EXCLUDING PLANT SCHERER													
14	*PURCHASES :*													
15	UNITS (TONS)	477,772	432,223	385,293	338,344	365,783	461,311	434,674	487,385	411,422	418,545	405,138	446,031	5,063,921
16	UNIT COST ($/TON)	39.58	39.54	39.42	39.53	39.52	39.60	39.59	39.61	39.57	39.59	39.54	39.63	39.56
17	AMOUNT ($)	18,908,837	17,089,279	15,186,707	13,373,285	14,455,584	18,267,278	17,207,859	19,304,192	16,281,679	16,568,989	16,020,890	17,675,731	200,340,310
18	*BURNED :*													
19	UNITS (TONS)	450,621	326,180	297,893	274,551	420,951	479,661	507,778	518,539	464,064	429,185	416,645	458,532	5,044,600
20	UNIT COST ($/TON)	40.46	40.31	39.80	40.40	39.59	39.62	39.56	39.58	39.57	39.52	39.45	39.63	39.75
21	AMOUNT ($)	18,233,116	13,147,122	11,855,545	11,091,073	16,666,685	19,004,069	20,085,831	20,521,197	18,361,015	16,961,852	16,434,721	18,170,327	200,532,553
22	*ENDING INVENTORY :*													
23	UNITS (TONS)	654,209	760,252	847,652	911,445	856,277	837,927	764,823	733,669	681,027	670,387	658,880	646,379	
24	UNIT COST ($/TON)	40.45	39.99	39.80	39.52	39.48	39.47	39.48	39.50	39.49	39.54	39.60	39.60	
25	AMOUNT ($)	26,463,703	30,405,860	33,737,022	36,019,234	33,808,133	33,071,342	30,193,370	28,976,365	26,897,029	26,504,166	26,090,335	25,595,739	
26	DAYS SUPPLY:	34	39	44	47	44	43	40	38	35	35	34	34	

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2002 - DECEMBER 2002

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	COAL AT PLANT SCHERER													
27	*PURCHASES :*													
28	UNITS (MMBTU)	448,127	448,127	450,901	872,326	952,991	1,011,759	1,058,556	1,133,378	1,042,287	929,917	1,053,763	956,289	10,358,421
29	UNIT COST ($/MMBTU)	2.20	2.20	2.20	1.91	1.88	1.87	1.87	1.86	1.88	1.91	1.88	1.91	1.92
30	AMOUNT ($)	984,293	984,293	989,810	1,665,864	1,796,308	1,890,594	1,977,960	2,102,423	1,960,229	1,780,379	1,984,357	1,823,430	19,939,940
31	*BURNED :*													
32	UNITS (MMBTU)	1,152,275	1,138,438	1,163,061	1,024,694	1,022,954	1,113,757	1,193,272	1,250,208	1,174,822	850,233	991,632	884,457	12,959,803
33	UNIT COST ($/MMBTU)	1.92	1.95	1.98	1.96	1.94	1.92	1.90	1.88	1.88	1.89	1.89	1.90	1.92
34	AMOUNT ($)	2,213,991	2,222,569	2,307,750	2,012,587	1,984,314	2,134,370	2,266,957	2,354,184	2,211,063	1,610,414	1,874,019	1,676,775	24,868,993
35	*ENDING INVENTORY :*													
36	UNITS (MMBTU)	3,532,207	2,841,896	2,129,736	1,977,368	1,907,405	1,805,407	1,670,691	1,553,861	1,421,326	1,501,010	1,563,141	1,634,973	
37	UNIT COST ($/MMBTU)	2.01	2.06	2.13	2.12	2.10	2.09	2.08	2.08	2.09	2.10	2.08	2.08	
38	AMOUNT ($)	7,101,301	5,863,025	4,545,085	4,198,362	4,010,356	3,766,580	3,477,583	3,225,822	2,974,988	3,144,953	3,255,291	3,401,946	
39	DAYS SUPPLY:	69	55	42	39	37	35	33	30	28	29	30	32	
	GAS													
44	*BURNED :*													
45	UNITS (MCF)	62,140	67,311	55,948	46,726	45,830	2,743,842	2,897,815	3,055,417	2,177,827	1,726,574	1,142,897	571,781	14,594,108
46	UNIT COST ($/MCF)	5.19	4.60	4.65	3.93	3.94	4.46	5.77	5.73	4.71	5.01	5.26	6.62	5.24
47	AMOUNT ($)	322,203	309,812	260,435	183,573	180,386	12,247,061	16,711,502	17,507,056	10,263,332	8,653,386	6,016,473	3,784,595	76,439,814
	OTHER - C.T. OIL													
53	*PURCHASES :*													
54	UNITS (BBL)	6,788	7,165	2,057	762	991	686	9,147	7,545	686	0	381	0	36,208
55	UNIT COST ($/BBL)	29.72	29.72	29.72	29.73	29.72	29.73	29.72	29.72	29.71	#N/A	29.73	#N/A	29.72
56	AMOUNT ($)	201,751	212,964	61,137	22,657	29,452	20,392	271,877	224,262	20,382	0	11,329	0	1,076,203
57	*BURNED :*													
58	UNITS (BBL)	6,786	7,166	2,058	762	991	686	9,146	7,545	686	0	381	0	36,207
59	UNIT COST ($/BBL)	30.93	30.38	30.25	30.22	30.16	30.13	29.92	29.83	29.82	#N/A	29.83	#N/A	30.21
60	AMOUNT ($)	209,873	217,713	62,262	23,027	29,888	20,667	273,663	225,035	20,454	0	11,364	0	1,093,946
61	*ENDING INVENTORY :*													
62	UNITS (BBL)	8,572	8,571	8,570	8,570	8,570	8,570	8,571	8,571	8,571	8,571	8,571	8,571	
63	UNIT COST ($/BBL)	30.94	30.39	30.26	30.22	30.16	30.13	29.92	29.83	29.82	29.82	29.82	29.82	
64	AMOUNT ($)	265,188	260,439	259,314	258,944	258,508	258,233	256,447	255,674	255,602	255,602	255,567	255,567	
65	DAYS SUPPLY:	107	107	107	107	107	107	107	107	107	107	107	107	

POWER SOLD
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2002 - DECEMBER 2002

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
			KWH		(A)	(B)	(6) x (7)(A)	(6) x (7)(B)
	MONTH	TOTAL	WHEELED	KWH	¢ / KWH		TOTAL $	
LINE	TYPE & SCHEDULE	KWH SOLD	FROM OTHER SYSTEMS	FROM OWN GENERATION	FUEL COST	TOTAL COST	FOR FUEL ADJUSTMENT	TOTAL COST $
	JANUARY							
1	Southern Co. Interchange	190,734,000	0	190,734,000	2.46	2.71	4,699,000	5,173,000
2	Unit Power Sales	112,806,000	0	112,806,000	2.10	2.38	2,373,000	2,689,000
3	Economy Sales	1,462,000	0	1,462,000	3.35	3.69	49,000	54,000
4	Gain on Economy Sales	0					5,000	5,000
5	Other Sales	832,000		832,000	3.25	4.33	27,000	36,000
6	TOTAL ESTIMATED SALES	305,834,000	0	305,834,000	2.34	2.60	7,153,000	7,957,000
	FEBRUARY							
1	Southern Co. Interchange	108,892,000	0	108,892,000	2.74	3.01	2,982,000	3,281,000
2	Unit Power Sales	100,443,000	0	100,443,000	2.03	2.31	2,040,000	2,320,000
3	Economy Sales	1,465,000	0	1,465,000	4.71	4.91	69,000	72,000
4	Gain on Economy Sales	0					7,000	7,000
5	Other Sales	817,000		817,000	3.30	4.16	27,000	34,000
6	TOTAL ESTIMATED SALES	211,617,000	0	211,617,000	2.42	2.70	5,125,000	5,714,000
	MARCH							
1	Southern Co. Interchange	36,206,000	0	36,206,000	2.20	2.40	797,000	868,000
2	Unit Power Sales	117,135,000	0	117,135,000	2.07	2.33	2,422,000	2,731,000
3	Economy Sales	1,462,000	0	1,462,000	3.63	3.83	53,000	56,000
4	Gain on Economy Sales	0					6,000	6,000
5	Other Sales	883,000		883,000	2.60	3.40	23,000	30,000
6	TOTAL ESTIMATED SALES	155,686,000	0	155,686,000	2.12	2.37	3,301,000	3,691,000
	APRIL							
1	Southern Co. Interchange	38,765,000	0	38,765,000	2.00	2.20	776,000	851,000
2	Unit Power Sales	109,900,000	0	109,900,000	1.99	2.26	2,187,000	2,482,000
3	Economy Sales	3,530,000	0	3,530,000	2.78	3.00	98,000	106,000
4	Gain on Economy Sales	0					11,000	11,000
5	Other Sales	780,000		780,000	2.31	3.33	18,000	26,000
6	TOTAL ESTIMATED SALES	152,975,000	0	152,975,000	2.02	2.27	3,090,000	3,476,000
	MAY							
1	Southern Co. Interchange	106,730,000	0	106,730,000	2.03	2.24	2,169,000	2,387,000
2	Unit Power Sales	117,466,000	0	117,466,000	2.00	2.27	2,354,000	2,665,000
3	Economy Sales	4,405,000	0	4,405,000	2.25	2.43	99,000	107,000
4	Gain on Economy Sales	0					11,000	11,000
5	Other Sales	839,000		839,000	2.74	3.46	23,000	29,000
6	TOTAL ESTIMATED SALES	229,440,000	0	229,440,000	2.03	2.27	4,656,000	5,199,000
	JUNE							
1	Southern Co. Interchange	341,683,000	0	341,683,000	2.44	2.67	8,336,000	9,127,000
2	Unit Power Sales	113,626,000	0	113,626,000	2.06	2.33	2,341,000	2,652,000
3	Economy Sales	4,386,000	0	4,386,000	10.62	11.08	466,000	486,000
4	Gain on Economy Sales	0					97,000	97,000
5	Other Sales	0		0	#N/A	#N/A	0	0
6	TOTAL ESTIMATED SALES	459,695,000	0	459,695,000	2.45	2.69	11,240,000	12,362,000

POWER SOLD
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2002 - DECEMBER 2002

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
			KWH		(A)	(B)	(6) x (7)(A)	(6) x (7)(B)
	MONTH	TOTAL	WHEELED	KWH	¢ / KWH		TOTAL $	
LINE	TYPE & SCHEDULE	KWH SOLD	FROM OTHER SYSTEMS	FROM OWN GENERATION	FUEL COST	TOTAL COST	FOR FUEL ADJUSTMENT	TOTAL COST $
	JULY							
1	Southern Co. Interchange	368,856,000	0	368,856,000	3.36	3.72	12,404,000	13,712,000
2	Unit Power Sales	123,771,000	0	123,771,000	2.23	2.50	2,761,000	3,097,000
3	Economy Sales	5,864,000	0	5,864,000	10.39	10.71	609,000	628,000
4	Gain on Economy Sales	0					126,000	126,000
5	Other Sales	0		0	#N/A	#N/A	0	0
6	TOTAL ESTIMATED SALES	498,491,000	0	498,491,000	3.19	3.52	15,900,000	17,563,000
	AUGUST							
1	Southern Co. Interchange	386,720,000	0	386,720,000	3.39	3.69	13,091,000	14,264,000
2	Unit Power Sales	126,872,000	0	126,872,000	2.16	2.43	2,746,000	3,085,000
3	Economy Sales	4,102,000	0	4,102,000	16.82	17.16	690,000	704,000
4	Gain on Economy Sales	0					141,000	141,000
5	Other Sales	0		0	#N/A	#N/A	0	0
6	TOTAL ESTIMATED SALES	517,694,000	0	517,694,000	3.22	3.51	16,668,000	18,194,000
	SEPTEMBER							
1	Southern Co. Interchange	393,289,000	0	393,289,000	2.11	2.33	8,318,000	9,164,000
2	Unit Power Sales	117,995,000	0	117,995,000	2.01	2.28	2,366,000	2,687,000
3	Economy Sales	4,378,000	0	4,378,000	2.81	3.02	123,000	132,000
4	Gain on Economy Sales	0					20,000	20,000
5	Other Sales	0		0	#N/A	#N/A	0	0
6	TOTAL ESTIMATED SALES	515,662,000	0	515,662,000	2.10	2.33	10,827,000	12,003,000
	OCTOBER							
1	Southern Co. Interchange	468,068,000	0	468,068,000	1.95	2.13	9,138,000	9,972,000
2	Unit Power Sales	80,098,000	0	80,098,000	1.99	2.25	1,593,000	1,805,000
3	Economy Sales	2,635,000	0	2,635,000	2.09	2.28	55,000	60,000
4	Gain on Economy Sales	0					9,000	9,000
5	Other Sales	0		0	#N/A	#N/A	0	0
6	TOTAL ESTIMATED SALES	550,801,000	0	550,801,000	1.96	2.15	10,795,000	11,846,000
	NOVEMBER							
1	Southern Co. Interchange	390,861,000	0	390,861,000	2.02	2.21	7,900,000	8,627,000
2	Unit Power Sales	110,249,000	0	110,249,000	2.01	2.28	2,217,000	2,513,000
3	Economy Sales	1,519,000	0	1,519,000	2.57	2.76	39,000	42,000
4	Gain on Economy Sales	0					6,000	6,000
5	Other Sales	0		0	#N/A	#N/A	0	0
6	TOTAL ESTIMATED SALES	502,629,000	0	502,629,000	2.02	2.23	10,162,000	11,188,000
	DECEMBER							
1	Southern Co. Interchange	258,325,000	0	258,325,000	1.96	2.15	5,065,000	5,548,000
2	Unit Power Sales	94,395,000	0	94,395,000	1.97	2.24	1,862,000	2,116,000
3	Economy Sales	2,926,000	0	2,926,000	2.19	2.36	64,000	69,000
4	Gain on Economy Sales	0					10,000	10,000
5	Other Sales	0		0	#N/A	#N/A	0	0
6	TOTAL ESTIMATED SALES	355,646,000	0	355,646,000	1.97	2.18	7,001,000	7,743,000
	TOTAL							
1	Southern Co. Interchange	3,089,129,000	0	3,089,129,000	2.45	2.69	75,675,000	82,974,000
2	Unit Power Sales	1,324,756,000	0	1,324,756,000	2.06	2.33	27,262,000	30,842,000
3	Economy Sales	38,134,000	0	38,134,000	6.33	6.60	2,414,000	2,516,000
4	Gain on Economy Sales						449,000	449,000
5	Other Sales	4,151,000	0	4,151,000	2.84	3.73	118,000	155,000
6	TOTAL ESTIMATED SALES	4,456,170,000	0	4,456,170,000	2.38	2.62	105,918,000	116,936,000

SCHEDULE E-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2002 - DECEMBER 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) ¢ / KWH		(9)
MONTH	PURCHASED FROM	TYPE & SCHED	TOTAL KWH PURCH.	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7)x(8)(a)
January	NONE								
February	NONE								
March	NONE								
April	NONE								
May	NONE								
June	NONE								
July	NONE								
August	NONE								
September	NONE								
October	NONE								
November	NONE								
December	NONE								
Total	NONE								

SCHEDULE E-8

ENERGY PAYMENT TO QUALIFYING FACILITIES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2002 - DECEMBER 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				KWH			¢/KWH		
MONTH	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
JANUARY	Solutia	COG-1				1,160,000	1.882	1.882	21,831
FEBRUARY	Solutia	COG-1				1,350,000	1.882	1.882	25,407
MARCH	Solutia	COG-1				1,460,000	1.882	1.882	27,477
APRIL	Solutia	COG-1				950,000	2.220	2.22	21,090
MAY	Solutia	COG-1				610,000	2.220	2.22	13,542
JUNE	Solutia	COG-1				1,410,000	2.220	2.22	31,302
JULY	Solutia	COG-1				4,070,000	2.220	2.22	90,354
AUGUST	Solutia	COG-1				1,730,000	2.220	2.22	38,406
SEPTEMBER	Solutia	COG-1				1,160,000	2.220	2.22	25,752
OCTOBER	Solutia	COG-1				230,000	2.220	2.22	5,106
NOVEMBER	Solutia	COG-1				650,000	1.933	1.933	12,565
DECEMBER	Solutia	COG-1				-	1.933	1.933	0
TOTAL			0			14,780,000			312,832

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2002- DECEMBER 2002

(1)	(2)	(3)	(4)	(5)
LINE	MONTH TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JANUARY			
1	Southern Co. Interchange	22,635,000	3.12	707,000
2	Unit Power Sales	4,202,000	5.45	229,000
3	Economy Energy	675,000	4.44	30,000
4	Other Purchases	35,313,000	1.86	657,000
5	TOTAL ESTIMATED PURCHASES	62,825,000	2.58	1,623,000
	FEBRUARY			
1	Southern Co. Interchange	53,799,000	4.55	2,448,000
2	Unit Power Sales	3,100,000	4.48	139,000
3	Economy Energy	891,000	5.84	52,000
4	Other Purchases	45,973,000	1.67	766,000
5	TOTAL ESTIMATED PURCHASES	103,763,000	3.28	3,405,000
	MARCH			
1	Southern Co. Interchange	81,330,000	2.90	2,357,000
2	Unit Power Sales	7,991,000	3.47	277,000
3	Economy Energy	890,000	4.49	40,000
4	Other Purchases	42,594,000	1.91	813,000
5	TOTAL ESTIMATED PURCHASES	132,805,000	2.63	3,487,000
	APRIL			
1	Southern Co. Interchange	121,068,000	2.44	2,951,000
2	Unit Power Sales	4,374,000	2.83	124,000
3	Economy Energy	1,618,000	3.65	59,000
4	Other Purchases	27,325,000	2.11	576,000
5	TOTAL ESTIMATED PURCHASES	154,385,000	2.40	3,710,000
	MAY			
1	Southern Co. Interchange	80,495,000	2.39	1,921,000
2	Unit Power Sales	4,936,000	2.92	144,000
3	Economy Energy	1,620,000	2.78	45,000
4	Other Purchases	37,775,000	2.46	930,000
5	TOTAL ESTIMATED PURCHASES	124,826,000	2.44	3,040,000
	JUNE			
1	Southern Co. Interchange	6,657,000	2.45	163,000
2	Unit Power Sales	1,564,000	3.96	62,000
3	Economy Energy	124,000	4.03	5,000
4	Other Purchases	14,140,000	4.12	582,000
5	TOTAL ESTIMATED PURCHASES	22,485,000	3.61	812,000

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2002 - DECEMBER 2002

(1)	(2)	(3)	(4)	(5)
LINE	MONTH TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JULY			
1	Southern Co. Interchange	10,422,000	3.51	366,000
2	Unit Power Sales	2,669,000	6.52	174,000
3	Economy Energy	159,000	8.18	13,000
4	Other Purchases	21,490,000	5.19	1,116,000
5	TOTAL ESTIMATED PURCHASES	34,740,000	4.80	1,669,000
	AUGUST			
1	Southern Co. Interchange	6,215,000	2.91	181,000
2	Unit Power Sales	1,965,000	6.21	122,000
3	Economy Energy	31,000	9.68	3,000
4	Other Purchases	19,780,000	5.18	1,024,000
5	TOTAL ESTIMATED PURCHASES	27,991,000	4.75	1,330,000
	SEPTEMBER			
1	Southern Co. Interchange	0	#N/A	0
2	Unit Power Sales	3,273,000	3.61	118,000
3	Economy Energy	1,622,000	3.08	50,000
4	Other Purchases	10,280,000	3.68	378,000
5	TOTAL ESTIMATED PURCHASES	15,175,000	3.60	546,000
	OCTOBER			
1	Southern Co. Interchange	3,928,000	2.93	115,000
2	Unit Power Sales	2,202,000	2.95	65,000
3	Economy Energy	1,023,000	2.54	26,000
4	Other Purchases	12,180,000	3.03	369,000
5	TOTAL ESTIMATED PURCHASES	19,333,000	2.97	575,000
	NOVEMBER			
1	Southern Co. Interchange	1,835,000	2.18	40,000
2	Unit Power Sales	2,188,000	3.11	68,000
3	Economy Energy	838,000	2.98	25,000
4	Other Purchases	15,990,000	3.12	499,000
5	TOTAL ESTIMATED PURCHASES	20,851,000	3.03	632,000
	DECEMBER			
1	Southern Co. Interchange	8,063,000	2.24	181,000
2	Unit Power Sales	2,508,000	2.23	56,000
3	Economy Energy	869,000	2.76	24,000
4	Other Purchases	10,250,000	3.00	308,000
5	TOTAL ESTIMATED PURCHASES	21,690,000	2.62	569,000
	TOTAL FOR PERIOD			
1	Southern Co. Interchange	396,447,000	2.88	11,430,000
2	Unit Power Sales	40,972,000	3.85	1,578,000
3	Economy Energy	10,360,000	3.59	372,000
4	Other Purchases	293,090,000	2.74	8,018,000
5	TOTAL ESTIMATED PURCHASES	740,869,000	2.89	21,398,000

RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1000 KWH
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2002 - DECEMBER 2002

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
Base Rate Revenues	$	44.63	44.63	44.63	44.63	44.63	44.63	44.63	44.63	44.63	44.63	44.63	44.63	535.56
Fuel Factor	¢/KWH	1.891	2.063	2.100	2.127	2.008	2.321	2.442	2.390	2.323	2.366	2.225	2.139	2.212
Group Loss Multiplier		1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228
Fuel Adjustment Revenues	$	19.14	20.88	21.26	21.53	20.33	23.50	24.72	24.19	23.52	23.95	22.52	21.65	267.19
TOTAL REVENUES	$	63.77	65.51	65.89	66.16	64.96	68.13	69.35	68.82	68.15	68.58	67.15	66.28	805.97

Note: ECCR is current 2001 factor because the projected 2002 factor has not been filed. Fuel, PPCC & ECRC are projected 2002 factors.
*Monthly and cumulative twelve month estimated data

SCHEDULE E-11

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST
GULF POWER COMPANY

		TOTAL ¢ / KWH
2002	JANUARY	1.882
	FEBRUARY	1.882
	MARCH	1.882
	APRIL	2.220
	MAY	2.220
	JUNE	2.220
	JULY	2.220
	AUGUST	2.220
	SEPTEMBER	2.220
	OCTOBER	2.220
	NOVEMBER	1.933
	DECEMBER	1.933
2003	JANUARY	1.933
	FEBRUARY	1.933
	MARCH	1.933
	APRIL	2.112
	MAY	2.112
	JUNE	2.112
	JULY	2.112
	AUGUST	2.112
	SEPTEMBER	2.112
	OCTOBER	2.112
	NOVEMBER	1.946
	DECEMBER	1.946

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 1999 - DECEMBER 2002

LINE	LINE DESCRIPTION	YEAR 1999	2000	2001	2002	DIFFERENCE (%) FROM PRIOR PERIOD 1999 to 2000	2000 to 2001	2001 to 2002
	FUEL COST OF SYSTEM NET GENERATION ($)							
2	LIGHTER OIL	392,387	322,069	604,951	595,280	(17.92)	87.83	(1.60)
3	COAL	166,188,239	168,960,185	175,540,970	200,532,553	1.67	3.89	14.24
3a	COAL at Scherer	20,044,252	23,003,584	16,932,117	24,868,993	14.76	(26.39)	46.87
4	GAS	3,344,750	2,483,862	2,098,156	76,046,394	(25.74)	(15.53)	3,524.44
4a	GAS (B.L.)	0	192,650	569,786	393,420	#N/A	195.76	(30.95)
6	OTHER - C.T.	171,403	44,787	2,406,188	1,093,946	(73.87)	5,272.51	(54.54)
6a	OTHER GENERATION	1,981,161	1,927,026	1,795,125	217,158	(2.73)	(6.84)	(87.90)
7	TOTAL ($)	192,122,192	192,122,192	196,934,163	303,747,744	0.00	2.50	54.24
	SYSTEM NET GENERATION (MWH)							
9	LIGHTER OIL	0	0	0	0	#N/A	#N/A	#N/A
10	COAL	12,334,820	12,113,210	12,508,400	13,141,770	(1.80)	3.26	5.06
11	GAS	103,260	55,020	26,920	1,838,690	(46.72)	(51.07)	6,730.20
13	OTHER - C.T.	2,490	960	31,750	15,210	(61.45)	3,207.29	(52.09)
13	OTHER GENERATION	123,900	102,720	102,520	10,200	(17.09)	(0.19)	(90.05)
14	TOTAL (MWH)	12,564,470	12,271,910	12,669,590	15,005,870	(2.33)	3.24	18.44
	UNITS OF FUEL BURNED							
16	LIGHTER OIL (BBL)	13,445	15,551	19,654	19,560	15.66	26.38	(0.48)
17	COAL excl. Scherer (TON)	5,247,061	4,843,797	4,870,369	5,044,600	(7.69)	0.55	3.58
18	GAS (MCF)	1,458,111	989,089	508,404	14,594,108	(32.17)	(48.60)	2,770.57
20	OTHER - C.T.	5,978	2,275	75,882	36,207	(61.94)	3,235.47	(52.29)
	BTU'S BURNED (MMBTU)							
22	LIGHTER OIL	0	0	0	0	#N/A	#N/A	#N/A
23	COAL + GAS B.L. + OIL B.L.	128,393,814	125,260,381	127,790,405	134,479,733	(2.44)	2.02	5.23
24	GAS - Generation	1,501,853	945,839	424,512	14,936,020	(37.02)	(55.12)	3,418.40
26	OTHER - C.T.	35,115	13,277	447,667	213,809	(62.19)	3,271.75	(52.24)
27	TOTAL (MMBTU)	129,930,782	129,930,782	126,219,497	149,629,562	0.00	(2.86)	18.55
	GENERATION MIX (% MWH)							
29	LIGHTER OIL	0.00	0.00	0.00	0.00	#N/A	#N/A	#N/A
30	COAL + GAS B.L. + OIL B.L.	98.17	98.70	98.73	87.58	0.54	0.03	(11.29)
31	GAS - Generation	0.82	0.45	0.21	12.25	(45.12)	(53.33)	5,733.33
33	OTHER - C.T.	0.02	0.01	0.25	0.10	(50.00)	2,400.00	(60.00)
33a	OTHER GENERATION	0.99	0.84	0.81	0.07	(15.15)	(3.57)	(91.36)
34	TOTAL (% MWH)	100.00	100.00	100.00	100.00	0.00	0.00	0.00
	FUEL COST PER UNIT							
36	LIGHTER OIL B.L. ($/BBL)	29.18	20.71	30.78	30.43	(29.03)	48.62	(1.14)
37	COAL ($/TON)	31.67	34.88	36.04	39.75	10.14	3.33	10.29
38	GAS +B.L. ($/MCF)	2.29	2.71	5.25	5.24	18.34	93.73	(0.19)
40	OTHER - C.T.	28.67	19.69	31.71	30.21	(31.32)	61.05	(4.73)
	FUEL COST ($) / MMBTU							
42	LIGHTER OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
43	COAL + GAS B.L. + OIL B.L.	1.45	1.54	1.51	1.67	6.21	(1.95)	10.60
44	GAS - Generation	2.23	2.63	4.94	5.09	17.94	87.83	3.04
46	OTHER - C.T.	4.88	3.37	5.37	5.12	(30.94)	59.35	(4.66)
47	TOTAL ($/MMBTU)	1.46	1.46	1.57	2.04	0.00	7.53	29.94
	BTU BURNED / KWH							
49	LIGHTER OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
50	COAL + GAS B.L. + OIL B.L.	10,409	10,341	10,216	10,233	(0.65)	(1.21)	0.17
51	GAS - Generation	14,544	17,191	15,769	8,123	18.20	(8.27)	(48.49)
53	OTHER - C.T.	14,102	13,830	14,100	14,057	(1.93)	1.95	(0.30)
54	TOTAL (BTU/KWH)	10,341	10,588	9,962	9,978	2.39	(5.91)	0.16
	FUEL COST (¢ / KWH)							
56	LIGHTER OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
57	COAL + GAS B.L. + OIL B.L.	1.51	1.59	1.54	1.73	5.30	(3.14)	12.34
58	GAS - Generation	3.24	4.51	7.79	4.14	39.20	72.73	(46.85)
60	OTHER - C.T.	6.88	4.67	7.58	7.19	(32.12)	62.31	(5.15)
60a	OTHER GENERATION	1.60	1.88	1.75	2.13	17.50	(6.91)	21.71
61	TOTAL (¢ / KWH)	1.53	1.57	1.55	2.02	2.61	(1.27)	30.32

Schedule CCE-1

Projected Purchased Power Capacity Payments/(Receipts)
Gulf Power Company
For January 2002 - December 2002

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	Projected IIC Payments/(Receipts) ($)	1,588,272	383,784	422,350	68,070	232,317	(422,598)	(393,120)	151,478	(116,004)	22,412	(99,498)	13,214	1,850,677
2	Projected Capacity Payments to Solutia ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
3	Projected Market Capacity Payments	361,168	266,668	172,168	85,500	180,000	0	0	0	0	0	0	0	1,065,504
4	Projected Transmission Revenue	(3,000)	(3,000)	(3,000)	(7,000)	(9,000)	(9,000)	(12,000)	(8,000)	(9,000)	(6,000)	(3,000)	(6,000)	(78,000)
5	Total Projected Capacity Payments/(Receipts) (Line 1 + 2 + 3 + 4) ($)	2,008,642	709,654	653,720	208,772	465,519	(369,396)	(342,918)	205,680	(62,802)	78,614	(40,296)	69,416	3,584,605
6	Jurisdictional %	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747
7	Projected Jurisdictional Capacity Payments/(Receipts) (Line 5 x Line 6) ($)	1,938,489	684,869	630,889	201,481	449,261	(356,495)	(330,941)	198,497	(60,609)	75,868	(38,889)	66,992	3,459,412
8	Amount Included in Retail Base Rate Revenues ($)	(137,666)	(137,666)	(137,666)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,666)	(1,652,000)
9	Jurisdictional Amount to be Recovered (Line 7 - Line 8) ($)	2,076,155	822,535	768,555	339,148	586,928	(218,828)	(193,274)	336,164	77,058	213,535	98,778	204,658	5,111,412
10	True-Up ($)													(1,856,247)
11	Total Jurisdictional Amount to be Recovered (Line 9 + Line 10) ($)													3,255,165
12	Revenue Tax Multiplier													1.01597
13	Total Recoverable Capacity Payments/(Receipts) (Line 11 x Line 12) ($)													3,307,150

Calculation of Jurisdictional % *

	12 CP KW	%
FPSC	1,716,060.61	96.50747%
FERC	62,102.98	3.49253%
Total	1,778,163.59	100.00000%

* Based on 1999 Actual Data

Schedule CCE-1a

Purchased Power Capacity Cost Recovery Clause
Calculation of True-up
Gulf Power Company
January 2002 - December 2002

1	Estimated over/(under)-recovery, January 2001 - December 2001 (Schedule CCE-1b-1, Line 18)	$1,515,391
2	Final True-Up, January 2000 - December 2000 (Exhibit No.____(TAD-1), filed April 2, 2001	340,856
3	Total Over/(Under)-Recovery (Line 1 & 2) (To be included in January 2002 - December 2002)	$1,856,247
4	Jurisdictional KWH sales, January 2002 - December 2002	10,265,886,000
5	True-up Factor (Line 3 / Line 4) x 100 (Cents/KWH)	(0.0181)

Schedule CCE-1b

Purchased Power Capacity Cost Recovery Clause
Calculation of Estimated True-Up Amount
Gulf Power Company
For the Period January 2001 - December 2001

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1	IIC Payments/(Receipts) ($)	756,739	478,834	435,604	416,580	449,533	1,656,328	3,291,404	820,247	910,482	81,203	(25,603)	93,860	9,365,211
2	Projected Capacity Payments to Monsanto ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
3	Transmission Revenue ($)	(35,910)	(11,404)	(39,862)	(13,748)	(14,826)	(52,093)	(5,068)	(23,000)	(25,000)	(81,000)	(91,000)	(38,000)	(430,911)
4	Projected Market Capacity Payments								3,373,375	1,606,063	344,400	344,400	344,400	6,012,638
5	Total Capacity Payments/(Receipts) (Line 1 + 2 + 3 + 4) ($)	783,031	529,632	457,944	465,034	496,909	1,666,437	3,348,538	4,232,824	2,553,747	406,805	289,999	462,462	15,693,362
6	Jurisdictional %	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
7	Jurisdictional Capacity Payments/(Receipts) (Line 5 x Line 6) ($)	755,683	511,134	441,950	448,793	479,554	1,608,236	3,231,589	4,084,991	2,464,557	392,597	279,871	446,310	15,145,265
8	Amount Included in Retail Base Rate Revenues ($)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,666)	(137,666)	(137,666)	(137,666)	(1,652,000)
9	Total Jurisdictional Recovery Amount (Line 7 - Line 8) ($)	893,350	648,801	579,617	586,460	617,221	1,745,903	3,369,256	4,222,658	2,602,223	530,263	417,537	583,976	16,797,265
10	Retail KWH Sales								1,087,159,000	910,120,000	746,881,000	690,615,000	818,601,000	
11	Purchased Power Capacity Cost Recovery Factor (¢/KWH)								0.176	0.176	0.176	0.176	0.176	
12	Capacity Cost Recovery Revenues (Line 10 x Line 11/100) ($)	1,612,108	1,149,770	1,266,208	1,292,654	1,510,924	1,740,018	1,897,050	1,913,400	1,601,811	1,314,511	1,215,482	1,440,738	17,954,673
13	Revenue Taxes (Line 12 x .01572) ($)	25,342	18,074	19,905	20,321	23,752	27,353	29,822	30,079	25,180	20,664	19,107	22,648	282,247
14	True-Up Provision ($)	46,130	46,130	46,130	46,131	46,130	46,130	46,130	46,131	46,130	46,130	46,130	46,131	553,563
15	Capacity Cost Recovery Revenues net of Revenue Taxes (Line 12 - Line 13 + Line 14) ($)	1,632,896	1,177,826	1,292,433	1,318,464	1,533,302	1,758,795	1,913,358	1,929,452	1,622,761	1,339,977	1,242,505	1,464,221	18,225,990
16	Over/(Under) Recovery (Line 15 - Line 9) ($)	739,546	529,025	712,816	732,004	916,081	12,892	(1,455,898)	(2,293,206)	(979,462)	809,714	824,968	880,245	1,428,725
17	Interest Provision ($)	6,231	8,183	10,228	12,122	13,487	13,954	11,241	5,234	(42)	(455)	1,970	4,513	86,666
18	Total Estimated True-Up for the Period January 2001 - December 2001 (Line 16 + Line 17) ($)													1,515,391

NOTE: Interest is Calculated for Aug - Dec at July's rate of 0.3146 %
Actual IIC Payments for January through July include Market Capacity Payments

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
January 2002 - December 2002

Rate Class	A Average 12 CP Load Factor at Meter	B Jan - Dec 02 Projected KWH Sales at Meter	C Projected Avg 12 CP KW at Meter Col B / (8,760 hours x Col A)	D Demand Loss Expansion Factor	E Energy Loss Expansion Factor	F Jan - Dec 02 Projected KWH Sales at Generation Col B x Col E	G Projected Avg 12 CP KW at Generation Col C x Col D	H Percentage of KWH Sales at Generation Col F / Total Col F	I Percentage of 12 CP KW Demand at Generation Col G / Total Col G
RS, RST, RSVP	58.269848%	4,769,844,000	934,450.25	1.1019333	1.0766175	5,135,297,523	1,029,701.85	46.93328%	55.92950%
GS, GST	58.862369%	286,366,000	55,536.64	1.1019255	1.0766135	308,305,502	61,197.24	2.81771%	3.32400%
GSD, GSDT	77.395927%	2,261,421,000	333,548.67	1.1016647	1.0764011	2,434,196,052	367,458.80	22.24697%	19.95897%
LP, LPT	85.767459%	1,898,666,000	252,709.71	1.0601470	1.0444167	1,982,998,478	267,909.44	18.12331%	14.55183%
PX, PXT, RTP, SBS	98.930621%	922,324,000	106,426.23	1.0313379	1.0235079	944,005,900	109,761.40	8.62760%	5.96182%
OS-I, OS-II	979.964079%	94,076,000	1,095.88	1.1020255	1.0766162	101,283,746	1,207.69	0.92567%	0.06560%
OS-III	100.678498%	29,100,000	3,299.53	1.1024447	1.0766529	31,330,599	3,637.55	0.28634%	0.19758%
OS-IV	254.007949%	3,976,000	178.69	1.1024447	1.0766529	4,280,772	197.00	0.03912%	0.01070%
TOTAL	69.388372%	10,265,773,000	1,687,245.60			10,941,698,572	1,841,070.97	100.00000%	100.00000%

Notes:
Col A - Average 12 CP load factor based on actual 1999 load research data.
Col C - 8,760 is the number of hours in 12 months.

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
January 2002 - December 2002

Rate Class	A Jan - Dec 02 Percentage of KWH Sales at Generation Page 1, Col H	B Percentage of 12 CP KW Demand at Generation Page 1, Col I	C Energy-Related Costs ($)	D Demand-Related Costs ($)	E Total Capacity Costs ($) Col C + Col D	F Jan - Dec 02 Projected KWH Sales at Meter Page 1, Col B	G Capacity Cost Recovery Factors (¢ / KWH) Col E / Col F x 100
RS, RST, RSVP	46.93328%	55.92950%	119,397	1,707,388	1,826,785	4,769,844,000	0.038
GS, GST	2.81771%	3.32400%	7,168	101,474	108,642	286,366,000	0.038
GSD, GSDT	22.24697%	19.95897%	56,595	609,298	665,893	2,261,421,000	0.029
LP, LPT	18.12331%	14.55183%	46,105	444,232	490,337	1,898,666,000	0.026
PX, PXT, RTP, SBS	8.62760%	5.96182%	21,948	182,000	203,948	922,324,000	0.022
OS-I, OS-II	0.92567%	0.06560%	2,355	2,003	4,358	94,076,000	0.005
OS-III	0.28634%	0.19758%	728	6,032	6,760	29,100,000	0.023
OS-IV	0.03912%	0.01070%	100	327	427	3,976,000	0.011
TOTAL	100.00000%	100.00000%	$254,396	$3,052,754	$3,307,150	10,265,773,000	0.032

Notes:
Col C - (Recoverable Amount from Schedule CCE-1, line 12) / 13 x Col A
Col D - (Recoverable Amount from Schedule CCE-1, line 12) x 12 / 13 x Col B

14

Florida Public Service Commission
Docket No. 010001-EI
GULF POWER COMPANY
Witness: Michael F. Oaks
Exhibit No. _____ (MFO-1)
Schedule 1
Page 1 of 1

GULF POWER COMPANY
COAL SUPPLIERS
January 1, 2000 - December 31, 2000

CONTRACT COAL	TONS PURCHASED(1)	
PEABODY CONTRACT	1,761,478	
DECKER	75,468	(2)
ARCH COAL SALES	260,540	(2)
TOTAL CONTRACT	2,097,486	
SPOT COAL		
ALABAMA POWER COMPANY	20,463	
AMERICAN COAL	313,630	
CONSOLIDATION	509,149	
BLACK MOUNTAIN COAL	148,408	
CYPRUS AMAX	709,357	(2)
DRUMMOND	74,560	
ARCH COAL SALES	240,528	(2)
GUASARE COAL INTERNATIONAL	57,994	
OXBOW CARBON & MINERAL	41,315	
PEABODY COALTRADE	530,494	
TOTAL SPOT	2,645,898	
GRAND TOTAL	4,743,384	

(1) Excludes Plant Scherer: The inventory at Plant Scherer is reported on a BTU basis. No inventory of tons is maintained.
(2) Mississippi Power Company Purchases - Plant Daniel

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 14
COMPANY/ WITNESS: Oaks
DATE: 10-20-21-01

Florida Public Service Commission
Docket No. 010001-EI
GULF POWER COMPANY
Witness: Michael F. Oaks
Exhibit No. _____ (MFO-2)
Schedule 1
Page 1 of 1

GULF POWER COMPANY
PROJECTED VS ACTUAL FUEL COST OF SYSTEM NET GENERATION

	Cents/KWH Fuel Cost (1)		
Period Ending	**Projected**	**Actual**	**Difference %**
March 1991	2.1028	2.2128	5.23
September 1991	2.1184	2.1255	0.34
March 1992	1.9524	2.0660	6.84
September 1992	1.9448	2.0401	4.90
March 1993	1.9458	1.9425	(0.17)
September 1993	1.9924	2.0408	2.43
March 1994	1.9050	2.0498	7.60
September 1994	1.8662	1.9373	3.81
March 1995	1.8874	2.0388	8.02
September 1995	2.0456	2.0344	(0.55)
March 1996	1.9795	2.0743	4.79
September 1996	2.0405	1.9639	(3.75)
March 1997	1.9282	2.0332	5.45
September 1997	1.9434	1.9431	(0.02)
March 1998	1.8734	1.8647	(0.46)
September 1998	1.5916	1.6361	2.80
December 1999	1.5291	1.5696	2.65
December 2000	1.6048	1.6460	2.57
December 2001	1.5782	-	-
December 2002	2.0242	-	-

(1) Line No. 1 from FPSC Schedule A-1.

Florida Public Service Commission
Docket No. 010001-EI
Gulf Power Company
Witness: J. R. Douglass
Exhibit No. ___ (JRD-1)

EXHIBIT TO THE TESTIMONY OF

J. R. DOUGLASS

IN FPSC DOCKET 010001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 15
COMPANY/ WITNESS: Douglass
DATE: 10-20&21-01

I. CORRECTIONS TO REPORTED DATA FOR THE JANUARY 2000 - DECEMBER 2000 PERIOD

Additions and Corrections to Outages Previously Reported
for the January 2000 - December 2000 Period

Date	Unit	Change	Outage Type	Hours	MW	Description
04/01	Crist 6	Event Length	PMO	9.8	98.0	Length Originally Reported as 8.75 Hours
06/02	Smith 1	MW Affected	PFO	0.6	157.0	MW Affected Originally Reported as 37 MW
08/02	Daniel 2	Event Length & MW Affected	PFO	5.0	272.0	Length Originally Reported as 9.98 Hours and MW Affected as 312

II. CALCULATIONS OF EQUIVALENT AVAILABILITY POINTS

Comparison of Forecast and Actual Planned Outages
for January 2000 - December 2000

Unit	Note	Forecast Planned Outage Schedule	Forecast Hours*	Actual Planned Outage Schedule	Actual Hours*
Crist 6	1	01/15/00 - 02/26/00	1032.0	01/15/00 - 02/20/00	868.3
Crist 7	2	02/26/00 - 04/15/00	1200.0	02/20/00 - 04/18/00	1396.0
Smith 1	3	02/05/00 - 02/20/00	384.0	02/05/00 - 02/19/00	341.3
Smith 1	4	11/04/00 - 11/12/00	216.0	11/03/00 - 11/11/00	185.3
Smith 2	5	05/13/0 - 05/28/00	384.0	03/31/00 - 04/15/00	341.8
Smith 2	6	11/25/00 - 12/05/00	264.0	10/08/00 - 10/21/00	294.2
Daniel 1	7	02/26/00 - 04/09/00	1055.0	03/04/00 - 04/15/00	1021.7
Daniel 1	8	10/21/00 - 10/29/00	216.0	Outage Cancelled	0.0
Daniel 2	9	03/18/00 - 04/02/00	384.0	03/25/00 - 04/08/00	348.1
Daniel 2	10	9/23/00 - 11/05/00	1056.0	09/22/00 - 10/26/00	830.2

* Planned outage hours in the January 2000 - December 2000 period only.

Notes:

1. This outage proceeded as scheduled and was completed ahead of schedule.
2. The outage date was changed subsequent to the target filing and it proceeded as scheduled.
3. This outage proceeded as scheduled and was completed ahead of schedule.
4. This outage proceeded as scheduled and was completed ahead of schedule.
5. The outage date was changed subsequent to the target filing and it proceeded as scheduled with all work completed ahead of schedule.
6. The outage date was changed subsequent to the target filing and it proceeded as scheduled.
7. The outage date was changed subsequent to the target filing and it proceeded as scheduled.
8. This outage was cancelled subsequent to the target filing.
9. The outage date was changed subsequent to the target filing and it proceeded as scheduled with all work completed ahead of schedule.
10. This outage proceeded as scheduled and was completed ahead of schedule.

Calculation of Actual Equivalent Availability
for January 2000 - December 2000
Based on Target Planned Outage Hours
Crist 6

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	15.3	0.0	
	0.0	0.0	37.0	29.1	0.0	0.0	81.4
EFOH	0.5	0.0	0.0	1.1	1.0	0.2	
	9.1	0.0	0.4	1.1	0.0	0.0	13.4
MOH	0.0	0.0	0.0	47.2	34.5	100.6	
	0.0	0.0	95.7	25.1	459.3	110.6	873.0
EMOH	0.0	10.4	96.4	12.9	49.2	31.9	
	22.2	20.8	35.5	39.6	22.0	0.0	340.9
PH	744.0	696.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
POH	394.5	473.7	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	868.2
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	86.3	86.3

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(81.4 + 13.4 + 873.0 + 340.9)}{(8784.0 - 868.2 - 86.3)}$$

$$EUOR = 0.1671$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 1032.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(1032.0 + 0.1671\ (8784.0 - 1032.0 - 0.0))}{8784.0} \right] \times 100 = 73.5\ \%$$

Note: Please refer to page 10 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2000 - December 2000
Based on Target Planned Outage Hours
Crist 7

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	117.3	36.7	0.0	0.0	0.0	0.0	
	0.0	33.8	4.9	19.9	12.5	0.0	225.1
EFOH	0.2	1.3	0.0	0.2	0.0	0.0	
	0.0	3.9	1.3	0.0	0.0	0.0	6.9
MOH	32.5	0.0	0.0	21.2	107.2	0.0	
	63.0	0.0	0.0	52.6	63.6	29.1	369.2
EMOH	0.0	0.0	0.0	0.0	1.5	0.0	
	2.5	0.0	0.5	6.6	0.0	0.0	11.1
PH	744.0	696.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
POH	0.0	230.6	744.0	421.5	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	1396.1
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(225.1 + 6.9 + 369.2 + 11.1)}{(8784.0 - 1396.1 - 0.0)}$$

$$EUOR = 0.0829$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 1200.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(1200.0 + 0.0829\ (8784.0 - 1200.0 - 0.0))}{8784.0} \right] \times 100 = 79.2\ \%$$

Note: Please refer to page 10 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2000 - December 2000
Based on Target Planned Outage Hours
Smith 1

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	2.3	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	2.3
EFOH	0.8	3.1	9.1	2.4	0.0	0.7	
	0.6	0.3	0.4	1.2	1.5	0.8	20.9
MOH	0.0	0.0	0.0	0.0	0.0	0.0	
	25.1	0.0	0.0	0.0	0.0	0.0	25.1
EMOH	0.0	0.0	3.6	0.0	0.0	0.0	
	0.0	0.0	0.8	0.0	0.0	0.0	4.4
PH	744.0	696.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
POH	0.0	341.3	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	185.3	0.0	526.6
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(2.3 + 20.9 + 25.1 + 4.4)}{(8784.0 - 526.6 - 0.0)}$$

$$EUOR = 0.0064$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 600.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(600.0 + 0.0064\ (8784.0 - 600.0 - 0.0))}{8784.0} \right] \times 100 = 92.6\ \%$$

Note: Please refer to page 10 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2000 - December 2000
Based on Target Planned Outage Hours
Smith 2

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	1.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	3.5	0.0	1.0	5.5
EFOH	0.0	3.3	0.0	0.0	0.1	0.2	
	0.0	0.0	1.3	1.9	1.6	0.0	8.4
MOH	0.0	0.0	0.0	0.0	25.4	0.0	
	0.0	0.0	9.6	0.0	17.5	26.0	78.5
EMOH	0.0	2.5	0.0	0.0	0.0	0.0	
	0.0	0.0	2.7	0.0	0.0	0.0	5.2
PH	744.0	696.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
POH	0.0	0.0	0.2	341.6	0.0	0.0	
	0.0	0.0	0.0	294.2	0.0	0.0	636.0
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(5.5 + 8.4 + 78.5 + 5.2)}{(8784.0 - 636.0 - 0.0)}$$

EUOR = 0.0120

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 648.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(648.0 + 0.0120\ (8784.0 - 648.0 - 0.0))}{8784.0} \right] \times 100 = 91.5\ \%$$

Note: Please refer to page 10 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2000 - December 2000
Based on Target Planned Outage Hours
Daniel 1

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	181.2	0.0	
	112.9	47.4	0.0	0.0	0.0	0.0	341.5
EFOH	3.5	4.5	0.7	18.0	41.0	3.5	
	14.4	7.3	8.6	0.2	7.6	5.9	115.2
MOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	31.4	0.0	0.0	0.0	31.4
EMOH	2.8	0.0	0.0	0.0	0.0	2.4	
	0.0	4.0	0.0	0.0	0.0	0.0	9.2
PH	744.0	696.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
POH	0.0	0.0	670.7	351.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	1021.7
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(341.5 + 115.2 + 31.4 + 9.2)}{(8784.0 - 1021.7 - 0.0)}$$

$$EUOR = 0.0641$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 1271.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(1271.0 + 0.0641\ (8784.0 - 1271.0 - 0.0))}{8784.0} \right] \times 100 = 80.0\ \%$$

Note: Please refer to page 10 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2000 - December 2000
Based on Target Planned Outage Hours
Daniel 2

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	34.2	0.0	0.0	0.0	0.0	0.0	
	66.5	0.0	0.0	0.0	0.0	0.0	100.7
EFOH	2.9	13.0	31.7	3.6	2.4	2.7	
	25.5	4.6	8.8	0.0	4.8	1.7	101.7
MOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EMOH	1.9	0.0	0.0	0.0	0.0	1.4	
	0.0	0.0	0.0	0.0	0.0	0.0	3.3
PH	744.0	696.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
POH	0.0	0.0	166.9	181.1	0.0	0.0	
	0.0	0.0	213.9	616.3	0.0	0.0	1178.2
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(100.7 + 101.7 + 0.0 + 3.3)}{(8784.0 - 1178.2 - 0.0)}$$

EUOR = 0.0270

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] x\ 100$$

Target POH* = 1440.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(1440.0 + 0.0270\ (8784.0 - 1440.0 - 0.0))}{8784.0} \right] \times 100 = 81.3\ \%$$

Note: Please refer to page 10 of this schedule for an explanation of symbols.

Calculation of Equivalent Availability Points
for January 2000 - December 2000

(1) Unit	(2) Equivalent Availability Target*	(3) Actual Equivalent Availability Adjusted to Target Planned Outage Basis**	(4) Minimum or Maximum Attainable Equivalent Availability*	(5) Availability Points***
Crist 6	84.3	73.5	82.5	-10.00
Crist 7	77.3	79.2	80.0	7.04
Smith 1	90.6	92.6	91.4	10.00
Smith 2	89.2	91.5	90.2	10.00
Daniel 1	75.3	80.0	78.4	10.00
Daniel 2	74.5	81.3	77.2	10.00

* As appropriate from page 5, Schedule 3 of Exhibit to J. R. Douglass's October 1, 1999 GPIF testimony in Docket 990001-EI.

** Refer to pages 3 through 8 of this schedule for calculations.

*** If (3) > (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times 10$$

If (3) < (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times -10$$

Summary of Equivalent Availability Symbols

EA - Equivalent Availability
POH - Planned Outage Hours
EUOR - Equivalent Unplanned Outage Rate
PH - Period Hours
FOH - Forced Outage Hours
EFOH - Equivalent Forced Outage Hours
MOH - Maintenance Outage Hours
EMOH - Equivalent Maintenance Outage Hours
RSH - Reserve Shutdown Hours

III. CALCULATION OF GPIF UNIT HEAT RATE POINTS

Calculation of Average Net Operating Heat Rate Points
for January 2000 - December 2000

Crist 6

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	64576.8	43755.5	140637.3	147047.2	149669.4	125451.9	
	160428.0	160247.8	109786.3	129946.3	59603.1	119509.3	1410658.9
BTU/Lb*	11921.3	12111.4	12052.7	12024.1	12028.3	11954.4	
	11943.4	11965.8	12034.5	12092.6	12081.7	11913.6	12003.6
Coal, MMBTU	769839.4	529940.4	1695059.2	1768110.2	1800268.4	1499702.2	
	1916055.8	1917493.1	1321223.2	1571388.6	720106.8	1423786.0	16932973.3
Oil, MMBTU	900.6	598.6	220.2	882.9	1608.9	767.5	
	759.0	876.8	1826.9	2351.3	597.2	1509.7	12899.6
Gas, MMBTU	192.0	2847.0	0.0	2277.0	1558.0	1272.0	
	0.0	0.0	3105.0	40346.0	0.0	8229.0	59826.0
Startup, MMBTU **	0.0	-8080.0	0.0	-4040.0	-4040.0	-4040.0	
	0.0	0.0	-8080.0	-8080.0	0.0	-8080.0	-44440.0
Total Fuel Consumption, MMBTU	770932.0	525306.0	1695279.4	1767230.1	1799395.3	1497701.7	
	1916814.8	1918369.9	1318075.1	1606005.9	720704.0	1425444.7	16961258.9
Net MWH Generation***	74135	49191	166967	173351	172005	141576	
	180922	180632	121421	150123	65888	135001	1611212
Average Net Operating Heat Rate	10399	10679	10153	10195	10461	10579	
	10595	10620	10855	10698	10938	10559	10527

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2000 - December 2000

Crist 7

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	206758.1	160500.0	0.0	99029.7	235438.2	264999.7	
	253317.1	267512.3	258694.0	215049.2	241752.4	261854.6	2464905.3
BTU/Lb*	11947.2	12000.3	0.0	12036.7	12034.0	11962.8	
	11963.5	11949.0	12064.1	12112.3	11973.9	11896.9	11990.0
Coal, MMBTU	2470180.4	1926048.2	0.0	1191990.8	2833263.3	3170138.4	
	3030559.1	3196504.5	3120910.3	2604740.4	2894719.1	3115258.0	29554312.5
Oil, MMBTU	117.1	71.4	0.0	35.0	11.7	3.7	
	3.1	16.2	1.4	150.3	4.2	0.0	414.1
Gas, MMBTU	6323.0	3209.0	0.0	4553.0	2750.0	0.0	
	3015.0	1764.0	5.0	3200.0	6034.0	1141.0	31994.0
Startup, MMBTU **	-6768.0	-2256.0	0.0	-2256.0	-4512.0	0.0	
	-2256.0	-2256.0	0.0	-2256.0	-2256.0	-2256.0	-27072.0
Total Fuel Consumption, MMBTU	2469852.5	1927072.6	0.0	1194322.8	2831513.0	3170142.1	
	3031321.2	3196028.7	3120916.7	2605834.7	2898501.3	3114143.0	29559648.6
Net MWH Generation***	247170	189478	0	119030	289447	309520	
	287910	307333	297571	250572	277871	307929	2883831
Average Net Operating Heat Rate	9993	10170	---	10034	9782	10242	
	10529	10399	10488	10400	10431	10113	10250

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2000 - December 2000

Smith 1

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	91515.0	45207.8	94580.0	91220.6	92905.4	88479.4	
	88106.4	91630.4	83810.4	81195.5	65797.9	92867.5	1007316.3
BTU/Lb*	12212.2	11993.9	12057.0	12156.8	12221.5	12038.6	
	11864.4	11893.7	11811.1	12853.8	11880.2	11918.1	12078.6
Coal, MMBTU	1117599.5	542217.8	1140351.1	1108950.6	1135443.3	1065168.1	
	1045329.6	1089824.5	989893.0	1043670.7	781692.2	1106804.2	12166944.6
Oil, MMBTU	283.1	1682.6	257.1	224.1	74.5	225.4	
	1326.6	267.2	434.7	414.6	1786.9	303.6	7280.4
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	-964.0	0.0	0.0	0.0	0.0	
	-964.0	0.0	0.0	0.0	-964.0	0.0	-2892.0
Total Fuel Consumption, MMBTU	1117882.6	542936.4	1140608.2	1109174.7	1135517.8	1065393.5	
	1045692.2	1090091.7	990327.7	1044085.3	782515.1	1107107.8	12171333.0
Net MWH Generation***	109933	54051	113169	109663	113621	105141	
	103281	108494	98384	102145	78664	110988	1207534
Average Net Operating Heat Rate	10169	10045	10079	10114	9994	10133	
	10125	10047	10066	10222	9948	9975	10079

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2000 - December 2000

Smith 2

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	100905.9	100977.8	108833.1	53482.7	104394.5	103280.0	
	107507.7	107494.5	95315.1	53832.9	100326.2	102311.3	1138661.7
BTU/Lb*	12180.8	11874.7	12018.1	12120.2	12196.8	12028.0	
	11804.3	11885.5	11768.7	12650.1	11898.8	11844.3	11992.0
Coal, MMBTU	1229114.6	1199081.1	1307967.1	648221.0	1273278.8	1242251.8	
	1269053.1	1277625.9	1121734.8	680991.6	1193761.4	1211805.7	13654886.9
Oil, MMBTU	102.6	326.6	93.3	2079.8	1067.8	176.0	
	395.4	259.4	1097.4	579.7	1307.2	1102.6	8587.8
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	0.0	0.0	-1190.0	-1190.0	0.0	
	0.0	0.0	0.0	-1190.0	0.0	-1190.0	-4760.0
Total Fuel Consumption, MMBTU	1229217.2	1199407.7	1308060.4	649110.8	1273156.6	1242427.8	
	1269448.5	1277885.3	1122832.2	680381.3	1195068.6	1211718.3	13658714.7
Net MWH Generation***	124942	122927	134326	63779	125753	121240	
	123574	124343	109314	65449	116911	119393	1351951
Average Net Operating Heat Rate	9838	9757	9738	10178	10124	10248	
	10273	10277	10272	10396	10222	10149	10103

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2000 - December 2000

Daniel 1

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	295226.0	310360.0	30565.0	141516.0	201524.0	267038.0	
	277674.0	301384.0	297122.0	319068.0	328562.0	353170.0	3123209.0
BTU/Lb*	9207.3	9272.4	9117.3	11464.7	11342.8	11033.3	
	11159.9	11267.0	11207.3	11055.3	10641.3	9407.1	10534.0
Coal, MMBTU	2718234.3	2877782.1	278670.3	1622438.5	2285846.4	2946310.4	
	3098814.1	3395693.5	3329935.4	3527392.5	3496326.8	3322305.5	32899749.8
Oil, MMBTU	182.2	232.8	403.2	4632.1	7642.5	188.3	
	4395.5	4060.0	2718.7	393.0	72.4	871.9	25792.6
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	0.0	0.0	-2388.7	-4777.4	0.0	
	-2388.7	-2388.7	-2388.7	0.0	0.0	0.0	-14332.2
Total Fuel Consumption, MMBTU	2718416.5	2878014.9	279073.5	1624681.9	2288711.5	2946498.7	
	3100820.9	3397364.8	3330265.4	3527785.5	3496399.2	3323177.4	32911210.2
Net MWH Generation***	257638	280793	31336	158482	226326	297070	
	286937	331637	331564	351622	344740	320743	3218888
Average Net Operating Heat Rate	10551	10250	8906	10252	10112	9919	
	10807	10244	10044	10033	10142	10361	10224

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2000 - December 2000

Daniel 2

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	257490.0	283634.0	283455.0	218782.0	296674.0	254380.0	
	243476.0	283892.0	173906.0	48368.0	277544.0	330996.0	2952597.0
BTU/Lb*	9203.5	9772.2	9029.8	11371.9	11358.3	11072.3	
	11264.5	11286.2	11287.6	11142.7	10633.8	10643.0	10600.2
Coal, MMBTU	2369809.2	2771728.2	2559542.0	2487967.0	3369712.3	2816571.7	
	2742635.4	3204061.9	1962981.4	538950.1	2951347.4	3522790.4	31298097.0
Oil, MMBTU	2803.3	318.1	1431.3	5128.4	4534.9	2.1	
	3914.2	350.5	1203.1	4062.7	1061.1	4.4	24814.1
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	-2388.7	0.0	0.0	-2388.7	0.0	0.0	
	-2388.7	0.0	0.0	-2388.7	0.0	0.0	-9554.8
Total Fuel Consumption, MMBTU	2370223.8	2772046.3	2560973.3	2490706.7	3374247.2	2816573.8	
	2744160.9	3204412.4	1964184.5	540624.1	2952408.5	3522794.8	31313356.3
Net MWH Generation***	226655	275068	255930	249710	338650	276733	
	261821	310900	196391	51040	308003	362616	3113517
Average Net Operating Heat Rate	10457	10078	10007	9974	9964	10178	
	10481	10307	10001	10592	9586	9715	10057

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate
for January 2000 - December 2000
Adjusted to Target Basis Using Heat Rate
Equations Filed October 1, 1999

Crist 6

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10667	10656	10637	10465	10563	10636	
		10637	10625	10658	10665	10682	10702	
2.	Target Heat Rate	10703	10686	10680	10456	10543	10673	
	at Actual Conditions**	10650	10651	10714	10693	10636	10645	
3.	Adjustment to Actual	-36	-30	-43	9	20	-37	
	Heat Rate (1-2)	-13	-26	-56	-28	46	57	
4.	Actual Heat Rate	10399	10679	10153	10195	10461	10579	
	(Page 2 of Sched. 3)	10595	10620	10855	10698	10938	10559	
5.	Adjusted Actual	10363	10649	10110	10204	10481	10542	
	Heat Rate (4+3)	10582	10594	10799	10670	10984	10616	
6.	Net MWH Generation	74135	49191	166967	173351	172005	141576	
		180922	180632	121421	150123	65888	135001	
7.	Adjusted Actual Heat Rate for January 2000 - December 2000 $=(\Sigma(5*6)/\Sigma 6)$							10515

* From pages 18 & 19, schedule 3 of Exhibit to J. R. Douglass's October 1, 1999 GPIF testimony in Docket 990001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 15 of this schedule.

Calculation of Average Net Operating Heat Rate
for January 2000 - December 2000
Adjusted to Target Basis Using Heat Rate
Equations Filed October 1, 1999

Crist 7

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10238	10229	-	10223	10377	10198	
		10202	10191	10231	10231	10216	10259	
2.	Target Heat Rate	10244	10213	-	10226	10320	10227	
	at Actual Conditions**	10235	10224	10244	10304	10225	10226	
3.	Adjustment to Actual	-6	16	0	-3	57	-29	
	Heat Rate (1-2)	-33	-33	-13	-73	-9	33	
4.	Actual Heat Rate	9993	10170	0	10034	9782	10242	
	(Page 3 of Sched. 3)	10529	10399	10488	10400	10431	10113	
5.	Adjusted Actual	9987	10186	0	10031	9839	10213	
	Heat Rate (4+3)	10496	10366	10475	10327	10422	10146	
6.	Net MWH Generation	247170	189478	0	119030	289447	309520	
		287910	307333	297571	250572	277871	307929	
7.	Adjusted Actual Heat Rate for January 2000 - December 2000 $=(\Sigma(5*6)/\Sigma 6)$							10241

* From pages 20 & 21, schedule 3 of Exhibit to J. R. Douglass's October 1, 1999 GPIF testimony in Docket 990001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 15 of this schedule.

Calculation of Average Net Operating Heat Rate
for January 2000 - December 2000
Adjusted to Target Basis Using Heat Rate
Equations Filed October 1, 1999

Smith 1

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10456 10383	10341 10263	10288 10360	10202 10352	10287 10243	10292 10526	
2.	Target Heat Rate at Actual Conditions**	10216 10306	10170 10195	10173 10244	10089 10258	10081 10098	10198 10199	
3.	Adjustment to Actual Heat Rate (1-2)	240 77	171 68	115 116	113 94	206 145	94 327	
4.	Actual Heat Rate (Page 4 of Sched. 3)	10169 10125	10045 10047	10079 10066	10114 10222	9994 9948	10133 9975	
5.	Adjusted Actual Heat Rate (4+3)	10409 10202	10216 10115	10194 10182	10227 10316	10200 10093	10227 10302	
6.	Net MWH Generation	109933 103281	54051 108494	113169 98384	109663 102145	113621 78664	105141 110988	
7.	Adjusted Actual Heat Rate for January 2000 - December 2000 $=(\Sigma(5*6)/\Sigma 6)$							10227

* From pages 22 & 23 , schedule 3 of Exhibit to J. R. Douglass's October 1, 1999 GPIF testimony in Docket 990001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 15 of this schedule.

Calculation of Average Net Operating Heat Rate
for January 2000 - December 2000
Adjusted to Target Basis Using Heat Rate
Equations Filed October 1, 1999

Smith 2

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10117	10081	10048	10068	10255	10147	
		10249	10209	10182	10089	10080	10159	
2.	Target Heat Rate	10043	10016	10006	10039	10144	10140	
	at Actual Conditions**	10246	10230	10167	10119	10047	10047	
3.	Adjustment to Actual	74	65	42	29	111	7	
	Heat Rate (1-2)	3	-21	15	-30	33	112	
4.	Actual Heat Rate	9838	9757	9738	10178	10124	10248	
	(Page 5 of Sched. 3)	10273	10277	10272	10396	10222	10149	
5.	Adjusted Actual	9912	9822	9780	10207	10235	10255	
	Heat Rate (4+3)	10276	10256	10287	10366	10255	10261	
6.	Net MWH Generation	124942	122927	134326	63779	125753	121240	
		123574	124343	109314	65449	116911	119393	
7.	Adjusted Actual Heat Rate for January 2000 - December 2000 $=(\Sigma(5*6)/\Sigma 6)$							10143

* From pages 24 & 25, schedule 3 of Exhibit to J. R. Douglass's October 1, 1999 GPIF testimony in Docket 990001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 15 of this schedule.

Calculation of Average Net Operating Heat Rate
for January 2000 - December 2000
Adjusted to Target Basis Using Heat Rate
Equations Filed October 1, 1999

Daniel 1

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10246	10312	-	10275	10418	10128	
		10203	10125	10238	10162	10184	10315	
2.	Target Heat Rate	10643	10522	10354	10064	10150	10071	
	at Actual Conditions**	10066	10009	10009	10049	10100	10412	
3.	Adjustment to Actual	-397	-210	-117	211	268	57	
	Heat Rate (1-2)	137	116	229	113	84	-97	
4.	Actual Heat Rate***	10551	10250	8906	10252	10112	9919	
	(Page 6 of Sched. 3)	10807	10244	10044	10033	10142	10361	
5.	Adjusted Actual	10154	10040	8789	10463	10380	9976	
	Heat Rate (4+3)	10944	10360	10273	10146	10226	10264	
6.	Net MWH Generation	257638	280793	31336	158482	226326	297070	
		286937	331637	331564	351622	344740	320743	
7.	Adjusted Actual Heat Rate for January 2000 - December 2000 $=(\Sigma(5*6)/\Sigma 6)$							10267

* From pages 26 & 27, schedule 3 of Exhibit to J. R. Douglass's October 1, 1999 GPIF testimony in Docket 990001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 15 of this schedule.

Calculation of Average Net Operating Heat Rate
for January 2000 - December 2000
Adjusted to Target Basis Using Heat Rate
Equations Filed October 1, 1999

Daniel 2

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10013	10093	10082	10069	10184	10027	
		10169	10113	10237	-	10026	10127	
2.	Target Heat Rate	10514	10249	10212	9880	9898	10095	
	at Actual Conditions**	10242	10172	10253	10053	10046	9924	
3.	Adjustment to Actual	-501	-156	-130	189	286	-68	
	Heat Rate (1-2)	-73	-59	-16	52	-20	203	
4.	Actual Heat Rate***	10457	10078	10007	9974	9964	10178	
	(Page 7 of Sched. 3)	10481	10307	10001	10592	9586	9715	
5.	Adjusted Actual	9956	9922	9877	10163	10250	10110	
	Heat Rate (4+3)	10408	10248	9985	10644	9566	9918	
6.	Net MWH Generation	226655	275068	255930	249710	338650	276733	
		261821	310900	196391	51040	308003	362616	
7.	Adjusted Actual Heat Rate for January 2000 - December 2000 $=(\Sigma(5*6)/\Sigma 6)$							10046

* From pages 28 & 29, schedule 3 of Exhibit to J. R. Douglass's October 1, 1999 GPIF testimony in Docket 990001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 15 of this schedule.

Actual Values of
Target Heat Rate Equation Parameters
for January 2000 - December 2000

	Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec
Crist 6						
$AKW * 10^{+3}$	212.1	221.3	224.4	258.0	247.8	228.6
	243.2	242.8	206.7	217.3	252.7	246.8
$LSRF * 10^{+6}$	50682.6	54317.0	56485.3	70442.5	66739.5	58251.8
	64842.0	64673.0	49053.2	53330.4	68860.7	65218.6
Crist 7						
$AKW * 10^{+3}$	416.0	442.0	0.0	430.8	454.5	429.9
	422.8	432.7	416.1	372.6	431.5	430.7
$LSRF * 10^{+6}$	180891.5	198463.5	0.0	194438.0	210012.2	190944.9
	187687.9	193136.2	181125.0	152421.9	193616.8	193422.0
Smith 1						
$AKW * 10^{+3}$	147.8	152.4	152.6	152.5	152.7	146.0
	143.7	145.8	136.6	137.1	147.1	149.2
$LSRF * 10^{+6}$	22718.4	23570.0	23654.3	23672.6	23731.9	22064.8
	21620.9	21985.1	19863.3	20112.6	22443.8	22952.6
Smith 2						
$AKW * 10^{+3}$	167.9	176.9	180.6	169.0	175.0	168.4
	166.1	167.1	153.9	146.3	166.4	166.5
$LSRF * 10^{+6}$	29685.6	31807.5	32993.1	29701.1	31549.4	29501.9
	29093.5	29081.3	25735.3	23882.8	29278.8	29298.1
Daniel 1						
$AKW * 10^{+3}$	346.3	403.4	427.5	430.7	402.1	412.6
	454.7	476.1	481.5	472.0	478.8	431.1
$LSRF * 10^{+6}$	134058.6	174796.8	192059.4	198725.6	179832.0	189926.7
	221570.0	234634.3	238461.9	231930.3	233291.2	189095.2
Daniel 2						
$AKW * 10^{+3}$	319.3	395.2	443.5	464.2	455.2	384.4
	386.5	417.9	388.0	396.6	427.8	487.4
$LSRF * 10^{+6}$	115976.8	170303.1	201950.1	223448.3	216595.5	168447.3
	171117.2	189460.2	170280.9	181790.1	199525.3	243569.4

Target Heat Rate Equations

Crist 6 ANOHR = 10^6 / AKW * [88.29 - 44.75 * APR - 24.93 * MAY]
+ 10,287

Crist 7 ANOHR = 10^6 / AKW * [215.83 + 54.63 * MAY]
+ 9,725

Smith 1 ANOHR = 10^6 / AKW * [303.56 - 13.60 * APR - 14.98 * MAY + 12.46 * JUL - 15.94 * NOV]
+ 5,563 + 0.01691 * LSRF / AKW

Smith 2 ANOHR = 10^6 / AKW * [86.76 + 21.35 * MAY + 16.56 * JUN + 32.76 * JUL + 30.95 * AUG + 11.83 * SEP]
+ 9,526

Daniel 1 ANOHR = 10^6 / AKW * [1223.24 - 40.12 * JAN - 50.48 * MAR - 44.86 * JUN]
+ 9,170 + 10^6 / AKW * [-0.0731 * BTU/LB]

Daniel 2 ANOHR = 10^6 / AKW * [1014.82 - 37.91 * JAN + 69.66 * JUL + 78.80 * AUG + 76.66 * SEP]
+ 9,052 + 10^6 / AKW * [-0.0554 * BTU/LB]

Where:

ANOHR	Average Net Operating Heat Rate, BTU/KWH
AKW	Average Kilowatt Load, KW
LSRF	Load Square Range Factor, KW^2
BTU/LB	Coal Burned Average Heat Content, BTU/LB
JAN	January, 0 if not January, 1 if January
FEB	February, 0 if not February, 1 if February
MAR	March, 0 if not March, 1 if March
APR	April, 0 if not April, 1 if April
MAY	May, 0 if not May, 1 if May
JUN	June, 0 if not June, 1 if June
JUL	July, 0 if not July, 1 if July
AUG	August, 0 if not August, 1 if August
SEP	September, 0 if not September, 1 if September
OCT	October, 0 if not October, 1 if October
NOV	November, 0 if not November, 1 if November

Calculation of Heat Rate Points
for January 2000 - December 2000

(1)	(2)	(3)	(4)	(5)
Unit	Actual Average Average Net Operating Heat Rate Target*	Net Operating Heat Rate Adjusted to Target Basis**	Minimum Attainable Heat Rate*	Heat Rate Points***
Crist 6	10629	10515	10310	1.60
Crist 7	10236	10241	9929	0.00
Smith 1	10332	10227	10022	1.28
Smith 2	10137	10143	9833	0.00
Daniel 1	10237	10267	9930	0.00
Daniel 2	10105	10046	9802	0.00

* From page 5, Schedule 3 of Exhibit to J. R. Douglass's October 1, 1999 GPIF testimony in Docket 990001-EI.

** Refer to pages 8 through 13 of this schedule for calculation.

*** If [(2) - 75] <= (3) <= [(2) + 75] then points = 0

If [(2) - (3) - 75] > 0 then points = $\frac{(2) - (3) - 75}{(2) - (4) - 75} * 10$

If [(2) - (3) + 75] < 0 then points = $\frac{(2) - (3) + 75}{(2) - (4) - 75} * 10$

IV. CALCULATION OF COMPANY GPIF POINTS AND REWARD/PENALTY

Calculation of Heat Rate Points

GPIF Points and Reward or Penalty

for January 2000 - December 2000

Unit	Availability Points	Availability* Weighting Factor	Heat Rate Points	Heat Rate* Weighting Factor
Crist 6	-10.00	0.019	1.60	0.121
Crist 7	7.04	0.088	0.00	0.173
Smith 1	10.00	0.005	1.28	0.041
Smith 2	10.00	0.012	0.00	0.053
Daniel 1	10.00	0.078	0.00	0.167
Daniel 2	10.00	0.065	0.00	0.177

Company GPIF Points - 10.00 • 0.019 + 1.60 * 0.121
+ 7.04 * 0.088 + 0.00 * 0.173
+ 10.00 * 0.005 + 1.28 * 0.041
+ 10.00 * 0.012 + 0.00 * 0.053
+ 10.00 * 0.078 + 0.00 • 0.167
+ 10.00 * 0.065 + 0.00 * 0.177
2.28

Company reward/penalty = 2.28 points • $166549 per point

= $379,732

* From page 5, Schedule 3 of Exhibit to J. R. Douglass's October 1, 1999 GPIF testimony in Docket 990001-EI.

V. GPIF MINIMUM FILING REQUIREMENTS FOR THE JANUARY 2000 - DECEMBER 2000 PERIOD

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Generating Performance Incentive Factor

Actual Reward/Penalty Table

Gulf Power Company

Period of: January 2000 - December 2000

Generating Performance Incentive Factor Points	Fuel Saving/Loss ($000)	Generating Performance Incentive Factor ($000)
	Maximum Attainable Fuel Savings	Maximum Incentive Dollars Allowed by Commission During Period (Reward)
+ 10	6941	1665
+ 9	6247	1499
+ 8	5553	1332
+ 7	4859	1166
+ 6	4165	999
+ 5	3471	833
+ 4	2776	666
+ 3	2082	500
+ 2	1388	333
+ 1	694	167
0	0	0
- 1	-795	-167
- 2	-1590	-333
- 3	-2385	-500
- 4	-3180	-666
- 5	-3975	-833
- 6	-4769	-999
- 7	-5564	-1166
- 8	-6359	-1332
- 9	-7154	-1499
- 10	-7949	-1665
	Minimum Attainable Fuel Loss	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

Generating Performance Incentive Factor

Calculation of Maximum Allowed Incentive Dollars

Actual

Gulf Power Company

Period of: January 2000 - December 2000

Line 1	Beginning of Period Balance of Common Equity	$422,313,404
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '00	$426,639,558
Line 3	Month of Feb '00	$413,384,995
Line 4	Month of Mar '00	$412,366,035
Line 5	Month of Apr '00	$399,012,745
Line 6	Month of May '00	$404,152,838
Line 7	Month of Jun '00	$410,393,325
Line 8	Month of Jul '00	$405,595,018
Line 9	Month of Aug '00	$423,892,934
Line 10	Month of Sep '00	$430,531,221
Line 11	Month of Oct '00	$420,239,575
Line 12	Month of Nov '00	$422,875,465
Line 13	Month of Dec '00	$427,378,641
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$416,828,904
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	60.4594%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16)	$1,723,590
Line 18	Jurisdictional Sales (KWH)	10,112,966,114
Line 19	Total Territorial Sales (KWH)	10,465,754,747
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	96.6291%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	$1,665,490

Issued by: T. J. Bowden

Filed: April 02, 2001
Suspended:
Effective: April 02, 2001
Docket No.: 010001-EI
Order No.:

Calculation of System Actual GPIF Points

Gulf Power Company

Period of: January 2000 - December 2000

Plant & Unit	Performance Indicator (EAF or ANOHR)	Weighting Factor	Unit Points	Weighted Unit Points
Crist 6	EAF1	1.9%	-10.00	-0.190
Crist 6	ANOHR1	12.1%	1.60	0.194
Crist 7	EAF2	8.8%	7.04	0.620
Crist 7	ANOHR2	17.3%	0.00	0.000
Smith 1	EAF3	0.5%	10.00	0.050
Smith 1	ANOHR3	4.1%	1.28	0.052
Smith 2	EAF4	1.2%	10.00	0.120
Smith 2	ANOHR4	5.3%	0.00	0.000
Daniel 1	EAF5	7.8%	10.00	0.780
Daniel 1	ANOHR5	16.7%	0.00	0.000
Daniel 2	EAF6	6.5%	10.00	0.650
Daniel 2	ANOHR6	17.7%	0.00	0.000
Gulf Power GPIF Total		99.9%		2.28

Issued by: T. J. Bowden

Filed: April 02, 2001
Suspended:
Effective: April 02, 2001
Docket No.: 010001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2000 - December 2000

Crist 6

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	132	85.50	+ 10	843	10,310
+ 9	119	85.38	+ 9	759	10,334
+ 8	106	85.26	+ 8	674	10,359
+ 7	92	85.14	+ 7	590	10,383
+ 6	79	85.02	+ 6	506	10,408
+ 5	66	84.90	+ 5	422	10,432
+ 4	53	84.78	+ 4	337	10,456
+ 3	40	84.66	+ 3	253	10,481
+ 2	26	84.54	+ 2	169	10,505
+ 1	13	84.42	+ 1	84	10,530
				0	10,554
0	0	84.30	0	0	10,629
				0	10,704
- 1	(18)	84.12	- 1	(84)	10,728
- 2	(36)	83.94	- 2	(169)	10,753
- 3	(55)	83.76	- 3	(253)	10,777
- 4	(73)	83.58	- 4	(337)	10,802
- 5	(91)	83.40	- 5	(422)	10,826
- 6	(109)	83.22	- 6	(506)	10,850
- 7	(127)	83.04	- 7	(590)	10,875
- 8	(146)	82.86	- 8	(674)	10,899
- 9	(164)	82.68	- 9	(759)	10,924
- 10	(182)	82.50	- 10	(843)	10,948
Weighting Factor:		0.019	Weighting Factor:		0.121

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2000 - December 2000

Crist 7

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	614	80.00	+ 10	1,204	9,929
+ 9	553	79.73	+ 9	1,084	9,952
+ 8	491	79.46	+ 8	963	9,975
+ 7	430	79.19	+ 7	843	9,999
+ 6	368	78.92	+ 6	722	10,022
+ 5	307	78.65	+ 5	602	10,045
+ 4	246	78.38	+ 4	482	10,068
+ 3	184	78.11	+ 3	361	10,091
+ 2	123	77.84	+ 2	241	10,115
+ 1	61	77.57	+ 1	120	10,138
				0	10,161
0	0	77.30	0	0	10,236
				0	10,311
- 1	(88)	76.90	- 1	(120)	10,334
- 2	(175)	76.50	- 2	(241)	10,357
- 3	(263)	76.10	- 3	(361)	10,381
- 4	(350)	75.70	- 4	(482)	10,404
- 5	(438)	75.30	- 5	(602)	10,427
- 6	(526)	74.90	- 6	(722)	10,450
- 7	(613)	74.50	- 7	(843)	10,473
- 8	(701)	74.10	- 8	(963)	10,497
- 9	(788)	73.70	- 9	(1,084)	10,520
- 10	(876)	73.30	- 10	(1,204)	10,543
Weighting Factor:		0.088	Weighting Factor:		0.173

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2000 - December 2000

Smith 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	38	91.40	+ 10	284	10,022
+ 9	34	91.32	+ 9	256	10,046
+ 8	30	91.24	+ 8	227	10,069
+ 7	27	91.16	+ 7	199	10,093
+ 6	23	91.08	+ 6	170	10,116
+ 5	19	91.00	+ 5	142	10,140
+ 4	15	90.92	+ 4	114	10,163
+ 3	11	90.84	+ 3	85	10,187
+ 2	8	90.76	+ 2	57	10,210
+ 1	4	90.68	+ 1	28	10,234
				0	10,257
0	0	90.60	0	0	10,332
				0	10,407
- 1	(5)	90.48	- 1	(28)	10,431
- 2	(9)	90.36	- 2	(57)	10,454
- 3	(14)	90.24	- 3	(85)	10,478
- 4	(18)	90.12	- 4	(114)	10,501
- 5	(23)	90.00	- 5	(142)	10,525
- 6	(27)	89.88	- 6	(170)	10,548
- 7	(32)	89.76	- 7	(199)	10,572
- 8	(36)	89.64	- 8	(227)	10,595
- 9	(41)	89.52	- 9	(256)	10,619
- 10	(45)	89.40	- 10	(284)	10,642
Weighting Factor:		0.005	Weighting Factor:		0.041

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2000 - December 2000

Smith 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	81	90.20	+ 10	369	9,833
+ 9	73	90.10	+ 9	332	9,856
+ 8	65	90.00	+ 8	295	9,879
+ 7	57	89.90	+ 7	258	9,902
+ 6	49	89.80	+ 6	221	9,925
+ 5	41	89.70	+ 5	185	9,948
+ 4	32	89.60	+ 4	148	9,970
+ 3	24	89.50	+ 3	111	9,993
+ 2	16	89.40	+ 2	74	10,016
+ 1	8	89.30	+ 1	37	10,039
				0	10,062
0	0	89.20	0	0	10,137
				0	10,212
- 1	(13)	89.04	- 1	(37)	10,235
- 2	(27)	88.88	- 2	(74)	10,258
- 3	(40)	88.72	- 3	(111)	10,281
- 4	(53)	88.56	- 4	(148)	10,304
- 5	(67)	88.40	- 5	(185)	10,327
- 6	(80)	88.24	- 6	(221)	10,349
- 7	(93)	88.08	- 7	(258)	10,372
- 8	(106)	87.92	- 8	(295)	10,395
- 9	(120)	87.76	- 9	(332)	10,418
- 10	(133)	87.60	- 10	(369)	10,441
Weighting Factor:		0.012	Weighting Factor:		0.053

Issued by: T. J. Bowden

Filed: April 02, 2001
Suspended:
Effective: April 02, 2001
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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2000 - December 2000

Daniel 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	539	78.40	+ 10	1,156	9,930
+ 9	485	78.09	+ 9	1,040	9,953
+ 8	431	77.78	+ 8	925	9,976
+ 7	377	77.47	+ 7	809	10,000
+ 6	323	77.16	+ 6	694	10,023
+ 5	270	76.85	+ 5	578	10,046
+ 4	216	76.54	+ 4	462	10,069
+ 3	162	76.23	+ 3	347	10,092
+ 2	108	75.92	+ 2	231	10,116
+ 1	54	75.61	+ 1	116	10,139
				0	10,162
0	0	75.30	0	0	10,237
				0	10,312
- 1	(88)	74.85	- 1	(116)	10,335
- 2	(175)	74.40	- 2	(231)	10,358
- 3	(263)	73.95	- 3	(347)	10,382
- 4	(350)	73.50	- 4	(462)	10,405
- 5	(438)	73.05	- 5	(578)	10,428
- 6	(525)	72.60	- 6	(694)	10,451
- 7	(613)	72.15	- 7	(809)	10,474
- 8	(700)	71.70	- 8	(925)	10,498
- 9	(788)	71.25	- 9	(1,040)	10,521
- 10	(875)	70.80	- 10	(1,156)	10,544
Weighting Factor:		0.078	Weighting Factor:		0.167

Issued by: T. J. Bowden

Filed: April 02, 2001
Suspended:
Effective: April 02, 2001
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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2000 - December 2000

Daniel 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	454	77.20	+ 10	1,227	9,802
+ 9	409	76.93	+ 9	1,104	9,825
+ 8	363	76.66	+ 8	982	9,848
+ 7	318	76.39	+ 7	859	9,870
+ 6	272	76.12	+ 6	736	9,893
+ 5	227	75.85	+ 5	614	9,916
+ 4	182	75.58	+ 4	491	9,939
+ 3	136	75.31	+ 3	368	9,962
+ 2	91	75.04	+ 2	245	9,984
+ 1	45	74.77	+ 1	123	10,007
				0	10,030
0	0	74.50	0	0	10,105
				0	10,180
- 1	(76)	74.08	- 1	(123)	10,203
- 2	(151)	73.66	- 2	(245)	10,226
- 3	(227)	73.24	- 3	(368)	10,248
- 4	(302)	72.82	- 4	(491)	10,271
- 5	(378)	72.40	- 5	(614)	10,294
- 6	(453)	71.98	- 6	(736)	10,317
- 7	(529)	71.56	- 7	(859)	10,340
- 8	(604)	71.14	- 8	(982)	10,362
- 9	(680)	70.72	- 9	(1,104)	10,385
- 10	(755)	70.30	- 10	(1,227)	10,408
Weighting Factor:		0.065	Weighting Factor:		0.177

Issued by: T. J. Bowden

Filed: April 02, 2001
Suspended:
Effective: April 02, 2001
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GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2000 - December 2000

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range Max %	EAF Range Min %	Max Fuel Savings ($000)	Max Fuel Loss ($000)	EAF Adjusted Actual %	Actual Fuel Savings/ Loss ($000)
Crist 6	1.9	84.3	85.5	82.5	132.0	-182.0	73.5	($182)
Crist 7	8.8	77.3	80.0	73.3	614.0	-876.0	79.2	$432
Smith 1	0.5	90.6	91.4	89.4	38.0	-45.0	92.6	$38
Smith 2	1.2	89.2	90.2	87.6	81.0	-133.0	91.5	$81
Daniel 1	7.8	75.3	78.4	70.8	539.0	-875.0	80.0	$539
Daniel 2	6.5	74.5	77.2	70.3	454.0	-755.0	81.3	$454
Total:	26.7							

Plant & Unit	Weighting Factor %	ANOHR Target BTU/KWH	Target NOF	ANOHR Range Max BTU/KWH	ANOHR Range Min BTU/KWH	Max Fuel Savings ($000)	Max Fuel Loss ($000)	ANOHR Adjusted Actual BTU/KWH	Actual Fuel Savings/ Loss ($000)
Crist 6	12.1	10,629	79.3	10,948	10,310	$843	($843)	10,515	$135
Crist 7	17.3	10,236	93.2	10,543	9,929	$1,204	($1,204)	10,241	$0
Smith 1	4.1	10,332	73.1	10,642	10,022	$284	($284)	10,227	$36
Smith 2	5.3	10,137	81.5	10,441	9,833	$369	($369)	10,143	$0
Daniel 1	16.7	10,237	82.3	10,544	9,930	$1,156	($1,156)	10,267	$0
Daniel 2	17.7	10,105	85.3	10,408	9,802	$1,227	($1,227)	10,046	$0
Total:	73.2								

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Actual Unit Performance Data

Gulf Power Company

Period of: January 2000 - December 2000

Plant & Unit	Actual EAF %	Adjustments* to EAF %	Adjusted Actual %
Crist 6	75.2	-1.7	73.5
Crist 7	77.1	2.1	79.2
Smith 1	93.4	-0.8	92.6
Smith 2	91.6	-0.1	91.5
Daniel 1	82.7	-2.7	80.0
Daniel 2	84.3	-3.0	81.3

Plant & Unit	Actual ANOHR BTU/KWH	Adjustments** to ANOHR BTU/KWH	ANOHR Adjusted Actual BTU/KWH
Crist 6	10,527	-12	10,515
Crist 7	10,250	-9	10,241
Smith 1	10,079	148	10,227
Smith 2	10,103	40	10,143
Daniel 1	10,224	43	10,267
Daniel 2	10,057	-11	10,046

* Refer to pages 3 through 8, Schedule 2.

** Refer to pages 8 through 13, Schedule 3.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	CRIST 6	Jan '00	Feb '00	Mar '00	Apr '00	May '00	Jun '00	
1.	EAF (%)	46.9	30.5	87.0	91.5	86.6	81.6	
2.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
3.	SH	349.5	222.3	744.0	671.8	694.2	619.4	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	394.5	473.7	0.0	47.2	49.8	100.6	
6.	POH	394.5	473.7	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	15.3	0.0	
8.	MOH	0.0	0.0	0.0	47.2	34.5	100.6	
9.	PFOH	0.6	0.0	0.0	1.3	2.1	1.1	
10.	LR pf (MW)	247.0	0.0	0.0	263.3	141.1	42.0	
11.	PMOH	0.0	20.1	227.9	40.0	76.3	54.7	
12.	LR pm (MW)	0.0	155.7	127.7	97.5	194.7	176.0	
13.	NSC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	
14.	Oper MBtu	770932	525306	1695279	1767230	1799395	1497702	
15.	Net Gen (MWH)	74135	49191	166967	173351	172005	141576	
16.	ANOHR (Btu/KWH)	10399	10679	10153	10195	10461	10579	
17.	NOF %	70.2	73.3	74.3	85.4	82.0	75.7	
18.	NPC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	

19.	ANOHR Equation	10^6 / AKW * [88.29 - 44.75 * APR - 24.93 * MAY] + 10,287

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	CRIST 6	Jul '00	Aug '00	Sep '00	Oct '00	Nov '00	Dec '00	Total
1.	EAF (%)	95.8	97.2	76.6	87.3	33.2	85.1	75.2
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
3.	SH	744.0	744.0	587.3	690.8	260.7	547.1	6875.1
4.	RSH	0.0	0.0	0.0	0.0	0.0	86.3	86.3
5.	UH	0.0	0.0	132.7	54.2	459.3	110.6	1822.6
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	868.2
7.	FOH	0.0	0.0	37.0	29.1	0.0	0.0	81.4
8.	MOH	0.0	0.0	95.7	25.1	459.3	110.6	873.0
9.	PFOH	15.6	0.0	0.4	4.2	0.0	0.0	25.3
10.	LR pf (MW)	176.0	0.0	268.4	77.0	0.0	0.0	158.5
11.	PMOH	39.4	35.7	57.1	66.9	39.0	0.0	657.1
12.	LR pm (MW)	170.4	176.0	187.6	178.7	170.4	0.0	156.6
13.	NSC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	302.0
14.	Oper MBtu	1916815	1918370	1318075	1606006	720704	1425445	16961259
15.	Net Gen (MWH)	180922	180632	121421	150123	65888	135001	1611212
16.	ANOHR (Btu/KWH)	10595	10620	10855	10698	10938	10559	10527
17.	NOF %	80.5	80.4	68.5	72.0	83.7	81.7	77.6
18.	NPC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	302.0
19.	ANOHR Equation	10^6 / AKW * [88.29 - 44.75 * APR - 24.93 * MAY] + 10,287						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	CRIST 7	Jan '00	Feb '00	Mar '00	Apr '00	May '00	Jun '00	
1.	EAF (%)	79.8	61.4	0.0	38.4	85.4	100.0	
2.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
3.	SH	594.2	428.7	0.0	276.3	636.8	720.0	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	149.8	267.3	744.0	442.7	107.2	0.0	
6.	POH	0.0	230.6	744.0	421.5	0.0	0.0	
7.	FOH	117.3	36.7	0.0	0.0	0.0	0.0	
8.	MOH	32.5	0.0	0.0	21.2	107.2	0.0	
9.	PFOH	3.7	11.9	0.0	0.8	0.0	0.0	
10.	LR pf (MW)	22.0	50.8	0.0	100.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	3.7	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	194.8	0.0	
13.	NSC (MW)	467.0	467.0	467.0	477.0	477.0	477.0	
14.	Oper MBtu	2469853	1927073	0	1194323	2831513	3170142	
15.	Net Gen (MWH)	247170	189478	0	119030	289447	309520	
16.	ANOHR (Btu/KWH)	9993	10170	0	10034	9782	10242	
17.	NOF %	89.1	94.6	0.0	90.3	95.3	90.1	
18.	NPC (MW)	467.0	467.0	467.0	477.0	477.0	477.0	

19.	ANOHR Equation	10^6 / AKW * [215.83 + 54.63 * MAY] + 9,725

Issued by: T. J. Bowden

Filed: April 02, 2001
Suspended:
Effective: April 02, 2001
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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	CRIST 7	Jul '00	Aug '00	Sep '00	Oct '00	Nov '00	Dec '00	Total
1.	EAF (%)	91.2	94.9	99.1	89.4	89.4	96.1	77.1
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
3.	SH	681.0	710.2	715.1	672.5	643.9	714.9	6793.6
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	63.0	33.8	4.9	72.5	76.1	29.1	1990.4
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1396.1
7.	FOH	0.0	33.8	4.9	19.9	12.5	0.0	225.1
8.	MOH	63.0	0.0	0.0	52.6	63.6	29.1	369.2
9.	PFOH	0.0	12.4	45.7	0.0	0.0	0.0	74.5
10.	LR pf (MW)	0.0	149.0	13.4	0.0	0.0	0.0	43.3
11.	PMOH	25.8	0.0	3.3	11.8	0.0	0.0	44.6
12.	LR pm (MW)	45.6	0.0	68.0	268.0	0.0	0.0	118.5
13.	NSC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	474.5
14.	Oper MBtu	3031321	3196029	3120917	2605835	2898501	3114143	29559650
15.	Net Gen (MWH)	287910	307333	297571	250572	277871	307929	2883831
16.	ANOHR (Btu/KWH)	10529	10399	10488	10400	10431	10113	10250
17.	NOF %	88.6	90.7	87.2	78.1	90.5	90.3	89.5
18.	NPC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	474.5

19.	ANOHR Equation	10^6 / AKW * [215.83 + 54.63 * MAY] + 9,725

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Filed: April 02, 2001
Suspended:
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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	SMITH 1	Jan '00	Feb '00	Mar '00	Apr '00	May '00	Jun '00	
1.	EAF (%)	99.9	50.5	98.0	99.7	100.0	99.9	
2.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
3.	SH	744.0	354.7	741.7	719.0	744.0	720.0	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	0.0	341.3	2.3	0.0	0.0	0.0	
6.	POH	0.0	341.3	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	2.3	0.0	0.0	0.0	
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	
9.	PFOH	5.9	55.0	22.8	2.7	0.0	1.1	
10.	LR pf (MW)	22.0	9.2	64.5	143.3	0.0	101.2	
11.	PMOH	0.0	0.0	10.1	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	57.0	0.0	0.0	0.0	
13.	NSC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	
14.	Oper MBtu	1117883	542936	1140608	1109175	1135518	1065393	
15.	Net Gen (MWH)	109933	54051	113169	109663	113621	105141	
16.	ANOHR (Btu/KWH)	10169	10045	10079	10114	9994	10133	
17.	NOF %	91.2	94.1	94.2	94.1	94.3	90.1	
18.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	
19.	ANOHR Equation	10^6 / AKW * [303.56 - 13.60 * APR - 14.98 * MAY + 12.46 * JUL - 15.94 * NOV] + 5,563 + 0.01691 * LSRF / AKW						

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Suspended:
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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	SMITH 1	Jul '00	Aug '00	Sep '00	Oct '00	Nov '00	Dec '00	Total
1.	EAF (%)	96.5	100.0	99.8	99.8	74.1	99.9	93.4
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
3.	SH	718.9	744.0	720.0	745.0	534.7	744.0	8230.0
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	25.1	0.0	0.0	0.0	185.3	0.0	554.0
6.	POH	0.0	0.0	0.0	0.0	185.3	0.0	526.6
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	2.3
8.	MOH	25.1	0.0	0.0	0.0	0.0	0.0	25.1
9.	PFOH	0.9	1.7	0.5	1.8	15.7	12.1	120.2
10.	LR pf (MW)	102.5	30.2	140.0	110.9	15.0	11.0	28.2
11.	PMOH	0.0	0.0	1.3	0.0	0.0	0.0	11.4
12.	LR pm (MW)	0.0	0.0	102.0	0.0	0.0	0.0	62.1
13.	NSC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	162.0
14.	Oper MBtu	1045692	1090092	990328	1044085	782515	1107108	12171333
15.	Net Gen (MWH)	103281	108494	98384	102145	78664	110988	1207534
16.	ANOHR (Btu/KWH)	10125	10047	10066	10222	9948	9975	10079
17.	NOF %	88.7	90.0	84.3	84.6	90.8	92.1	90.6
18.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	162.0

19.	ANOHR Equation	10^6 / AKW * [303.56 - 13.60 * APR - 14.98 * MAY + 12.46 * JUL - 15.94 * NOV] + 5,563 + 0.01691 * LSRF / AKW

Issued by: T. J. Bowden

Filed: April 02, 2001
Suspended:
Effective: April 02, 2001
Docket No.: 010001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	SMITH 2	Jan '00	Feb '00	Mar '00	Apr '00	May '00	Jun '00	
1.	EAF (%)	100.0	99.0	100.0	52.5	96.6	100.0	
2.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
3.	SH	744.0	695.0	743.8	377.4	718.6	720.0	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	0.0	1.0	0.2	341.6	25.4	0.0	
6.	POH	0.0	0.0	0.2	341.6	0.0	0.0	
7.	FOH	0.0	1.0	0.0	0.0	0.0	0.0	
8.	MOH	0.0	0.0	0.0	0.0	25.4	0.0	
9.	PFOH	0.5	25.6	0.0	0.0	0.2	3.8	
10.	LR pf (MW)	18.0	24.7	0.0	0.0	71.0	10.8	
11.	PMOH	0.0	3.5	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	133.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	190.0	190.0	190.0	190.0	190.0	190.0	
14.	Oper MBtu	1229217	1199408	1308060	649111	1273157	1242428	
15.	Net Gen (MWH)	124942	122927	134326	63779	125753	121240	
16.	ANOHR (Btu/KWH)	9838	9757	9738	10178	10124	10248	
17.	NOF %	88.4	93.1	95.0	88.9	92.1	88.6	
18.	NPC (MW)	190.0	190.0	190.0	190.0	190.0	190.0	

19.	ANOHR Equation	10^6 / AKW * [86.76 + 21.35 * MAY + 16.56 * JUN + 32.76 * JUL + 30.95 * AUG + 11.83 * SEP] + 9,526

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Suspended:
Effective: April 02, 2001
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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	SMITH 2	Jul '00	Aug '00	Sep '00	Oct '00	Nov '00	Dec '00	Total
1.	EAF (%)	100.0	100.0	98.1	59.8	97.4	96.4	91.6
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
3.	SH	744.0	744.0	710.4	447.3	702.5	717.0	8064.0
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	0.0	0.0	9.6	297.7	17.5	27.0	720.0
6.	POH	0.0	0.0	0.0	294.2	0.0	0.0	636.0
7.	FOH	0.0	0.0	0.0	3.5	0.0	1.0	5.5
8.	MOH	0.0	0.0	9.6	0.0	17.5	26.0	78.5
9.	PFOH	0.0	0.0	1.7	4.5	13.4	0.0	49.7
10.	LR pf (MW)	0.0	0.0	146.9	79.8	22.3	0.0	32.3
11.	PMOH	0.0	0.0	4.2	0.0	0.0	0.0	7.7
12.	LR pm (MW)	0.0	0.0	123.0	0.0	0.0	0.0	127.5
13.	NSC (MW)	190.0	190.0	190.0	190.0	190.0	190.0	190.0
14.	Oper MBtu	1269449	1277885	1122832	680381	1195069	1211718	13658715
15.	Net Gen (MWH)	123574	124343	109314	65449	116911	119393	1351951
16.	ANOHR (Btu/KWH)	10273	10277	10272	10396	10222	10149	10103
17.	NOF %	87.4	88.0	81.0	77.0	87.6	87.6	88.2
18.	NPC (MW)	190.0	190.0	190.0	190.0	190.0	190.0	190.0
19.	ANOHR Equation	10^6 / AKW * [86.76 + 21.35 * MAY + 16.56 * JUN + 32.76 * JUL + 30.95 * AUG + 11.83 * SEP] + 9,526						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	DANIEL 1	Jan '00	Feb '00	Mar '00	Apr '00	May '00	Jun '00	
1.	EAF (%)	99.2	99.4	9.8	48.7	70.1	99.2	
2.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
3.	SH	744.0	696.0	73.3	368.0	562.8	720.0	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	0.0	0.0	670.7	351.0	181.2	0.0	
6.	POH	0.0	0.0	670.7	351.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	181.2	0.0	
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	
9.	PFOH	10.5	8.8	11.5	36.0	103.6	16.9	
10.	LR pf (MW)	158.0	242.3	27.9	255.3	201.8	104.2	
11.	PMOH	9.2	0.0	0.0	0.0	0.0	5.5	
12.	LR pm (MW)	148.0	0.0	0.0	0.0	0.0	223.0	
13.	NSC (MW)	478.0	478.0	478.0	510.0	510.0	510.0	
14.	Oper MBtu	2718417	2878015	279074	1624682	2288712	2946499	
15.	Net Gen (MWH)	257638	280793	31336	158482	226326	297070	
16.	ANOHR (Btu/KWH)	10551	10250	8906	10252	10112	9919	
17.	NOF %	72.4	84.4	89.4	84.4	78.9	80.9	
18.	NPC (MW)	478.0	478.0	478.0	510.0	510.0	510.0	

19.	ANOHR Equation	10^6 / AKW * [1223.24 - 40.12 * JAN - 50.48 * MAR - 44.86 * JUN] + 9,170 + 10^6 / AKW * [-0.0731 * BTU/LB]

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Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	DANIEL 1	Jul '00	Aug '00	Sep '00	Oct '00	Nov '00	Dec '00	Total
1.	EAF (%)	82.9	92.1	94.4	100.0	98.9	99.2	82.7
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
3.	SH	631.1	696.6	688.6	745.0	720.0	744.0	7389.4
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	112.9	47.4	31.4	0.0	0.0	0.0	1394.6
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1021.7
7.	FOH	112.9	47.4	0.0	0.0	0.0	0.0	341.5
8.	MOH	0.0	0.0	31.4	0.0	0.0	0.0	31.4
9.	PFOH	23.2	15.3	31.8	0.3	44.6	21.7	324.2
10.	LR pf (MW)	316.6	240.7	137.5	273.0	86.4	115.8	178.3
11.	PMOH	0.0	7.9	0.0	0.0	0.0	0.0	22.6
12.	LR pm (MW)	0.0	258.0	0.0	0.0	0.0	0.0	204.7
13.	NSC (MW)	510.0	507.0	507.0	507.0	507.0	425.0	493.9
14.	Oper MBtu	3100821	3397365	3330265	3527785	3496399	3323177	32911212
15.	Net Gen (MWH)	286937	331637	331564	351622	344740	320743	3218888
16.	ANOHR (Btu/KWH)	10807	10244	10044	10033	10142	10361	10224
17.	NOF %	89.1	93.9	95.0	93.1	94.4	101.4	88.2
18.	NPC (MW)	510.0	507.0	507.0	507.0	507.0	425.0	493.9

19.	ANOHR Equation	10^6 / AKW * [1223.24 - 40.12 * JAN - 50.48 * MAR - 44.86 * JUN] + 9,170 + 10^6 / AKW * [-0.0731 * BTU/LB]

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Filed: April 02, 2001
Suspended:
Effective: April 02, 2001
Docket No.: 010001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	DANIEL 2	Jan '00	Feb '00	Mar '00	Apr '00	May '00	Jun '00	
1.	EAF (%)	94.8	98.1	73.3	74.3	99.7	99.4	
2.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
3.	SH	709.8	696.0	577.1	537.9	744.0	720.0	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	34.2	0.0	166.9	181.1	0.0	0.0	
6.	POH	0.0	0.0	166.9	181.1	0.0	0.0	
7.	FOH	34.2	0.0	0.0	0.0	0.0	0.0	
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	
9.	PFOH	15.0	33.4	82.5	13.8	20.0	14.7	
10.	LR pf (MW)	92.7	186.5	183.5	134.8	60.8	93.0	
11.	PMOH	19.4	0.0	0.0	0.0	0.0	2.9	
12.	LR pm (MW)	46.0	0.0	0.0	0.0	0.0	243.0	
13.	NSC (MW)	478.0	478.0	478.0	510.0	510.0	510.0	
14.	Oper MBtu	2370224	2772046	2560973	2490707	3374247	2816574	
15.	Net Gen (MWH)	226655	275068	255930	249710	338650	276733	
16.	ANOHR (Btu/KWH)	10457	10078	10007	9974	9964	10178	
17.	NOF %	66.8	82.7	92.8	91.0	89.2	75.4	
18.	NPC (MW)	478.0	478.0	478.0	510.0	510.0	510.0	
19.	ANOHR Equation	10^6 / AKW * [1014.82 - 37.91 * JAN + 69.66 * JUL + 78.80 * AUG + 76.66 * SEP] + 9,052 + 10^6 / AKW * [-0.0554 * BTU/LB]						

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Suspended:
Effective: April 02, 2001
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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	DANIEL 2	Jul '00	Aug '00	Sep '00	Oct '00	Nov '00	Dec '00	Total
1.	EAF (%)	87.6	99.4	69.1	17.3	99.3	99.8	84.3
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
3.	SH	677.5	744.0	506.1	128.7	720.0	744.0	7505.1
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	66.5	0.0	213.9	616.3	0.0	0.0	1278.9
6.	POH	0.0	0.0	213.9	616.3	0.0	0.0	1178.2
7.	FOH	66.5	0.0	0.0	0.0	0.0	0.0	100.7
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9.	PFOH	45.6	9.4	31.9	0.0	39.4	5.2	310.9
10.	LR pf (MW)	284.9	250.0	141.3	0.0	61.8	170.2	162.0
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	22.3
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	71.6
13.	NSC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	502.0
14.	Oper MBtu	2744161	3204412	1964184	540624	2952408	3522795	31313355
15.	Net Gen (MWH)	261821	310900	196391	51040	308003	362616	3113517
16.	ANOHR (Btu/KWH)	10481	10307	10001	10592	9586	9715	10057
17.	NOF %	75.8	81.9	76.1	77.8	83.9	95.6	82.6
18.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	502.0
19.	ANOHR Equation	10^6 / AKW * [1014.82 - 37.91 * JAN + 69.66 * JUL + 78.80 * AUG + 76.66 * SEP] + 9,052 + 10^6 / AKW * [-0.0554 * BTU/LB]						

Issued by: T. J. Bowden

Filed: April 02, 2001
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Planned Outage Schedules (Actual)

Period of: January 2000 - December 2000

Critical path bar charts of actual work activity performed during major planned outages are not shown here since corresponding bar charts of forecast work activity were not provided earlier in conformance with agreement with Staff to avoid the premature production of charts prior to their normal course of development. Forecast and actual critical path bar charts are developed for each planned outage and, per agreement with Staff, these charts will be provided on request.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 010001-EI

Before me the undersigned authority, personally appeared James R. Douglass, who being first duly sworn, deposes, and says that he is the Performance Test Specialist for Gulf Power Company, a Maine corporation, and that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

James R. Douglass
Performance Test Specialist

Sworn to and subscribed before me this 28th day of March, 2001.

Notary Public, State of Florida at Large

Commission Number:

Commission Expires:

ROLLANDA R. COTHRAN
MY COMMISSION # CC 697388
EXPIRES: February 26, 2002
Bonded Thru Notary Public Underwriters

Florida Public Service Commission
Docket No. 010001-EI
Gulf Power Company
Witness: J. R. Douglass
Exhibit No. ___ (JRD-2)

EXHIBIT TO THE TESTIMONY OF

J. R. DOUGLASS

IN FPSC DOCKET 010001-EI

I. DETERMINATION OF HEAT RATE TARGETS

Target Heat Rate Equations

Crist 4 ANOHR = 10^6 / AKW * (449.21 - 12.61 * JAN + 16.96 * JUN + 24.56 * JUL + 27.59 * AUG)

- 3640 + 0.10501 * LSRF / AKW

Crist 6 ANOHR = 10^6 / AKW * (187.63 - 85.12 * APR + 32.17 * JUN)

+ 9,810

Crist 7 ANOHR = 10^6 / AKW * (204.45 - 44.16 * MAY + 83.05 * JUL + 67.20 * AUG + 91.16 * SEP + 58.82 * OCT)

+ 9,704

Smith 1 ANOHR = 10^6 / AKW * (43.96 - 17.87 * FEB - 12.85 * MAY - 18.43 * NOV)

+ 9,793

Smith 2 ANOHR = 10^6 / AKW * (410.85 - 30.87 * JAN - 38.46 * FEB - 38.20 * MAR - 18.64 * APR)

+ 4,743 + 0.01678 * LSRF / AKW

Daniel 1 ANOHR = 10^6 / AKW * (-429.41 - 91.37 * FEB - 136.56 * JUN + 105.89 * JUL)

+ 14,936 - 0.00805 * LSRF / AKW

Daniel 2 ANOHR = 10^6 / AKW * (-42.23 + 77.21 * MAY + 79.18 * JUL + 123.19 * AUG - 68.28 * NOV)

+ 13,010 - 0.00640 * LSRF / AKW

Where:

ANOHR = Average Net Operating Heat Rate, BTU/KWH
AKW = Average Kilowatt Load, KW
LSRF = Load Square Range Factor, KW^2
BTU/LB = Coal Burned Average Heat Content, BTU/LB
JAN = January, 0 if not January, 1 if January
FEB = February, 0 if not February, 1 if February
MAR = March, 0 if not March, 1 if March
APR = April, 0 if not April, 1 if April
MAY = May, 0 if not May, 1 if May
JUN = June, 0 if not June, 1 if June
JUL = July, 0 if not July, 1 if July
AUG = August, 0 if not August, 1 if August
SEP = September, 0 if not September, 1 if September
OCT = October, 0 if not October, 1 if October
NOV = November, 0 if not November, 1 if November

WEEKLY UNIT OPERATING

DATA USED TO DEVELOP

TARGET HEAT RATE EQUATIONS

Data Base for CRIST 4 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10587	168	77.9	6074	0	0	0	0	0	0	1	0	0	0	0	0	1998
10498	168	78.7	6209	0	0	0	0	0	0	1	0	0	0	0	0	1998
10623	168	75.6	5728	0	0	0	0	0	0	1	0	0	0	0	0	1998
10594	116	75.7	5762	0	0	0	0	0	0	1	0	0	0	0	0	1998
10974	95	71.6	5376	0	0	0	0	0	0	0	1	0	0	0	2	1998
10680	165	77.8	6120	0	0	0	0	0	0	0	1	0	0	0	1	1998
10531	168	78.8	6232	0	0	0	0	0	0	0	1	0	0	0	0	1998
10263	168	75.8	5785	0	0	0	0	0	0	0	1	0	0	0	0	1998
10393	168	78.2	6123	0	0	0	0	0	0	0	1	0	0	0	0	1998
10343	168	77.8	6061	0	0	0	0	0	0	0	0	1	0	0	0	1998
10192	168	79.8	6376	0	0	0	0	0	0	0	0	1	0	0	0	1998
10225	76	79.1	6258	0	0	0	0	0	0	0	0	1	0	0	0	1998
11275	68	61.3	4069	0	0	0	0	0	0	0	0	0	1	0	1	1998
11013	168	46.3	2223	0	0	0	0	0	0	0	0	0	1	0	0	1998
10738	168	59.1	3711	0	0	0	0	0	0	0	0	0	1	0	0	1998
10849	56	49.8	2716	0	0	0	0	0	0	0	0	0	1	0	1	1998
10492	168	54.1	3129	0	0	0	0	0	0	0	0	0	0	1	0	1998
10162	168	62.6	4088	0	0	0	0	0	0	0	0	0	0	1	0	1998
10369	168	60.5	3903	0	0	0	0	0	0	0	0	0	0	1	0	1998
10158	81	63.7	4331	0	0	0	0	0	0	0	0	0	0	1	0	1998
11114	51	48.1	2417	0	0	0	0	0	0	0	0	0	0	0	1	1998
10430	45	56.0	3289	0	0	0	0	0	0	0	0	0	0	0	0	1998
10549	92	61.5	4079	1	0	0	0	0	0	0	0	0	0	0	1	1999
10406	108	50.4	2697	1	0	0	0	0	0	0	0	0	0	0	0	1999
10729	114	54.1	3087	0	1	0	0	0	0	0	0	0	0	0	1	1999
10683	145	55.9	3335	0	1	0	0	0	0	0	0	0	0	0	1	1999
10732	168	46.3	2206	0	0	1	0	0	0	0	0	0	0	0	0	1999
10702	168	53.9	3068	0	0	1	0	0	0	0	0	0	0	0	0	1999
10587	168	53.4	3011	0	0	1	0	0	0	0	0	0	0	0	0	1999
10427	118	63.5	4254	0	0	1	0	0	0	0	0	0	0	0	1	1999
10478	140	65.8	4494	0	0	1	0	0	0	0	0	0	0	0	1	1999
10589	167	70.1	5045	0	0	0	1	0	0	0	0	0	0	0	0	1999
10409	168	71.3	5160	0	0	0	1	0	0	0	0	0	0	0	0	1999
10377	168	68.2	4815	0	0	0	1	0	0	0	0	0	0	0	0	1999
10487	168	67.7	4758	0	0	0	1	0	0	0	0	0	0	0	0	1999
10601	168	56.2	3359	0	0	0	0	1	0	0	0	0	0	0	0	1999
10502	168	54.8	3179	0	0	0	0	1	0	0	0	0	0	0	0	1999
10620	168	50.5	2623	0	0	0	0	1	0	0	0	0	0	0	0	1999
10592	168	56.1	3329	0	0	0	0	1	0	0	0	0	0	0	0	1999
10491	168	57.2	3467	0	0	0	0	1	0	0	0	0	0	0	0	1999
10744	168	61.3	3991	0	0	0	0	0	1	0	0	0	0	0	0	1999
11262	168	59.8	3848	0	0	0	0	0	1	0	0	0	0	0	0	1999
10858	155	58.8	3701	0	0	0	0	0	1	0	0	0	0	0	0	1999
11365	127	57.5	3527	0	0	0	0	0	1	0	0	0	0	0	1	1999
10903	167	59.0	3758	0	0	0	0	0	0	1	0	0	0	0	0	1999
10935	168	57.0	3458	0	0	0	0	0	0	1	0	0	0	0	0	1999
10975	168	61.0	3945	0	0	0	0	0	0	1	0	0	0	0	0	1999

Data Base for CRIST 4 Target Heat Rate Equation

	HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
	10938	168	65.6	4524	0	0	0	0	0	0	1	0	0	0	0	0	1999
	11508	168	66.1	4586	0	0	0	0	0	0	0	1	0	0	0	0	1999
	11614	130	63.3	4263	0	0	0	0	0	0	0	1	0	0	0	1	1999
	10773	168	66.8	4681	0	0	0	0	0	0	0	1	0	0	0	0	1999
	11141	168	60.7	3980	0	0	0	0	0	0	0	1	0	0	0	0	1999
	11982	159	54.7	3312	0	0	0	0	0	0	0	1	0	0	0	0	1999
	10970	168	60.3	3897	0	0	0	0	0	0	0	0	1	0	0	0	1999
	10892	168	60.0	3867	0	0	0	0	0	0	0	0	1	0	0	0	1999
	10657	168	56.8	3473	0	0	0	0	0	0	0	0	1	0	0	0	1999
	10569	168	60.9	3941	0	0	0	0	0	0	0	0	1	0	0	0	1999
	10617	168	57.3	3533	0	0	0	0	0	0	0	0	0	1	0	0	1999
	10576	168	66.6	4681	0	0	0	0	0	0	0	0	0	1	0	0	1999
	10711	168	64.6	4433	0	0	0	0	0	0	0	0	0	1	0	0	1999
	10929	159	59.0	3758	0	0	0	0	0	0	0	0	0	1	0	0	1999
	10597	169	68.4	4968	0	0	0	0	0	0	0	0	0	1	0	0	1999
	10053	49	74.4	5642	0	0	0	0	0	0	0	0	0	0	1	0	1999
*	8889	56	46.3	2298	0	0	0	0	0	0	0	0	0	0	0	1	1999
	9960	163	55.0	3216	0	0	0	0	0	0	0	0	0	0	0	1	1999
*	12785	86	58.2	3663	0	0	0	0	0	0	0	0	0	0	0	1	1999
*	13092	24	45.3	2054	0	0	0	0	0	0	0	0	0	0	0	0	1999
	10253	62	45.1	2102	1	0	0	0	0	0	0	0	0	0	0	1	2000
	9870	127	52.9	2916	1	0	0	0	0	0	0	0	0	0	0	1	2000
	10823	168	52.5	2895	1	0	0	0	0	0	0	0	0	0	0	0	2000
	10667	168	62.2	4069	1	0	0	0	0	0	0	0	0	0	0	0	2000
	10670	168	62.8	4090	0	1	0	0	0	0	0	0	0	0	0	0	2000
	10622	168	65.1	4428	0	1	0	0	0	0	0	0	0	0	0	0	2000
	10641	168	56.7	3379	0	1	0	0	0	0	0	0	0	0	0	0	2000
	10558	168	63.0	4189	0	1	0	0	0	0	0	0	0	0	0	0	2000
	10577	168	66.0	4571	0	1	0	0	0	0	0	0	0	0	0	0	2000
	10566	168	66.1	4589	0	0	1	0	0	0	0	0	0	0	0	0	2000
	10565	168	67.1	4698	0	0	1	0	0	0	0	0	0	0	0	0	2000
	10654	168	67.2	4738	0	0	1	0	0	0	0	0	0	0	0	0	2000
	10687	115	68.1	4838	0	0	1	0	0	0	0	0	0	0	0	1	2000
	10546	167	65.8	4521	0	0	0	1	0	0	0	0	0	0	0	0	2000
	10454	168	68.6	4863	0	0	0	1	0	0	0	0	0	0	0	0	2000
	10418	168	66.8	4693	0	0	0	1	0	0	0	0	0	0	0	0	2000
	10485	168	62.3	4086	0	0	0	1	0	0	0	0	0	0	0	0	2000
	10305	168	64.0	4327	0	0	0	0	1	0	0	0	0	0	0	0	2000
	10463	168	66.3	4600	0	0	0	0	1	0	0	0	0	0	0	0	2000
	10365	168	66.6	4623	0	0	0	0	1	0	0	0	0	0	0	0	2000
	10668	168	65.3	4469	0	0	0	0	1	0	0	0	0	0	0	0	2000
	10834	168	59.8	3832	0	0	0	0	1	0	0	0	0	0	0	0	2000
	10937	168	57.7	3574	0	0	0	0	0	1	0	0	0	0	0	0	2000
	10983	168	58.6	3685	0	0	0	0	0	1	0	0	0	0	0	0	2000
	11034	168	57.8	3578	0	0	0	0	0	1	0	0	0	0	0	0	2000
	11153	168	56.2	3375	0	0	0	0	0	1	0	0	0	0	0	0	2000
	10841	168	55.3	3270	0	0	0	0	0	0	1	0	0	0	0	0	2000

Data Base for CRIST 4 Target Heat Rate Equation

	HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
	11096	168	64.3	4313	0	0	0	0	0	0	1	0	0	0	0	0	2000
	11273	168	61.1	3941	0	0	0	0	0	0	1	0	0	0	0	0	2000
	11174	168	52.8	3007	0	0	0	0	0	0	1	0	0	0	0	0	2000
	11103	168	51.6	2831	0	0	0	0	0	0	0	1	0	0	0	0	2000
	11101	168	56.2	3424	0	0	0	0	0	0	0	1	0	0	0	0	2000
	11126	168	55.5	3331	0	0	0	0	0	0	0	1	0	0	0	0	2000
	11059	168	57.5	3525	0	0	0	0	0	0	0	1	0	0	0	0	2000
	11074	168	59.2	3741	0	0	0	0	0	0	0	1	0	0	0	0	2000
	11020	168	53.0	3035	0	0	0	0	0	0	0	0	1	0	0	0	2000
	10827	168	57.1	3474	0	0	0	0	0	0	0	0	1	0	0	0	2000
	10732	168	54.4	3197	0	0	0	0	0	0	0	0	1	0	0	0	2000
	12271	45	55.4	3614	0	0	0	0	0	0	0	0	0	0	1	1	2000
	10462	168	70.5	5046	0	0	0	0	0	0	0	0	0	0	0	0	2000
	10639	168	56.6	3361	0	0	0	0	0	0	0	0	0	0	0	0	2000
	10265	168	64.4	4352	0	0	0	0	0	0	0	0	0	0	0	0	2000
*	12730	24	57.0	3462	0	0	0	0	0	0	0	0	0	0	0	0	2000
	10440	168	66.0	4500	1	0	0	0	0	0	0	0	0	0	0	0	2001
	10440	143	64.2	4307	1	0	0	0	0	0	0	0	0	0	0	1	2001
	10405	82	51.0	2738	1	0	0	0	0	0	0	0	0	0	0	0	2001
	10730	118	51.9	2835	1	0	0	0	0	0	0	0	0	0	0	1	2001
	10882	90	50.1	2626	0	1	0	0	0	0	0	0	0	0	0	1	2001
	10339	168	61.7	4061	0	1	0	0	0	0	0	0	0	0	0	0	2001
	10348	168	69.0	4893	0	1	0	0	0	0	0	0	0	0	0	0	2001
	10338	168	73.6	5473	0	1	0	0	0	0	0	0	0	0	0	0	2001
	10416	168	73.0	5408	0	0	1	0	0	0	0	0	0	0	0	0	2001
	10285	168	73.3	5436	0	0	1	0	0	0	0	0	0	0	0	0	2001
	10347	168	67.0	4650	0	0	1	0	0	0	0	0	0	0	0	0	2001
	10372	168	68.9	4879	0	0	1	0	0	0	0	0	0	0	0	0	2001
	10279	167	66.9	4574	0	0	1	0	0	0	0	0	0	0	0	0	2001
	9943	168	70.1	5051	0	0	0	1	0	0	0	0	0	0	0	0	2001
	9956	168	73.2	5441	0	0	0	1	0	0	0	0	0	0	0	0	2001
	9966	168	76.5	5861	0	0	0	1	0	0	0	0	0	0	0	0	2001
	10022	168	63.1	4175	0	0	0	1	0	0	0	0	0	0	0	0	2001
	10174	168	67.7	4763	0	0	0	0	1	0	0	0	0	0	0	0	2001
	10260	168	64.7	4373	0	0	0	0	1	0	0	0	0	0	0	0	2001
	10413	168	57.4	3515	0	0	0	0	1	0	0	0	0	0	0	0	2001
	10362	168	59.5	3710	0	0	0	0	1	0	0	0	0	0	0	0	2001
	10603	168	56.1	3324	0	0	0	0	1	0	0	0	0	0	0	0	2001
	10743	168	57.5	3547	0	0	0	0	0	1	0	0	0	0	0	0	2001
	10565	168	64.4	4379	0	0	0	0	0	1	0	0	0	0	0	0	2001
	10494	168	61.8	4079	0	0	0	0	0	1	0	0	0	0	0	0	2001
	10721	144	56.6	3437	0	0	0	0	0	1	0	0	0	0	0	0	2001

Data Base for CRIST 4 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for CRIST 6 Target Heat Rate Equation

	HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
	10763	168	235.8	60731	0	0	0	0	0	0	1	0	0	0	0	0	1998
	10686	168	251.2	2627	0	0	0	0	0	0	1	0	0	0	0	0	1998
	10678	168	251.3	2213	0	0	0	0	0	0	1	0	0	0	0	0	1998
	10792	154	264.0	10891	0	0	0	0	0	0	1	0	0	0	0	0	1998
	10770	168	246.8	1664	0	0	0	0	0	0	0	1	0	0	0	0	1998
	10840	168	240.9	63176	0	0	0	0	0	0	0	1	0	0	0	0	1998
	11101	168	229.8	58271	0	0	0	0	0	0	0	1	0	0	0	0	1998
	11028	168	238.7	63320	0	0	0	0	0	0	0	1	0	0	0	0	1998
	10652	168	273.9	12562	0	0	0	0	0	0	0	1	0	0	0	0	1998
	10772	157	222.8	55696	0	0	0	0	0	0	0	0	1	0	0	0	1998
	10725	168	209.8	47428	0	0	0	0	0	0	0	0	1	0	0	0	1998
	11071	142	213.4	48377	0	0	0	0	0	0	0	0	1	0	0	1	1998
	10671	168	236.5	60544	0	0	0	0	0	0	0	0	1	0	0	0	1998
	11260	24	216.8	52596	0	0	0	0	0	0	0	0	1	0	0	0	1998
	11279	168	234.9	60121	0	0	0	0	0	0	0	0	0	1	0	0	1998
	10915	168	184.6	38492	0	0	0	0	0	0	0	0	0	1	0	0	1998
	10616	168	240.2	62106	0	0	0	0	0	0	0	0	0	1	0	0	1998
	10836	169	178.0	33687	0	0	0	0	0	0	0	0	0	1	0	0	1998
	11241	46	163.8	27811	0	0	0	0	0	0	0	0	0	0	1	0	1998
	10834	97	237.1	61976	0	0	0	0	0	0	0	0	0	0	1	1	1998
	10726	167	239.7	62983	0	0	0	0	0	0	0	0	0	0	1	0	1998
	10388	168	251.0	1578	0	0	0	0	0	0	0	0	0	0	1	0	1998
	10731	168	181.0	37056	0	0	0	0	0	0	0	0	0	0	1	0	1998
	10699	168	218.8	53167	0	0	0	0	0	0	0	0	0	0	0	0	1998
	10606	168	206.1	46963	0	0	0	0	0	0	0	0	0	0	0	0	1998
	10573	168	197.2	42770	0	0	0	0	0	0	0	0	0	0	0	0	1998
	10711	168	159.2	27797	0	0	0	0	0	0	0	0	0	0	0	0	1998
	10489	24	212.0	48246	0	0	0	0	1	0	0	0	0	0	0	0	1998
	10493	168	233.2	59731	1	0	0	0	0	0	0	0	0	0	0	0	1999
	10901	168	186.5	38813	1	0	0	0	0	0	0	0	0	0	0	0	1999
	10987	168	157.4	27151	1	0	0	0	0	0	0	0	0	0	0	0	1999
	11079	168	149.8	24220	1	0	0	0	0	0	0	0	0	0	0	0	1999
	11015	168	168.5	30545	0	1	0	0	0	0	0	0	0	0	0	0	1999
	10985	168	173.0	33086	0	1	0	0	0	0	0	0	0	0	0	0	1999
	10696	168	224.0	54377	0	1	0	0	0	0	0	0	0	0	0	0	1999
	10871	168	204.9	46925	0	1	0	0	0	0	0	0	0	0	0	0	1999
	11118	168	156.8	26531	0	0	1	0	0	0	0	0	0	0	0	0	1999
	10779	168	194.3	41923	0	0	1	0	0	0	0	0	0	0	0	0	1999
	10718	168	199.4	43824	0	0	1	0	0	0	0	0	0	0	0	0	1999
	10780	112	220.7	53263	0	0	1	0	0	0	0	0	0	0	0	1	1999
	10408	168	266.5	7673	0	0	1	0	0	0	0	0	0	0	0	0	1999
	10495	26	221.8	55893	0	0	0	1	0	0	0	0	0	0	0	0	1999
	10164	166	236.3	61472	0	0	0	1	0	0	0	0	0	0	0	1	1999
*	9147	168	206.0	48180	0	0	0	0	1	0	0	0	0	0	0	0	1999
*	9339	168	204.1	46604	0	0	0	0	1	0	0	0	0	0	0	0	1999
	11254	159	190.9	41135	0	0	0	0	1	0	0	0	0	0	0	0	1999
	10719	168	226.8	57330	0	0	0	0	1	0	0	0	0	0	0	0	1999

Data Base for CRIST 6 Target Heat Rate Equation

	HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
	10224	168	212.8	50396	0	0	0	0	1	0	0	0	0	0	0	0	1999
*	8907	168	239.3	62415	0	0	0	0	0	1	0	0	0	0	0	0	1999
	10612	168	227.1	57552	0	0	0	0	0	1	0	0	0	0	0	0	1999
	10166	168	225.3	56766	0	0	0	0	0	1	0	0	0	0	0	0	1999
	11745	144	217.7	52645	0	0	0	0	0	1	0	0	0	0	0	0	1999
	10632	168	234.4	60956	0	0	0	0	0	0	1	0	0	0	0	0	1999
	10761	168	223.6	56906	0	0	0	0	0	0	1	0	0	0	0	0	1999
	10682	168	229.9	60010	0	0	0	0	0	0	1	0	0	0	0	0	1999
	10608	168	299.6	24229	0	0	0	0	0	0	1	0	0	0	0	0	1999
	10595	168	300.5	24774	0	0	0	0	0	0	0	1	0	0	0	0	1999
	10195	168	297.1	23389	0	0	0	0	0	0	0	1	0	0	0	0	1999
	10331	165	295.3	22823	0	0	0	0	0	0	0	1	0	0	0	0	1999
	10244	168	301.3	25241	0	0	0	0	0	0	0	1	0	0	0	0	1999
	10300	168	300.6	24833	0	0	0	0	0	0	0	1	0	0	0	0	1999
	10725	109	220.4	57526	0	0	0	0	0	0	0	0	1	0	0	1	1999
	10518	168	229.2	58953	0	0	0	0	0	0	0	0	1	0	0	0	1999
	10578	168	207.2	48684	0	0	0	0	0	0	0	0	1	0	0	0	1999
	10470	168	238.1	61962	0	0	0	0	0	0	0	0	1	0	0	0	1999
	10866	168	174.4	37683	0	0	0	0	0	0	0	0	0	1	0	0	1999
	10621	168	245.8	246	0	0	0	0	0	0	0	0	0	1	0	0	1999
	10666	168	248.1	1271	0	0	0	0	0	0	0	0	0	1	0	0	1999
	10498	168	234.3	60546	0	0	0	0	0	0	0	0	0	1	0	0	1999
	10374	169	255.6	4438	0	0	0	0	0	0	0	0	0	1	0	0	1999
	10275	168	259.9	5830	0	0	0	0	0	0	0	0	0	0	1	0	1999
	10497	168	224.6	56148	0	0	0	0	0	0	0	0	0	0	1	0	1999
	10382	98	240.4	64364	0	0	0	0	0	0	0	0	0	0	1	1	1999
	10486	168	195.1	44377	0	0	0	0	0	0	0	0	0	0	1	0	1999
	9870	168	265.6	8688	0	0	0	0	0	0	0	0	0	0	0	0	1999
	10021	168	246.7	2174	0	0	0	0	0	0	0	0	0	0	0	0	1999
	10237	168	199.3	45227	0	0	0	0	0	0	0	0	0	0	0	0	1999
	10422	168	203.6	46342	0	0	0	0	0	0	0	0	0	0	0	0	1999
	10708	24	145.9	22684	0	0	0	0	0	0	0	0	0	0	0	0	1999
	10565	168	174.9	35116	1	0	0	0	0	0	0	0	0	0	0	0	2000
	10308	168	244.7	64249	1	0	0	0	0	0	0	0	0	0	0	0	2000
	10093	14	259.7	9147	1	0	0	0	0	0	0	0	0	0	0	0	2000
	11163	127	194.7	43622	0	1	0	0	0	0	0	0	0	0	0	2	2000
	10272	168	259.0	4741	0	1	0	0	0	0	0	0	0	0	0	0	2000
	10311	168	196.8	47017	0	0	1	0	0	0	0	0	0	0	0	0	2000
	10073	168	263.7	7450	0	0	1	0	0	0	0	0	0	0	0	0	2000
	10035	168	258.7	5482	0	0	1	0	0	0	0	0	0	0	0	0	2000
	10422	168	161.3	27975	0	0	1	0	0	0	0	0	0	0	0	0	2000
	10150	167	282.5	16680	0	0	0	1	0	0	0	0	0	0	0	0	2000
	10487	122	224.5	56109	0	0	0	1	0	0	0	0	0	0	0	1	2000
	10215	168	260.1	5799	0	0	0	1	0	0	0	0	0	0	0	0	2000
	10136	168	257.6	4800	0	0	0	1	0	0	0	0	0	0	0	0	2000
	10256	168	254.7	3068	0	0	0	0	1	0	0	0	0	0	0	0	2000
	10654	119	229.4	60866	0	0	0	0	1	0	0	0	0	0	0	1	2000

Data Base for CRIST 6 Target Heat Rate Equation

	HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
	10429	168	255.1	4903	0	0	0	0	1	0	0	0	0	0	0	0	2000
	10534	168	249.6	1339	0	0	0	0	1	0	0	0	0	0	0	0	2000
	10572	168	237.3	61960	0	0	0	0	1	0	0	0	0	0	0	0	2000
	10750	118	202.6	47617	0	0	0	0	0	1	0	0	0	0	0	0	2000
	10522	118	248.5	415	0	0	0	0	0	1	0	0	0	0	0	1	2000
	10672	168	219.1	54451	0	0	0	0	0	1	0	0	0	0	0	0	2000
	10521	168	241.8	63906	0	0	0	0	0	1	0	0	0	0	0	0	2000
	10485	168	211.0	51070	0	0	0	0	0	0	1	0	0	0	0	0	2000
	10565	168	280.8	15208	0	0	0	0	0	0	1	0	0	0	0	0	2000
	10611	168	252.8	3624	0	0	0	0	0	0	1	0	0	0	0	0	2000
	10668	168	235.8	61723	0	0	0	0	0	0	1	0	0	0	0	0	2000
	10623	168	227.5	57701	0	0	0	0	0	0	0	1	0	0	0	0	2000
	10538	168	250.0	2051	0	0	0	0	0	0	0	1	0	0	0	0	2000
	10679	168	233.9	61200	0	0	0	0	0	0	0	1	0	0	0	0	2000
	10605	168	248.8	1943	0	0	0	0	0	0	0	1	0	0	0	0	2000
	10697	168	249.4	2022	0	0	0	0	0	0	0	1	0	0	0	0	2000
	10747	168	214.3	51845	0	0	0	0	0	0	0	0	1	0	0	0	2000
	10997	131	235.8	61505	0	0	0	0	0	0	0	0	1	0	0	1	2000
	11444	74	146.0	26635	0	0	0	0	0	0	0	0	1	0	0	1	2000
	10880	168	199.4	45140	0	0	0	0	0	0	0	0	1	0	0	0	2000
	9891	168	208.2	49192	0	0	0	0	0	0	0	0	0	1	0	0	2000
	11127	168	192.7	41069	0	0	0	0	0	0	0	0	0	1	0	0	2000
	11039	140	204.9	49527	0	0	0	0	0	0	0	0	0	1	0	1	2000
	10803	168	248.9	1752	0	0	0	0	0	0	0	0	0	1	0	0	2000
	11136	143	231.4	60640	0	0	0	0	0	0	0	0	0	1	0	1	2000
	11000	168	255.8	4710	0	0	0	0	0	0	0	0	0	0	1	0	2000
	10520	21	283.3	16815	0	0	0	0	0	0	0	0	0	0	1	0	2000
	11290	106	172.4	32972	0	0	0	0	0	0	0	0	0	0	0	1	2000
	10669	145	265.2	9296	0	0	0	0	0	0	0	0	0	0	0	0	2000
	10294	168	282.4	16106	0	0	0	0	0	0	0	0	0	0	0	0	2000
	10950	86	200.2	47802	0	0	0	0	0	0	0	0	0	0	0	1	2000
	10404	24	283.7	15342	0	0	0	0	0	0	0	0	0	0	0	0	2000
	10421	168	279.7	14308	1	0	0	0	0	0	0	0	0	0	0	0	2001
	10375	147	278.6	14905	1	0	0	0	0	0	0	0	0	0	0	0	2001
	11365	133	182.4	39770	1	0	0	0	0	0	0	0	0	0	0	1	2001
	10839	168	193.7	44148	1	0	0	0	0	0	0	0	0	0	0	0	2001
	10980	99	208.3	50570	0	1	0	0	0	0	0	0	0	0	0	1	2001
	10561	168	280.5	14378	0	1	0	0	0	0	0	0	0	0	0	0	2001
	10612	168	275.6	13630	0	1	0	0	0	0	0	0	0	0	0	0	2001
	10496	119	288.6	19299	0	1	0	0	0	0	0	0	0	0	0	0	2001
	10985	144	262.7	7859	0	0	1	0	0	0	0	0	0	0	0	1	2001
	10870	168	286.8	18155	0	0	1	0	0	0	0	0	0	0	0	0	2001
	11177	168	256.3	3420	0	0	1	0	0	0	0	0	0	0	0	0	2001
	10687	168	243.7	65011	0	0	1	0	0	0	0	0	0	0	0	0	2001
	10719	122	276.4	13578	0	0	1	0	0	0	0	0	0	0	0	0	2001
*	13272	88	128.8	22929	0	0	0	0	1	0	0	0	0	0	0	1	2001
	10764	159	224.2	56291	0	0	0	0	1	0	0	0	0	0	0	0	2001

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11574	72	131.0	17426	0	0	0	0	1	0	0	0	0	0	0	1	2001
11961	83	128.3	16682	0	0	0	0	1	0	0	0	0	0	0	1	2001
11061	168	192.5	43304	0	0	0	0	0	1	0	0	0	0	0	0	2001
11006	168	225.5	57031	0	0	0	0	0	1	0	0	0	0	0	0	2001
11046	168	229.4	59143	0	0	0	0	0	1	0	0	0	0	0	0	2001
11036	144	201.4	46708	0	0	0	0	0	1	0	0	0	0	0	0	2001

Data Base for CRIST 6 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10090	168	429.6	61868	0	0	0	0	0	0	1	0	0	0	0	0	1998
10129	168	453.5	14655	0	0	0	0	0	0	1	0	0	0	0	0	1998
10200	168	430.3	63296	0	0	0	0	0	0	1	0	0	0	0	0	1998
10194	137	432.6	3305	0	0	0	0	0	0	1	0	0	0	0	1	1998
10243	168	435.1	891	0	0	0	0	0	0	0	1	0	0	0	0	1998
10349	145	420.9	56695	0	0	0	0	0	0	0	1	0	0	0	0	1998
10351	95	389.8	36893	0	0	0	0	0	0	0	1	0	0	0	1	1998
10428	148	413.3	52550	0	0	0	0	0	0	0	1	0	0	0	1	1998
10385	121	445.5	7060	0	0	0	0	0	0	0	1	0	0	0	1	1998
10342	168	373.4	17339	0	0	0	0	0	0	0	0	1	0	0	0	1998
10531	90	359.1	14662	0	0	0	0	0	0	0	0	1	0	0	2	1998
10263	168	399.5	42618	0	0	0	0	0	0	0	0	1	0	0	0	1998
10316	168	443.2	5640	0	0	0	0	0	0	0	0	1	0	0	0	1998
11002	24	466.9	22477	0	0	0	0	0	0	0	0	1	0	0	0	1998
10321	168	426.4	56252	0	0	0	0	0	0	0	0	0	1	0	0	1998
10540	168	352.6	4248	0	0	0	0	0	0	0	0	0	1	0	0	1998
9952	48	402.1	44617	0	0	0	0	0	0	0	0	0	1	0	0	1998
10493	83	347.9	2710	0	0	0	0	0	0	0	0	0	1	0	1	1998
10368	168	396.8	40007	0	0	0	0	0	0	0	0	0	0	1	0	1998
10547	62	338.4	2486	0	0	0	0	0	0	0	0	0	0	1	2	1998
10218	168	415.9	51892	0	0	0	0	0	0	0	0	0	0	1	0	1998
10195	168	406.4	47955	0	0	0	0	0	0	0	0	0	0	1	0	1998
10037	168	386.5	31082	0	0	0	0	0	0	0	0	0	0	1	0	1998
10235	168	376.1	31467	0	0	0	0	0	0	0	0	0	0	0	0	1998
10056	168	419.7	55906	0	0	0	0	0	0	0	0	0	0	0	0	1998
10129	168	408.7	46606	0	0	0	0	0	0	0	0	0	0	0	0	1998
10114	168	353.6	6592	0	0	0	0	0	0	0	0	0	0	0	0	1998
10104	24	486.8	40538	0	0	0	0	1	0	0	0	0	0	0	0	1998
10185	165	396.2	36430	1	0	0	0	0	0	0	0	0	0	0	0	1999
10322	115	363.3	12558	1	0	0	0	0	0	0	0	0	0	0	1	1999
10299	168	319.3	45360	1	0	0	0	0	0	0	0	0	0	0	0	1999
10226	168	338.1	58476	1	0	0	0	0	0	0	0	0	0	0	0	1999
10146	24	306.3	39838	0	1	0	0	0	0	0	0	0	0	0	0	1999
10792	77	386.7	31072	0	1	0	0	0	0	0	0	0	0	0	1	1999
10273	168	351.9	1432	0	0	1	0	0	0	0	0	0	0	0	0	1999
10069	168	446.9	7990	0	0	1	0	0	0	0	0	0	0	0	0	1999
10312	168	424.8	56685	0	0	1	0	0	0	0	0	0	0	0	0	1999
10405	79	400.0	43636	0	0	1	0	0	0	0	0	0	0	0	2	1999
10063	168	450.7	11795	0	0	1	0	0	0	0	0	0	0	0	0	1999
10404	105	403.1	45205	0	0	0	1	0	0	0	0	0	0	0	1	1999
10074	168	477.5	32152	0	0	0	1	0	0	0	0	0	0	0	0	1999
10061	141	454.7	15374	0	0	0	1	0	0	0	0	0	0	0	1	1999
10217	121	423.3	55264	0	0	0	1	0	0	0	0	0	0	0	1	1999
10186	168	421.1	53519	0	0	0	0	1	0	0	0	0	0	0	0	1999
10177	168	380.4	25553	0	0	0	0	1	0	0	0	0	0	0	0	1999
10165	168	396.4	36075	0	0	0	0	1	0	0	0	0	0	0	0	1999
10299	168	415.0	47750	0	0	0	0	1	0	0	0	0	0	0	0	1999

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10225	168	395.5	34635	0	0	0	0	1	0	0	0	0	0	0	0	1999
9330	153	392.4	33042	0	0	0	0	0	1	0	0	0	0	0	0	1999
10280	156	415.2	47265	0	0	0	0	0	1	0	0	0	0	0	0	1999
10263	103	393.6	37975	0	0	0	0	0	1	0	0	0	0	0	2	1999
10217	144	441.9	871	0	0	0	0	0	1	0	0	0	0	0	0	1999
10394	168	448.4	7089	0	0	0	0	0	0	1	0	0	0	0	0	1999
10515	168	449.6	8626	0	0	0	0	0	0	1	0	0	0	0	0	1999
10459	168	446.6	6130	0	0	0	0	0	0	1	0	0	0	0	0	1999
10216	168	429.2	60356	0	0	0	0	0	0	1	0	0	0	0	0	1999
10481	127	420.2	55254	0	0	0	0	0	0	0	1	0	0	0	1	1999
10240	168	451.2	8570	0	0	0	0	0	0	0	1	0	0	0	0	1999
10200	168	467.0	21464	0	0	0	0	0	0	0	1	0	0	0	0	1999
10184	152	456.6	13113	0	0	0	0	0	0	0	1	0	0	0	0	1999
10511	122	404.8	43821	0	0	0	0	0	0	0	1	0	0	0	1	1999
10236	168	447.8	6368	0	0	0	0	0	0	0	0	1	0	0	0	1999
10251	168	433.0	61052	0	0	0	0	0	0	0	0	1	0	0	0	1999
10298	168	396.0	35716	0	0	0	0	0	0	0	0	1	0	0	0	1999
10283	168	423.5	55648	0	0	0	0	0	0	0	0	1	0	0	0	1999
10379	168	423.9	54267	0	0	0	0	0	0	0	0	0	1	0	0	1999
10498	168	434.9	61924	0	0	0	0	0	0	0	0	0	1	0	0	1999
10664	112	380.3	26982	0	0	0	0	0	0	0	0	0	1	0	1	1999
10335	168	412.5	46176	0	0	0	0	0	0	0	0	0	1	0	0	1999
10201	153	432.7	60399	0	0	0	0	0	0	0	0	0	1	0	0	1999
10083	168	440.9	603	0	0	0	0	0	0	0	0	0	0	1	0	1999
10318	168	421.9	53155	0	0	0	0	0	0	0	0	0	0	1	0	1999
10180	168	425.1	57080	0	0	0	0	0	0	0	0	0	0	1	0	1999
10200	168	379.0	20609	0	0	0	0	0	0	0	0	0	0	1	0	1999
10118	167	437.7	1136	0	0	0	0	0	0	0	0	0	0	0	0	1999
10390	114	414.0	49548	0	0	0	0	0	0	0	0	0	0	0	1	1999
10236	168	444.7	3263	0	0	0	0	0	0	0	0	0	0	0	0	1999
10120	107	386.2	27487	0	0	0	0	0	0	0	0	0	0	0	1	1999
10183	24	347.4	65354	0	0	0	0	0	0	0	0	0	0	0	0	1999
9948	168	381.4	24757	1	0	0	0	0	0	0	0	0	0	0	0	2000
10124	54	370.5	22500	1	0	0	0	0	0	0	0	0	0	0	1	2000
10142	168	422.1	55478	1	0	0	0	0	0	0	0	0	0	0	1	2000
9872	150	452.0	9740	1	0	0	0	0	0	0	0	0	0	0	0	2000
10111	152	455.2	13789	0	1	0	0	0	0	0	0	0	0	0	1	2000
10112	132	444.5	6854	0	1	0	0	0	0	0	0	0	0	0	1	2000
10250	168	439.3	65018	0	1	0	0	0	0	0	0	0	0	0	0	2000
10509	34	357.8	4382	0	1	0	0	0	0	0	0	0	0	0	0	2000
10006	82	380.2	29499	0	0	0	1	0	0	0	0	0	0	0	1	2000
9976	168	467.2	22875	0	0	0	1	0	0	0	0	0	0	0	0	2000
9745	147	439.5	3872	0	0	0	0	1	0	0	0	0	0	0	0	2000
9770	168	465.4	21217	0	0	0	0	1	0	0	0	0	0	0	0	2000
9863	112	434.7	65372	0	0	0	0	1	0	0	0	0	0	0	1	2000
9873	168	468.6	23623	0	0	0	0	1	0	0	0	0	0	0	0	2000
10150	117	415.0	49936	0	0	0	0	1	0	0	0	0	0	0	1	2000

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10082	168	421.8	54001	0	0	0	0	0	1	0	0	0	0	0	0	2000
10229	168	443.1	4320	0	0	0	0	0	1	0	0	0	0	0	0	2000
10306	168	431.4	60249	0	0	0	0	0	1	0	0	0	0	0	0	2000
10324	168	427.2	58475	0	0	0	0	0	1	0	0	0	0	0	0	2000
10354	168	385.4	29837	0	0	0	0	0	0	1	0	0	0	0	0	2000
10709	129	444.0	7806	0	0	0	0	0	0	1	0	0	0	0	1	2000
10662	145	453.3	13602	0	0	0	0	0	0	1	0	0	0	0	0	2000
10541	168	417.3	53347	0	0	0	0	0	0	1	0	0	0	0	0	2000
10368	168	423.4	55245	0	0	0	0	0	0	0	1	0	0	0	0	2000
10336	134	424.1	56216	0	0	0	0	0	0	0	1	0	0	0	1	2000
10414	168	425.9	57782	0	0	0	0	0	0	0	1	0	0	0	0	2000
10373	168	448.3	7636	0	0	0	0	0	0	0	1	0	0	0	0	2000
10483	168	438.3	65261	0	0	0	0	0	0	0	1	0	0	0	0	2000
10412	168	421.9	54666	0	0	0	0	0	0	0	0	1	0	0	0	2000
10789	168	432.6	60523	0	0	0	0	0	0	0	0	1	0	0	0	2000
10360	164	399.2	39589	0	0	0	0	0	0	0	0	1	0	0	0	2000
10398	168	409.3	45590	0	0	0	0	0	0	0	0	1	0	0	0	2000
9522	168	386.9	31831	0	0	0	0	0	0	0	0	0	1	0	0	2000
10801	155	378.7	25697	0	0	0	0	0	0	0	0	0	1	0	0	2000
10721	161	305.7	42809	0	0	0	0	0	0	0	0	0	1	0	0	2000
10610	118	407.1	46399	0	0	0	0	0	0	0	0	0	1	0	1	2000
10525	169	410.2	48065	0	0	0	0	0	0	0	0	0	1	0	0	2000
10531	119	384.8	28794	0	0	0	0	0	0	0	0	0	0	1	0	2000
10357	161	441.5	4501	0	0	0	0	0	0	0	0	0	0	1	1	2000
10407	168	455.3	14647	0	0	0	0	0	0	0	0	0	0	1	0	2000
10452	149	435.5	1050	0	0	0	0	0	0	0	0	0	0	1	0	2000
10025	168	477.9	31815	0	0	0	0	0	0	0	0	0	0	0	0	2000
10114	139	440.3	4058	0	0	0	0	0	0	0	0	0	0	0	1	2000
10107	168	439.1	2882	0	0	0	0	0	0	0	0	0	0	0	0	2000
10292	168	347.8	1329	0	0	0	0	0	0	0	0	0	0	0	0	2000
10149	24	475.6	29574	0	0	0	0	0	0	0	0	0	0	0	0	2000
10373	104	434.1	2291	1	0	0	0	0	0	0	0	0	0	0	1	2001
10170	168	420.5	54657	1	0	0	0	0	0	0	0	0	0	0	0	2001
10279	168	337.3	58535	1	0	0	0	0	0	0	0	0	0	0	0	2001
10897	129	313.4	41749	1	0	0	0	0	0	0	0	0	0	0	1	2001
10455	157	359.4	8987	0	1	0	0	0	0	0	0	0	0	0	0	2001
10618	37	281.9	23817	0	1	0	0	0	0	0	0	0	0	0	1	2001
10246	165	433.5	64953	0	0	1	0	0	0	0	0	0	0	0	1	2001
10591	168	377.9	17738	0	0	0	1	0	0	0	0	0	0	0	0	2001
10236	143	394.7	33673	0	0	0	1	0	0	0	0	0	0	0	1	2001
10182	168	458.7	17277	0	0	0	1	0	0	0	0	0	0	0	0	2001
10526	122	401.4	42940	0	0	0	1	0	0	0	0	0	0	0	1	2001
10155	89	444.4	7400	0	0	0	0	1	0	0	0	0	0	0	1	2001
10580	168	412.6	49950	0	0	0	0	1	0	0	0	0	0	0	0	2001
10151	139	380.7	28732	0	0	0	0	1	0	0	0	0	0	0	1	2001
10058	168	418.4	53067	0	0	0	0	1	0	0	0	0	0	0	0	2001
10273	168	384.1	29664	0	0	0	0	1	0	0	0	0	0	0	0	2001

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10301	168	394.5	36344	0	0	0	0	0	1	0	0	0	0	0	0	2001
10334	168	419.8	54449	0	0	0	0	0	1	0	0	0	0	0	0	2001
10301	168	410.2	47815	0	0	0	0	0	1	0	0	0	0	0	0	2001
10293	144	404.2	42880	0	0	0	0	0	1	0	0	0	0	0	0	2001

Data Base for CRIST 7 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10084	168	153.3	23709	0	0	0	0	0	0	1	0	0	0	0	0	1998
10093	168	154.1	23798	0	0	0	0	0	0	1	0	0	0	0	0	1998
10429	168	155.9	24350	0	0	0	0	0	0	1	0	0	0	0	0	1998
10232	168	156.3	24481	0	0	0	0	0	0	1	0	0	0	0	0	1998
10354	168	154.5	23900	0	0	0	0	0	0	0	1	0	0	0	0	1998
10193	168	154.2	23834	0	0	0	0	0	0	0	1	0	0	0	0	1998
10010	168	155.2	24085	0	0	0	0	0	0	0	1	0	0	0	0	1998
10184	168	153.9	23779	0	0	0	0	0	0	0	1	0	0	0	0	1998
10019	168	154.9	24039	0	0	0	0	0	0	0	1	0	0	0	0	1998
10301	168	154.9	24017	0	0	0	0	0	0	0	0	1	0	0	0	1998
10116	168	150.8	23099	0	0	0	0	0	0	0	0	1	0	0	0	1998
10062	72	147.9	22243	0	0	0	0	0	0	0	0	1	0	0	0	1998
10312	112	146.6	21989	0	0	0	0	0	0	0	0	1	0	0	1	1998
10510	24	150.2	22608	0	0	0	0	0	0	0	0	1	0	0	0	1998
10331	168	152.8	23468	0	0	0	0	0	0	0	0	0	1	0	0	1998
10004	168	147.5	22219	0	0	0	0	0	0	0	0	0	1	0	0	1998
10306	168	155.6	24293	0	0	0	0	0	0	0	0	0	1	0	0	1998
10037	169	153.4	23641	0	0	0	0	0	0	0	0	0	1	0	0	1998
9979	168	150.6	22849	0	0	0	0	0	0	0	0	0	0	1	0	1998
10089	168	151.8	23243	0	0	0	0	0	0	0	0	0	0	1	0	1998
10003	168	141.1	20239	0	0	0	0	0	0	0	0	0	0	1	0	1998
9887	144	146.8	22213	0	0	0	0	0	0	0	0	0	0	1	1	1998
9978	168	136.6	19550	0	0	0	0	0	0	0	0	0	0	1	0	1998
9896	168	141.0	20608	0	0	0	0	0	0	0	0	0	0	0	0	1998
10259	142	145.5	21957	0	0	0	0	0	0	0	0	0	0	0	1	1998
10253	168	140.5	20567	0	0	0	0	0	0	0	0	0	0	0	0	1998
9976	168	136.6	19356	0	0	0	0	0	0	0	0	0	0	0	0	1998
9876	24	148.6	22178	0	0	0	0	1	0	0	0	0	0	0	0	1998
10053	168	154.2	23977	1	0	0	0	0	0	0	0	0	0	0	0	1999
9994	168	147.1	22167	1	0	0	0	0	0	0	0	0	0	0	0	1999
10130	168	136.0	19443	1	0	0	0	0	0	0	0	0	0	0	0	1999
10017	144	135.6	19427	1	0	0	0	0	0	0	0	0	0	0	0	1999
10004	114	126.0	17341	0	1	0	0	0	0	0	0	0	0	0	1	1999
11244	52	107.9	13960	0	0	0	1	0	0	0	0	0	0	0	1	1999
10192	68	108.0	12633	0	0	0	1	0	0	0	0	0	0	0	1	1999
9550	168	148.2	22163	0	0	0	1	0	0	0	0	0	0	0	0	1999
9811	100	145.3	22106	0	0	0	0	1	0	0	0	0	0	0	1	1999
9887	168	145.5	21922	0	0	0	0	1	0	0	0	0	0	0	0	1999
9881	168	143.6	21454	0	0	0	0	1	0	0	0	0	0	0	0	1999
9885	168	144.7	21631	0	0	0	0	1	0	0	0	0	0	0	0	1999
10230	113	138.7	20405	0	0	0	0	1	0	0	0	0	0	0	1	1999
9941	168	149.3	22693	0	0	0	0	0	1	0	0	0	0	0	0	1999
10150	168	153.5	23731	0	0	0	0	0	1	0	0	0	0	0	0	1999
10061	168	145.8	22147	0	0	0	0	0	1	0	0	0	0	0	0	1999
10104	144	152.5	23755	0	0	0	0	0	1	0	0	0	0	0	0	1999
10080	168	149.3	22824	0	0	0	0	0	0	1	0	0	0	0	0	1999
10032	129	152.7	23711	0	0	0	0	0	0	1	0	0	0	0	0	1999

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10220	143	149.6	23119	0	0	0	0	0	0	1	0	0	0	0	2	1999
10022	168	152.7	23714	0	0	0	0	0	0	1	0	0	0	0	0	1999
10003	168	159.9	25574	0	0	0	0	0	0	0	1	0	0	0	0	1999
10013	168	158.5	25164	0	0	0	0	0	0	0	1	0	0	0	0	1999
10020	168	155.0	24222	0	0	0	0	0	0	0	1	0	0	0	0	1999
10040	168	143.3	21178	0	0	0	0	0	0	0	1	0	0	0	0	1999
10020	168	144.6	21534	0	0	0	0	0	0	0	1	0	0	0	0	1999
10041	161	144.7	21639	0	0	0	0	0	0	0	0	1	0	0	0	1999
9940	168	149.4	22720	0	0	0	0	0	0	0	0	1	0	0	0	1999
9896	168	142.6	21163	0	0	0	0	0	0	0	0	1	0	0	0	1999
10033	43	126.3	17756	0	0	0	0	0	0	0	0	1	0	0	0	1999
9951	117	145.9	22062	0	0	0	0	0	0	0	0	0	1	0	1	1999
9963	168	155.5	24375	0	0	0	0	0	0	0	0	0	1	0	0	1999
10026	168	152.5	23565	0	0	0	0	0	0	0	0	0	1	0	0	1999
9978	168	147.8	22345	0	0	0	0	0	0	0	0	0	1	0	0	1999
9966	168	152.7	23818	0	0	0	0	0	0	0	0	0	1	0	0	1999
9969	168	156.2	24575	0	0	0	0	0	0	0	0	0	0	1	0	1999
10033	168	154.7	24208	0	0	0	0	0	0	0	0	0	0	1	0	1999
9951	168	153.5	23961	0	0	0	0	0	0	0	0	0	0	1	0	1999
9900	168	148.4	22670	0	0	0	0	0	0	0	0	0	0	1	0	1999
10005	168	153.4	23929	0	0	0	0	0	0	0	0	0	0	0	0	1999
10035	168	152.0	23656	0	0	0	0	0	0	0	0	0	0	0	0	1999
10028	168	152.0	23754	0	0	0	0	0	0	0	0	0	0	0	0	1999
10116	168	153.1	23976	0	0	0	0	0	0	0	0	0	0	0	0	1999
10108	24	128.4	17352	0	0	0	0	0	0	0	0	0	0	0	0	1999
10160	168	133.6	19338	1	0	0	0	0	0	0	0	0	0	0	0	2000
10187	168	145.7	22214	1	0	0	0	0	0	0	0	0	0	0	0	2000
10112	168	149.5	23057	1	0	0	0	0	0	0	0	0	0	0	0	2000
10142	168	156.2	24787	1	0	0	0	0	0	0	0	0	0	0	0	2000
10237	168	158.9	25274	0	1	0	0	0	0	0	0	0	0	0	0	2000
9861	2	58.5	6502	0	1	0	0	0	0	0	0	0	0	0	0	2000
10045	161	151.3	23311	0	1	0	0	0	0	0	0	0	0	0	1	2000
10009	168	152.2	23520	0	1	0	0	0	0	0	0	0	0	0	0	2000
10081	167	145.4	21964	0	0	1	0	0	0	0	0	0	0	0	0	2000
10128	168	157.9	25086	0	0	1	0	0	0	0	0	0	0	0	0	2000
10085	168	153.2	23806	0	0	1	0	0	0	0	0	0	0	0	0	2000
10037	168	152.3	23696	0	0	1	0	0	0	0	0	0	0	0	0	2000
10189	167	152.6	23763	0	0	0	1	0	0	0	0	0	0	0	0	2000
10138	168	157.2	24858	0	0	0	1	0	0	0	0	0	0	0	0	2000
10105	168	151.0	23283	0	0	0	1	0	0	0	0	0	0	0	0	2000
10028	168	152.0	23492	0	0	0	1	0	0	0	0	0	0	0	0	2000
10023	168	151.1	23282	0	0	0	0	1	0	0	0	0	0	0	0	2000
9956	168	153.9	23941	0	0	0	0	1	0	0	0	0	0	0	0	2000
9932	168	153.3	23919	0	0	0	0	1	0	0	0	0	0	0	0	2000
10055	168	156.7	24679	0	0	0	0	1	0	0	0	0	0	0	0	2000
10036	168	142.4	21309	0	0	0	0	1	0	0	0	0	0	0	0	2000
10048	168	141.1	20967	0	0	0	0	0	1	0	0	0	0	0	0	2000

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10069	168	150.3	23135	0	0	0	0	0	1	0	0	0	0	0	0	2000
10057	168	147.2	22259	0	0	0	0	0	1	0	0	0	0	0	0	2000
10393	168	147.0	22230	0	0	0	0	0	1	0	0	0	0	0	0	2000
10488	144	127.0	17979	0	0	0	0	0	0	1	0	0	0	0	1	2000
10084	168	157.0	24787	0	0	0	0	0	0	1	0	0	0	0	0	2000
10065	168	155.8	24454	0	0	0	0	0	0	1	0	0	0	0	0	2000
10051	168	135.1	19578	0	0	0	0	0	0	1	0	0	0	0	0	2000
10044	168	140.1	20658	0	0	0	0	0	0	0	1	0	0	0	0	2000
10198	168	149.4	22784	0	0	0	0	0	0	0	1	0	0	0	0	2000
9980	168	144.7	21837	0	0	0	0	0	0	0	1	0	0	0	0	2000
9976	168	143.7	21421	0	0	0	0	0	0	0	1	0	0	0	0	2000
10015	168	147.9	22474	0	0	0	0	0	0	0	1	0	0	0	0	2000
10040	168	137.7	20122	0	0	0	0	0	0	0	0	1	0	0	0	2000
10169	168	143.0	21326	0	0	0	0	0	0	0	0	1	0	0	0	2000
10058	168	131.3	18662	0	0	0	0	0	0	0	0	1	0	0	0	2000
9979	168	135.1	19504	0	0	0	0	0	0	0	0	1	0	0	0	2000
10211	168	123.3	16508	0	0	0	0	0	0	0	0	0	1	0	0	2000
10171	168	139.6	20554	0	0	0	0	0	0	0	0	0	1	0	0	2000
10280	168	146.6	22480	0	0	0	0	0	0	0	0	0	1	0	0	2000
10202	168	138.2	20503	0	0	0	0	0	0	0	0	0	1	0	0	2000
10149	167	131.9	19136	0	0	0	0	0	0	0	0	0	1	0	0	2000
9894	153	148.9	22856	0	0	0	0	0	0	0	0	0	0	1	1	2000
9841	168	153.1	24033	0	0	0	0	0	0	0	0	0	0	1	0	2000
10130	168	148.6	22606	0	0	0	0	0	0	0	0	0	0	1	0	2000
9878	168	160.0	25639	0	0	0	0	0	0	0	0	0	0	0	0	2000
9920	168	136.1	19624	0	0	0	0	0	0	0	0	0	0	0	0	2000
10133	168	141.8	21218	0	0	0	0	0	0	0	0	0	0	0	0	2000
9977	168	153.3	23895	0	0	0	0	0	0	0	0	0	0	0	0	2000
10077	24	162.6	26435	0	0	0	0	0	0	0	0	0	0	0	0	2000
9887	168	157.5	24988	1	0	0	0	0	0	0	0	0	0	0	0	2001
9893	168	146.0	22120	1	0	0	0	0	0	0	0	0	0	0	0	2001
10024	168	112.2	13972	1	0	0	0	0	0	0	0	0	0	0	0	2001
10218	168	109.0	12976	1	0	0	0	0	0	0	0	0	0	0	0	2001
10032	168	103.0	11523	0	1	0	0	0	0	0	0	0	0	0	0	2001
10118	168	131.7	18687	0	1	0	0	0	0	0	0	0	0	0	0	2001
9795	168	152.5	23758	0	1	0	0	0	0	0	0	0	0	0	0	2001
9850	168	158.8	25318	0	1	0	0	0	0	0	0	0	0	0	0	2001
9866	168	156.7	24710	0	0	1	0	0	0	0	0	0	0	0	0	2001
9730	168	160.3	25748	0	0	1	0	0	0	0	0	0	0	0	0	2001
10064	168	154.7	24212	0	0	1	0	0	0	0	0	0	0	0	0	2001
10494	168	157.2	25050	0	0	1	0	0	0	0	0	0	0	0	0	2001
10087	167	162.7	26459	0	0	1	0	0	0	0	0	0	0	0	0	2001
10116	168	157.7	25093	0	0	0	1	0	0	0	0	0	0	0	0	2001
10018	168	158.2	25306	0	0	0	1	0	0	0	0	0	0	0	0	2001
9958	118	159.8	25786	0	0	0	1	0	0	0	0	0	0	0	0	2001
10339	75	141.4	21164	0	0	0	0	1	0	0	0	0	0	0	1	2001
10050	168	134.4	19566	0	0	0	0	1	0	0	0	0	0	0	0	2001

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10083	168	143.1	21620	0	0	0	0	1	0	0	0	0	0	0	0	2001
10325	168	135.0	19676	0	0	0	0	1	0	0	0	0	0	0	0	2001
10253	168	147.0	22151	0	0	0	0	0	1	0	0	0	0	0	0	2001
10325	168	150.7	23060	0	0	0	0	0	1	0	0	0	0	0	0	2001
10086	168	146.7	22062	0	0	0	0	0	1	0	0	0	0	0	0	2001
10035	144	144.9	21675	0	0	0	0	0	1	0	0	0	0	0	0	2001

Data Base for SMITH 1 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRP	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10196	168	182.5	33810	0	0	0	0	1	0	0	0	0	0	0	0	1999
10094	168	182.4	33508	0	0	0	0	0	1	0	0	0	0	0	0	1999
10168	168	185.1	34306	0	0	0	0	0	1	0	0	0	0	0	0	1999
10094	168	174.8	31554	0	0	0	0	0	1	0	0	0	0	0	0	1999
10132	144	185.6	34450	0	0	0	0	0	1	0	0	0	0	0	0	1999
10148	168	180.9	32975	0	0	0	0	0	0	1	0	0	0	0	0	1999
10177	168	182.6	33688	0	0	0	0	0	0	1	0	0	0	0	0	1999
10200	168	184.3	34039	0	0	0	0	0	0	1	0	0	0	0	0	1999
10217	168	184.8	34235	0	0	0	0	0	0	1	0	0	0	0	0	1999
10161	168	185.4	34417	0	0	0	0	0	0	0	1	0	0	0	0	1999
10138	168	183.0	33630	0	0	0	0	0	0	0	1	0	0	0	0	1999
10140	168	177.9	31972	0	0	0	0	0	0	0	1	0	0	0	0	1999
10171	168	162.4	27654	0	0	0	0	0	0	0	1	0	0	0	0	1999
10108	168	166.6	28824	0	0	0	0	0	0	0	1	0	0	0	0	1999
10177	165	179.8	32603	0	0	0	0	0	0	0	0	1	0	0	0	1999
10089	168	184.0	33979	0	0	0	0	0	0	0	0	1	0	0	0	1999
10203	145	168.7	30198	0	0	0	0	0	0	0	0	1	0	0	0	1999
10156	168	179.8	32979	0	0	0	0	0	0	0	0	1	0	0	0	1999
10031	168	181.9	33261	0	0	0	0	0	0	0	0	0	1	0	0	1999
10082	168	185.0	34367	0	0	0	0	0	0	0	0	0	1	0	0	1999
10136	168	187.8	35352	0	0	0	0	0	0	0	0	0	1	0	0	1999
10154	168	187.7	35269	0	0	0	0	0	0	0	0	0	1	0	0	1999
10175	169	187.3	35114	0	0	0	0	0	0	0	0	0	1	0	0	1999
10255	168	188.2	35440	0	0	0	0	0	0	0	0	0	0	1	0	1999
10258	47	180.9	33653	0	0	0	0	0	0	0	0	0	0	1	0	1999
10381	114	167.4	29945	0	0	0	0	0	0	0	0	0	0	1	1	1999
10225	168	182.8	33819	0	0	0	0	0	0	0	0	0	0	1	0	1999
10150	168	185.6	34642	0	0	0	0	0	0	0	0	0	0	0	0	1999
10157	168	185.5	34529	0	0	0	0	0	0	0	0	0	0	0	0	1999
9808	168	180.2	32764	0	0	0	0	0	0	0	0	0	0	0	0	1999
10115	34	164.6	29142	0	0	0	0	0	0	0	0	0	0	0	1	1999
9662	24	178.5	32078	0	0	0	0	0	0	0	0	0	0	0	0	1999
9830	168	146.8	23825	1	0	0	0	0	0	0	0	0	0	0	0	2000
9848	168	164.1	28615	1	0	0	0	0	0	0	0	0	0	0	0	2000
9800	168	170.0	30050	1	0	0	0	0	0	0	0	0	0	0	0	2000
9871	168	181.8	33669	1	0	0	0	0	0	0	0	0	0	0	0	2000
9823	168	184.4	34122	0	1	0	0	0	0	0	0	0	0	0	0	2000
9745	168	186.4	34843	0	1	0	0	0	0	0	0	0	0	0	0	2000
9750	168	168.2	29408	0	1	0	0	0	0	0	0	0	0	0	0	2000
9751	168	174.4	31080	0	1	0	0	0	0	0	0	0	0	0	0	2000
9750	168	175.5	31375	0	1	0	0	0	0	0	0	0	0	0	0	2000
9778	168	178.0	32102	0	0	1	0	0	0	0	0	0	0	0	0	2000
9737	168	183.3	33877	0	0	1	0	0	0	0	0	0	0	0	0	2000
9742	168	178.0	32245	0	0	1	0	0	0	0	0	0	0	0	0	2000
9690	168	183.9	34140	0	0	1	0	0	0	0	0	0	0	0	0	2000
10272	162	156.7	26426	0	0	0	1	0	0	0	0	0	0	0	1	2000
10147	168	179.2	32568	0	0	0	1	0	0	0	0	0	0	0	0	2000

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10052	168	173.2	30985	0	0	0	0	1	0	0	0	0	0	0	0	2000
10057	168	180.3	32891	0	0	0	0	1	0	0	0	0	0	0	0	2000
10045	168	176.8	32141	0	0	0	0	1	0	0	0	0	0	0	0	2000
10345	143	177.8	32471	0	0	0	0	1	0	0	0	0	0	0	1	2000
10267	168	162.5	28132	0	0	0	0	1	0	0	0	0	0	0	0	2000
10221	168	161.4	27769	0	0	0	0	0	1	0	0	0	0	0	0	2000
10228	168	173.2	30887	0	0	0	0	0	1	0	0	0	0	0	0	2000
10252	168	169.3	29619	0	0	0	0	0	1	0	0	0	0	0	0	2000
10264	168	171.5	30175	0	0	0	0	0	1	0	0	0	0	0	0	2000
10344	168	154.4	26091	0	0	0	0	0	0	1	0	0	0	0	0	2000
10268	168	182.7	33641	0	0	0	0	0	0	1	0	0	0	0	0	2000
10207	168	179.6	32561	0	0	0	0	0	0	1	0	0	0	0	0	2000
10291	168	152.7	25443	0	0	0	0	0	0	1	0	0	0	0	0	2000
10286	168	160.1	27329	0	0	0	0	0	0	0	1	0	0	0	0	2000
10337	168	172.1	30359	0	0	0	0	0	0	0	1	0	0	0	0	2000
10265	168	164.9	28619	0	0	0	0	0	0	0	1	0	0	0	0	2000
10236	168	164.2	28229	0	0	0	0	0	0	0	1	0	0	0	0	2000
10240	168	170.7	30046	0	0	0	0	0	0	0	1	0	0	0	0	2000
10327	168	155.9	26274	0	0	0	0	0	0	0	0	1	0	0	0	2000
10273	159	161.4	27879	0	0	0	0	0	0	0	0	1	0	0	0	2000
10299	168	148.8	24487	0	0	0	0	0	0	0	0	1	0	0	0	2000
10193	168	148.6	24297	0	0	0	0	0	0	0	0	1	0	0	0	2000
10352	168	138.2	21356	0	0	0	0	0	0	0	0	0	1	0	0	2000
10345	46	144.3	23091	0	0	0	0	0	0	0	0	0	1	0	0	2000
10408	161	153.2	26067	0	0	0	0	0	0	0	0	0	1	0	1	2000
10435	169	147.7	24530	0	0	0	0	0	0	0	0	0	1	0	0	2000
10233	168	157.6	27061	0	0	0	0	0	0	0	0	0	0	1	0	2000
10129	168	174.5	31493	0	0	0	0	0	0	0	0	0	0	1	0	2000
10148	168	177.3	32400	0	0	0	0	0	0	0	0	0	0	1	0	2000
10353	151	165.4	28720	0	0	0	0	0	0	0	0	0	0	1	0	2000
10033	166	181.2	33381	0	0	0	0	0	0	0	0	0	0	0	0	2000
10311	143	138.0	21194	0	0	0	0	0	0	0	0	0	0	0	1	2000
10214	168	156.2	26632	0	0	0	0	0	0	0	0	0	0	0	0	2000
10144	168	176.9	32034	0	0	0	0	0	0	0	0	0	0	0	0	2000
10226	24	189.9	36054	0	0	0	0	0	0	0	0	0	0	0	0	2000
10095	168	183.3	33830	1	0	0	0	0	0	0	0	0	0	0	0	2001
10093	168	172.2	30541	1	0	0	0	0	0	0	0	0	0	0	0	2001
10249	168	124.6	17746	1	0	0	0	0	0	0	0	0	0	0	0	2001
10290	168	120.6	16199	1	0	0	0	0	0	0	0	0	0	0	0	2001
10133	168	113.9	14471	0	1	0	0	0	0	0	0	0	0	0	0	2001
9904	168	148.4	24306	0	1	0	0	0	0	0	0	0	0	0	0	2001
9958	144	170.5	30450	0	1	0	0	0	0	0	0	0	0	0	1	2001
9906	168	185.1	34423	0	1	0	0	0	0	0	0	0	0	0	0	2001
9923	146	178.6	32686	0	0	1	0	0	0	0	0	0	0	0	0	2001
9758	168	186.4	34791	0	0	1	0	0	0	0	0	0	0	0	0	2001
9836	118	176.7	31832	0	0	1	0	0	0	0	0	0	0	0	0	2001
10365	42	168.0	29964	0	0	0	1	0	0	0	0	0	0	0	1	2001

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
9783	168	187.6	35293	0	0	0	1	0	0	0	0	0	0	0	0	2001
9839	168	182.9	34103	0	0	0	1	0	0	0	0	0	0	0	0	2001
10017	168	179.9	33126	0	0	0	1	0	0	0	0	0	0	0	0	2001
10095	168	181.9	33502	0	0	0	0	1	0	0	0	0	0	0	0	2001
9891	168	163.6	28730	0	0	0	0	1	0	0	0	0	0	0	0	2001
9786	147	151.0	25413	0	0	0	0	1	0	0	0	0	0	0	0	2001
10140	142	157.6	27252	0	0	0	0	1	0	0	0	0	0	0	1	2001
10264	168	164.7	28740	0	0	0	0	1	0	0	0	0	0	0	0	2001
9929	168	166.2	28499	0	0	0	0	0	1	0	0	0	0	0	0	2001
10127	168	172.0	30223	0	0	0	0	0	1	0	0	0	0	0	0	2001
10058	168	165.7	28860	0	0	0	0	0	1	0	0	0	0	0	0	2001
10062	117	162.5	27836	0	0	0	0	0	1	0	0	0	0	0	0	2001

Data Base for SMITH 2 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for DANIEL 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR	BTU/LB
10495	168	395.3	31894	0	0	0	0	0	0	1	0	0	0	0	0	1998	9242
10506	168	387.5	23954	0	0	0	0	0	0	1	0	0	0	0	0	1998	9202
10884	93	319.0	54718	0	0	0	0	0	0	1	0	0	0	0	1	1998	9201
10353	168	419.8	51147	0	0	0	0	0	0	1	0	0	0	0	0	1998	9233
10517	168	414.4	46670	0	0	0	0	0	0	0	1	0	0	0	0	1998	9179
10388	168	418.6	51403	0	0	0	0	0	0	0	1	0	0	0	0	1998	9414
10434	168	399.3	36538	0	0	0	0	0	0	0	1	0	0	0	0	1998	9334
10436	168	431.3	61441	0	0	0	0	0	0	0	1	0	0	0	0	1998	9278
10443	168	450.6	9674	0	0	0	0	0	0	0	1	0	0	0	0	1998	9265
10404	168	436.3	60384	0	0	0	0	0	0	0	0	1	0	0	0	1998	9260
10336	70	426.9	56245	0	0	0	0	0	0	0	0	1	0	0	0	1998	9274
• 15296	31	106.4	14196	0	0	0	0	0	0	0	0	0	0	0	1	1998	9223
10691	113	321.8	45477	1	0	0	0	0	0	0	0	0	0	0	1	1999	9239
10581	128	356.3	7540	1	0	0	0	0	0	0	0	0	0	0	1	1999	9346
10629	100	357.9	9553	1	0	0	0	0	0	0	0	0	0	0	1	1999	9242
10630	168	395.3	35605	0	1	0	0	0	0	0	0	0	0	0	0	1999	9715
10291	161	304.6	42395	0	1	0	0	0	0	0	0	0	0	0	0	1999	11273
10211	168	386.1	24572	0	1	0	0	0	0	0	0	0	0	0	0	1999	10468
10188	159	390.1	31909	0	1	0	0	0	0	0	0	0	0	0	0	1999	10168
10325	168	362.1	5889	0	0	1	0	0	0	0	0	0	0	0	0	1999	9970
10519	130	431.9	60612	0	0	1	0	0	0	0	0	0	0	0	1	1999	9644
10219	168	450.0	7639	0	0	1	0	0	0	0	0	0	0	0	0	1999	9264
10264	156	435.2	62443	0	0	1	0	0	0	0	0	0	0	0	0	1999	9398
10648	51	392.3	40367	0	0	1	0	0	0	0	0	0	0	0	2	1999	9333
10306	24	441.0	4510	0	0	0	1	0	0	0	0	0	0	0	0	1999	9263
10554	127	329.5	47472	0	0	0	1	0	0	0	0	0	0	0	1	1999	9320
10157	168	457.2	13348	0	0	0	1	0	0	0	0	0	0	0	0	1999	9321
10319	168	451.7	9866	0	0	0	1	0	0	0	0	0	0	0	0	1999	9353
10874	127	356.5	4407	0	0	0	0	1	0	0	0	0	0	0	1	1999	9819
10750	148	387.9	32600	0	0	0	0	1	0	0	0	0	0	0	0	1999	9932
9925	168	388.6	39595	0	0	0	0	1	0	0	0	0	0	0	0	1999	11148
10369	150	409.5	53289	0	0	0	0	1	0	0	0	0	0	0	0	1999	11325
10681	168	366.8	22172	0	0	0	0	1	0	0	0	0	0	0	0	1999	11256
10087	168	417.5	56698	0	0	0	0	0	1	0	0	0	0	0	0	1999	11009
9819	168	427.1	62675	0	0	0	0	0	1	0	0	0	0	0	0	1999	10644
9997	168	417.3	58604	0	0	0	0	0	1	0	0	0	0	0	0	1999	10698
9617	144	439.4	3399	0	0	0	0	0	1	0	0	0	0	0	0	1999	10207
10303	168	420.6	61871	0	0	0	0	0	0	1	0	0	0	0	0	1999	10808
9844	168	459.6	22865	0	0	0	0	0	0	1	0	0	0	0	0	1999	10382
10195	168	444.6	10421	0	0	0	0	0	0	1	0	0	0	0	0	1999	10815
10179	168	480.5	38602	0	0	0	0	0	0	1	0	0	0	0	0	1999	10887
10205	168	507.1	60700	0	0	0	0	0	0	0	1	0	0	0	0	1999	10988
9669	168	503.7	57341	0	0	0	0	0	0	0	1	0	0	0	0	1999	10428
9846	168	488.2	45463	0	0	0	0	0	0	0	1	0	0	0	0	1999	10633
10292	168	466.7	28079	0	0	0	0	0	0	0	1	0	0	0	0	1999	11079
10353	168	441.5	8995	0	0	0	0	0	0	0	1	0	0	0	0	1999	10971
10152	168	428.9	1110	0	0	0	0	0	0	0	0	1	0	0	0	1999	10679

Data Base for DANIEL 1 Target Heat Rate Equation

	HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR	BTU/LB
	10091	168	454.4	17151	0	0	0	0	0	0	0	0	1	0	0	0	1999	10845
	11280	47	336.5	1053	0	0	0	0	0	0	0	0	1	0	0	0	1999	11679
	12890	14	258.9	15579	0	0	0	0	0	0	0	0	1	0	0	2	1999	9366
	10187	168	444.9	3991	0	0	0	0	0	0	0	0	0	1	0	0	1999	9294
	10731	168	451.4	8770	0	0	0	0	0	0	0	0	0	1	0	0	1999	9417
	9999	168	464.7	19928	0	0	0	0	0	0	0	0	0	1	0	0	1999	9259
	10041	168	459.2	15270	0	0	0	0	0	0	0	0	0	1	0	0	1999	9340
	10306	169	461.1	17428	0	0	0	0	0	0	0	0	0	1	0	0	1999	9347
	10403	168	470.1	24775	0	0	0	0	0	0	0	0	0	0	1	0	1999	9333
	10729	168	459.0	16436	0	0	0	0	0	0	0	0	0	0	1	0	1999	9799
	10390	122	451.6	11751	0	0	0	0	0	0	0	0	0	0	1	0	1999	9344
	10269	97	411.6	50858	0	0	0	0	0	0	0	0	0	0	1	1	1999	9305
	10095	168	453.7	11726	0	0	0	0	0	0	0	0	0	0	0	0	1999	9276
	9869	119	448.8	9097	0	0	0	0	0	0	0	0	0	0	0	0	1999	9202
	11114	139	413.5	49042	0	0	0	0	0	0	0	0	0	0	0	1	1999	9246
	10609	168	400.7	37973	0	0	0	0	0	0	0	0	0	0	0	0	1999	9340
*	7108	24	360.4	4175	0	0	0	0	0	0	0	0	0	0	0	0	1999	9214
	10884	168	294.4	37735	1	0	0	0	0	0	0	0	0	0	0	0	2000	9276
	10474	168	346.7	2394	1	0	0	0	0	0	0	0	0	0	0	0	2000	9110
	10609	168	325.4	53662	1	0	0	0	0	0	0	0	0	0	0	0	2000	9262
	10453	168	381.2	24554	1	0	0	0	0	0	0	0	0	0	0	0	2000	9231
	10223	168	405.4	39968	0	1	0	0	0	0	0	0	0	0	0	0	2000	9190
	10371	168	436.5	426	0	1	0	0	0	0	0	0	0	0	0	0	2000	9586
	10236	168	381.1	30180	0	1	0	0	0	0	0	0	0	0	0	0	2000	9160
	10256	168	396.0	38906	0	1	0	0	0	0	0	0	0	0	0	0	2000	9206
	9573	167	426.9	59436	0	1	0	0	0	0	0	0	0	0	0	0	2000	9070
*	11359	1	59.0	3481	0	0	1	0	0	0	0	0	0	0	0	0	2000	9222
	10343	152	408.2	49331	0	0	0	1	0	0	0	0	0	0	0	1	2000	11466
	10238	167	451.1	18114	0	0	0	1	0	0	0	0	0	0	0	0	2000	11535
	10316	168	359.9	16710	0	0	0	0	1	0	0	0	0	0	0	0	2000	11287
	10056	130	422.4	61333	0	0	0	0	1	0	0	0	0	0	0	0	2000	11292
	10326	53	457.3	23427	0	0	0	0	1	0	0	0	0	0	0	1	2000	11397
	10019	139	450.8	16596	0	0	0	0	1	0	0	0	0	0	0	1	2000	11372
	10100	168	376.3	32403	0	0	0	0	1	0	0	0	0	0	0	0	2000	11352
	10113	168	369.8	29920	0	0	0	0	0	1	0	0	0	0	0	0	2000	11300
	10027	168	403.0	49948	0	0	0	0	0	1	0	0	0	0	0	0	2000	11239
	9939	168	399.0	51230	0	0	0	0	0	1	0	0	0	0	0	0	2000	11127
	9594	168	489.1	46128	0	0	0	0	0	1	0	0	0	0	0	0	2000	10526
	10428	24	378.2	32473	0	0	0	0	1	0	0	0	0	0	0	0	2000	11493
	11089	168	497.2	52373	0	0	0	0	0	0	1	0	0	0	0	0	2000	11354
	10889	71	471.7	35127	0	0	0	0	0	0	1	0	0	0	0	1	2000	11406
	10655	168	472.4	36019	0	0	0	0	0	0	1	0	0	0	0	0	2000	11221
	10597	168	406.6	59116	0	0	0	0	0	0	1	0	0	0	0	0	2000	10718
	10358	150	465.8	28794	0	0	0	0	0	0	0	1	0	0	0	0	2000	11168
	10137	168	501.3	54885	0	0	0	0	0	0	0	1	0	0	0	0	2000	11167
	10372	167	466.2	31150	0	0	0	0	0	0	0	1	0	0	0	0	2000	1152
	10294	167	462.6	27431	0	0	0	0	0	0	0	1	0	0	0	0	2000	1128

Data Base for DANIEL 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR	BTU/LB
10272	121	469.3	32424	0	0	0	0	0	0	0	1	0	0	0	1	2000	11454
10142	168	475.6	38231	0	0	0	0	0	0	0	0	1	0	0	0	2000	11314
10004	168	491.6	46405	0	0	0	0	0	0	0	0	1	0	0	0	2000	11183
10037	136	487.5	47356	0	0	0	0	0	0	0	0	1	0	0	1	2000	11149
10010	168	482.6	42707	0	0	0	0	0	0	0	0	1	0	0	0	2000	11141
10067	168	460.1	27650	0	0	0	0	0	0	0	0	0	1	0	0	2000	11173
10103	168	482.1	43593	0	0	0	0	0	0	0	0	0	1	0	0	2000	10797
9919	168	463.2	28003	0	0	0	0	0	0	0	0	0	1	0	0	2000	10973
9937	168	470.2	32498	0	0	0	0	0	0	0	0	0	1	0	0	2000	11358
9854	169	473.6	37604	0	0	0	0	0	0	0	0	0	1	0	0	2000	10611
9960	168	488.3	46339	0	0	0	0	0	0	0	0	0	0	1	0	2000	10857
9912	168	498.9	53929	0	0	0	0	0	0	0	0	0	0	1	0	2000	10925
9910	168	480.6	37063	0	0	0	0	0	0	0	0	0	0	1	0	2000	10499
11327	168	442.6	1816	0	0	0	0	0	0	0	0	0	0	1	0	2000	10349
9417	168	479.6	35078	0	0	0	0	0	0	0	0	0	0	0	0	2000	9845
10658	168	422.7	48045	0	0	0	0	0	0	0	0	0	0	0	0	2000	9143
10222	168	407.2	42023	0	0	0	0	0	0	0	0	0	0	0	0	2000	9104
10975	168	417.9	45312	0	0	0	0	0	0	0	0	0	0	0	0	2000	9482
11374	24	425.3	49837	0	0	0	0	0	0	0	0	0	0	0	0	2000	9779
9962	168	479.4	36727	1	0	0	0	0	0	0	0	0	0	0	0	2001	10432
10416	168	429.6	55290	1	0	0	0	0	0	0	0	0	0	0	0	2001	9324
10180	96	417.8	57434	1	0	0	0	0	0	0	0	0	0	0	0	2001	11319
10620	69	428.7	468	0	0	1	0	0	0	0	0	0	0	0	1	2001	11090
10176	138	474.0	33707	0	0	1	0	0	0	0	0	0	0	0	1	2001	11180
10086	168	435.8	2427	0	0	1	0	0	0	0	0	0	0	0	0	2001	11144
10054	168	463.7	25592	0	0	1	0	0	0	0	0	0	0	0	0	2001	11378
10428	167	309.3	49744	0	0	1	0	0	0	0	0	0	0	0	0	2001	11446
9879	168	407.7	54000	0	0	0	1	0	0	0	0	0	0	0	0	2001	11438
10008	168	387.8	42553	0	0	0	1	0	0	0	0	0	0	0	0	2001	11212
9942	168	413.9	57117	0	0	0	1	0	0	0	0	0	0	0	0	2001	11314
10147	168	336.1	3674	0	0	0	1	0	0	0	0	0	0	0	0	2001	11492
9920	168	337.1	3178	0	0	0	0	1	0	0	0	0	0	0	0	2001	11563
10175	168	330.3	1056	0	0	0	0	1	0	0	0	0	0	0	0	2001	11552
10477	168	278.4	34345	0	0	0	0	1	0	0	0	0	0	0	0	2001	11676
10706	168	279.8	27721	0	0	0	0	1	0	0	0	0	0	0	0	2001	11484
10512	168	315.7	53213	0	0	0	0	1	0	0	0	0	0	0	0	2001	11396
10147	168	372.8	28388	0	0	0	0	0	1	0	0	0	0	0	0	2001	11417
9911	168	423.7	62662	0	0	0	0	0	1	0	0	0	0	0	0	2001	11389
9960	168	388.0	40274	0	0	0	0	0	1	0	0	0	0	0	0	2001	11315
9992	144	360.9	18129	0	0	0	0	0	1	0	0	0	0	0	0	2001	11332

Data Base for DANIEL 1 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for DANIEL 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR	BTU/LB
10438	168	423.3	50685	0	0	0	0	0	0	1	0	0	0	0	0	1998	9240
10452	168	427.4	51836	0	0	0	0	0	0	1	0	0	0	0	0	1998	9195
10608	168	409.2	36775	0	0	0	0	0	0	1	0	0	0	0	0	1998	9248
10556	168	414.6	40870	0	0	0	0	0	0	1	0	0	0	0	0	1998	9231
10866	108	387.2	24377	0	0	0	0	0	0	0	1	0	0	0	1	1998	9131
10491	168	420.9	46457	0	0	0	0	0	0	0	1	0	0	0	0	1998	9416
10480	168	420.9	47347	0	0	0	0	0	0	0	1	0	0	0	0	1998	9334
10600	130	402.7	37177	0	0	0	0	0	0	0	1	0	0	0	1	1998	9270
10567	168	408.1	36545	0	0	0	0	0	0	0	1	0	0	0	0	1998	9264
10531	90	390.8	27406	0	0	0	0	0	0	0	0	1	0	0	1	1998	9240
10440	168	395.3	29659	0	0	0	0	0	0	0	0	1	0	0	0	1998	9115
10511	168	405.4	33492	0	0	0	0	0	0	0	0	1	0	0	0	1998	9056
10536	139	394.9	27285	0	0	0	0	0	0	0	0	1	0	0	0	1998	9071
10518	123	396.4	28503	0	0	0	0	0	0	0	0	0	1	0	1	1998	9097
10551	137	371.1	11890	0	0	0	0	0	0	0	0	0	1	0	1	1998	8964
10572	140	362.8	8252	0	0	0	0	0	0	0	0	0	1	0	1	1998	9358
10413	124	343.5	60406	0	0	0	0	0	0	0	0	0	1	0	1	1998	9290
10645	168	317.4	44496	0	0	0	0	0	0	0	0	0	0	1	0	1998	9361
10438	49	335.9	55108	0	0	0	0	0	0	0	0	0	0	1	0	1998	9389
11007	67	275.3	12017	0	0	0	0	0	0	0	0	0	0	1	1	1998	9113
10555	168	296.0	24399	0	0	0	0	0	0	0	0	0	0	0	0	1998	9177
10304	163	359.7	315	0	0	0	0	0	0	0	0	0	0	0	0	1998	9189
10730	110	304.6	34139	0	0	0	0	0	0	0	0	0	0	0	1	1998	9192
10355	168	347.0	55803	0	0	0	0	0	0	0	0	0	0	0	0	1998	9261
10406	168	357.0	62503	1	0	0	0	0	0	0	0	0	0	0	0	1999	9257
10549	168	330.6	46824	1	0	0	0	0	0	0	0	0	0	0	0	1999	9222
10617	168	320.2	40288	1	0	0	0	0	0	0	0	0	0	0	0	1999	9357
10889	128	296.9	27870	1	0	0	0	0	0	0	0	0	0	0	1	1999	9238
10699	168	334.9	47194	0	1	0	0	0	0	0	0	0	0	0	0	1999	9242
11053	22	326.9	45253	0	1	0	0	0	0	0	0	0	0	0	0	1999	9843
* 19150	25	157.4	30819	0	0	0	1	0	0	0	0	0	0	0	1	1999	9413
* 9934	150	330.4	53663	0	0	0	1	0	0	0	0	0	0	0	1	1999	9341
9932	168	466.4	25472	0	0	0	0	1	0	0	0	0	0	0	0	1999	10168
9437	168	434.9	5315	0	0	0	0	1	0	0	0	0	0	0	0	1999	10765
10317	168	406.1	52437	0	0	0	0	1	0	0	0	0	0	0	0	1999	11341
10392	123	396.7	44796	0	0	0	0	1	0	0	0	0	0	0	1	1999	11367
10478	168	405.9	51009	0	0	0	0	1	0	0	0	0	0	0	0	1999	11262
10115	168	413.4	55008	0	0	0	0	0	1	0	0	0	0	0	0	1999	11006
10033	157	390.1	38800	0	0	0	0	0	1	0	0	0	0	0	0	1999	10642
9966	168	407.2	52888	0	0	0	0	0	1	0	0	0	0	0	0	1999	10698
9563	144	435.9	1888	0	0	0	0	0	1	0	0	0	0	0	0	1999	10209
10126	168	406.8	51222	0	0	0	0	0	0	1	0	0	0	0	0	1999	10810
9807	120	411.9	56298	0	0	0	0	0	0	1	0	0	0	0	1	1999	10435
9693	168	427.7	62984	0	0	0	0	0	0	1	0	0	0	0	0	1999	10875
9846	168	478.1	35547	0	0	0	0	0	0	1	0	0	0	0	0	1999	10885
10216	130	452.5	16912	0	0	0	0	0	0	0	1	0	0	0	1	1999	10961
9816	168	495.4	49692	0	0	0	0	0	0	0	1	0	0	0	0	1999	10433

Data Base for DANIEL 2 Target Heat Rate Equation

	HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR	BTU/LB
	10003	168	457.7	20527	0	0	0	0	0	0	0	1	0	0	0	0	1999	10639
	10223	168	441.4	8497	0	0	0	0	0	0	0	1	0	0	0	0	1999	10826
	10462	168	434.5	3750	0	0	0	0	0	0	0	1	0	0	0	0	1999	10972
	10092	143	392.2	39136	0	0	0	0	0	0	0	0	1	0	0	0	1999	10566
	10077	126	432.4	1340	0	0	0	0	0	0	0	0	1	0	0	1	1999	10579
	9953	168	406.2	52145	0	0	0	0	0	0	0	0	1	0	0	0	1999	11708
	9960	168	430.6	563	0	0	0	0	0	0	0	0	1	0	0	0	1999	10677
	10094	168	447.3	6804	0	0	0	0	0	0	0	0	0	1	0	0	1999	9293
	10684	168	457.3	13130	0	0	0	0	0	0	0	0	0	1	0	0	1999	9422
	9983	168	452.6	10402	0	0	0	0	0	0	0	0	0	1	0	0	1999	9259
	9959	168	451.8	9419	0	0	0	0	0	0	0	0	0	1	0	0	1999	9340
	10065	169	460.1	16597	0	0	0	0	0	0	0	0	0	1	0	0	1999	9347
	10167	168	394.4	31737	0	0	0	0	0	0	0	0	0	0	1	0	1999	9662
	9495	119	457.7	22032	0	0	0	0	0	0	0	0	0	0	1	0	1999	9866
	9892	128	439.5	5757	0	0	0	0	0	0	0	0	0	0	1	1	1999	9308
	10261	168	414.8	45907	0	0	0	0	0	0	0	0	0	0	1	0	1999	9303
	9879	168	438.1	62907	0	0	0	0	0	0	0	0	0	0	0	0	1999	9266
*	11030	168	440.7	4520	0	0	0	0	0	0	0	0	0	0	0	0	1999	9162
	9434	168	403.4	42629	0	0	0	0	0	0	0	0	0	0	0	0	1999	9247
	10549	168	377.1	20699	0	0	0	0	0	0	0	0	0	0	0	0	1999	9332
	11033	24	330.2	50321	0	0	0	0	0	0	0	0	0	0	0	0	1999	9214
	11086	133	250.9	10254	1	0	0	0	0	0	0	0	0	0	0	1	2000	9278
	10381	168	322.0	50549	1	0	0	0	0	0	0	0	0	0	0	0	2000	9109
	10650	168	291.8	31872	1	0	0	0	0	0	0	0	0	0	0	0	2000	9259
	10311	168	363.2	12404	1	0	0	0	0	0	0	0	0	0	0	0	2000	9231
	10148	168	409.9	43776	0	1	0	0	0	0	0	0	0	0	0	0	2000	10468
	9560	167	407.5	47634	0	1	0	0	0	0	0	0	0	0	0	0	2000	10597
	10850	168	367.4	21657	0	1	0	0	0	0	0	0	0	0	0	0	2000	9158
	9877	168	385.0	31999	0	1	0	0	0	0	0	0	0	0	0	0	2000	9204
	9971	168	428.5	60068	0	1	0	0	0	0	0	0	0	0	0	0	2000	9072
	10012	168	459.3	16171	0	0	1	0	0	0	0	0	0	0	0	0	2000	8987
	9989	168	467.9	22892	0	0	1	0	0	0	0	0	0	0	0	0	2000	9058
	9985	168	411.1	47818	0	0	1	0	0	0	0	0	0	0	0	0	2000	9007
	9995	154	445.5	15101	0	0	0	1	0	0	0	0	0	0	0	1	2000	11198
	9961	168	469.6	30819	0	0	0	1	0	0	0	0	0	0	0	0	2000	11415
	10039	168	482.9	39296	0	0	0	1	0	0	0	0	0	0	0	0	2000	11521
	9861	168	455.4	19956	0	0	0	0	1	0	0	0	0	0	0	0	2000	11291
	9993	168	465.1	26538	0	0	0	0	1	0	0	0	0	0	0	0	2000	11297
	9868	168	463.0	25392	0	0	0	0	1	0	0	0	0	0	0	0	2000	11422
	9980	168	472.9	31629	0	0	0	0	1	0	0	0	0	0	0	0	2000	11387
	10191	168	391.1	43187	0	0	0	0	1	0	0	0	0	0	0	0	2000	11351
	10167	168	384.5	39110	0	0	0	0	0	1	0	0	0	0	0	0	2000	11299
	10154	168	394.5	43111	0	0	0	0	0	1	0	0	0	0	0	0	2000	11239
*	11352	168	380.7	35826	0	0	0	0	0	1	0	0	0	0	0	0	2000	11118
*	9003	168	381.2	32754	0	0	0	0	0	1	0	0	0	0	0	0	2000	10513
	10776	24	354.8	19958	0	0	0	0	1	0	0	0	0	0	0	0	2000	1143
	10774	168	368.4	28982	0	0	0	0	0	0	1	0	0	0	0	0	2000	1138

Data Base for DANIEL 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR	BTU/LB
10337	168	470.4	29745	0	0	0	0	0	0	1	0	0	0	0	0	2000	11589
10591	101	372.3	29627	0	0	0	0	0	0	1	0	0	0	0	1	2000	11221
10333	168	333.1	4008	0	0	0	0	0	0	1	0	0	0	0	0	2000	10763
10367	168	383.9	35525	0	0	0	0	0	0	0	1	0	0	0	0	2000	11171
10268	168	412.3	52753	0	0	0	0	0	0	0	1	0	0	0	0	2000	11171
10319	168	405.8	52147	0	0	0	0	0	0	0	1	0	0	0	0	2000	11324
10351	168	424.3	63503	0	0	0	0	0	0	0	1	0	0	0	0	2000	11285
10246	168	451.8	16172	0	0	0	0	0	0	0	1	0	0	0	0	2000	11449
10004	168	396.9	45858	0	0	0	0	0	0	0	0	1	0	0	0	2000	11303
10098	168	382.8	34021	0	0	0	0	0	0	0	0	1	0	0	0	2000	11306
9897	146	373.3	30430	0	0	0	0	0	0	0	0	1	0	0	0	2000	11220
* 11997	31	354.7	18614	0	0	0	0	0	0	0	0	0	1	0	1	2000	11438
9792	169	405.4	55285	0	0	0	0	0	0	0	0	0	1	0	0	2000	10664
9653	168	394.9	46968	0	0	0	0	0	0	0	0	0	0	1	0	2000	10882
9634	168	423.4	64160	0	0	0	0	0	0	0	0	0	0	1	0	2000	10931
9681	168	472.9	34118	0	0	0	0	0	0	0	0	0	0	1	0	2000	10490
9679	168	444.9	14439	0	0	0	0	0	0	0	0	0	0	1	0	2000	10625
9858	168	507.0	60458	0	0	0	0	0	0	0	0	0	0	0	0	2000	10713
9326	168	498.9	54553	0	0	0	0	0	0	0	0	0	0	0	0	2000	10214
9835	168	488.4	45274	0	0	0	0	0	0	0	0	0	0	0	0	2000	10519
9945	168	446.4	21276	0	0	0	0	0	0	0	0	0	0	0	0	2000	11097
9230	24	511.0	64514	0	0	0	0	0	0	0	0	0	0	0	0	2000	10550
9667	168	504.2	58746	1	0	0	0	0	0	0	0	0	0	0	0	2001	10830
9584	168	484.4	43398	1	0	0	0	0	0	0	0	0	0	0	0	2001	11026
10154	168	412.0	54289	1	0	0	0	0	0	0	0	0	0	0	0	2001	11174
9922	168	457.3	18662	1	0	0	0	0	0	0	0	0	0	0	0	2001	11068
10171	168	430.4	64453	0	1	0	0	0	0	0	0	0	0	0	0	2001	11079
10218	168	290.4	35743	0	1	0	0	0	0	0	0	0	0	0	0	2001	10825
9958	168	370.0	28222	0	1	0	0	0	0	0	0	0	0	0	0	2001	11217
9771	168	501.5	55221	0	1	0	0	0	0	0	0	0	0	0	0	2001	11475
9860	168	494.5	49242	0	0	1	0	0	0	0	0	0	0	0	0	2001	11207
9951	168	503.4	57060	0	0	1	0	0	0	0	0	0	0	0	0	2001	11196
9862	168	478.0	34809	0	0	1	0	0	0	0	0	0	0	0	0	2001	11146
9782	168	474.5	34884	0	0	1	0	0	0	0	0	0	0	0	0	2001	11377
10118	167	358.1	14508	0	0	1	0	0	0	0	0	0	0	0	0	2001	11442
9880	168	485.4	44053	0	0	0	1	0	0	0	0	0	0	0	0	2001	11422
9909	165	487.9	46353	0	0	0	1	0	0	0	0	0	0	0	0	2001	11211
9752	83	477.5	39176	0	0	0	1	0	0	0	0	0	0	0	1	2001	11340
9675	119	499.6	56318	0	0	0	1	0	0	0	0	0	0	0	0	2001	11274
10735	100	337.2	4161	0	0	0	0	1	0	0	0	0	0	0	1	2001	11523
10620	138	359.8	26279	0	0	0	0	1	0	0	0	0	0	0	1	2001	11692
10466	168	361.4	27590	0	0	0	0	1	0	0	0	0	0	0	0	2001	11481
10620	168	308.8	58946	0	0	0	0	1	0	0	0	0	0	0	0	2001	11339
10310	168	366.4	30914	0	0	0	0	0	1	0	0	0	0	0	0	2001	11422
10154	168	419.2	539	0	0	0	0	0	1	0	0	0	0	0	0	2001	11392
10123	168	410.3	59692	0	0	0	0	0	1	0	0	0	0	0	0	2001	11511
10120	144	377.2	38663	0	0	0	0	0	1	0	0	0	0	0	0	2001	11337

Data Base for DANIEL 2 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Calculation of
Target Average Net Operating Heat Rates
for January 2002 - December 2002

Unit	Month	(1) Forecast AKW * 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKW * 10^3 Generation	(5) Weighted ANOHR Target
CRIST 4	Jan '02	69.5	4,998	10,194	37,681	
	Feb '02	70.6	5,137	10,364	34,927	
	Mar '02	69.5	4,998	10,376	48,611	
	Apr '02	64.0	4,316	10,461	35,822	
	May '02	64.0	4,316	10,461	46,752	
	Jun '02	66.0	4,562	10,682	39,781	
	Jul '02	66.5	4,624	10,787	47,705	
	Aug '02	68.9	4,923	10,784	44,996	
	Sep '02	67.6	4,760	10,400	46,745	
	Oct '02	62.1	4,084	10,500	5,649	
	Nov '02	64.0	4,316	10,461	43,288	
	Dec '02	68.7	4,898	10,386	21,366	10,499
CRIST 6	Jan '02	263.7	73,562	10,522	176,154	
	Feb '02	271.0	76,840	10,502	49,869	
	Mar '02	0.0	0	-	0	
	Apr '02	235.6	61,089	10,245	124,859	
	May '02	244.0	64,794	10,579	162,992	
	Jun '02	252.3	68,474	10,681	174,310	
	Jul '02	252.9	68,741	10,552	180,538	
	Aug '02	263.7	73,562	10,522	188,265	
	Sep '02	256.8	70,478	10,541	165,649	
	Oct '02	234.7	60,694	10,609	157,021	
	Nov '02	241.5	63,689	10,587	150,233	
	Dec '02	249.8	67,364	10,561	166,844	10,546
CRIST 7	Jan '02	471.0	221,867	10,138	300,038	
	Feb '02	474.6	224,476	10,135	291,891	
	Mar '02	474.9	224,693	10,135	302,538	
	Apr '02	0.0	0	-	0	
	May '02	462.3	215,571	10,051	233,472	
	Jun '02	467.4	219,261	10,141	308,038	
	Jul '02	459.1	213,259	10,330	312,657	
	Aug '02	467.7	219,478	10,285	318,507	
	Sep '02	466.0	218,247	10,338	276,362	
	Oct '02	455.5	210,659	10,282	310,626	
	Nov '02	461.9	215,282	10,147	284,088	
	Dec '02	473.2	223,461	10,136	322,261	10,196

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on page 2 of Schedule 1.

Column (5) = $(\Sigma ((3)*(4))) / (\Sigma (4))$

Calculation of
Target Average Net Operating Heat Rates
for January 2002 - December 2002

Unit	Month	(1) Forecast AKW * 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKW * 10^3 Generation	(5) Weighted ANOHR Target
SMITH 1	Jan '02	157.5	24,967	10,072	108,071	
	Feb '02	159.5	25,509	9,957	105,723	
	Mar '02	159.8	25,591	10,068	117,330	
	Apr '02	152.2	23,562	10,082	93,422	
	May '02	151.9	23,484	9,998	68,367	
	Jun '02	153.9	24,008	10,079	109,235	
	Jul '02	151.6	23,405	10,083	111,279	
	Aug '02	155.5	24,432	10,076	114,113	
	Sep '02	154.6	24,193	10,077	109,792	
	Oct '02	149.5	22,863	10,087	88,664	
	Nov '02	152.1	23,536	9,961	90,070	
	Dec '02	158.4	25,210	10,071	116,237	10,054
SMITH 2	Jan '02	183.3	33,822	9,912	133,451	
	Feb '02	185.4	34,405	9,865	113,281	
	Mar '02	182.0	33,462	9,875	4,369	
	Apr '02	176.0	31,800	10,003	123,898	
	May '02	178.6	32,520	10,098	129,993	
	Jun '02	178.7	32,548	10,098	125,967	
	Jul '02	177.1	32,105	10,104	128,955	
	Aug '02	180.5	33,046	10,091	131,438	
	Sep '02	179.7	32,825	10,094	126,696	
	Oct '02	173.9	31,219	10,117	126,789	
	Nov '02	178.7	32,548	10,098	83,972	
	Dec '02	183.9	33,989	10,078	133,856	10,050
DANIEL 1	Jan '02	464.8	221,849	10,168	258,418	
	Feb '02	477.1	231,908	9,930	233,280	
	Mar '02	479.4	233,812	10,112	330,300	
	Apr '02	432.8	196,662	10,284	249,709	
	May '02	443.2	204,692	10,247	305,355	
	Jun '02	450.8	210,655	9,917	300,698	
	Jul '02	441.6	203,447	10,493	304,274	
	Aug '02	461.9	219,508	10,179	318,269	
	Sep '02	455.0	213,985	10,204	303,502	
	Oct '02	429.6	194,221	10,295	296,431	
	Nov '02	440.2	202,360	10,258	293,635	
	Dec '02	464.5	221,607	10,169	299,111	10,191

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on page 2 of Schedule 1.

Column (5) = $(\Sigma ((4) * (5))) / (\Sigma (5))$

Calculation of
Target Average Net Operating Heat Rates
for January 2002 - December 2002

Unit	Month	(1) Forecast AKW * 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKW * 10^3 Generation	(5) Weighted ANOHR Target
DANIEL 2	Jan '02	489.3	241,860	9,761	197,189	
	Feb '02	0.0	0	-	0	
	Mar '02	0.0	0	-	0	
	Apr '02	444.0	206,245	9,942	188,705	
	May '02	458.6	217,592	10,050	318,236	
	Jun '02	465.5	222,998	9,854	312,328	
	Jul '02	459.0	217,904	10,053	318,555	
	Aug '02	472.0	228,116	10,089	327,592	
	Sep '02	471.6	227,800	9,830	284,836	
	Oct '02	447.0	208,566	9,930	310,659	
	Nov '02	463.5	221,428	9,715	311,024	
	Dec '02	485.8	239,065	9,774	315,268	9,906

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on page 2 of Schedule 1.

Column (5) = $(\Sigma ((4) * (5))) / (\Sigma (5))$

Summary of Target, Maximum, and Minimum
Average Net Operating Heat Rates
for January 2002 - December 2002

Unit	Target Heat Rate BTU/KWH (0 Points)	Minimum Attainable Heat Rate (+ 10 Points)	Maximum Attainable Heat Rate (- 10 Points)
CRIST 4	10,499	10,184	10,814
CRIST 6	10,546	10,230	10,862
CRIST 7	10,196	9,890	10,502
SMITH 1	10,054	9,752	10,356
SMITH 2	10,050	9,749	10,352
DANIEL 1	10,191	9,885	10,497
DANIEL 2	9,906	9,609	10,203

II. DETERMINATION OF EQUIVALENT AVAILABILITY TARGETS

Calculation of
Target Equivalent Availabilities
for January 2002 - December 2002

Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR *	Planned Outage Hours for Jan '02 - Dec '02	Reserve Shutdown Hours for Jan '02 - Dec '02	Target Equivalent Availability **
Crist 4	0.0350	553	1,201	90.9
Crist 6	0.0810	1,391	0	77.3
Crist 7	0.1135	887	0	79.7
Smith 1	0.0263	600	0	90.7
Smith 2	0.0307	936	0	86.6
Daniel 1	0.0979	216	0	88.0
Daniel 2	0.0976	1,895	0	70.7

* For Period July 1996 Through June 2001.

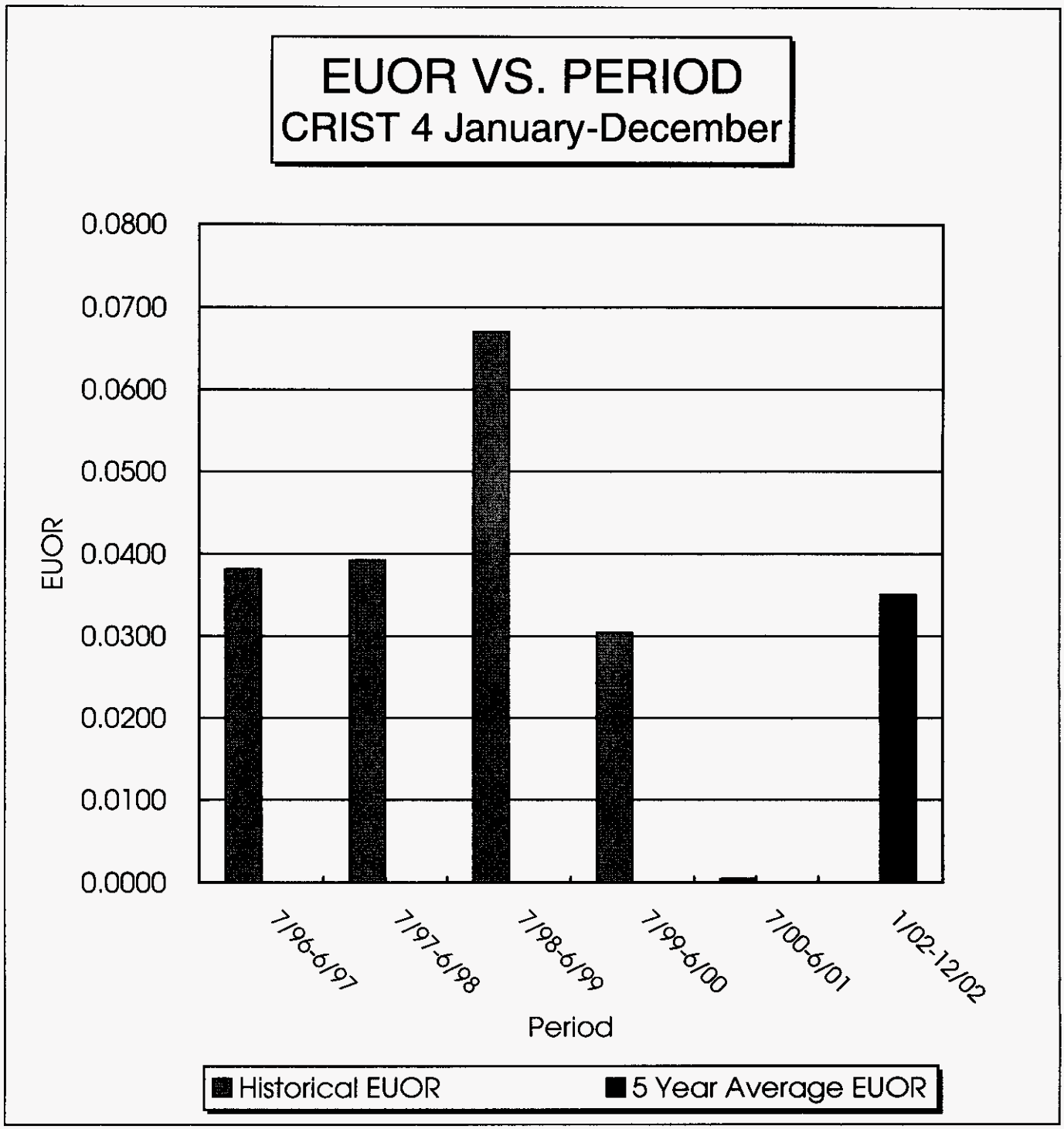
** EA = [1 - (POH + EUOR * (PH - POH - RSH)) / PH] * 100

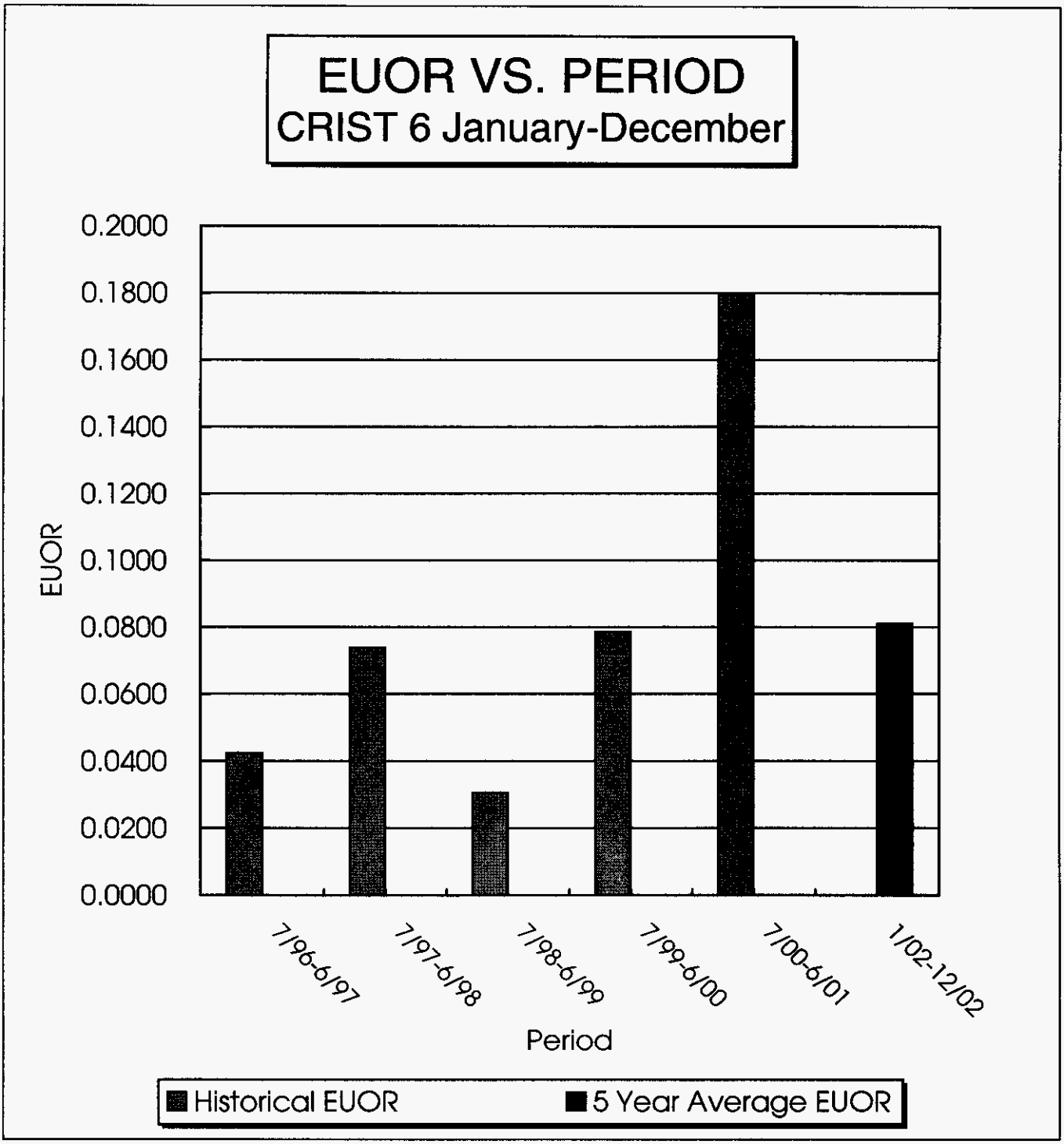
Calculation of Maximum and Minimum
Attainable Equivalent Availabilities
for January 2002 - December 2002

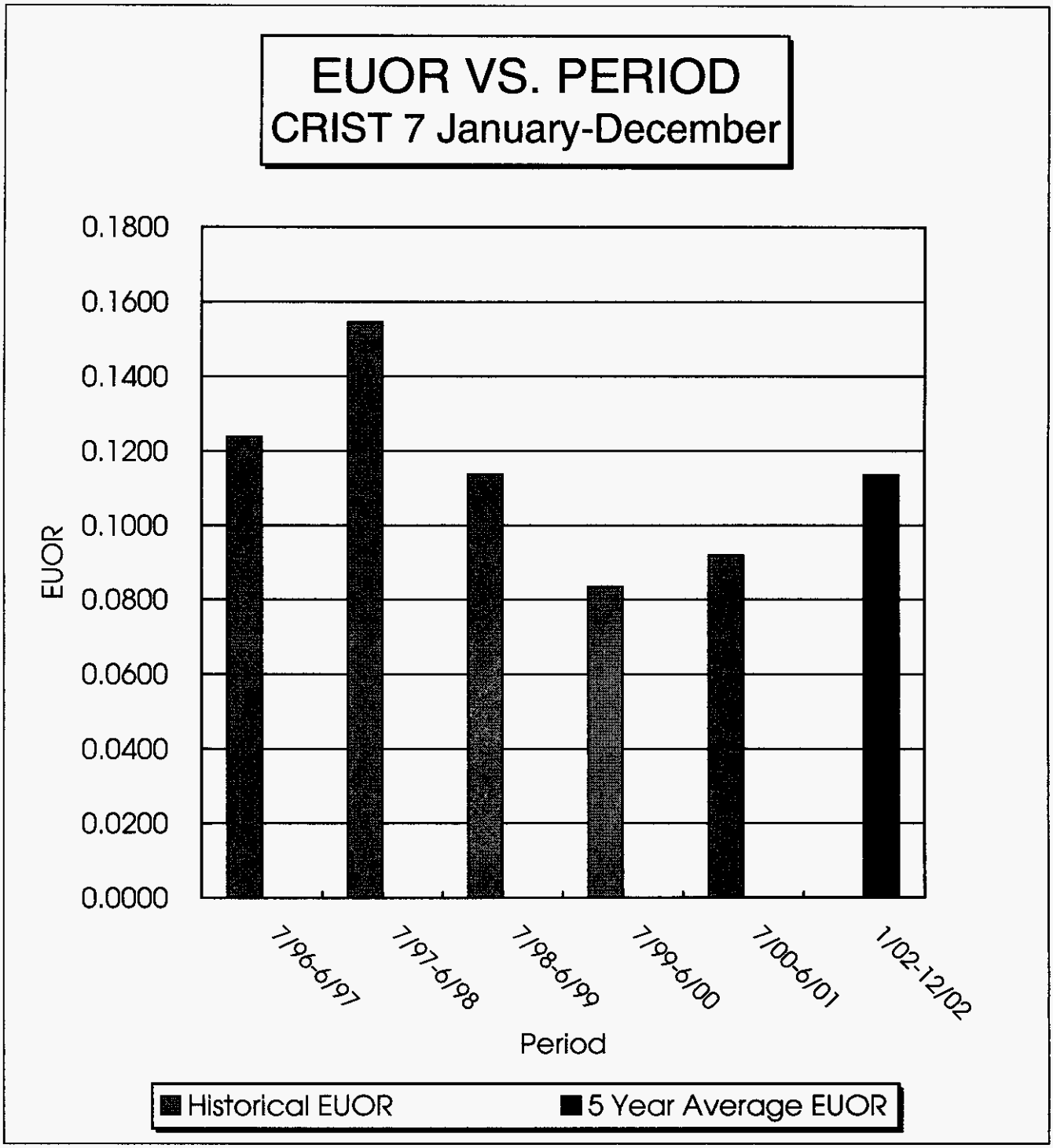
Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR (TARGET EUOR)	Minimum Attainable EUOR 70% of Target EUOR	Maximum Attainable Equivalent Availability	Maximum Attainable EUOR 145% of Target EUOR	Minimum Attainable Equivalent Availability
Crist 4	0.0350	0.0245	91.7	0.0508	89.6
Crist 6	0.0810	0.0567	79.4	0.1175	74.2
Crist 7	0.1135	0.0795	82.7	0.1646	75.1
Smith 1	0.0263	0.0184	91.4	0.0381	89.6
Smith 2	0.0307	0.0215	87.4	0.0445	85.3
Daniel 1	0.0979	0.0685	90.9	0.1420	83.7
Daniel 2	0.0976	0.0683	73.0	0.1415	67.3

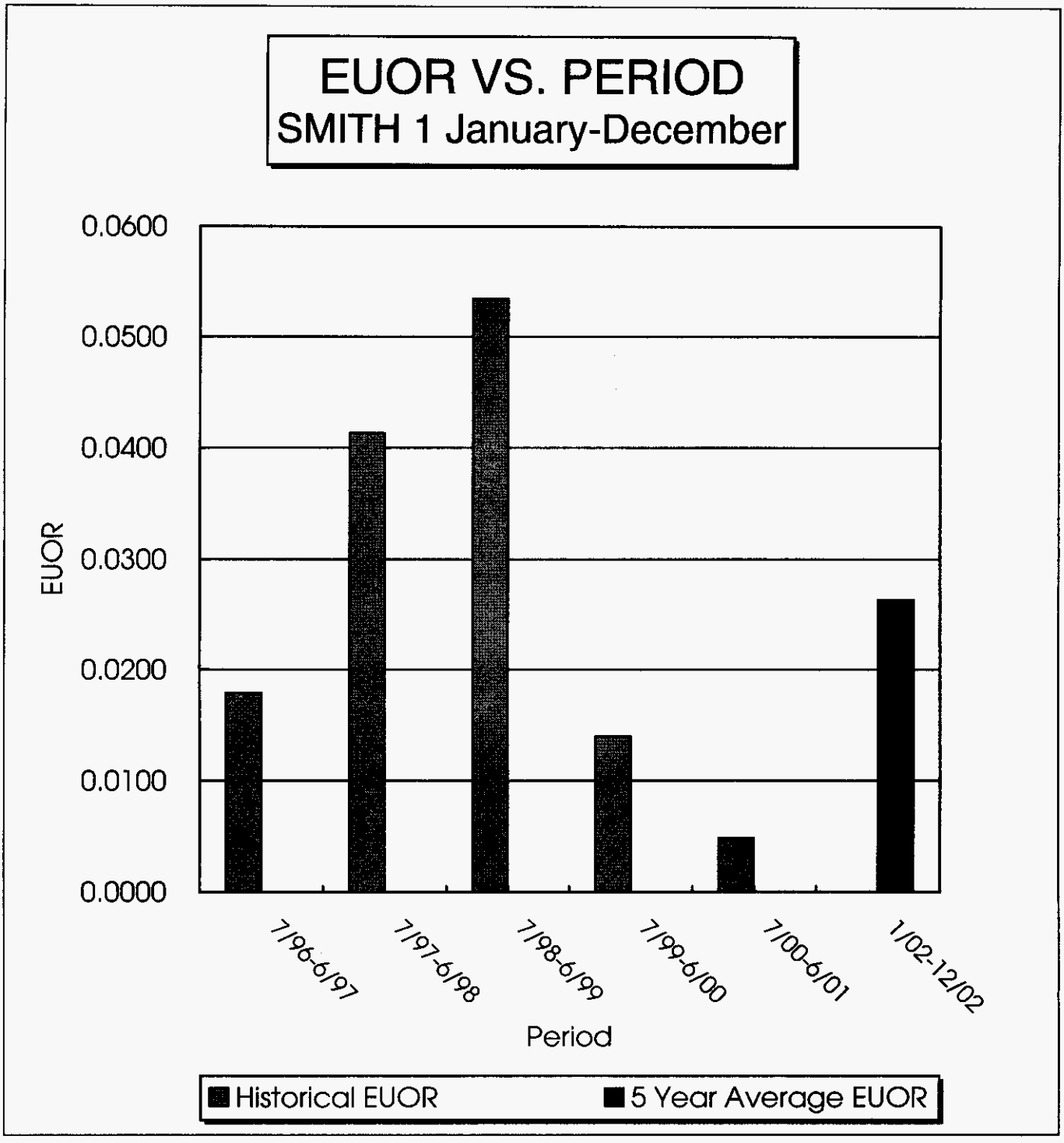
Summary of Target, Maximum, and Minimum
Equivalent Availabilities
for January 2002 - December 2002

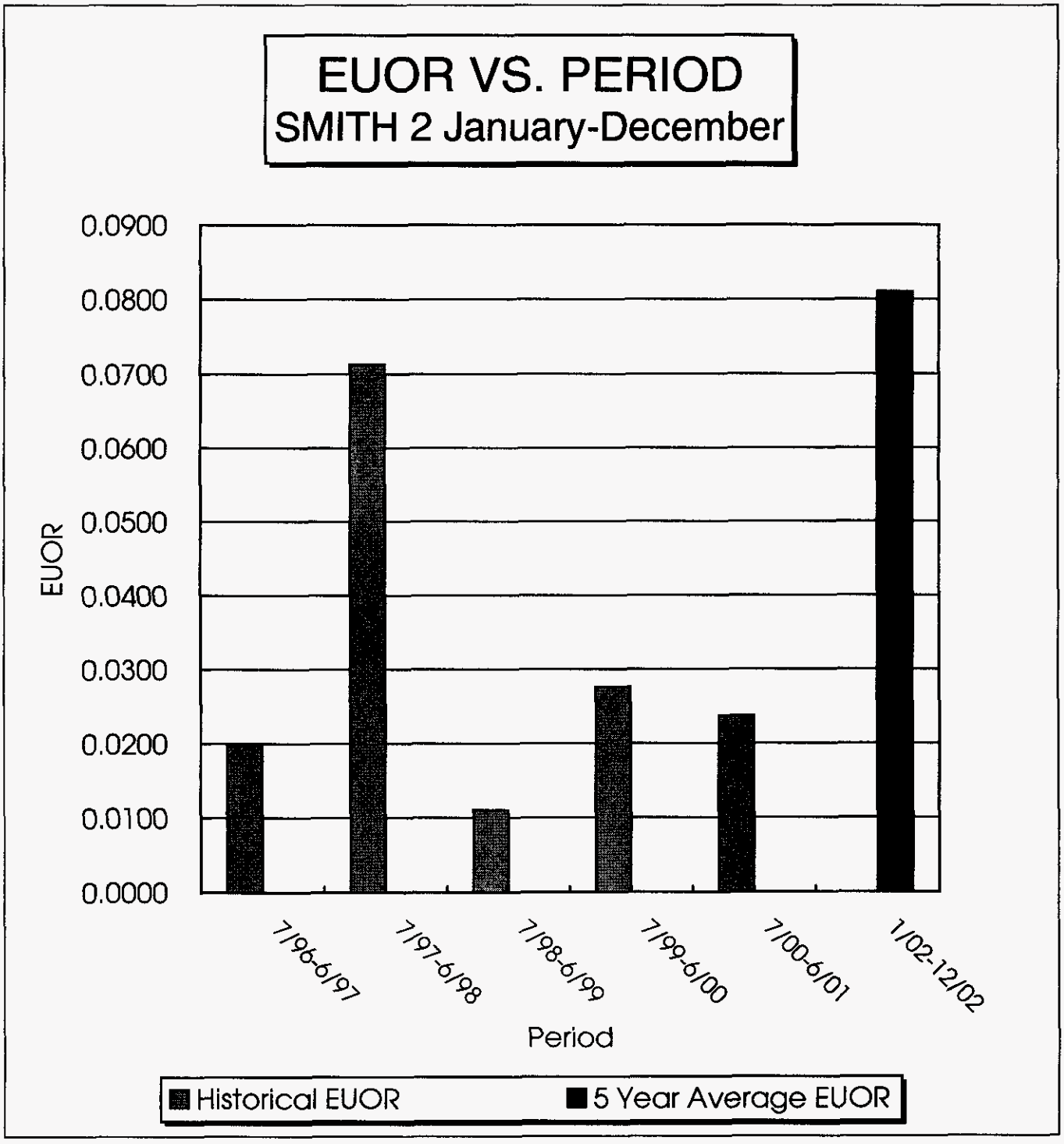
Unit	Target Equivalent Availability (0 Points)	Maximum Attainable Equivalent Availability (+10 Points)	Minimum Attainable Equivalent Availability (-10 Points)
Crist 4	90.9	91.7	89.6
Crist 6	77.3	79.4	74.2
Crist 7	79.7	82.7	75.1
Smith 1	90.7	91.4	89.6
Smith 2	86.6	87.4	85.3
Daniel 1	88.0	90.9	83.7
Daniel 2	70.7	73.0	67.3

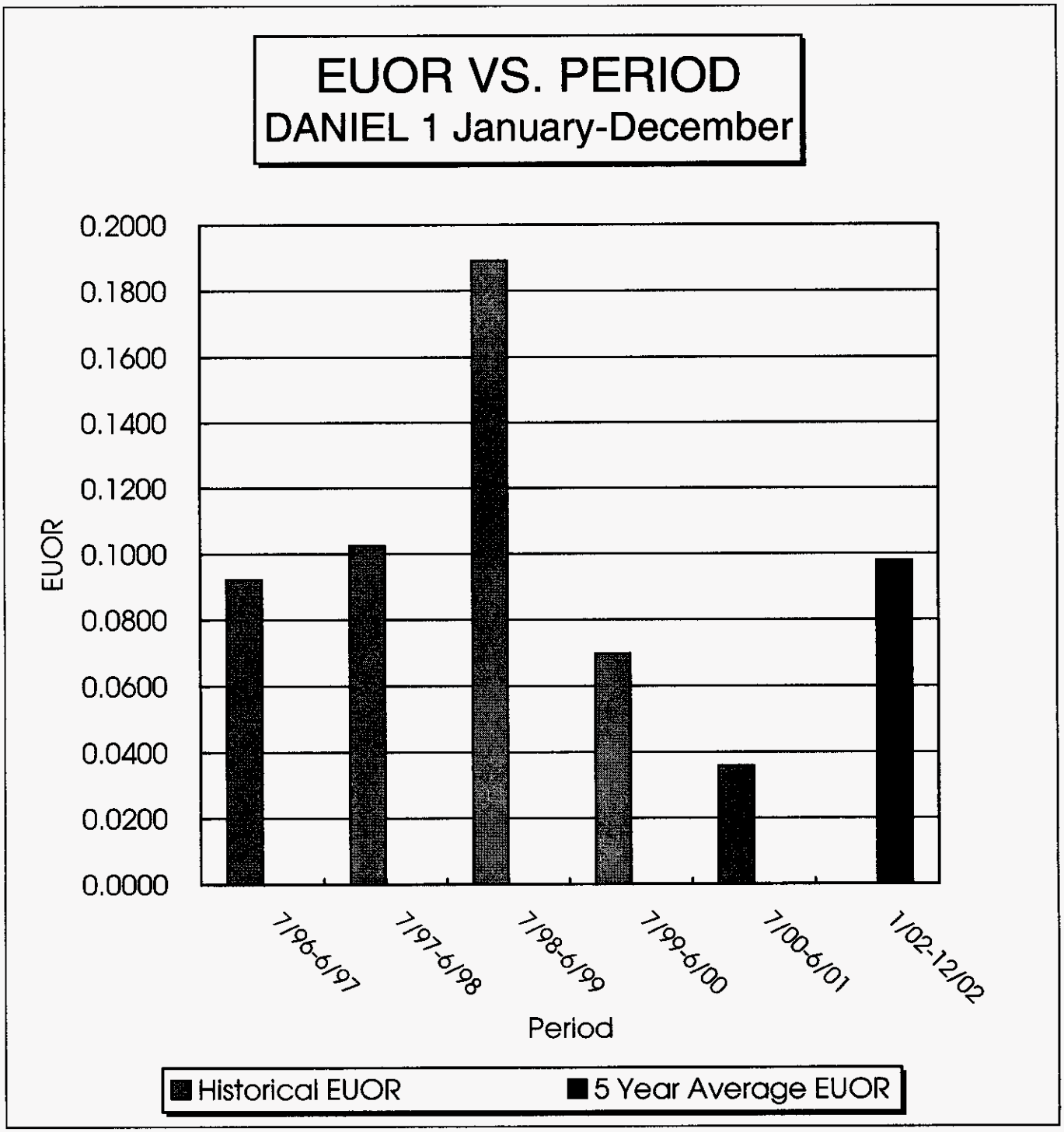

EUOR VS. PERIOD
CRIST 4 January-December
0.0800
0.0700
0.0600
0.0500
0.0400
0.0300
0.0200
0.0100
0.0000
EUOR
7/96-6/97
7/97-6/98
7/98-6/99
7/99-6/00
7/00-6/01
1/02-12/02
Period
Historical EUOR
5 Year Average EUOR

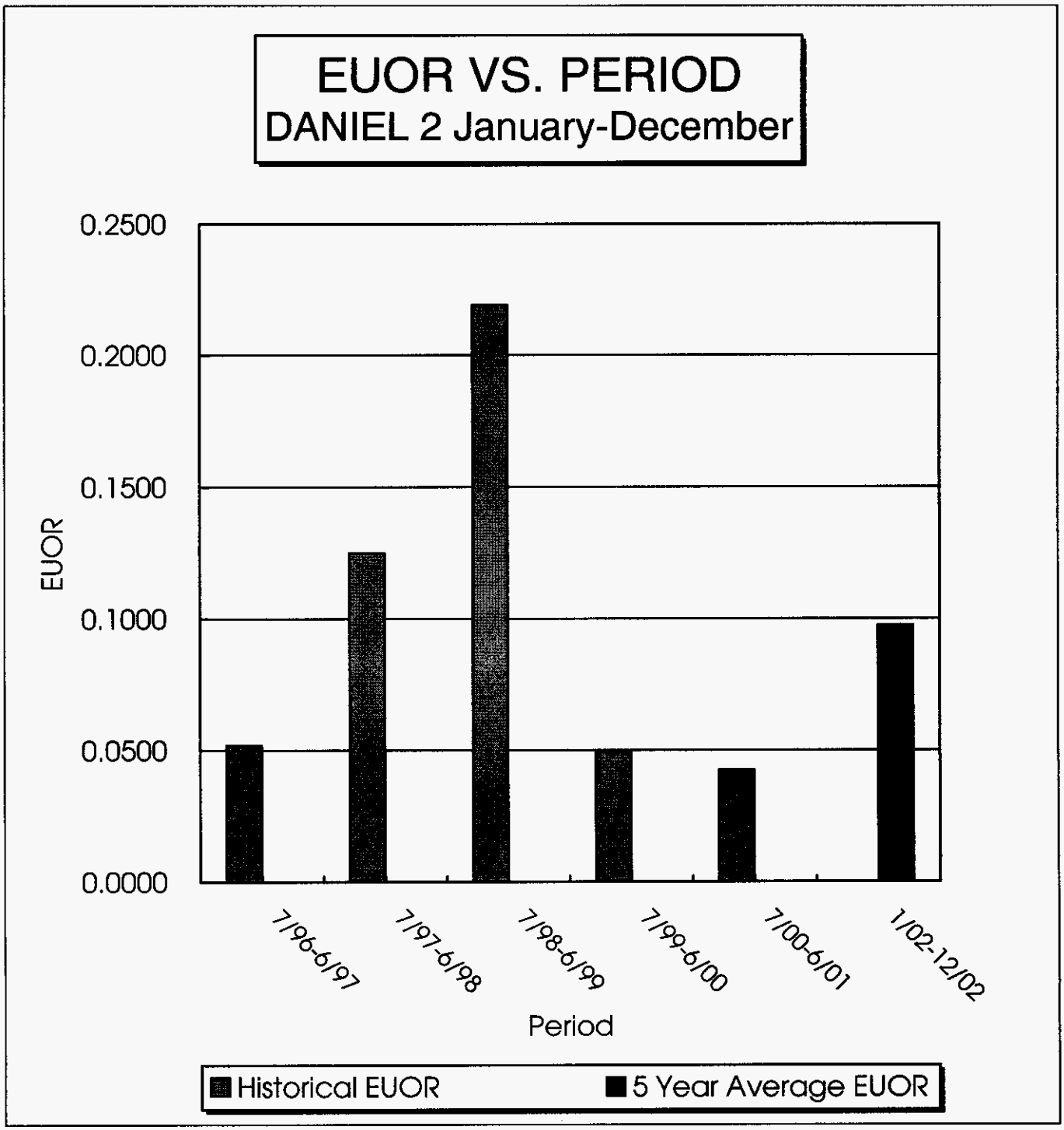

EUOR VS. PERIOD
CRIST 6 January-December
0.2000
0.1800
0.1600
0.1400
0.1200
0.1000
0.0800
0.0600
0.0400
0.0200
0.0000
EUOR
7/96-6/97
7/97-6/98
7/98-6/99
7/99-6/00
7/00-6/01
1/02-12/02
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
CRIST 7 January-December
0.1800
0.1600
0.1400
0.1200
0.1000
0.0800
0.0600
0.0400
0.0200
0.0000
EUOR
7/96-6/97
7/97-6/98
7/98-6/99
7/99-6/00
7/00-6/01
1/02-12/02
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
SMITH 1 January-December
0.0600
0.0500
0.0400
0.0300
0.0200
0.0100
0.0000
EUOR
7/96-6/97
7/97-6/98
7/98-6/99
7/99-6/00
7/00-6/01
1/02-12/02
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
SMITH 2 January-December
0.0900
0.0800
0.0700
0.0600
0.0500
0.0400
0.0300
0.0200
0.0100
0.0000
EUOR
7/96-6/97
7/97-6/98
7/98-6/99
7/99-6/00
7/00-6/01
1/02-12/02
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
DANIEL 1 January-December
0.2000
0.1800
0.1600
0.1400
0.1200
0.1000
0.0800
0.0600
0.0400
0.0200
0.0000
EUOR
7/96-6/97
7/97-6/98
7/98-6/99
7/99-6/00
7/00-6/01
1/02-12/02
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
DANIEL 2 January-December
0.2500
0.2000
0.1500
0.1000
0.0500
0.0000
EUOR
7/96-6/97
7/97-6/98
7/98-6/99
7/99-6/00
7/00-6/01
1/02-12/02
Period
Historical EUOR
5 Year Average EUOR

III. GPIF MINIMUM FILING REQUIREMENTS FOR THE
PERIOD JANUARY 2002 - DECEMBER 2002

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Generating Performance Incentive Factor

Estimated Reward/Penalty Table

Gulf Power Company

Period of: January 2002 - December 2002

Generating Performance Incentive Factor Points	Fuel Saving/Loss ($000)	Generating Performance Incentive Factor ($000)
	Maximum Attainable Fuel Savings	Maximum Incentive Dollars Allowed by Commission During Period (Reward)
+ 10	6301	2161
+ 9	5671	1945
+ 8	5041	1729
+ 7	4411	1513
+ 6	3781	1297
+ 5	3151	1081
+ 4	2520	864
+ 3	1890	648
+ 2	1260	432
+ 1	630	216
0	0	0
- 1	-749	-216
- 2	-1498	-432
- 3	-2247	-648
- 4	-2996	-864
- 5	-3746	-1081
- 6	-4495	-1297
- 7	-5244	-1513
- 8	-5993	-1729
- 9	-6742	-1945
- 10	-7491	-2161
	Minimum Attainable Fuel Loss	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

Generating Performance Incentive Factor

Calculation of Maximum Allowed Incentive Dollars

Estimated

Gulf Power Company

Period of: January 2002 - December 2002

Line 1	Beginning of Period Balance of Common Equity	$505,838,000
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '02	$547,331,000
Line 3	Month of Feb '02	$532,992,000
Line 4	Month of Mar '02	$533,813,000
Line 5	Month of Apr '02	$515,815,000
Line 6	Month of May '02	$547,709,000
Line 7	Month of Jun '02	$553,766,000
Line 8	Month of Jul '02	$544,920,000
Line 9	Month of Aug '02	$553,077,000
Line 10	Month of Sep '02	$557,714,000
Line 11	Month of Oct '02	$542,746,000
Line 12	Month of Nov '02	$542,097,000
Line 13	Month of Dec '02	$552,388,000
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$540,785,077
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	60.4594%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16 multiplied by 1.0)	$2,236,150
Line 18	Jurisdictional Sales (KWH)	10,265,887,000
Line 19	Total Territorial Sales (KWH)	10,622,732,000
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	96.6407%
Line 21	Maximum Allowed Jurisdictional Incentive Dollar (line 17 multiplied by line 20)	$2,161,031

Issued by: T. J. Bowden

Filed: September 20, 2001
Suspended:
Effective: January 1, 2002
Docket No.: 010001-EI
Order No.:

GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2002 - December 2002

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range Max %	EAF Range Min %	Max Fuel Savings ($000)	Max Fuel Loss ($000)
Crist 4	0.3%	90.9	91.7	89.6	$17	($42)
Crist 6	3.1%	77.3	79.4	74.2	$197	($303)
Crist 7	16.2%	79.7	82.7	75.1	$1,020	($1,509)
Smith 1	1.1%	90.7	91.4	89.6	$67	($116)
Smith 2	1.5%	86.6	87.4	85.3	$94	($158)
Daniel 1	6.0%	88.0	90.9	83.7	$375	($635)
Daniel 2	5.0%	70.7	73.0	67.3	$315	($512)

Plant & Unit	Weighting Factor %	ANOHR Target BTU/KWH	Target NOF	ANOHR Range Min BTU/KWH	ANOHR Range Max BTU/KWH	Max Fuel Savings ($000)	Max Fuel Loss ($000)
Crist 4	2.9%	10,499	85.9	10,184	10,814	$182	($182)
Crist 6	9.4%	10,546	83.0	10,230	10,862	$594	($594)
Crist 7	19.7%	10,196	97.8	9,890	10,502	$1,242	($1,242)
Smith 1	8.0%	10,054	95.6	9,752	10,356	$505	($505)
Smith 2	8.7%	10,050	95.0	9,749	10,352	$548	($548)
Daniel 1	10.0%	10,191	89.3	9,885	10,497	$633	($633)
Daniel 2	8.1%	9,906	91.2	9,609	10,203	$512	($512)

Issued by: T. J. Bowden

Filed: September 20, 2001
Suspended:
Effective: January 1, 2002
Docket No.: 010001-EI
Order No.:

Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2002 - December 2002

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Target			Actual Performance 1st Prior Period Jul '00 - Jun '01			Actual Performance 2nd Prior Period Jul '99 - Jun '00		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Crist 4	0.3%	0.8%	0.0631	0.0280	0.0350	0.1868	0.0003	0.0004	0.0974	0.0266	0.0304
Crist 6	3.1%	9.4%	0.1588	0.0682	0.0810	0.1102	0.1580	0.1795	0.0768	0.0281	0.0305
Crist 7	16.2%	48.9%	0.1013	0.1021	0.1135	0.1224	0.0808	0.0920	0.0888	0.1072	0.1177
Smith 1	1.1%	3.2%	0.0685	0.0245	0.0263	0.0759	0.0044	0.0048	0.2058	0.0417	0.0526
Smith 2	1.5%	4.5%	0.1068	0.0275	0.0307	0.0920	0.0216	0.0237	0.0583	0.0103	0.0110
Daniel 1	6.0%	18.0%	0.0247	0.0955	0.0979	0.1153	0.0318	0.0359	0.2959	0.1352	0.1920
Daniel 2	5.0%	15.1%	0.2163	0.0765	0.0976	0.1167	0.0374	0.0424	0.2633	0.1614	0.2191
Weighted GPIF System Average:			0.1092	0.0874	0.0980	0.1168	0.0669	0.0761	0.1537	0.1058	0.1305

Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2002 - December 2002

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Actual Performance 3rd Prior Period Jul '98 - Jun '99			Actual Performance 4th Prior Period Jul '97 - Jun '98			Actual Performance 5th Prior Period Jul '96 - Jun '97		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Crist 4	0.3%	0.8%	0.0435	0.0512	0.0670	0.1851	0.0263	0.0392	0.0000	0.0211	0.0381
Crist 6	3.1%	9.4%	0.1549	0.0593	0.0739	0.0273	0.0363	0.0424	0.1183	0.0176	0.0236
Crist 7	16.2%	48.9%	0.0721	0.1426	0.1545	0.1595	0.0985	0.1238	0.3446	0.0518	0.0809
Smith 1	1.1%	3.2%	0.0468	0.0394	0.0413	0.0647	0.0165	0.0179	0.0602	0.0105	0.0111
Smith 2	1.5%	4.5%	0.2248	0.0547	0.0713	0.0669	0.0181	0.0197	0.0580	0.0702	0.0750
Daniel 1	6.0%	18.0%	0.1325	0.0889	0.1025	0.1143	0.0817	0.0922	0.2291	0.0649	0.0869
Daniel 2	5.0%	15.1%	0.0235	0.1221	0.1251	0.0995	0.0468	0.0519	0.2586	0.0532	0.0731
Weighted GPIF System Average:			0.0893	0.1139	0.1250	0.1228	0.0749	0.0908	0.2646	0.0504	0.0725

Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Average Net Operating Heat Rate

Gulf Power Company

Period of: January 2002 - December 2002

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Heat Rate Target	1st Prior Period Heat Rate Jul '00 - Jun '01	2nd Prior Period Heat Rate Jul '99 - Jun '00	3rd Prior Period Heat Rate Jul '98 - Jun '99
Crist 4	2.9%	4.3%	10,499	10,621	10,607	10,426
Crist 6	9.4%	14.1%	10,546	10,680	10,407	10,546
Crist 7	19.7%	29.5%	10,196	10,307	10,165	10,178
Smith 1	8.0%	12.0%	10,054	10,038	10,042	10,023
Smith 2	8.7%	13.0%	10,050	10,076	10,081	10,010
Daniel 1	10.0%	15.0%	10,191	10,165	10,007	10,531
Daniel 2	8.1%	12.1%	9,906	10,078	9,954	10,028
Weighted GPIF System Average:			10,186	10,262	10,143	10,235

Issued by: T. J. Bowden

Filed: September 20, 2001
Suspended:
Effective: January 1, 2002
Docket No.: 010001-EI
Order No.:

Example Calculation of Prior Season

Average Net Operating Heat Rate

Adjusted to Target Basis

Crist 6 Jul '99 - Jun '00

	Jul Jan	Aug Feb	Sep Mar	Oct Apr	Nov May	Dec Jun
1. Target Heat Rate*	10552.0 10522.0	10522.0 10502.0	10541.0 -	10609.0 10245.0	10587.0 10579.0	10561.0 10681.0
2. Target Heat Rate at Actual Conditions**	10555.0 10695.0	10437.0 10658.0	10635.0 10646.0	10636.0 10207.0	10617.0 10567.0	10645.0 10772.0
3. Adjustments to Actual Heat Rate (1-2)	-3.0 -173.0	85.0 -156.0	-94.0 0.0	-27.0 38.0	-30.0 12.0	-84.0 -91.0
4. Actual Heat Rate for Prior Period	10679.0 10399.0	10286.0 10679.0	10514.0 10153.0	10636.0 10195.0	10388.0 10461.0	10127.0 10579.0
5. Adjusted actual Heat Rate (4+3)	10676.0 10226.0	10371.0 10523.0	10420.0 10153.0	10609.0 10233.0	10358.0 10473.0	10043.0 10488.0
6. Forecast Net MWH Generation*	180538.1 176153.5	188265.0 49869.1	165649.4 0.0	157021.2 124859.0	150232.8 162992.2	166843.9 174310.4

7. Adjusted Actual Heat Rate for Jul '99 - Jun '00 = (Σ ((5)*(6)))/(Σ (6)) 10,407

* For the January 2002 - December 2002 time period.

** Based on the target heat rate equation from page 2 of Schedule 1 using actual rather than forecast variable values.

Derivation of Weighting Factors

Gulf Power Company

Period of: January 2002 - December 2002

Plant & Unit	Unit Performance Indicator	Production Cost Simulation Fuel Cost ($000) At Target (1)	At Maximum Improvement (2)	Savings (3)	Weighting Factor (% of Savings)
Crist 4	EA-1	$273,592	$273,575	$17	0.3%
Crist 4	ANOHR-1	$273,592	$273,410	$182	2.9%
Crist 6	EA-1	$273,592	$273,395	$197	3.1%
Crist 6	ANOHR-1	$273,592	$272,998	$594	9.4%
Crist 7	EA-2	$273,592	$272,572	$1,020	16.2%
Crist 7	ANOHR-2	$273,592	$272,350	$1,242	19.7%
Smith 1	EA-3	$273,592	$273,525	$67	1.1%
Smith 1	ANOHR-3	$273,592	$273,087	$505	8.0%
Smith 2	EA-4	$273,592	$273,498	$94	1.5%
Smith 2	ANOHR-4	$273,592	$273,044	$548	8.7%
Daniel 1	EA-5	$273,592	$273,217	$375	6.0%
Daniel 1	ANOHR-5	$273,592	$272,959	$633	10.0%
Daniel 2	EA-6	$273,592	$273,277	$315	5.0%
Daniel 2	ANOHR-6	$273,592	$273,080	$512	8.1%

(1) Fuel Adjustment Base Case - All unit performance indicators at target.

(2) All other unit performance indicators at target.

(3) Expressed in replacement energy costs. Also includes variable operating and maintenance expense savings associated with availability improvements.

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2002 - December 2002

Crist 4

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	17	91.70	+ 10	182	10,184
+ 9	15	91.62	+ 9	164	10,208
+ 8	14	91.54	+ 8	146	10,232
+ 7	12	91.46	+ 7	127	10,256
+ 6	10	91.38	+ 6	109	10,280
+ 5	9	91.30	+ 5	91	10,304
+ 4	7	91.22	+ 4	73	10,328
+ 3	5	91.14	+ 3	55	10,352
+ 2	3	91.06	+ 2	36	10,376
+ 1	2	90.98	+ 1	18	10,400
				0	10,424
0	0	90.90	0	0	10,499
				0	10,574
- 1	(4)	90.77	- 1	(18)	10,598
- 2	(8)	90.64	- 2	(36)	10,622
- 3	(13)	90.51	- 3	(55)	10,646
- 4	(17)	90.38	- 4	(73)	10,670
- 5	(21)	90.25	- 5	(91)	10,694
- 6	(25)	90.12	- 6	(109)	10,718
- 7	(29)	89.99	- 7	(127)	10,742
- 8	(34)	89.86	- 8	(146)	10,766
- 9	(38)	89.73	- 9	(164)	10,790
- 10	(42)	89.60	- 10	(182)	10,814
Weighting Factor:		0.003	Weighting Factor:		0.029

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2002 - December 2002

Crist 6

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	197	79.40	+ 10	594	10,230
+ 9	177	79.19	+ 9	535	10,254
+ 8	158	78.98	+ 8	475	10,278
+ 7	138	78.77	+ 7	416	10,302
+ 6	118	78.56	+ 6	356	10,326
+ 5	99	78.35	+ 5	297	10,351
+ 4	79	78.14	+ 4	238	10,375
+ 3	59	77.93	+ 3	178	10,399
+ 2	39	77.72	+ 2	119	10,423
+ 1	20	77.51	+ 1	59	10,447
				0	10,471
0	0	77.30	0	0	10,546
				0	10,621
- 1	(30)	76.99	- 1	(59)	10,645
- 2	(61)	76.68	- 2	(119)	10,669
- 3	(91)	76.37	- 3	(178)	10,693
- 4	(121)	76.06	- 4	(238)	10,717
- 5	(152)	75.75	- 5	(297)	10,742
- 6	(182)	75.44	- 6	(356)	10,766
- 7	(212)	75.13	- 7	(416)	10,790
- 8	(242)	74.82	- 8	(475)	10,814
- 9	(273)	74.51	- 9	(535)	10,838
- 10	(303)	74.20	- 10	(594)	10,862
Weighting Factor:		0.031	Weighting Factor:		0.094

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Filed: September 20, 2001
Suspended:
Effective: January 1, 2002
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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2002 - December 2002

Crist 7

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	1,020	82.70	+ 10	1,242	9,890
+ 9	918	82.40	+ 9	1,118	9,913
+ 8	816	82.10	+ 8	994	9,936
+ 7	714	81.80	+ 7	869	9,959
+ 6	612	81.50	+ 6	745	9,982
+ 5	510	81.20	+ 5	621	10,006
+ 4	408	80.90	+ 4	497	10,029
+ 3	306	80.60	+ 3	373	10,052
+ 2	204	80.30	+ 2	248	10,075
+ 1	102	80.00	+ 1	124	10,098
				0	10,121
0	0	79.70	0	0	10,196
				0	10,271
- 1	(151)	79.24	- 1	(124)	10,294
- 2	(302)	78.78	- 2	(248)	10,317
- 3	(453)	78.32	- 3	(373)	10,340
- 4	(604)	77.86	- 4	(497)	10,363
- 5	(755)	77.40	- 5	(621)	10,387
- 6	(905)	76.94	- 6	(745)	10,410
- 7	(1,056)	76.48	- 7	(869)	10,433
- 8	(1,207)	76.02	- 8	(994)	10,456
- 9	(1,358)	75.56	- 9	(1,118)	10,479
- 10	(1,509)	75.10	- 10	(1,242)	10,502
Weighting Factor:		0.162	Weighting Factor:		0.197

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2002 - December 2002

Smith 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	67	91.40	+ 10	505	9,752
+ 9	60	91.33	+ 9	455	9,775
+ 8	54	91.26	+ 8	404	9,797
+ 7	47	91.19	+ 7	354	9,820
+ 6	40	91.12	+ 6	303	9,843
+ 5	34	91.05	+ 5	253	9,866
+ 4	27	90.98	+ 4	202	9,888
+ 3	20	90.91	+ 3	152	9,911
+ 2	13	90.84	+ 2	101	9,934
+ 1	7	90.77	+ 1	51	9,956
				0	9,979
0	0	90.70	0	0	10,054
				0	10,129
- 1	(12)	90.59	- 1	(51)	10,152
- 2	(23)	90.48	- 2	(101)	10,174
- 3	(35)	90.37	- 3	(152)	10,197
- 4	(46)	90.26	- 4	(202)	10,220
- 5	(58)	90.15	- 5	(253)	10,243
- 6	(70)	90.04	- 6	(303)	10,265
- 7	(81)	89.93	- 7	(354)	10,288
- 8	(93)	89.82	- 8	(404)	10,311
- 9	(104)	89.71	- 9	(455)	10,333
- 10	(116)	89.60	- 10	(505)	10,356
Weighting Factor:		0.011	Weighting Factor:		0.080

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2002 - December 2002

Smith 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	94	87.40	+ 10	548	9,749
+ 9	85	87.32	+ 9	493	9,772
+ 8	75	87.24	+ 8	438	9,794
+ 7	66	87.16	+ 7	384	9,817
+ 6	56	87.08	+ 6	329	9,839
+ 5	47	87.00	+ 5	274	9,862
+ 4	38	86.92	+ 4	219	9,885
+ 3	28	86.84	+ 3	164	9,907
+ 2	19	86.76	+ 2	110	9,930
+ 1	9	86.68	+ 1	55	9,952
				0	9,975
0	0	86.60	0	0	10,050
				0	10,125
- 1	(16)	86.47	- 1	(55)	10,148
- 2	(32)	86.34	- 2	(110)	10,170
- 3	(47)	86.21	- 3	(164)	10,193
- 4	(63)	86.08	- 4	(219)	10,216
- 5	(79)	85.95	- 5	(274)	10,239
- 6	(95)	85.82	- 6	(329)	10,261
- 7	(111)	85.69	- 7	(384)	10,284
- 8	(126)	85.56	- 8	(438)	10,307
- 9	(142)	85.43	- 9	(493)	10,329
- 10	(158)	85.30	- 10	(548)	10,352
Weighting Factor:		0.015	Weighting Factor:		0.087

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2002 - December 2002

Daniel 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	375	90.90	+ 10	633	9,885
+ 9	338	90.61	+ 9	570	9,908
+ 8	300	90.32	+ 8	506	9,931
+ 7	263	90.03	+ 7	443	9,954
+ 6	225	89.74	+ 6	380	9,977
+ 5	188	89.45	+ 5	317	10,001
+ 4	150	89.16	+ 4	253	10,024
+ 3	113	88.87	+ 3	190	10,047
+ 2	75	88.58	+ 2	127	10,070
+ 1	38	88.29	+ 1	63	10,093
				0	10,116
0	0	88.00	0	0	10,191
				0	10,266
- 1	(64)	87.57	- 1	(63)	10,289
- 2	(127)	87.14	- 2	(127)	10,312
- 3	(191)	86.71	- 3	(190)	10,335
- 4	(254)	86.28	- 4	(253)	10,358
- 5	(318)	85.85	- 5	(317)	10,382
- 6	(381)	85.42	- 6	(380)	10,405
- 7	(445)	84.99	- 7	(443)	10,428
- 8	(508)	84.56	- 8	(506)	10,451
- 9	(572)	84.13	- 9	(570)	10,474
- 10	(635)	83.70	- 10	(633)	10,497
Weighting Factor:		0.060	Weighting Factor:		0.100

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Suspended:
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Generating Performance Incentive Points Table

Gulf Power Company

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Daniel 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	315	73.00	+ 10	512	9,609
+ 9	284	72.77	+ 9	461	9,631
+ 8	252	72.54	+ 8	410	9,653
+ 7	221	72.31	+ 7	358	9,676
+ 6	189	72.08	+ 6	307	9,698
+ 5	158	71.85	+ 5	256	9,720
+ 4	126	71.62	+ 4	205	9,742
+ 3	95	71.39	+ 3	154	9,764
+ 2	63	71.16	+ 2	102	9,787
+ 1	32	70.93	+ 1	51	9,809
				0	9,831
0	0	70.70	0	0	9,906
				0	9,981
- 1	(51)	70.36	- 1	(51)	10,003
- 2	(102)	70.02	- 2	(102)	10,025
- 3	(154)	69.68	- 3	(154)	10,048
- 4	(205)	69.34	- 4	(205)	10,070
- 5	(256)	69.00	- 5	(256)	10,092
- 6	(307)	68.66	- 6	(307)	10,114
- 7	(358)	68.32	- 7	(358)	10,136
- 8	(410)	67.98	- 8	(410)	10,159
- 9	(461)	67.64	- 9	(461)	10,181
- 10	(512)	67.30	- 10	(512)	10,203
Weighting Factor:		0.050	Weighting Factor:		0.081

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ESTIMATED UNIT PERFORMANCE DATA

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	CRIST 4	Jan '02	Feb '02	Mar '02	Apr '02	May '02	Jun '02	
1.	EAF (%)	92.2	87.5	98.1	98.6	98.5	98.6	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	7.8	12.5	1.9	1.4	1.5	1.4	
4.	EUOR (%)	9.7	14.6	2.0	1.8	1.5	1.6	
5.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
6.	SH	542.0	495.0	699.0	560.0	731.0	603.0	
7.	RSH	144.0	96.0	34.0	149.0	2.0	107.0	
8.	UH	58.0	81.0	11.0	10.0	11.0	10.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	10.0	12.0	14.0	10.0	11.0	10.0	
11.	MOH & EMOH	48.0	72.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	384119.0	361982.0	504390.0	374732.0	489076.0	424942.0	
13.	Net Gen (MWH)	37680.9	34926.9	48611.2	35821.8	46752.3	39781.1	
14.	ANOHR (Btu/KWH)	10194.0	10364.0	10376.0	10461.0	10461.0	10682.0	
15.	NOF %	89.1	90.5	89.2	82.0	82.0	84.6	
16.	NPC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	

19.	ANOHR Equation	10^6 / AKW * [449.21 - 12.61 * JAN + 16.96 * JUN + 24.56 * JUL + 27.59 * AUG] - 3640 + 0.10501 * LSRF / AKW

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PERIOD OF: January 2002 - December 2002

	CRIST 4	Jul '02	Aug '02	Sep '02	Oct '02	Nov '02	Dec '02	Total
1.	EAF (%)	98.5	98.5	98.6	25.4	98.3	98.5	90.9
2.	POF (%)	0.0	0.0	0.0	74.2	0.0	0.0	6.3
3.	EUOF (%)	1.5	1.5	1.4	0.4	1.7	1.5	2.8
4.	EUOR (%)	1.5	1.7	1.4	3.2	1.7	3.4	3.5
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
6.	SH	717.0	653.0	691.0	91.0	676.0	311.0	6769.0
7.	RSH	16.0	80.0	19.0	98.0	34.0	422.0	1201.0
8.	UH	11.0	11.0	10.0	556.0	10.0	11.0	790.0
9.	POH	0.0	0.0	0.0	553.0	0.0	0.0	553.0
10.	FOH & EFOH	11.0	11.0	10.0	3.0	12.0	11.0	125.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	120.0
12.	Oper MBtu	514590.0	485234.0	486150.0	59309.0	452838.0	221908.0	4759270.0
13.	Net Gen (MWH)	47704.6	44995.7	46745.2	5648.5	43288.2	21366.1	453322.5
14.	ANOHR (Btu/KWH)	10787.0	10784.0	10400.0	10500.0	10461.0	10386.0	10499.0
15.	NOF %	85.3	88.3	86.7	79.6	82.1	88.1	85.9
16.	NPC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	78.0

19.	ANOHR Equation	10^6 / AKW * [449.21 - 12.61 * JAN + 16.96 * JUN + 24.56 * JUL + 27.59 * AUG] - 3640 + 0.10501 * LSRF / AKW

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PERIOD OF: January 2002 - December 2002

	CRIST 6	Jan '02	Feb '02	Mar '02	Apr '02	May '02	Jun '02	
1.	EAF (%)	89.8	27.2	0.0	73.7	89.8	96.0	
2.	POF (%)	0.0	71.4	100.0	23.2	0.0	0.0	
3.	EUOF (%)	10.2	1.4	0.0	3.1	10.2	4.0	
4.	EUOR (%)	10.2	4.7	0.0	4.0	10.2	4.0	
5.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
6.	SH	668.0	184.0	0.0	530.0	668.0	691.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	76.0	488.0	744.0	189.0	76.0	29.0	
9.	POH	0.0	480.0	744.0	167.0	0.0	0.0	
10.	FOH & EFOH	28.0	9.0	0.0	22.0	28.0	29.0	
11.	MOH & EMOH	48.0	0.0	0.0	0.0	48.0	0.0	
12.	Oper MBtu	1853487.0	523725.0	0.0	1279180.0	1724294.0	1861809.0	
13.	Net Gen (MWH)	176153.5	49869.1	0.0	124859.0	162992.2	174310.4	
14.	ANOHR (Btu/KWH)	10522.0	10502.0	-	10245.0	10579.0	10681.0	
15.	NOF %	87.3	89.7	0.0	78.0	80.8	83.5	
16.	NPC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	

19.	ANOHR Equation	10^6 / AKW * [187.63 - 85.12 * APR + 32.17 * JUN] + 9,810

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PERIOD OF: January 2002 - December 2002

	CRIST 6	Jul '02	Aug '02	Sep '02	Oct '02	Nov '02	Dec '02	Total
1.	EAF (%)	96.0	96.0	89.6	89.8	86.4	89.8	77.3
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	15.9
3.	EUOF (%)	4.0	4.0	10.4	10.2	13.6	10.2	6.8
4.	EUOR (%)	4.0	4.0	10.4	10.2	13.6	10.2	8.1
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
6.	SH	714.0	714.0	645.0	669.0	622.0	668.0	6773.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	30.0	30.0	75.0	76.0	98.0	76.0	1987.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1391.0
10.	FOH & EFOH	30.0	30.0	27.0	28.0	26.0	28.0	285.0
11.	MOH & EMOH	0.0	0.0	48.0	48.0	72.0	48.0	312.0
12.	Oper MBtu	1905038.0	1980924.0	1746110.0	1665838.0	1590515.0	1762038.0	17892958.0
13.	Net Gen (MWH)	180538.1	188265.0	165649.4	157021.2	150232.8	166843.9	1696734.6
14.	ANOHR (Btu/KWH)	10552.0	10522.0	10541.0	10609.0	10587.0	10561.0	10546.0
15.	NOF %	83.7	87.3	85.0	77.7	80.0	82.7	83.0
16.	NPC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	302.0

19.	ANOHR Equation	10^6 / AKW * [187.63 - 85.12 * APR + 32.17 * JUN] + 9,810

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PERIOD OF: January 2002 - December 2002

	CRIST 7	Jan '02	Feb '02	Mar '02	Apr '02	May '02	Jun '02	
1.	EAF (%)	85.6	91.5	85.2	0.0	67.3	91.5	
2.	POF (%)	0.0	0.0	6.5	100.0	16.1	0.0	
3.	EUOF (%)	14.4	8.5	8.3	0.0	16.6	8.5	
4.	EUOR (%)	14.4	8.5	8.9	0.0	19.7	8.5	
5.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
6.	SH	637.0	615.0	637.0	0.0	505.0	659.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	107.0	57.0	107.0	719.0	239.0	61.0	
9.	POH	0.0	0.0	48.0	719.0	120.0	0.0	
10.	FOH & EFOH	59.0	57.0	62.0	0.0	51.0	61.0	
11.	MOH & EMOH	48.0	0.0	0.0	0.0	72.0	0.0	
12.	Oper MBtu	3041784.0	2958319.0	3066225.0	0.0	2346629.0	3123813.0	
13.	Net Gen (MWH)	300037.9	291891.4	302538.2	0.0	233472.2	308038.0	
14.	ANOHR (Btu/KWH)	10138.0	10135.0	10135.0	-	10051.0	10141.0	
15.	NOF %	98.7	99.5	99.6	0.0	96.9	98.0	
16.	NPC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	

19.	ANOHR Equation	10^6 / AKW * [204.45 - 44.16 * MAY + 83.05 * JUL + 67.20 * AUG + 91.16 * SEP + 58.82 * OCT] + 9,704

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Effective: January 1, 2002
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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	CRIST 7	Jul '02	Aug '02	Sep '02	Oct '02	Nov '02	Dec '02	Total
1.	EAF (%)	91.5	91.5	82.4	91.5	85.4	91.5	79.7
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	10.1
3.	EUOF (%)	8.5	8.5	17.6	8.5	14.6	8.5	10.2
4.	EUOR (%)	8.5	8.5	17.6	8.5	14.6	8.5	11.4
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
6.	SH	681.0	681.0	593.0	682.0	615.0	681.0	6986.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	63.0	63.0	127.0	63.0	105.0	63.0	1774.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	887.0
10.	FOH & EFOH	63.0	63.0	55.0	63.0	57.0	63.0	654.0
11.	MOH & EMOH	0.0	0.0	72.0	0.0	48.0	0.0	240.0
12.	Oper MBtu	3229742.0	3275841.0	2857028.0	3193853.0	2882645.0	3266435.0	33242314.0
13.	Net Gen (MWH)	312656.5	318506.7	276361.8	310625.7	284088.4	322260.8	3260477.6
14.	ANOHR (Btu/KWH)	10330.0	10285.0	10338.0	10282.0	10147.0	10136.0	10196.0
15.	NOF %	96.3	98.1	97.7	95.5	96.8	99.2	97.8
16.	NPC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	477.0

19.	ANOHR Equation	10^6 / AKW * [204.45 - 44.16 * MAY + 83.05 * JUL + 67.20 * AUG + 91.16 * SEP + 58.82 * OCT] + 9,704

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GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	SMITH 1	Jan '02	Feb '02	Mar '02	Apr '02	May '02	Jun '02	
1.	EAF (%)	92.2	98.2	98.3	85.4	60.5	98.6	
2.	POF (%)	0.0	0.0	0.0	13.4	38.7	0.0	
3.	EUOF (%)	7.8	1.8	1.7	1.2	0.8	1.4	
4.	EUOR (%)	7.8	1.8	1.7	1.4	1.3	1.4	
5.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
6.	SH	686.0	663.0	734.0	614.0	450.0	710.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	58.0	9.0	10.0	105.0	294.0	10.0	
9.	POH	0.0	0.0	0.0	96.0	288.0	0.0	
10.	FOH & EFOH	10.0	12.0	13.0	9.0	6.0	10.0	
11.	MOH & EMOH	48.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	1088493.0	1052683.0	1181273.0	941884.0	683532.0	1100975.0	
13.	Net Gen (MWH)	108071.2	105722.9	117329.5	93422.3	68366.9	109234.5	
14.	ANOHR (Btu/KWH)	10072.0	9957.0	10068.0	10082.0	9998.0	10079.0	
15.	NOF %	97.2	98.4	98.7	93.9	93.8	95.0	
16.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	

19.	ANOHR Equation	10^6 / AKW * [43.96 - 17.87 * FEB - 12.85 * MAY - 18.43 * NOV] + 9,793

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Effective: January 1, 2002
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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	SMITH 1	Jul '02	Aug '02	Sep '02	Oct '02	Nov '02	Dec '02	Total
1.	EAF (%)	98.7	98.7	98.2	79.6	82.2	98.7	90.7
2.	POF (%)	0.0	0.0	0.0	19.3	10.0	0.0	6.8
3.	EUOF (%)	1.3	1.3	1.8	1.1	7.8	1.3	2.5
4.	EUOR (%)	1.3	1.3	1.8	1.3	8.6	1.3	2.6
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
6.	SH	734.0	734.0	710.0	593.0	592.0	734.0	7954.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	10.0	10.0	10.0	152.0	128.0	10.0	806.0
9.	POH	0.0	0.0	0.0	144.0	72.0	0.0	600.0
10.	FOH & EFOH	10.0	10.0	13.0	8.0	8.0	10.0	119.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	48.0	0.0	96.0
12.	Oper MBtu	1122024.0	1149803.0	1106378.0	894358.0	897190.0	1170618.0	12389211.0
13.	Net Gen (MWH)	111278.8	114113.0	109792.4	88664.4	90070.3	116236.5	1232302.7
14.	ANOHR (Btu/KWH)	10083.0	10076.0	10077.0	10087.0	9961.0	10071.0	10054.0
15.	NOF %	93.6	96.0	95.5	92.3	93.9	97.8	95.6
16.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	162.0
19.	ANOHR Equation	10^6 / AKW * [43.96 - 17.87 * FEB - 12.85 * MAY - 18.43 * NOV] + 9,793						

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	SMITH 2	Jan '02	Feb '02	Mar '02	Apr '02	May '02	Jun '02	
1.	EAF (%)	97.8	90.5	3.2	97.9	97.8	97.9	
2.	POF (%)	0.0	0.0	96.8	0.0	0.0	0.0	
3.	EUOF (%)	2.2	9.5	0.0	2.1	2.2	2.1	
4.	EUOR (%)	2.2	9.5	0.0	2.1	2.2	2.1	
5.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
6.	SH	728.0	611.0	24.0	704.0	728.0	705.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	16.0	61.0	720.0	15.0	16.0	15.0	
9.	POH	0.0	0.0	720.0	0.0	0.0	0.0	
10.	FOH & EFOH	16.0	16.0	0.0	15.0	16.0	15.0	
11.	MOH & EMOH	0.0	48.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	1322761.0	1117517.0	43139.0	1239351.0	1312669.0	1272012.0	
13.	Net Gen (MWH)	133450.5	113281.0	4368.5	123897.9	129993.0	125966.7	
14.	ANOHR (Btu/KWH)	9912.0	9865.0	9875.0	10003.0	10098.0	10098.0	
15.	NOF %	97.0	98.1	96.3	93.1	94.5	94.5	
16.	NPC (MW)	189.0	189.0	189.0	189.0	189.0	189.0	

19.	ANOHR Equation	10^6 / AKW * [410.85 - 30.87 * JAN - 38.46 * FEB - 38.20 * MAR - 18.64 * APR] + 4,743 + 0.01678 * LSRF / AKW

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	SMITH 2	Jul '02	Aug '02	Sep '02	Oct '02	Nov '02	Dec '02	Total
1.	EAF (%)	97.8	97.8	97.9	97.9	65.0	97.8	86.6
2.	POF (%)	0.0	0.0	0.0	0.0	30.0	0.0	10.7
3.	EUOF (%)	2.2	2.2	2.1	2.1	5.0	2.2	2.7
4.	EUOR (%)	2.2	2.2	2.1	2.1	7.1	2.2	3.1
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
6.	SH	728.0	728.0	705.0	729.0	470.0	728.0	7588.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	16.0	16.0	15.0	16.0	250.0	16.0	1172.0
9.	POH	0.0	0.0	0.0	0.0	216.0	0.0	936.0
10.	FOH & EFOH	16.0	16.0	15.0	16.0	12.0	16.0	169.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	24.0	0.0	72.0
12.	Oper MBtu	1302963.0	1326344.0	1278867.0	1282724.0	847950.0	1349001.0	13695298.0
13.	Net Gen (MWH)	128955.2	131438.3	126695.8	126789.0	83972.1	133856.0	1362664.0
14.	ANOHR (Btu/KWH)	10104.0	10091.0	10094.0	10117.0	10098.0	10078.0	10050.0
15.	NOF %	93.7	95.5	95.1	92.0	94.5	97.3	95.0
16.	NPC (MW)	189.0	189.0	189.0	189.0	189.0	189.0	189.0

19.	ANOHR Equation	10^6 / AKW * [410.85 - 30.87 * JAN - 38.46 * FEB - 38.20 * MAR - 18.64 * APR] + 4,743 + 0.01678 * LSRF / AKW

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	DANIEL 1	Jan '02	Feb '02	Mar '02	Apr '02	May '02	Jun '02	
1.	EAF (%)	74.7	72.8	92.2	80.3	92.2	92.6	
2.	POF (%)	19.4	10.7	0.0	0.0	0.0	0.0	
3.	EUOF (%)	5.9	16.5	7.8	19.7	7.8	7.4	
4.	EUOR (%)	7.3	18.5	7.8	19.7	7.8	7.4	
5.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
6.	SH	556.0	489.0	689.0	577.0	689.0	667.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	188.0	183.0	55.0	142.0	55.0	53.0	
9.	POH	144.0	72.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	44.0	39.0	58.0	46.0	58.0	53.0	
11.	MOH & EMOH	0.0	72.0	0.0	96.0	0.0	0.0	
12.	Oper MBtu	2627592.0	2316466.0	3339996.0	2568009.0	3128971.0	2982018.0	
13.	Net Gen (MWH)	258417.8	233279.6	330300.2	249709.2	305354.8	300697.6	
14.	ANOHR (Btu/KWH)	10168.0	9930.0	10112.0	10284.0	10247.0	9917.0	
15.	NOF %	91.7	94.1	94.6	85.4	87.4	88.9	
16.	NPC (MW)	507.0	507.0	507.0	507.0	507.0	507.0	

19.	ANOHR Equation	10^6 / AKW * [-429.41 - 91.37 * FEB - 136.56 * JUN + 105.89 * JUL] + 14,936 - 0.00805 * LSRF / AKW

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	DANIEL 1	Jul '02	Aug '02	Sep '02	Oct '02	Nov '02	Dec '02	Total
1.	EAF (%)	92.6	92.6	92.6	92.6	92.6	86.6	88.0
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	2.5
3.	EUOF (%)	7.4	7.4	7.4	7.4	7.4	13.4	9.5
4.	EUOR (%)	7.4	7.4	7.4	7.4	7.4	13.4	9.8
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
6.	SH	689.0	689.0	667.0	690.0	667.0	644.0	7713.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	55.0	55.0	53.0	55.0	53.0	100.0	1047.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	216.0
10.	FOH & EFOH	55.0	55.0	53.0	55.0	53.0	52.0	621.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	48.0	216.0
12.	Oper MBtu	3192747.0	3239658.0	3096936.0	3051759.0	3012110.0	3041664.0	35597926.0
13.	Net Gen (MWH)	304274.0	318268.8	303502.2	296431.2	293635.2	299111.4	3492982.0
14.	ANOHR (Btu/KWH)	10493.0	10179.0	10204.0	10295.0	10258.0	10169.0	10191.0
15.	NOF %	87.1	91.1	89.7	84.7	86.8	91.6	89.3
16.	NPC (MW)	507.0	507.0	507.0	507.0	507.0	507.0	507.0

19.	ANOHR Equation	10^6 / AKW * [-429.41 - 91.37 * FEB - 136.56 * JUN + 105.89 * JUL] + 14,936 - 0.00805 * LSRF / AKW

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GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	DANIEL 2	Jan '02	Feb '02	Mar '02	Apr '02	May '02	Jun '02	
1.	EAF (%)	53.8	0.0	0.0	59.1	93.0	93.2	
2.	POF (%)	41.9	100.0	100.0	23.2	0.0	0.0	
3.	EUOF (%)	4.3	0.0	0.0	17.7	7.0	6.8	
4.	EUOR (%)	7.4	0.0	0.0	23.0	7.0	6.8	
5.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
6.	SH	403.0	0.0	0.0	425.0	694.0	671.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	341.0	672.0	744.0	294.0	50.0	49.0	
9.	POH	312.0	672.0	744.0	167.0	0.0	0.0	
10.	FOH & EFOH	32.0	0.0	0.0	31.0	52.0	49.0	
11.	MOH & EMOH	0.0	0.0	0.0	96.0	0.0	0.0	
12.	Oper MBtu	1924762.0	0.0	0.0	1876107.0	3198270.0	3077678.0	
13.	Net Gen (MWH)	197189.0	0.0	0.0	188705.2	318235.8	312327.8	
14.	ANOHR (Btu/KWH)	9761.0	-	-	9942.0	10050.0	9854.0	
15.	NOF %	95.9	0.0	0.0	87.1	89.9	91.3	
16.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	

19.	ANOHR Equation	10^6 / AKW * [-42.23 + 77.21 * MAY + 79.18 * JUL + 123.19 * AUG - 68.28 * NOV] + 13,010 - 0.00640 * LSRF / AKW

Issued by: T. J. Bowden

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	DANIEL 2	Jul '02	Aug '02	Sep '02	Oct '02	Nov '02	Dec '02	Total
1.	EAF (%)	93.3	93.3	83.9	93.3	93.2	87.2	70.7
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	21.6
3.	EUOF (%)	6.7	6.7	16.1	6.7	6.8	12.8	7.7
4.	EUOR (%)	6.7	6.7	16.1	6.7	6.8	12.8	9.8
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
6.	SH	694.0	694.0	604.0	695.0	671.0	649.0	6200.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	50.0	50.0	116.0	50.0	49.0	95.0	2560.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1895.0
10.	FOH & EFOH	50.0	50.0	44.0	50.0	49.0	47.0	454.0
11.	MOH & EMOH	0.0	0.0	72.0	0.0	0.0	48.0	216.0
12.	Oper MBtu	3202431.0	3305078.0	2799936.0	3084842.0	3021600.0	3081429.0	28572133.0
13.	Net Gen (MWH)	318554.8	327592.2	284835.8	310658.8	311024.2	315268.0	2884391.6
14.	ANOHR (Btu/KWH)	10053.0	10089.0	9830.0	9930.0	9715.0	9774.0	9906.0
15.	NOF %	90.0	92.6	92.5	87.6	90.9	95.3	91.2
16.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0

19.	ANOHR Equation	10^6 / AKW * [-42.23 + 77.21 * MAY + 79.18 * JUL + 123.19 * AUG - 68.28 * NOV] + 13,010 - 0.00640 * LSRF / AKW

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Planned Outage Schedules (Estimated)

Gulf Power Company

Period of: January 2002 - December 2002

Plant & Unit	Planned Outage Dates			Reason for Outage
Crist 4	10/05/02	-	10/27/02	Annual general boiler maintenance and inspection.
Crist 6	02/09/02	-	04/07/02	Turbine & generator overhaul and boiler inspection.
Crist 7	03/30/02	-	05/05/02	Annual general boiler maintenance and inspection.
Smith 1	04/27/02	-	05/12/02	Semi-annual general boiler maintenance and inspection.
Smith 1	10/26/02	-	11/03/02	Semi-annual general boiler maintenance and inspection.
Smith 2	03/02/02	-	03/31/02	Semi-annual general boiler maintenance and inspection.
Smith 2	11/09/02	-	11/17/02	Semi-annual general boiler maintenance and inspection.
Daniel 1	01/26/02	-	02/03/02	Annual general boiler maintenance and inspection.
Daniel 2	01/19/02	-	04/07/02	Turbine & generator overhaul and boiler inspection.

Notes Regarding Estimated Planned Outage Schedules

Gulf Power Company

Period of: January 2002 - December 2002

It is important to understand that estimated dates for planned outages and their bar chart schedules are frequently changed in timing and work scope due to system conditions, findings of inspections, subcontractor requirements, material availability and so on.

Please note that in addition to the outages scheduled for the target period of January 2002 - December 2002, the outages shown below are currently planned and could be rescheduled for the target period.

Plant & Unit	Planned Outage Dates	Reason for Outage

None

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AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 010001-EI

Before me the undersigned authority, personally appeared James R. Douglass, who being first duly sworn, deposes, and says that he is the Performance Test Specialist for Gulf Power Company, a Maine corporation, and that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

James R. Douglass
Performance Test Specialist

Sworn to and subscribed before me this 18th day of September, 2001.

Notary Public, State of Florida at Large

Commission Number:

Commission Expires:

ROLLANDA R. COTHRAN
MY COMMISSION # CC 697388
EXPIRES: February 26, 2002
Bonded Thru Notary Public Underwriters

GULF POWER COMPANY
PROJECTED PURCHASED POWER CONTRACT TRANSACTIONS
JANUARY 2002 - DECEMBER 2002

Contract		MW Purchase/(Sale)	Capacity ($) Costs/(Receipts)
Southern Company Intercompany Interchange (IIC)			
	January 2002	587.8	1,588,272
	February	355.1	383,784
	March	390.7	422,350
	April	126.0	68,070
	May	214.9	232,317
	June	(64.0)	(422,598)
	July	(21.8)	(393,120)
	August	9.8	151,478
	September	(13.8)	(116,004)
	October	41.5	22,412
	November	(165.8)	(99,498)
	December	24.4	13,214
	SUBTOTAL		1,850,677
Solutia			
	January 2002	19.0	62,202
	February	19.0	62,202
	March	19.0	62,202
	April	19.0	62,202
	May	19.0	62,202
	June	19.0	62,202
	July	19.0	62,202
	August	19.0	62,202
	September	19.0	62,202
	October	19.0	62,202
	November	19.0	62,202
	December	19.0	62,202
	SUBTOTAL		746,424

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010001-EI EXHIBIT NO. 16
COMPANY/
WITNESS: Howell
DATE: 11-20 & 21-01

GULF POWER COMPANY
PROJECTED PURCHASED POWER CONTRACT TRANSACTIONS
JANUARY 2002 - DECEMBER 2002

Contract	Capacity ($) Costs/(Receipts)
Market Capacity Purchases	
January 2002	361,168
February	266,668
March	172,168
April	85,500
May	180,000
June	0
July	0
August	0
September	0
October	0
November	0
December	0
SUBTOTAL	1,065,504
TOTAL	**3,662,605**

EXHIBIT NO. _____

DOCKET NO: 010001-EI

WITNESS: VARIOUS

DESCRIPTION: COMPOSITE EXHIBIT:

1) Transcript of Gerard Yupp's deposition taken on October 22-23, 2001;
2) Transcript of Javier Portuondo's deposition taken on November 1, 2001;
3) Late-filed exhibits 1-3 of Javier Portuondo's deposition taken on November 1, 2001;
4) Late-filed exhibit 1 of Richard McMillan's deposition taken on October 29, 2001; and
5) FPUC's responses to staff's first set of interrogatories in Docket No. 010001, numbers 1-6

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010001-EI EXHIBIT NO. 17
COMPANY/
WITNESS: FPSC Staff
DATE: 11-20-01

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 010001-EI

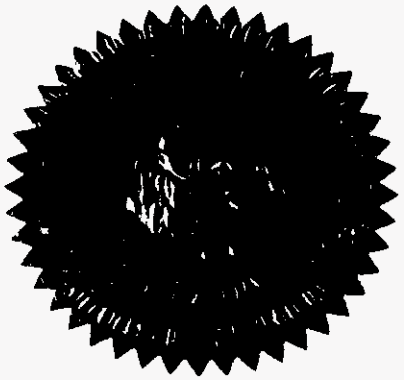
In the Matter of

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE AND
GENERATING PERFORMANCE
INCENTIVE FACTOR.
_____/

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VOLUME 1

Pages 1 through 50



DEPOSITION OF:	GERARD YUPP
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
PLACE:	Gerald L. Gunter Building Room 309 2540 Shumard Oak Boulevard Tallahassee, Florida
TIME:	Commenced at 2:45 p.m. Adjourned at 4:45 p.m.
DATE:	Monday, October 22, 2001
REPORTED BY:	TRICIA DeMARTE Official FPSC Reporter (850) 413-6736

APPEARANCES:

JONATHAN E. SJOSTROM, Steel, Hector & Davis, LLP, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301, appearing on behalf of Florida Power & Light Company.

ROBERT VANDIVER, Deputy Public Counsel, Office of Public Counsel, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

WM. COCHRAN KEATING, IV, Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0870, appearing on behalf of the Commission Staff.

TIM PERRY, McWhirter, Reeves Law Firm, 117 South Gadsden Street, Tallahassee, Florida 32301, on behalf of Florida Industrial Power Users Group, appearing telephonically.

MISCELLANEOUS

	PAGE NO.
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WITNESS

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S T I P U L A T I O N

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure; that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

GERARD YUPP

appeared as a witness and, after being duly sworn by the court reporter, testified as follows:

DIRECT EXAMINATION

BY MR. KEATING:

Q Good afternoon, Mr. Yupp.

A Good afternoon.

Q For the record, could you state your name and your business address?

A My name is Gerard Yupp. My business address is 11770 U.S. Highway One, North Palm Beach, Florida 33408.

Q And what's your position with Florida Power & Light?

A Currently, I am the manager of regulated wholesale power trading for Florida Power & Light Company.

Q How long have you been in that position?

A Roughly two years.

Q Were you employed in the energy marketing and trading division before you --

A Yes, I was.

Q -- became in your current position?

A Yes, I was. I've been employed in the energy marketing and trading division since the fall of 1996.

Q If I were to ask a question about a decision made by the energy marketing and trading division after you started there in 1996, would you be able to respond to it based on your

firsthand knowledge?

A Depending on what the question was, yes.

Q Okay. And of the witnesses that FPL has put forward in this docket, would you be the appropriate witness to ask questions about policy, procedure, or actions taken by FPL's energy marketing and trading division?

A Yes, I would say that's true. I'm not 100 percent sure on policy or procedure, but overall on fuel costs, yes.

Q Okay. What commodities do you or individuals under your supervision buy or sell on behalf of Florida Power & Light?

A Myself and the individuals under -- that currently work for me right now are -- the commodity is power, wholesale energy, both buying and selling. As far as the entire group, including individuals that do not report to me, natural gas, fuel oil are also commodities that are traded at EMT.

Q Are there any particular sources of information about domestic natural gas demand and production which you consider to be credible sources?

A Let's see, gas -- as far as sources we use, gas daily would be a credible source. Of course, the AGA storage numbers are also something we have used. WEFA, and I'm not exactly sure of some of the acronyms, WEFA, PIRA, that pretty much would cover it as far as publications or sources that we look at.

Q What was the last one?
A PIRA.
Q PIRA. Do you know what that stands for?
A Petroleum Intelligence -- or what?
MR. UNGAR: Petroleum Industry Research Associates.
A Petroleum Industry Research Associates.
Q Other than -- those are sources that you use or that your division uses?
A Yes.
Q Are there any particular sources of information about natural gas imports that you consider to be credible sources?
A To the best of my knowledge, I would assume that those publications also include information on imports.
Q In your testimony, you refer to five factors that affect natural gas prices. If you want to look on that, I think it's Page 7 of your August 31st testimony, Lines 10 through 15.
A Yes.
Q And you do not mention weather as one of those factors; correct?
A Uh-huh.
Q Why is weather not a factor, in your opinion?
A Weather would really be covered -- well, I guess to a certain extent, weather is covered under factor number one as far as natural gas demand goes. I think weather is directly

related to demand in some shape or form, so that's why it's not specifically broken out.

Q I think further down on Page 7 in the second paragraph under that Q&A that starts on Line 10, you state that domestic natural gas production -- I'm sorry, domestic natural gas demand is projected to increase because of increases in natural gas-fired generation; is that correct?

A Yes.

Q Okay. Is that a new trend?

A I think you could say it is a fairly new trend given the recent development of new generation throughout the country. I think most of what you see is in the gas-fired generation sector.

Q When do you -- I guess, approximately when would you say that that trend began?

A Probably within the last two years, I would think. Yeah, within the last two years I think is a good rough estimate.

Q Staff has compared some of FPL's projected fuel prices as reflected in the E Schedules for 2001 and 2001.

A Okay.

Q So I'm going to ask, I guess, subject to check, for a few of these questions for you to assume that the comparison is an accurate one.

A Okay.

Q I believe Staff has handed you the 2001 E Schedules to refer to. First, in comparing the two, Staff determined that the projected price of distillate oil increased by 11 percent from 2001 to 2002. Would you agree with that figure, subject to check?

A Subject to check -- you said on distillate; right?

Q Yes.

A Well, it looks to be the case. I mean, roughly I would say yes.

Q Okay. Do you know why -- do you know the reason for that increase?

A In distillate fuel, lower supply stocks increase demand. That's about, I guess, what I would tell you.

Q Do you know what the cause of the increased demand is?

A Well, for one, obviously last year, from our point of view, I know just in the utility sector there was a higher demand in the beginning of the year -- or this year, I should say, for distillate oil just to replace gas generation that had become uneconomical and was more economical on distillate. Other than that, no, I'm not quite sure.

Q Would the natural gas prices settling back down, would the utility rely less on distillate oil or projected to rely less on it?

A Yes, currently we would.

Q Would you expect that other utilities would do likewise?

A It's hard to speak for utilities, but if the choice is between natural gas or distillate and you can run either fuel, yes.

Q Can you, I guess, reconcile that with your understanding that part of the increase that we see in 2002 from 2001 is due to increased demand?

A Yeah, you know, that's obviously part of it. I would think that obviously with increased demand and lower inventory levels, that's all part of it also.

Q Staff also calculated that for coal that the projected price increased by 12 percent from 2001 to 2002 based on review of the E Schedules. Would you agree with that approximate number, subject to check?

A Subject to check, yes, it looks -- yes, I would agree with that.

Q Can you explain why the projections for coal increased between last year and this year -- or this year and next year, I should say?

A Right now, no, I honestly could not give you a good answer on that.

Q Would you agree, subject to check, that the projected price of natural gas for FPL increased by 2.6 percent from 2001 to 2002 -- I'm sorry, decreased?

A Decreased, yes.

Q And would you agree that at the same time natural gas-fired generation has increased by approximately 40 percent?

A Natural gas-fired generation?

Q Yes.

A Oh, as far as the mix of what fuel we're making megawatts with, yes.

Q Okay. Would you agree, subject to check, that the projected price of residual oil decreased by 3.6 percent from the 2001 to 2002 projections?

A Yes.

Q Okay. Is it correct that residual oil-fired generation as it's used to produce the megawatts that FPL produces has -- or its projected use of residual oil-fired generation is decreased by 17.4 percent, or approximately 17 percent?

A I would agree with that, subject to check. Yes.

Q Can you explain why the projected price -- while the projected price of residual oil had decreased, that FPL's projected use of residual oil-fired generation has decreased?

A Relative to the natural gas price decrease, you will still see a decrease in the residual. Even though prices have come down, we are replacing residual oil with natural gas now that natural gas has fallen to less expensive than residual oil.

Q How has the price of petroleum coke changed since FPL prepared its E Schedules for 2001?

A Boy, I could not answer that either. I think it's remained relatively stable.

Q Do you know who would be familiar with that?

A Really, Gene Ungar would be, who is sitting here.

MR. KEATING: Do you want to go off the record briefly?

MR. SJOSTROM: Sure, let's go off the record.

(Discussion off the record.)

BY MR. KEATING:

Q So it's your understanding that the price of petroleum coke has remained fairly stable since 2001 when these schedules were prepared?

A Yes.

Q I think we went through the coal -- the projected coal price increases from 2001 to 2002 already, and you had agreed, subject to check, that that was approximately 12 percent?

A Yes.

Q Is it correct that the -- would you agree, subject to check, that the projected price of energy payments for wholesale energy purchases from SJRPP increased 18 percent during the same period?

A Subject to check, that would make logical sense.

Q Could you explain why -- I'm sorry, strike that.

Would you agree, subject to check, that the projected price of economy energy purchases within Florida decreased approximately 9 percent from 2001 to 2002?

A Yes, subject to check.

Q Would you also agree, subject to check, that the projected price of economy energy purchases from outside Florida increased by approximately 12 percent during the same period?

A Subject to check -- well, I really would have to check that, but yes. I'll say yes.

Q If as you've agreed, subject to check, that the projected price of coal increased by 12 percent from the 2001 to 2002 projections and pet coke has remained relatively stable, why the projected price of energy payments for purchases from SJRPP has increased 18 percent during the same period?

A I believe that pet coke is not a large part of what St. Johns burns coal-wise, but that's basically what I can tell you on that.

Q Would the increase in coal of about 12 percent and the payments to SJRPP for purchases at about 18 percent, how do you reconcile the higher increase for payments for wholesale purchases from SJRPP as compared to the lower increase in coal prices?

A Can you repeat that again?

Q Yeah, I know, that didn't sound right coming out either.

MR. SJOSTROM: I don't think you can repeat that again.

MR. KEATING: Yeah. I'm going to say something completely different.

BY MR. KEATING:

Q If the projected price of coal is increased by 12 percent from 2001 to 2002 but the projected price of energy payments for wholesale purchases from SJRPP has increased 18 percent and pet coke remains relatively stable and isn't a large part of what's burned at SJRPP, why is there a greater increase in the projected energy payments than there is an increase in the coal price?

A I don't know if possibly that could be contractually related. I really don't know that. My guess would be that it may be something contractually, but I'm not sure as far as the purchase goes from SJRPP.

Q You can't think of any other reason why that would have gone -- why the payments to SJRPP would have increased it to a greater extent than coal prices?

A No.

Q And to follow up on the numbers with respect to projected price of economy energy purchases within Florida

versus from outside Florida. You would agree, subject to check, that for economy purchases within Florida, the projected price has decreased by about 9 percent from 2001 to 2002?

A Uh-huh.

Q But for those purchases from outside Florida, the projected prices has increased by approximately 12 percent for that same period?

A Uh-huh.

Q Can you provide any explanation or insight into why the prices within Florida would decrease at approximately 9 percent while from outside Florida it would increase almost to 12 percent?

A I would explain it fairly easily in this manner. I think within Florida we have now seen more generation coming on-line. I know ourselves alone as far as our repowering projects go in adding more megawatts, that would tend to decrease the price in Florida. Outside of Florida, again, coal price is going higher. It's hard to say specifically, but in shoulder periods when coal is on the margin to the north of us, that increase in prices would effectively raise our economy purchased price. That should pretty much explain it as far as what our thinking was in forecasting economy purchases.

Q Staff also compared the projected annual heat rates by generating unit that FPL provided as part of its E Schedules for 2001 and 2002, and I have just a couple of questions about

some of the differences.

A Okay.

Q Again, subject to check, would you agree that the heat rates for Turkey Point Units 3 and 4 increased approximately 14 percent from 2001 to 2002?

A I would agree.

Q Okay. What is the reason for that heat rate increase?

A That I do not know.

Q Do you know who would be able -- who would have that information, or who could respond to that?

A We believe that -- and I was thinking this -- there was an error in what we filed for 2001 and that has since been corrected. What's filed for 2002 should be the correct heat rates.

Q So what was filed in 2001 perhaps showed a lower heat rate than --

A Yeah, 9,330 is a little low. Yes.

Q Would you agree, subject to check, that the heat rates for Putnam Units 1 and 2 increased approximately 14 percent from 2001 to 2002; that is, the projected heat rates?

A Yes, I would.

Q And can you explain that increase from 2001 to 2002?

A Well, we would have to go month by month to look at

that. It would really depend on the -- on how much the Putnam units were dispatching at any given time and at what load levels for -- to come up with your average net heat rate. So you really -- it's hard to do it across the period. You have to break it down by month to see how much the unit was dispatching and then to -- in order to look at the differences. It may just be that the units not run as much or in a high megawatt level and the heat rate is higher, but you'd have to go more in-depth to determine that answer.

Q One more question with respect to the projected heat rates. Would you agree, subject to check, that the heat rate for Sanford Unit 3 increased approximately 8 percent from 2001 to 2002?

A Subject to check, yes.

Q Okay. And can you provide any insight into the reason for that increase?

A Again, it really depends on how much the unit dispatched and at what megawatt levels that it ran at. It's very hard to make an assumption on why it increased. It could be efficiency. It could be a number of things.

Q Are there any particular sources of information about historical weather data that you believe are -- that are credible sources of information?

A Historical weather data?

Q Yes.

A Boy, I don't use any historical weather data. The only, I guess, roundabout way we look historical weather-wise is in our historical loads and then our current load forecasts giving those historical temperatures, but other than that, no. I'm sure they're out there. I, you know, just right now off the top of my head couldn't think of them.

Q So in producing forecasts, does Florida Power & Light then typically rely on -- solely rely on forecasted weather data?

A Yes.

Q Okay. Are there any particular sources of information concerning forecasted weather data that Florida Power & Light uses or finds credible?

A Just recently, it actually came out last week, the Salomon Smith Barney weather forecast for this upcoming winter we find to be credible, as I think the industry does. We use a wide variety of Web sites, and mainly Web sites really for, you know, forecasts on weather. My view is normally short term, so I'm -- Intellicast and EarthSat, more of a shorter term seven-day outlook on weather.

Q I guess you mentioned earlier that while weather is not listed as one of the specific five factors in your testimony affecting natural gas prices, that it's accounted for under demand.

A Under demand.

Q Okay. In determining what -- in projecting what that demand will be, what types of forecasts does Florida Power & Light use for weather as a factor in determining demand?

A What -- I'm not sure I follow the question. What weather forecasts or --

Q Well, I guess what I wanted to clarify, you said that -- when I asked about forecasts that -- or credible sources of forecasted weather data, you mentioned, was it, Smith Salomon?

A Salomon Smith Barney.

Q Salomon Smith Barney for this winter, and then some shorter term forecasts.

A Right.

Q But when you prepare a demand forecast further out, are there any particular longer term weather forecasts that are used or relied upon?

A Not that I'm aware of. Weather is hard enough to predict within a six-month time period, so --

Q All other factors being equal, if the United States were to experience a warmer than normal winter, would you expect natural gas prices to be lower at the end of the winter compared to natural gas prices at the end of a normal winter?

A Yes, I'd say that's true.

Q When evaluating the impact of weather on the price that FPL may have to pay for natural gas, is there a specific

geographic region that FPL focuses on?

A Well, I guess, you know, to clarify, I think that when FPL is forecasting prices, the only -- or anybody else for that matter, I think on a longer term basis the only type of weather you can assume is normal weather. If you want to look at regions that can affect the natural gas price, obviously the northeast, a higher demand for natural gas for heating as well as utilities. So we assume normal weather in all conditions, but specifically if weather does change, what regions can affect the price of natural gas, and northeast is a big driver. Predominately the northeast, I believe.

Q Okay. Your direct testimony was filed on August 31st in this case.

A Uh-huh.

Q Have the events that occurred, the terrorist attacks on September 11th, had any impact on FPL's fuel price or availability assumptions for the remainder of 2001 and 2002?

A I think that right now what's being considered is the impact on load, on sales due to the attacks and also the downturn in the economy.

Q So are you saying that they have had an impact on --

A We are projecting --

Q -- assumptions --

A -- them to have an impact --

Q -- on the demand --

A -- on at least load or our sales, yes.

Q Have they had any impact on availabiity assumptions for the remainder of 2001 and 2002?

A No.

Q On Page 13 of your August 31st testimony at Lines 7 through 13 --

A Okay.

Q -- you were asked how were the outage factors for the January to December 2002 period developed. You reference nonrecurring events --

A Right.

Q -- on Page 11 -- or sorry, on Line 11. Could you provide an example of an unplanned outage that FPL does not consider a nonrecurring event?

A I would look at that maybe -- and I won't give you a specific, maybe just a type of an unplanned outage that occurred due to a piece of equipment that was determined to be faulty and replaced, and FPL assumes that that will not be a recurring event. Maybe it was a manufacturer's defect, something along those lines, that when we came back from that unplanned outage and corrected whatever caused the unplanned outage, that it would not recur again; that the specific root cause was found and it was deemed that that was an event or a factor that we could take care of and not have happen again.

Q What type of -- or is there an example you could

provide of an unplanned outage that would be a recurring event?

A A tube leak on a boiler.

Q What's that?

A A tube leak on a boiler would be a recurring unplanned outage.

Q At Page 4 of your September 20th supplemental testimony -- is that it?

A No, this is -- oh, maybe it is.

Q I believe it's included with the same packet with Ms. Dubin's.

A Yes.

Q Ms. Dubin's is provided first and yours second. At Page 4, beginning at Line 12, there's a discussion concerning whether the PSC should encourage FPL to enter into derivative transactions to manage risks. Does FPL -- I'm sorry.

A Okay. Go ahead.

Q Does FPL have a natural incentive to use derivatives in light of the presence of the fuel cost recovery clauses?

A Yes. I believe FPL does have an incentive, and that incentive comes in the form of lowering -- minimizing costs to our customers and also, and maybe more importantly, given what has happened over the past year, of trying to stabilize costs for our customers.

Q Do you believe that the Commission needs to provide sort of a regulatory approach, so to speak, as an incentive for

the use of derivatives?

A I think that would be important to know where the Commission stands on how they feel in regard to hedging and the use of derivative instruments in order to hedge. I think it would be important for all the groups to get together and really talk about the issues on hedging, what is recommended, and a utility can give its view and hopefully come to an understanding of what forms of hedging are acceptable, to what degree utilities should hedge their portfolios. So, yes, ultimately the answer to your question is yes.

Q But it is your opinion that FPL does have an incentive already to use derivatives even with the presence of the fuel clause so that it can minimize costs to its ratepayers?

A Yes, we do.

Q But for most of those ratepayers, can they -- they can't go somewhere else to buy electricity, though, if the costs did go up, if their price of electricity did go up?

A That is true. But speaking from my standpoint and the rest of our group and what we do on fuel procurement, our job is to minimize costs, removal volatility, and overall minimize costs for our customers. So that's what we strive to do with or without the fuel clause.

Q Are you familiar with FERC's surcharges that are applied to FERC-regulated interstate pipeline charges to fund

activities at the Gas Research Institute?

A No, I'm not.

Q Do you know who might be familiar with that?

A No, not off the top of my head, I don't.

Q For the next set of questions I have, we're going to ask you to assume a few facts and then offer the question. First, assuming that FPL's energy marketing and trading division receives a credible report on July 1st, say, of a given year that an anticipated low storage level of natural gas during the next six to nine months is expected to place upward pressure on natural gas prices during the time period. Prior to the current year, 2001, what would FPL's energy marketing and trading division's response to this report have been?

A Okay. Let me make sure I understand what you're saying.

Q Okay.

A In July of 2000?

Q Say, in a given year --

A Any year.

Q -- prior to 2001. Yeah, July 1st, 2000, you receive credible information that an anticipated low storage level of natural gas during the next six to nine months would place upward pressure on natural gas prices during that period, that six to nine months. What would the energy marketing and trading division's response or reaction have been?

A In that -- if we're talking in that specific time period, I think our reaction may have been a little bit different than what it would be currently. But I don't know if you're specifically asking that whether the years matter, the years you gave, or are you just looking generally for what our reaction would be in that -- given that kind of information, low storage levels going into a winter.

Q Right.

A I think our -- ultimately, our reaction would be right now to assume that there, like you said, would be upward pressure on prices, and we would probably look to fix the cost of some of our gas to quantify what those costs would be to remove some of that volatility that could occur in that time period due to low storage levels.

Q Prior to 2001, would the response have been the same?

A Prior to that, it may have been a little different, and only because we hadn't seen the kind of volatility in the market that we did see over the past winter. There were swings within a narrow band within natural gas and fuel oil that FPL was always able to handle through its fuel switching capability. As one price went up, we could fuel switch and burn a lower cost fuel. After what has happened, what has taken place at the end of last year and now through this winter, and we've seen this high volatility in prices, I think our approach would have to be somewhat different.

Q I think you stated, and correct me if I'm wrong, that on a going-forward basis, that FPL would seek out some fixed prices for that based on that information?

A Uh-huh.

Q How would FPL go about looking for fixed prices for natural gas?

A It could be done a number of ways. I think predominately the way we would look to do it right now would be in the physical market, to actually go physically buy gas for a given time period that we see as a highly volatile time period to fix the price and take physical delivery of the gas. There are a number of ways you could do it, obviously. That would probably be one of the primary ways we would do it.

If you're looking just to take some of the volatility out, you could buy a physical call option with a cap to at least set an upper limit on what you would pay for a certain quantity of gas, a number of different ways to do it. I think that we would be looking to physically take that position.

Q How would you judge whether the fixed price was too high or not to fix -- to commit to?

A I think we would have to, again, take into account what we felt prices could go to, what we forecasted that they could possibly go to given that information, the range of prices and really take it from there. I don't think there's any scientific way to say this is a good or this isn't a good

price. For us, it would be, does the fuel fit within our economic mix for our generation? And if it does, then we could go lock in that price. Really, no set way to do it.

Again, it's what could prices get to? What are my needs over that period for gas? And what can I -- can I remove some of the volatility that I perceive that natural gas may have in this time period by fuel switching, by burning other fuels, by buying power? A lot of different things to look at. So, you know, first of all, what are my needs? And then does that price look good for our customers? Is it a good price to fix at?

Q Did you say that options where one of the options?

A It could be a -- a call option could be a method to fix or at least to cap the price of what you could possibly pay for fuel in a given time period.

Q How do you measure the value of the -- in the options premium relative to its costs?

A The value of the option premium relative to -- I assume you mean the strike price? That is done by our analytics group, and I won't pretend to tell you how I know that is valued, but we do -- our analytics group will value any option that is presented to us or that we're looking to go pick up. So it's done by that group. They tell us where the market should be, and we can negotiate from there.

Q How do you attempt to determine where the point is at

which you are overpaying for a call option?

A Again, I think when the option is valued against the market and what the bid asks spread is on that option, you should be somewhere within that spread to make sure you are getting a product that is what we would term "at market."

Q I'm going to ask you to assume another set of facts. Assuming that the energy management and trading division receives a credible report on July 1st of a given year and an anticipated low production level of natural gas during the next six to nine months is expected to post upward pressure on natural gas prices, what on a going-forward basis would the division's response be to that information?

A I think the answer is very similar to the case of low storage. I think you take into account all the factors that could possibly affect natural gas in this case and the price of natural gas over that time period and decide what your best strategy is to procure fuel during that time period. There's no set answer to that. It's all the factors combined and what you feel the best thing to do to, again, take out some of the volatility while trying to minimize costs.

Q Would the response, do you believe, have been different prior to 2001?

A I would say that on a whole, a lot of things have changed given what has happened over the last year, as I stated before. We have seen such a high degree of volatility. We

have seen where prices can go to, maybe not even to the full extent. But whereas, in the past, FPL was able to minimize costs through a lot of more operational type hedging of fuel switching in oil storage and gas imbalances on a pipeline, what I consider to be more operational type hedging, that could still serve to minimize costs as natural gas or residual fuel oil moved within a narrow band.

What has happened over this past year has really changed that when we've seen this high -- extremely high volatility in extremely high gas prices. So our approach, I think, now becomes a little bit different and to more of trying to find a price that works to fix a certain percentage of our portfolio to make sure that we can take away some of that upside risk. So, yes. The answer is, I think you have two different viewpoints from 2000 and now what has happened to currently how we view it.

Q And again, another hypothetical, very similar. The division receives a credible report on July 1st of a given year that a colder than normal winter is expected to place upward pressure on natural gas prices. Would the division's response -- the energy management and trading division's response be the same as in the previous two hypotheticals?

A The same, yes.

Q And do you believe that similar to the other two hypotheticals that prior to this year that the response may

have been different?

A Yes, I do.

Q Okay. I've got a few more questions that provide a hypothetical. Taking the first hypothetical, which was the credible report on July 1st of a given year that there was an anticipated low storage level that would put upward pressure on the natural gas prices, assuming that that's now a report of an anticipated historically low storage level, would that change the way that the energy management and trading division would respond?

A Let me make sure I understand. The only difference in this to what you previously stated is that now the low storage inventory level is a record low level?

Q Right.

A No, I don't think that would -- obviously, that is a little more -- I'm searching for the right word -- a little more informative, or I don't know how to put it, but obviously that's a little bit more information. I guess it gives us a little better idea, or not even a little better idea, but it would indicate that gas could move even higher than in your previous case. So I don't think we would approach it any differently. It's just an extra piece of information for us to maybe quantify, as I talked about before, what that range is that we feel gas can trade in in that time period and speaks to the volatility of it.

Q And again, assuming the same facts of the previous hypotheticals, you get credible information on July 1st of a given year. This time instead of just anticipated low production levels placing upward pressure on natural gas, it's again historically low production level. Would the energy management and trading division's reaction be the same as you stated in the prior example where there's an anticipated historically low storage level?

A I think it would be the same. I think the one thing I would also tell you, and back to the previous question, depending on the type of information, and we went from low storage to record low and low production to, say, nonexistent production, but I think it may speak to even a longer term strategy than -- and maybe information that comes in like that, it may lead you to look farther in the future to see what that impact would be, not just within that six-to-nine month period but a father out period. And so that may be the difference in -- with this information being severe to very severe, then you may look farther out.

Q And if the hypothetical were to change from just a colder to normal winter to a historically record cold winter, would the response be similar?

A It's very similar.

Q Well, I'm going to give you two more of these with the hypotheticals. Assuming that FPL's emergency management

and trading division receives a credible report July 1st of a given year that a -- what did I say?

MR. SJOSTROM: Emergency management.

MR. KEATING: I keep seeing EMT here, and I keep wanting to say "emergency management," and it finally slipped out, 3:46. It slipped out.

(Discussion off the record.)

BY MR. KEATING:

Q Assuming that FPL's energy management and trading division receives a credible report on July 1st of a given year that a 1 percent probability exists that natural gas prices would tripple during the next two years, what would be the division's response to this report?

A It's a hard question to answer. I don't -- I think that the way we currently operate, I'm not sure much -- and even the hypotheticals you're giving would change. I think that what we're looking at now is a balanced portfolio, a mixture of fixed prices and longer term contracts, short-term spot. And I understand you're asking hypotheticals. I just don't -- what our response would be would be to continue with the strategy that we're trying to put in place now, what we feel the best mix is for our customers to remove some volatility to minimize costs. So given that information, I'm not sure much would change as far as how we're trying to procure fuel.

Q Would -- do you believe that your response to that information, that a 1 percent probability exists that natural gas prices will tripple in the next two years, that your response today would be any different than it would have been prior to 2001 given those assumptions?

A It's tough to say. Prior to 2001, it would have been very hard to imagine that gas prices could tripple, so I think that's a little tough to answer. But, no, I think if it was a credible, to use the word that you had used, information that, yeah, there was a high likelihood that gas prices could tripple, no, I think we would have had to have taken the same approach at that time.

Q And finally, the last hypothetical asks if there's a credible report that there was a 10 percent probability that the prices would tripple in the next two years, how would the division respond to that information today, and would that be different than it would have responded prior to 2001?

A I think it would be the same response, but again, it would be a response of making sure that our current procurement strategies and what we see ourselves doing in the future are adequate to, again, maintain some stability and cost minimization at -- if there is a chance that prices could rise, make sure -- it may be a case of changing something in the strategy that we have with a chance that gas prices could tripple. Maybe it's making sure we have a little bit more

fixed price gas to alleviate some of that upside.

So ultimately the response is the same, though, that the procurement strategies that we have now and that we're trying to implement is good, it's a balanced portfolio approach, and that we could -- that that procurement strategy even given the scenarios that you laid out would still result in some volatility and cost minimization.

MR. KEATING: Could we take a short five-minute break or a long five-minute break?

MR. SJOSTROM: Absolutely.

(Brief recess.)

BY MR. KEATING:

Q Do you have with you, Mr. Yupp, Florida Power & Light's responses to Staff's first set of interrogatories in this docket?

A Yes, I do.

Q That was set numbered 1 through 126.

MR. SJOSTROM: I got it.

THE WITNESS: You've got it there?

MR. SJOSTROM: Yes.

BY MR. KEATING:

Q I've got several questions to follow up on the responses to the interrogatories.

A Okay.

Q And let's start with Number 18. Are you there?

A Yes.

Q Okay. Referring to your response to that interrogatory -- well, first let me ask you, did you prepare the response to this interrogatory?

A I don't believe I did on this one. No, I don't believe I answered this question.

Q Well, I will try to address the subject, and hopefully it's something that you would be familiar with. The interrogatory asked how FPL evaluates the effectiveness of an individual hedged position, and I'll let you take a minute to look at the response.

A Uh-huh.

Q Have you read through it?

A Yes.

Q Can you provide any more specific detail about how Florida Power & Light determines whether an individual hedge minimized FPL's fuel costs?

A I think we've talked about it before. We evaluate the effectiveness of our overall procurement plan by our cumulative savings at the end of a time period, and that we can't just look at each individual transaction and say, well, that was -- or we don't evaluate the effectiveness of our overall procurement by one transaction by saying that that was a bad transaction or this one was. But I think -- and that is the proper way to look at the procurement plan, overall how

well it did.

I think, though, on an individual transaction basis there's something to be learned from individual transactions to take after, let's say, the transaction is completed or the position is done. What were your underlying assumptions in executing that transaction? How well did it meet the overall goal of cost minimization? And maybe it didn't meet the goal very well at all. But there's something to be learned to make better decisions the next time, to correct your assumptions or to have better assumptions and to be able to make a better decision the next time. But, again, that's on an individual transaction basis, a method of learning and gaining knowledge for next transactions. Overall, though, again it's on a cumulative basis how well did all the transactions sum up to savings.

Q Okay. The response to the interrogatory indicates that FPL attempts to determine how well each individual hedge meets its overall strategy. How specifically does FPL determine whether a specific individual hedge helps meet its overall strategy with respect to fuel costs and volatility?

A Well, if your overall objective is volatility and cost minimization, you can look at each individual transaction and say, does that transaction minimize volatility, or did it? Did it minimize costs? And the answer could be yes; the answer could be no. But that's why, again, I still go back to the

fact than on individual transactions, there's more to be gained by looking at how each individual transaction faired in order to make better decisions in the future. But again, I stress that we don't look at individual transactions to evaluate how effectively the overall procurement has gone.

Q And I guess what I'm getting at is, how do you -- when you look at each individual transaction to see how it faired, how do you go about determining how well it faired?

A To the degree of savings that were realized from that transaction, or maybe there were no savings realized from that transaction, and that's a way to look at how well it did too. Maybe it didn't accomplish cost minimization or volatility minimization. Maybe it didn't do anything of those things. So I'm not sure specifically how to answer you.

I think you can look at individual transactions to determine how well maybe a transaction helped to minimize costs in a certain month, and so you can say overall it was an effective transaction. Maybe it didn't, and you go back and look and reevaluate why you entered into that transaction and see if you can change something.

Q How would FPL measure the savings or attempt to determine the savings, if any, from an individual transaction? Would that depend on the type of transaction?

A It would depend on the type. I can tell you briefly how we measure savings on our physical procurement for a given

month. And I don't know if that's what you're getting towards.

Q I guess let's not get into the specific -- by transaction at least at this point. I'll move on.

A Okay.

Q For FPL's portfolio of hedged positions, how does it measure cost minimization and volatility minimization?

A Cost minimization is measured through the gas savings or fuel oil savings that we passed back through to our customers. It's measured on a cumulative basis on a yearly period.

Q And how do you measure the volatility minimization?

A Volatility is tough. I think we're just getting into that realm of hedging, and so I would tell you that ultimately we -- cost minimization was most important to us now that we're looking into further hedging strategies that -- you know, how well we minimize volatility will be shown in how close we come to the projections we make at the beginning of the year in the filing. If we're managing the volatility well, then we will be within our dead band, so to speak, around what we tell our customers their costs are going to be. I think that remains to be seen. I think that's a beginning effort and will be an ongoing effort. So that's a tough question to answer now on how you measure volatility minimization, but again, I think it will be how well -- how close were you to what you've told your customers your costs were going to be -- their costs were going

to be.

Q Is the difficulty in measuring finding the right basis to compare it to?

A I guess I would agree with that. How do you really measure how well you minimize volatility is, if it was a volatile market and there were price swings, were you subject or were your customers subject to those price swings, such as last January when gas prices went very high. I think cost minimization to a certain extent almost measures how well you minimize your volatility also. I think they work hand in hand.

Q And just to follow up, with respect to cost minimization and how that's measured, is it correct that it's essentially measured by comparing the costs that result from using a hedged portfolio versus a portfolio that's not hedged?

A No, it's really compared to how well you -- how much you procured fuel below the market price of fuel, and that's how we look at it right now. How well is -- or how much did you save compared to what the market price of fuel was on whether it's an index or whatever that may be.

Q Let me flip over to Interrogatory 32. There was discussion about the optimal mix of long-term, medium-term, and short-term contracts for natural gas, residual oil, and distillate oil purchases. My question is -- I'll give you a minute to read the interrogatory and response.

A Go ahead. I'm all set.

Q My question is, how does the ratio among the long-term, medium-term, and short-term contracts for natural gas and residual oil change as the price for these fuels change?

A I guess we can take a couple of different scenarios. In a market that we see as rising and steady upward pressure on prices, we may tend to go towards a more long-term mix of our fuel and whether that's fixed price or whatever it may be. But in a falling market, we may see that in order to take advantage of that falling market, we go more towards spot purchasing and daily purchasing. So I think it depends on the direction of the market. And what you try to do is mix your portfolio to take advantage of whatever direction that market is moving.

Q What do you believe is the current optimal mix of long-term, medium-term, and short-term contracts for natural gas?

A We are evaluating that right now. We are in some discussions with a consulting firm to really quantify that, what the best mix would be. I think some of what we heard may be leaning more towards a 50 percent mark on at least I would say fixed price. As far as contract goes, I don't know. Again, we're in the process of evaluating it and actually plan to get back to the Commission on what our findings are from the study that we're doing.

Q When do you expect to get the results from that

study?

A I think preliminary in the beginning of November, if I'm not mistaken, but I'm not 100 percent sure on that.

Q Do you know when FPL anticipates it would provide that -- those results or present them to the Commission?

A It may be sometime after the fuel hearing, given the amount of workload that we have right now and depending on when we do ultimately get the final results. So I don't have a specific time period. It could be in the beginning of next year. We do plan to update the Commission on what point we're at at the fuel hearing or for the fuel hearing, and maybe have a better idea then on when we're going to have something concrete.

Q Okay. Is that study also looking at current optimal mix for residual oil?

A Residual oil is also a part of the study, yes.

Q Has there been any -- let me step back from that. How often does FPL reevaluate what the optimal mix for natural gas is?

A Can you clarify what the optimal mix is? When? For long-term? For --

Q The optimal mix of long-term, medium-term, and short-term contracts for natural gas.

A I guess realistic -- well, realistically I'd tell you there's a couple of points there. I don't know how often we're

evaluating long-term, short-term, and midterm contracts. How often we're evaluating the optimal mix of our fuel is on a daily basis, and then to a certain extent, I guess contractually we could say more on a monthly type basis in our fuel planning for forward months. That's about the best answer I can give you. We're constantly evaluating what our fuel mix is, what our optimal fuel mix is. And in the area that I deal in, it's on a daily basis. As far as longer term, you know, again, it's more on a monthly basis.

Q Do you know what that -- what the optimal mix of long-term, medium-term, and short-term contracts for natural gas would have been in the November 2000 to March 2001 time frame?

A I'm not sure what the optimal mix -- I guess maybe I'm a little confused when we say the "optimal mix of contracts." I'm not sure a contract does much to -- if you're getting at the high prices in that time period, a contract, you could have all short-term contracts, all medium-term, all long-term or a combination of all three. And if they're all at index, then that wasn't an effective contract. So I don't think it's contract that we want to focus on. It's, I guess, how much the portfolio was hedged. Were there fixed price positions on, or were you buying at index? So anyways, the question confuses me a little bit because I'm not sure contracts is the right way to look at it.

Q Well, looking at it without reference to contracts, what do you believe the optimal mix was for the November 2000 and March 2001 period?

A Well, the optimal mix would have been to have bought natural gas the year ahead of time and not had to worry about the price spike, if you had seen it coming. So it's a hard question to answer. What was the optimal mix? I don't know if hindsight is 20/20. So I do know what it was now. It was that very low-priced natural gas that was purchased sometime beforehand. What was the optimal mix right when we got into that time period? It was to burn as little gas as you possibly could, and that's what Florida Power & Light tried to do at that time given the fact that nobody saw the market rise coming. And so you would not have had that kind of hedged position to not have to experience some of that price increase during that time period.

Q For residual oil, what would you say the optimal mix was for that time period, I guess, both with 20/20 hindsight and based on how FPL actually had to deal with the situation?

A For residual oil across that time period, there was a lot less volatility in it. It did rise, of course, so some fixed price, you know, obviously purchased prior to that when prices were lower would have been the optimal mix, but again, a lot less volatility in residual fuel oil, and we did burn as much as we could during that time period.

Q Let me move on to the next interrogatory, 33.
A Okay.
Q I'll give you a minute to look at that.
A Okay.
Q The response to that interrogatory is a table which shows the length and type of contracts for FPL's purchases of residual and distillate oil and coal and natural gas during 2000. Did you provide the response to this interrogatory?
A No, I did not.
Q Looking at the column for residual oil, it indicates that FPL purchased 100 percent of the residual oil that burned with the price at or based on the market prices; is that correct?
A Yes, index.
Q Okay.
A Well, it does not say that we -- that's how the pricing mechanism was on those contracts, that it was based on an index number.
Q So those that indicate indexed, those are based on market price?
A Right.
Q Okay. And obviously spot market is market price.
A Yes.
Q And then the natural gas column on the right side of the table shows that FPL purchased 100 percent of the natural

gas it burned with the price at or based on the market price; is that correct?

A Yes.

Q This states this data for 2000. For 1999, would -- with respect to the residual oil and natural gas all being purchased price at or based on the market price, would that be true for 1999 as well?

A Yes. I'd have to go back and look at the percentages per contract, but it would be, yes, at index or market price.

Q Okay. There wouldn't be any fixed --

A No.

Q -- contracts for those two commodities?

A Not that I'm aware of.

Q Okay. Flip over to Interrogatory 34 which asks the same type of information, but instead of 2000, it asked for 2001. And obviously there's some -- it's comprised of some estimates as well as actual data, I believe. Looking at the residual oil column, again, FPL -- is it correct that FPL expects to purchase 100 percent of the residual oil it expects to burn with a price at or based on the market price?

A Yes, those were the projections.

Q Now, with respect to natural gas in 2001, is it correct that FPL expects to purchase 26 percent of the natural gas it expects to burn at a fixed price with the remainder at a market price or based on market price?

A Yes.

Q Turn to Interrogatory Number 35 which the table purports to show the volume of natural gas FPL has by transaction type. Are you familiar with this data? Would you like a minute to look at it?

A I'm fairly familiar with it. I did not prepare it, but I have seen it.

Q Okay. Assuming that FPL opened the long future's position of 1 million MMBtu of natural gas during 1999 and assuming that later in 1999 FPL closed out that position with an offsetting transaction, how would those two transactions be represented on this table?

A I believe that those should be -- well, you should see them in long, and in your first case of a long future's position, and then in the second case of a short future's position to cancel each other out.

Q And based on those assumptions, what portion of the long position was opened long?

A Can you repeat that?

MR. KEATING: Can we go off the record for a moment?

MR. SJOSTROM: Yes, absolutely.

(Discussion off the record.)

BY MR. KEATING:

Q Looking at the long and short future's positions for 1999 and 2000 in the table in response to Interrogatory 35, the

table shows approximately the same volume of natural gas hedged for each year under long- and short-term positions -- future's positions. Do you believe that that indicates anything about FPL's expectations about changes in actual gas prices in 1999 and 2000?

A Just some clarification. You said that it shows the same amount of long and short positions for each year?

Q I'm sorry, the -- approximately the same volume of natural gas hedged through long and --

MR. KEATING: I'll tell you what, I think it may be a good point to stop for today, and we can freshen up for tomorrow morning and start.

(Deposition adjourned at 4:45 p.m.)

(Transcript continues in sequence with Volume 2.)

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ERRATA SHEET
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IN RE: DOCKET NO. 010001-EI
NAME: GERARD YUPP
DATE: OCTOBER 22, 2001

PAGE	LINE	CHANGE

Under penalties of perjury, I declare that I have read my deposition and that it is true and correct subject to any changes in form or substance entered here.

DATE _____ GERARD YUPP

STATE OF FLORIDA)
COUNTY OF LEON)

CERTIFICATE OF OATH

I, the undersigned authority, certify that GERARD YUPP personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 29th DAY OF OCTOBER, 2001.

Tricia DeMarte

TRICIA DeMARTE
Notary Public - State of Florida

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, TRICIA DeMARTE, Official FPSC Commission Reporter, do hereby certify that I was authorized to and did stenographically report the foregoing deposition at the time and place herein stated.

I FURTHER CERTIFY that this transcript, consisting of 47 pages, constitutes a true record of the testimony given by the witness.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 29th DAY OF OCTOBER, 2001.

Tricia DeMarte

TRICIA DeMARTE
Official FPSC Reporter
(850) 413-6736

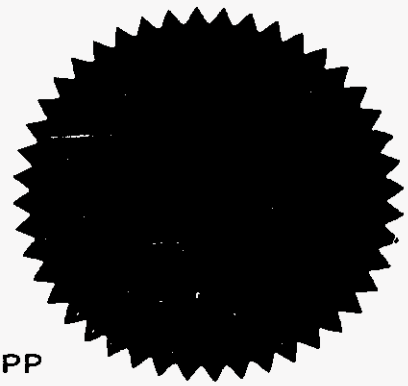
BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of

DOCKET NO. 010001-EI

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE AND GENERATING PERFORMANCE INCENTIVE FACTOR.

_____/



DEPOSITION OF:	GERARD YUPP
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
DATE:	Tuesday, October 23, 2001
TIME:	Commenced at 9:58 a.m. Concluded at 3:21 p.m.
LOCATION:	Gerald L. Gunter Building Room 309 2540 Shumard Oak Boulevard Tallahassee, Florida
REPORTED BY:	MARY ALLEN NEEL, RPR Notary Public, State of Florida at Large

VOLUME 2
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APPEARANCES:

JON SJOSTROM, Steel, Hector & Davis, 215 South Monroe Street, Suite 601 Tallahassee, Florida 32301, appearing on behalf of Florida Power & Light Company.

ROBERT VANDIVER, Deputy Public Counsel, Office of Public Counsel, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

MARLENE STERN, Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0870, appearing on behalf of the Commission Staff.

ALSO PRESENT:

KORY DUBIN, GENE UNGAR, and JOE STEPENOVITCH, Florida Power & Light Company.
TODD BOHRMANN, MATTHEW BRINKLEY, ROLAND FLOYD, PETER LESTER, and WILLIAM McNULTY, Commission Staff.

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PROCEEDINGS

Thereupon,

GERARD YUPP

continues his testimony under oath from Volume 1 as follows:

CONTINUED DIRECT EXAMINATION

BY MS. STERN:

Q Good morning, Mr. Yupp.

A Good morning.

Q We're continuing the deposition today from yesterday. You understand that you're still under oath?

A Yes, I do.

Q Okay. And I'm Marlene Stern. I'm sitting in for Cochran Keating today as the attorney representing the Commission staff.

Yesterday it's my understanding that you left off discussing staff's Interrogatory No. 35.

A Yes, that's correct.

Q And staff had some revisions that they want to make to that table. And instead of pursuing the information through the deposition, what we've decided to do is send out another interrogatory writing down clearly the type of information that we want to see. And it's my understanding that we've stipulated, the

staff and FP&L, that we can get a response to that interrogatory within two weeks of today.

MR. SJOSTROM: I'm sorry. Is it time for me to agree to the stipulation?

MS. STERN: Yes.

MR. SJOSTROM: FPL agrees to the stipulation, preserving its right to make an objection in the unlikely event that FPL determines that the interrogatory as written is inconsistent with the discussions that we've had today. Barring that unlikely eventuality, FPL will agree to respond to the interrogatory within two weeks from today and will make every effort to respond to the interrogatory more quickly than that.

MS. STERN: Okay. With that, I think we can proceed on to a different question.

BY MS. STERN:

Q Still, though, looking at the response to Interrogatory No. 35, Mr. Yupp, could you tell me under which price expectations would FP&L buy a natural gas call?

A FPL would buy a natural gas call under price expectations seen to be increasing. In other words, FPL would purchase a call for a time period

that they felt natural gas prices could be high or volatile in that period, and it would be done to put a cap or a ceiling on the price that FPL would pay for natural gas.

Q Okay. Under which price expectations would FP&L sell a natural gas call?

A FPL could sell a natural gas call I would say in two types of situations. First, obviously, FPL could sell a natural gas call to reverse the purchase of a natural gas call and get out of that transaction.

The second situation in which FPL could sell a natural gas call would be at a time when the utility feels that it has excess transportation or excess supply at any given time where the natural gas that the utility has may be able to be sold into the market to capture a better profit or a better gain for its customers than it would be to burn that fuel. So in that situation, FPL could go out and sell a call option on natural gas and thereby receive a better gain than it would in burning that natural gas.

Q Okay. Thank you. Under which price expectations would FP&L buy a natural gas put?

A A very similar situation on buying a put. FPL would utilize a put when it felt that it may have excess supply in order to be able -- when it could not

burn that natural gas economically in its system, in order to be able to put the natural gas to another counterparty at a predetermined price and put, for lack of a better description, a floor on what FPL would know then that it was going to receive for that natural gas.

Q Okay. Under which price expectations would FP&L sell a natural gas put?

A Again, I think selling a natural gas put could be in a time period when FPL sees a good bit of volatility or increasing prices, but I don't think it has to be limited to that. I think it really can be sold at any time and in combination with a call option. FPL can utilize both of those instruments to capture a range of prices, in other words, a floor on what FPL would pay for gas, and to create a ceiling also on what FPL would pay for gas.

So I don't think I would pin the selling of a put to a specific market movement. I think that can be utilized at any time if FPL's strategy is to somewhat quantify a range of natural gas prices that it would like to be within.

Q Okay. Thank you. Could you turn to the response to Interrogatory 45, please?

A Yes, I can.

Q Is the cost that FP&L incurs to store natural gas a one-time or a recurring cost?

A The cost would be recurring for the amount -- I'll put it this way. The amount of natural gas that is injected or that FPL injects or withdraws from storage will incur the dollar per MMBTU charge and also the percentage fuel charge on injection. So the fuel charge on injection, the percentage that is listed in the response to that interrogatory would be incurred on injection. That would be any volume that we inject. In other words, if we were to inject and then withdraw and on the next day inject again, then we would incur that charge. Similarly, we would also incur the dollar per MMBTU charge on what we inject into storage.

Q Okay. Would you please turn to Interrogatory No. 50, the response, and take moment to look it over and refresh your memory?

A Okay.

Q Okay. Which commodities did FP&L hedge whose gains and losses from futures contracts are reflected in the "Other" column? That's the last column in the table titled "Other."

A I would need to check into exactly what "Other" is. I think we had some conflicting

information when we reviewed this as far as what the "Other" column is. I believe it to be residual fuel oil, but I'm not sure that's the case, and so we would need to check into that.

Q Okay. Thank you. When FP&L opens a long futures position in natural gas, how does FP&L hedge its natural gas prices?

A By opening a long futures position in natural gas -- and the underlying information that needs to be characterized here is that FPL is a net short utility. Our position on a day-to-day basis is that we are short fuel for generation to meet our demand. So by opening a long futures position, FPL is basically fixing the price of a certain quantity of fuel for their customers.

Q When FPL opens a short futures position in natural gas, how does FPL hedge its natural gas prices?

A I would have to check if we have opened short positions without it being the closing out of a long position. That answer, we would need to -- I think from the interrogatory or the additional interrogatory that we will be answering as part of this, we will get a little bit more information on that. Right now I would be reluctant to say that we

have opened short positions without it being to close out a long position and just open a short position.

Q If you bought excess gas and then you wanted to sell it back into the market, could that be a reason why you would open a short futures, open a short futures position in natural gas?

A Well, I would first answer that by saying we do not buy excess gas. We do not buy more gas than we need to meet our load, and that is in theory. Now, that doesn't always work out due to weather conditions, generator outages, whatever it may be. There are a lot of other factors that go into that.

So normally what we would see on FPL having excess gas, it could be that the weather did not materialize the way we had projected it to in a given time period. And let's just take a month, for example. And on a day-to-day basis, FPL may have excess gas to sell. But in that case, they would be selling it into the market, usually physically delivered gas.

So I don't know if I can agree with that specifically, because there is not any time that FPL goes out and buys more gas than it needs, so it's hard to say that you would go then into a futures contract to sell that gas, or a short position.

Q Okay. So generally the only time you're aware of that FPL would open a short futures position would be to close out a long one?

A Yes.

Q Okay. When FP&L purchases a natural gas call, how does FP&L hedge its natural gas prices?

A When FPL purchases -- can you repeat that question? I'm sorry.

Q Sure. When FP&L purchases a natural gas call, how does FP&L hedge its natural gas prices?

A Well, again, now that we have already stated that FPL is a net short utility on fuel, by purchasing a call, again, FPL can -- at least for a given time period that that call pertains to, we can cap the price of a portion of what our short position is.

Q Okay. When FP&L sells a natural gas call, how does FP&L hedge its natural gas prices?

A Well, on selling a call -- and again, this pertains more to a day-to-day physical type position. By selling a call, FPL is able to capture a premium, first of all, from selling the call, which we can then pass back to our customers. And realistically, it's just a way to add value to our fuel procurement portfolio. When we feel we may have the excess

capacity and we can go out into the -- or in this case, maybe we're intermonth and the weather has not worked for us or we are long a little bit of gas. We may be able to sell a call for a short time period, capture a premium, and reduce overall fuel costs. And that's basically it, reducing overall fuel costs. That's what it helps us to do by capturing a premium.

Q Okay. When FP&L captures a natural gas put, how does FP&L hedge its natural gas prices?

A In a similar manner there, except by purchasing a put, we would be paying a premium to purchase that put. But what it would ultimately do is give us a floor that we know we could sell our gas for, that we would not -- that we could kind of quantify the bottom point that we could sell excess natural gas that we may have at any given time into the market. So it puts a floor or our natural gas sales.

Q When FP&L sells a natural gas put, how does FP&L hedge its natural gas prices?

A Similarly, when FPL sells a natural gas put, we are capturing a premium, which helps to overall lower our fuel cost. And it also -- it gives us -- again, I would mention, in combination with a call, or even not, we know that at any given time

we've taken in that premium, and we can be put gas at a certain price. Obviously, that gas we would feel would be a good mix in our portfolio. And if the natural gas is put to us, then we would burn it in our units, but ultimately we're capturing a premium to do that.

Q When FPL swaps fixed price natural gas for floating price natural gas, how does FPL hedge its natural gas prices?

A What FPL is trying to do in a type of transaction such as this is capture the value in which direction we see the market going. We may swap fixed price. We may have a view that the market is going in one direction or another.

And I can give an example here. We may feel that the market is going in an upward trend. We may like to swap fixed for floating, and we can assume our fixed price is $3 on the gas, but we see the market going higher than that. Anytime the market is higher than that, we will be paid that difference between our fixed price and the index price, or whatever was agreed to on the floating price, which would then again overall lower our fuel cost for our customers. And that would pertain to any type of swap, whether fixed for floating or floating for

fixed. It would really depend on the view of the market.

Q When FPL swaps floating price natural gas for fixed price natural gas, how does FPL hedge its natural gas prices?

A In just the exact way I answered that question. I think it goes both ways, whether fixed for floating or floating for fixed. It depends on what your view of the market is and what you're -- how you see it going compared to the price that you would like to receive and hopefully lower your cost.

Q Are you familiar with the term or concept of marking to market an open futures position?

A Somewhat, yes.

Q Okay. Do you know how FPL's open futures positions are marked to market?

A I could not speak to that with a great amount of knowledge.

I just need to clear up one thing.

MR. SJOSTROM: I know there's a question pending, but --

MS. STERN: Yes, that's fine. Let's go off the record.

(Discussion off the record.)

BY MS. STERN:

Q Okay. Mr. Yupp, you were going to answer -- I'll repeat the question.

A Okay.

Q How are FPL's open futures positions marked to market?

A FPL does not mark to market their futures position. Because FPL is a net short utility on fuel, any positions we take are ultimately for fuel to burn in our units to meet our demand, so we do not mark to market our fuel procurement purchases or strategies that we use.

MS. STERN: Can we go off the record?

MR. SJOSTROM: Sure.

(Discussion off the record.)

BY MS. STERN:

Q Mr. Yupp, could you please clarify your answer to the question?

A The way FPL marks to market their positions, or as we've described, open positions, is through a VAR calculation, which I won't get into the technical aspects behind it because I'm not an expert in that area. But VAR is simply a measure of how much a position can swing in either direction for a given time period, how much value is at risk at any given time due to the volatility of the market.

Q Okay. Thank you. I want to back up just a minute back to calls and puts. With respect to calls and puts, what roughly is the percentage of your options that are embedded in non-marketable contracts versus exchange-traded contracts?

A Can you clarify a non-marketable contract?

Q Bilateral.

A Okay. So the question is the percentage of options that are in bilateral contracts versus exchange-traded contracts?

Q That's correct.

A That I don't know off the top of my head. We would have to look into that. I'm not sure. I think ultimately the answer is that most of what we do is in bilateral contracts. We do not have a lot of exchange-traded products. So the answer is that a great percentage is in bilateral contracts. What that exact percentage is I don't know.

Q Okay. Thank you. What's the accounting treatment that FPL uses when its open futures positions are marked to market?

A Accounting treatment? Again, that's out of my area of expertise. I do not know the answer to that question.

Q Could you now please turn to FPL's response

to Interrogatory 53?

A Okay.

Q Please distinguish between monthly index and daily index as these terms are used in FPL's response.

A Okay. A monthly index would be an index number that is set prior to the month or going into the next month. In particular, FPL uses an Inside FERC Monthly Index at FGT Zone 2 to value how well FPL has procured its monthly fuel requirements versus market. So the market that we use is a monthly number that comes out for a specific delivery point.

A daily index is exactly the same, except it is an index that is posted daily. And in our case, we use the Gas Daily Index to determine how well FPL has procured fuel in the daily market versus the market price or, in this case, the Gas Daily Index.

Q Thank you. Would you now please turn to FPL's response to staff's Interrogatory 54 and take whatever time you need to refresh yourself with that response?

A Okay.

Q Okay. Looking at Column C, could you please define "evergreen" as this term is used in the table?

A I believe -- and I'm not in the contracts group, but I believe evergreen is a renewing contract that neither party needs to say they are going to renew that contract. It just perpetually renews until one counterparty or the other options out of the contract, so to speak.

That is my limited knowledge of an evergreen contract. Again, I'm not in the contracts department, but I believe that's what "evergreen" means.

Q Okay. Thank you. Do you know how -- well, you sort of answered this, but how an evergreen contract can be terminated?

A I assume, as in any contract, there is probably an out clause, a notification time period that must be given to terminate the contract. And in this case, if that is not given by one or both counterparties, then the contract would just renew itself.

MS. STERN: Any objection to going off the record for a moment?

MR. SJOSTROM: No.

(Discussion off the record.)

BY MS. STERN:

Q Mr. Yupp, in the response to Interrogatory

54, in that table, could you please explain what the term -- why you used the word "negotiated" in Columns E, F, and G, and yet sometimes you used actual numerical values? Why did you use negotiated as opposed to numerical values?

A The term "negotiated" was used in Columns E, F, and G because there is no specific volume or pricing mechanism. These are purely contracts that we have in place in order to be able to do business with the counterparties that are listed or suppliers that are listed in this response. So price and/or volume are negotiated on a daily basis according to where the market is.

When you look in Columns E, F, and G and see specific responses as far as volume wise and/or pricing mechanism wise, those are the current long-term contracts that we do have in place with certain counterparties. And those items are spelled out in the contract, the pricing mechanism and/or the volumes.

Q Okay. Thank you. Would you turn now to the response to Interrogatory 56, please? And there's another table attached there. Take whatever time you need to review that. I think actually we're going to have -- we're basically just going to need the same

clarification on that table. In Columns E, F, and G you use the term "negotiated" for 99% of the entries, and occasionally you have numerical values.

A And that is the same response. This table covers a different time period than the response to Interrogatory 54. Interrogatory 56 is for a different time period, and the information is basically the same. Those are contracts we have in place with suppliers. Most are just price and volume that is negotiated on a daily basis. Wherever you do see responses in Columns E, F, and G for pricing and volume, those are long-term contracts that are in effect during that time period.

Q Okay. Thank you. My next question involves FPL's response to three separate interrogatories, No. 34, No. 54, and No. 56. What I'll do is read you the question, and then you can take whatever time you need to review those interrogatory responses.

In FPL's response to Interrogatory 34, FPL indicates that 26% of FPL's natural gas purchases in 2001 are fixed price contracts. However, FPL's responses to Interrogatories 54 and 56 indicate that all contracts are market-based price contracts. Please reconcile these two statements.

A Okay. In response to Interrogatory 34, that fixed price gas was done -- well, I don't think it's confidential. It was done with a counterparty that we have a long-term contract in place with that is an indexed contract. However, we are at any given time able to fix the price of that contract and not go with index.

In this case, this 26% represents a swap that we made within those contract guidelines on gas in January of 2001 for the summer of 2001. We did not need the gas in January of 2001 due to the high prices. We were able to take that gas and swap it out for summer gas, take delivery in the summer when we knew we would need it, and we did it at a fixed price. That is all within the contract guidelines.

So in response to 54 and 56, although the contract that we have with that counterparty is at index, there are guidelines within that contract that allow us to fix the price of any or all of our must-take volume. So that should clarify that discrepancy.

Q Okay. Thank you. Now would you please turn to Interrogatory 58? And I think here again we might need the same clarification as you made for the tables in Interrogatories 54 and 56. If you look at

Interrogatory 58 and the table for that response, why are the contract start and end dates not available for lines 33 through 45?

A I am not sure why the start and end dates are not available for those particular counterparties.

MR. SJOSTROM: Could we go off the record for a second?

MS. STERN: Sure.

(Discussion off the record.)

MS. STERN: Back on the record.

THE WITNESS: In response to that question, a contract start and end date is not available there because there is not a contract in place. Those are mainly for spot purchases of cargos that we may have to fill a need. Those contracts are negotiated on a case-by-case basis. So the pricing and the quantities will be negotiated whenever we need to fill a spot need or have a spot need.

BY MS. STERN:

Q Okay. Could you explain why in Columns E, F, and G the entries just say "negotiated"?

A Again, those -- whenever we are going to do business in the spot market for fuel oil, the price and the volume is negotiated at the time that the

contract is done. There is not a contract in place that spells out volume and/or pricing. That is negotiated at the time that the transaction is executed.

Q So for these suppliers that would be listed in rows 33 to 45, you don't have those sort of long-term contracts with them that are just terminated when one party wants to?

A That's correct, unlike in natural gas, where there is a GISB in a standard contract. In residual fuel oil, there is not. We just negotiate with those counterparties on a case-by-case basis.

Q Okay. Thank you. Now would you please turn to the response to Interrogatory 60? And my questions are the same. In lines 32 through 46 of the table, there are no start and end dates.

A Correct. And that again refers, I believe, to a different time period, and in that case, my answer is the same. Those are spot negotiated contracts.

Q Okay. Would you please turn to Interrogatory 64, the response.

Could you explain why FPL has not hedged its natural gas transactions to ensure that its average natural gas commodity costs do not exceed a

predetermined level?

A Prior to the end of last year and, of course, the winter of this year, 2001, the commodities of natural gas and fuel oil had historically traded within a very narrow range. FPL was able to remove whatever volatility was there in that market through its fuel switching capability and switch to -- when oil was cheaper, then we would burn oil. If gas was cheaper, we would burn gas and back off on the other commodity. So in that time frame, we never went in and said, "Okay. For next year, we want to make sure that our fuel cost does not exceed a certain range," because it always traded within a narrow band anyway.

So that's why we answered that question as, you know, not currently. We had never looked at that. We had never gone into a year saying we need to keep our cost at this level, because for the most part, with our operational hedging techniques, we were able to keep our cost in that narrow band.

Now that we've seen this kind of volatility, the second part of that answer is that we currently are reviewing the hedging strategy and working with a consultant to determine, you know, what is needed going forward. And that may take the shape more of trying to stay within what we tell the

Commission on a yearly basis the cost to our customers is going to be for fuel purchases. So I think you see a changing now of philosophy.

Q I'm going to refer to two interrogatory responses in my next question, Interrogatory 36 and Interrogatory 66. And I'll read the question, and then you can take whatever time you need to review those interrogatory responses.

A Okay.

Q In FPL's response to staff's Interrogatory 36, FPL indicates that it used long futures positions and short futures positions of 899,000 units, barrels, MMBTU, whatever, in 2000 to hedge FPL's residual oil purchases. In FPL's response to staff's Interrogatory 66, FPL states that FPL does not use exchange-traded derivatives to hedge its residual oil transactions. Could you please reconcile the two statements?

A Sure. In the response to Interrogatory 36, those long and short futures positions would be more -- would be over-the-counter type transactions with bilateral contracts with counterparties.

Question 66 specifically states does FPL use exchange-traded derivatives, and there are not currently any exchange-traded derivatives available in the fuel oil market, residual fuel oil market.

Q Thank you. Would you refer to the response to Interrogatory 69, please?

A Okay.

Q Why has FPL not hedged its residual oil transactions to ensure that its average residual oil costs do not exceed a predetermined level?

A The answer to that is fairly similar to the natural gas response, in that we did not see that kind of volatility and never had or saw a need to do that. Again, through our fuel switching capability, we were able to minimize costs and take out whichever fuel was the higher priced fuel.

Moving forward here, we're evaluating it. There is less volatility in the fuel oil market, and we're currently evaluating whether we do need to hedge to meet a predetermined level. I think the answer would be similar, that we need to try to make sure that what we're telling the Commission and our customers our costs are going to be, that we come through with that number. So we may move to a strategy that will try to hold at least a portion of our residual fuel oil, at least fix the price of it and try to hit a predetermined cost level. So it's a very similar answer to natural gas, but less volatility in fuel oil.

Q I have a follow-up question on the residual oil that refers to Interrogatory Responses 37 and 73. And I think the question will sound familiar to you.

A It is in regard to distillate, I believe.

Q Yes. I'll read you the question, and you can look at the responses.

In FPL's response to staff's Interrogatory 37, FPL indicates that it used long futures positions and short futures positions of 25.2 million units and 8.4 million units respectively in 2000 to hedge FPL's distillate oil purchases. In FPL's response to staff's Interrogatory 73, FPL states that FPL does not use exchange-traded derivatives to hedge its distillate oil transactions. Could you please reconcile these two statements?

A Right. And again, the same answer, that FPL has not used exchange-traded derivatives in the distillate oil arena, and what you see in response to Interrogatory 37 would be over-the-counter type transactions, bilateral, with a counterparty.

Q Thank you. Now would you please turn to the response to Interrogatory 74?

A Okay.

Q Okay. Why has FPL not hedged its distillate oil transactions to ensure that its average

distillate oil costs do not exceed a predetermined level?

A In the case of distillate oil, FPL is not a very large consumer of distillate oil. It is used more as an emergency backup fuel for us if we were to experience problems in gas supplies. The price of distillate oil never warranted that we would burn it economically in our system. We do have some units that can switch from natural gas to distillate oil. But again, the economics have never been there.

So with the quantity of distillate oil we may burn in any given year, and that may be more in peaking type units over the course of a summer or a winter peak, there was and is not a need there currently to try fix cost at a predetermine level. Most distillate oil we buy is on a spot basis as needed. But, again, it's more of an emergency backup fuel for us.

Q Okay. Thank you. Would you please turn to the Interrogatory 76 response?

A Okay.

Q How did FPL find itself with excess natural gas that FPL couldn't turn back to its natural gas supplier?

A Under one of our long-term contracts, which

is the longest term contract we have for the most volume, we do have must-take volumes under that contract. I will say in a normal pricing scenario, natural gas -- we do have a certain portion of our generation that is natural gas combined cycle that is base load units that always run. We have never seen a price disparity between natural gas and oil that would warrant our combined cycles not being economically dispatched.

So what happened in January of 2001, as gas prices climbed higher and higher, our combined cycle units became not economical to run in that time period. We were able to run our residual fuel oil units to meet our load, except for peak occasions, which is when we utilize the storage facility to cover our peak occasions. So what we decided to do, and we had the leeway in the long-term contract we have, we swapped out our January gas and took it back in the summer when we knew that loads would warrant that all our units run, and we knew we would burn our natural gas in that period.

MS. STERN: Any objection to going off the record?

MR. SJOSTROM: None.

(Short recess.)

BY MS. STERN:

Q Mr. Yupp, could we -- could you please look at the response to Interrogatory 77?

A Okay.

Q Would you explain the term -- could you define the term "embedded options" as it's used in the context of the February 2, 2001 document?

A That could be similar to a put option where we may sell a put to give a supplier the right to put us gas, and we collect the premium for that option, and then we apply it to -- if a price strike was at index, we apply that premium to the index price, which then allows us to achieve the below market or below index pricing.

Q Why would FPL wish to establish a floor price for a volume of natural gas?

A Well, I don't think it's a case of trying to establish a floor price, but it's looking at a price that we feel may be below the market, and all we're trying to do is trying to procure at the lowest possible cost we can. When you look at selling a put, you have obviously established some sort of floor price for that quantity of natural gas that you're working with. However, we assume, or we feel in that case that that price, that floor price that has been

set will be below market. And that's what we're trying to achieve, below market procurement.

Q You might have answered this question. I'll ask it, though. How specifically has FPL taken advantage of embedded options?

A I think we've taken advantage of embedded options in the fact that we on a year-to-year basis have shown a significant overall procurement savings on natural gas or residual oil, but I speak more to natural gas. We've taken advantage of buying gas with embedded options and being able to achieve below market pricing, as reflected in what we show as savings versus market in our overall procurement plan.

Q Okay. Please consider a utility with fuel switching capability between gas and oil. Is there an embedded option based on fuel switching that is of value to the utility?

A I don't know if I would say embedded option. I'll describe it in a different term. There is a tremendous amount of value in fuel switching capability. FPL has -- approximately 41% of FPL's assets are fuel switching capable.

The value comes in in being to economically burn the lowest possible cost fuel that we can. And where a lot of fuel switching takes place, in order to

achieve this goal, on a daily basis, we can look at the spot market for natural gas, obviously versus fuel oil. As the natural gas market is low or is trending lower, we are able to buy a larger volume of natural gas and switch our units over to burn it.

So our fuel switching capability gives us tremendous advantage and flexibility in being able to lower costs, because at any given time, we can burn the lowest cost fuel available to us.

Q Okay. Earlier in your response you said a percentage of your assets that you were capable of switching. What percentage was that?

A Roughly 40% or 41% of our assets are fuel switching capable.

Q Would you turn to your supplemental testimony, page 3, please?

A Yes.

Q All right. Would you take a look, please, at lines 14 through 127? And take your time to read over that.

A Okay.

Q And I want to ask you basically a question about embedded options and exchanging winter gas. Does that represent a significant percentage of FPL's gas purchases?

A No, it does not. It's a minimal percent.

Q Do you know what percent that is?

A Off the top of my head I don't. In the past it has been a minimal -- the winter gas exchange was a one-time -- actually, two months we did that for. So overall, on a natural gas portfolio where we may burn over 200 million MMBTUs a year, that may have been, say, for 300,000. So it's not a large percentage of our portfolio. The exact percent I do not know.

Q Let's go back to the interrogatories. Would you please take a look at Interrogatory 80?

A Okay.

Q How did FPL calculate the savings that FPL achieved by hedging its natural gas and fuel oil purchases in 1999 and 2000?

A Okay. For both years, that is calculated the same way. We can start with natural gas. We calculated our savings on natural gas. I guess I would say there are four components of it. We take a look at what we procure on a monthly basis for what we feel our base load needs to be. We compare what we procure our monthly takes at versus an index, and it in this case it would be Inside FERC, first of the month, FGT Zone 2 Index. We take a look at what our

price was versus that index, calculate the difference, and multiply it by the volume we had on a monthly basis, and that's the savings we show there.

Added into that, we must take into account or daily purchases, which again are done the same exact way, only we use the Gas Daily Index for the same delivery point. We look at our secondary delivered markets or our delivered gas if we were to go buy gas delivered under somebody else's transportation to us, and we compare that to what the delivered market was for the day, and we add in our financial transactions.

The sum of all four of those would represent our cumulative savings. And we obviously calculate that on a monthly basis and at the end of the year. That's what number is reflected here on natural gas.

Fuel oil is done very similar. We take a look at any cargos that we took shipment on during any given month. We compare what we paid for the cargos of oil compared to an average, a daily average of the Platts and -- or a monthly average of the Platts and Argus postings, which are again an oil index. We calculate the difference between our price and that average index price and multiply it times the total

volume we took, and that's what we have here as gas savings -- or residual fuel oil savings. And again, that's done monthly and then at the end of the year, a cumulative number.

Q Okay. Thank you. How do FPL's efforts to hedge its natural gas and fuel oil purchases impact the fuel cost volatility?

A In any particular time period or just --

Q Let's look at 1999 and 2000.

A Given what I would describe as minimal volatility during those time periods, I believe that FPL's hedging techniques in that time period were able to minimize costs and minimize the volatility, whatever was there in those markets, pretty effectively. Again, it would be more leaning towards the operational type hedging, which we've talked about here as our fuel switching capability. As one fuel rises in price, we're able to turn -- a large percentage of our units can switch and burn another fuel, cheaper cost fuel. That in itself removes the volatility.

I think in those years our portfolio or our generation mix, which is a mix of coal, nuclear, natural gas, and residual fuel oil, and then, of course, fuel switching capable units, that in itself

removes some of the volatility when you're not captive to one fuel. Our oil inventory or our oil storage capability is also what we consider to be hedging, which helps us to lower fuel costs and take out volatility.

So, you know, our hedging techniques in the past in that time period were very effective in removing what volatility there was in the fuel market and helping us to minimize costs and take out volatility for our customers.

Q Okay. Thank you. Would you turn to the response to Interrogatory 88, please?

A Okay.

Q Okay. Could you clarify the response to part B, options contracts?

A Okay. I think what we're -- I know what we were trying to say in part B is that we don't incur -- the options contracts that we have entered into have been from the purchase side, and they have been entered into during times of peak demand, for example, the summer. Those option contracts have purely been purchased for reliability concerns with the utility. They are there for reliability. They are there if our peak loads are excessive so that we can call on a certain volume of power to help us meet our peaks. So

in that respect, we don't feel there is any basis risk here.

And I guess I would ask you first to explain in this question what you mean by basis risk or what we're talking about there, which may help me to answer it a little better. But my answer is that these were bought for reliability. They do support load. They're not options that were bought to trade. And I guess maybe that's the underlying answer, that we do not buy these options to trade them back into the market. They are there to support our native load requirements.

Now, on any given day, if we do not need them for our native load requirements and the market dictates that we could go and sell that option back to try to capture back some of what we paid for the option, then we will do that, but that is not the primary purpose. They are there for native load.

Q Okay. For the options contracts in part B there, are they exchange-traded, or are they within bilateral contracts?

A They are bilateral.

Q Okay. Thank you. Would you turn back to your supplemental testimony, please, page 2, line 16?

A Okay.

Q All right. You mentioned fuel hedging on that line. Could you please define hedging and speculation?

A Hedging I would define more as insurance or protection. The way we view hedging is, we have a net short physical position. When we hedge, any type of transactions we enter into are to hedge that net short physical position.

As I stated before, we do not buy more gas than we need. And I'm just speaking of gas here, but it applies to everything. We do not buy more than we need, and we do not sell more than we have. We are participating in transactions to help minimize costs and stabilize costs. And again, we have a net short physical position. So if we go take a long position in the market, that is to offset the short position that we already have.

Speculating is entirely different, and maybe an example will clear it up. If I am a trading company that takes a long position without an offsetting position behind that and I take a long position in the market with the hopes that the market will rise so I can sell that position back into the market and make a profit, then I am speculating. I am betting that I know more than everybody else

participating in that market, and I want to try to make money off that transaction.

We are hedging to minimize volatility and try to stabilize costs for our customers.

Q Okay. Is a hedge a circumstance where the risk of one contract is used to offset the risk of another, for example, a financial derivative coupled to an indexed physical contract, in order to reduce net risk?

A Can you repeat that one more time?

Q Sure. Is a hedge a circumstance where the risk of one contract is used to offset the risk of another, for example, a financial derivative coupled to an indexed physical contract, in order to reduce net risk?

A I will say yes to that, and I guess let me give an example to make sure I'm clear here. We have long-term indexed contracts. Some of our contracts are long-term indexed, and we have a net short position. We can go into the financial markets and lock in a volume of natural gas, which then does take the risk, some of the risk out of the indexed contract that the market could swing wildly in the upper direction, and it sets a ceiling for us. So I guess my answer to that is yes. That is the way you can

view it.

Q Okay. Is speculating a circumstance where risk is assumed?

A I assume there is -- well, I assume in my own personal opinion that there is a lot of risk in speculating. You are taking a position purely to try to beat or guess where the market is going, and that inherently has risk in it. If you're guessing where a market is going to go in order to make a profit, yes, you are assuming a lot of risk.

Q Okay. Is speculating a circumstance where price risk is assumed?

A Can you define price risk?

MS. STERN: Let's go off the record.

(Discussion off the record.)

BY MS. STERN:

Q Mr. Yupp, I'm just going to rephrase the last question. Is speculating a circumstance where price volatility is assumed?

A Yes.

Q Does the purchase of a derivative without an offsetting physical position assume price volatility?

A Maybe we need to, I guess, first clear up derivative and what we're speaking to when we say

derivative to make sure we're all talking about the same thing. I think I would like to clear that up, and maybe it's off the record or maybe on. I don't know, but --

Q Why don't you explain -- we're on the record. Why don't you explain how you interpret the term "derivative"?

A Well, can you ask the question again, and I guess --

Q Okay. In the context of this question, you can start out telling me how you interpret the term "derivative" so we'll be clear on that.

A Okay.

Q Okay. Does the purchase of a derivative without an offsetting physical position assume price volatility?

A And my question to that is, the purchase of what derivative, or what are we speaking about here?

Q A futures contract.

A Okay. So does the purchase of a futures contract --

Q Without an offsetting physical position --

A Assume price volatility?

Q Correct.

A Yes, I believe that to be the case,

because, again, what we talked about in speculation is, price volatility is what is going to either reward you or hurt you in the long run, so we would have to assume that in anything there's volatility, volatility is existent there, or it assumes price volatility.

Q Okay. In that circumstance, the purchase of a futures contract without an offsetting physical position, is that speculating?

A Yes.

Q Okay. Does entering into an indexed physical position without an offsetting derivative assume price volatility?

A Yes. Again, there is price volatility there.

Q Okay. Is it speculating?

A I don't believe it's speculating, and I think we have to look at it from FPL's perspective on its indexed contracts. We have a short position that we need to fill. And if you are indexed, there is volatility there. Index is a way to capture the bottom of any market or to incur the prices at the top of any market.

So, yes, a simple answer to the question is, sure, an indexed contract does have -- there is price volatility associated with that indexed

contract.

Q Okay. And then I asked is it speculating.

A No, it's not speculating. Again, I still go back to that the utility has a short position and has indexed contracts that it has entered into under long-term. But are we speculating? No. We still have a need to buy fuel. We still have a need to take that fuel and burn it to meet demand. We're not trying to do anything as far as trying to speculate in a market with a given price movement and capture a gain on it. We are first of all trying to keep the lights on for our customers, and to do that, we need fuel. We do have some contracts that are indexed.

In the past -- I'll go back and say that in the past, that index was a fairly good way to buy fuel, given that prices did not swing all over the place. As we move into the future here and we're looking at different ways to protect our price to our customers, then, yes, that's where you may have to introduce a wide variety of hedging products, physical, some financial, whatever it may be, in order to stabilize costs or take out some of that volatility.

So, no, I don't think inherently you can say that if you have an indexed contract and you have

a price you're going to receive on the other end, you know, in the past, if you didn't participate in any type of instruments to quantify the costs, that you were speculating. We look at it as we have a need to fill, and the indexed contract does fill that need. Are you taking on some volatility? Yes, you are, especially now, now that we've seen that.

MS. STERN: Okay. Thank you. Off the record.

(Discussion off the record.)

BY MS. STERN:

Q Okay. Could you compare and contrast an unhedged position with a speculative position in terms of leverage?

A Repeat it one more time, please.

Q Sure. Could you compare and contrast an unhedged position with a speculative position in terms of leverage?

A What type of unhedged position?

MS. STERN: Any objection to going off the record?

MR. SJOSTROM: None at all.

(Discussion off the record.)

BY MS. STERN:

Q Is not hedging the same thing as

speculation?

A I do not believe hedging is the same thing as speculating. I believe hedging is a -- or the instruments used in hedging are used to remove volatility, to be able to stabilize costs, taking out the risk of fuel moving upward to a large degree.

In speculating, you are hoping for that move in order to make your gain. And we can speak a little to exposure then on a pure trading company, XYZ. Their exposure as they're speculating in the market is really unlimited as the market moves, or it could be. Florida Power & Light's is not. Our exposure really is in the quantity of fuel that we -- only in the quantity of fuel that we need to burn to meet our customers' demand.

But hedging and speculating are very different. FPL participates now in hedging.

Q You just referred to hedging. You just compared hedging with speculating. We're asking about not hedging.

A Is not hedging speculating. Okay. I want to answer this as things have changed.

Q Okay.

A In the past. And if we're specifically referring to indexed contracts, I don't believe that

was speculating, given the low amount of volatility in the market. Buying at index could capture the lows. It would allow you to at least capture the lows and try to minimize costs.

In Florida Power & Light's case, if the price of one of those fuels rose, we could use fuel switching. We could implement operational hedging techniques to really remove whatever volatility was there.

In the future, I don't disagree that an indexed contract or a large majority of indexed contracts -- I'm not going to say it's speculating. There is a risk there. The purpose then of hedging will be to take some of that risk out.

Q So you're saying in the future, entering into an indexed contract will be riskier than it is now?

A I believe from what we've seen in the fuel market, yes, indexed contracts will have a higher degree of risk than they had. But that's not to say that an indexed contract will not continue to be a part of the procurement portfolio. I think that for a large volume of your fuel needs, a more stable fixed price is the way -- a portfolio has to be broken down, and that may consist of a large number or a large

volume of fixed price to meet a base load generation need. In the middle you may have intermediate needs that you may want to do on a -- that you may want to fix on a shorter term basis or hedge on a shorter term basis. On your peaking requirements, indexed may be a good form. If you see the market in a down trend, then an indexed contract or buying at index on any given day is a good way to procure fuel in a falling market.

So it's not that it will be totally eliminated. The indexed allows you to capture the downside of the market. On an overall basis, if everything is on index, then you are at extreme risk to incur the upside of the market, and that's what you're trying to take away. So more of your portfolio becomes at a fixed price, less at index, but it's important to keep index to be able to capture a falling market.

Q And right now is your portfolio mostly indexed?

A A large percentage --

Q Contracts based on the index price?

A Our contracts that we do have in place are based on the index. But we do have the flexibility in those contracts to fix the price on them, as I alluded

to before in one of the other questions. So, yes, they are indexed, but at any given time we can go fixed price with them, and we've built that flexibility into all our contracts, so we're not locked into index. And as our philosophy now is changing, then you're going to see more of the fixed price.

Q Right. But you still will maintain some indexed, some contracts where the cost of your fuel purchases are tied to an index?

A And it may not be a specifically spelled out contract. We have long-term contracts that are at index that we fix. But also, I consider buying index -- going into the forward month buying at index is acceptable. That may not be a term contract with somebody. You may have a contract with a bilateral counterparty, and you buy at index, at the index posted at the beginning of the month. And if you see the market falling, that may be a good way to procure fuel, or a portion of your fuel.

Q Because the index hedges against the falling?

A Yes.

Q And so -- I'm trying to understand some of the things you said. To the extent that you -- in the

market as it is today and as you anticipate it to be in the future, will you need to hedge against your index purchases? Is that --

A Yes.

Q Okay. But in the past, that has not been the case?

A That has really not been the case in the past, only because of the low volatility in the fuel market in the past. And again, I reiterate that we were able to take care of or effectively mitigate price movement in the fuel markets through our operational hedging techniques of fuel switching which, as we stated before, is of tremendous value to us.

Q Okay. Thank you. Would you turn to your supplemental testimony, please, page 2, line 16? I think that's were we were. That's where we left off with the previous question.

A Right.

Q You talk about portfolio diversification there. Could you just explain what you mean by that term?

A Well, portfolio diversification can mean a lot of things, and we can start with our generation mix. Not being captive to one fuel, having a wide

variety of fuel that makes up generation mix is portfolio diversification.

There's portfolio diversification within each fuel procurement. And we can speak to natural gas, that portfolio diversification may mean 50% fixed price gas, another 25% fixed price for only certain periods, another 25% done at index.

So portfolio diversification is in the form of everything from our generation mix to how we procure fuel individually.

Q Okay. Would a portfolio of fuels which are all spot contracts have less price risk than any of the individual fuels alone?

A Would one particular fuel that has all spot contracts --

Q Well, a portfolio of fuels.

A That is all done on spot contracts?

Q Correct.

A Have less --

Q Price risk, price volatility, than any of the individual fuels alone.

A No, I don't think I would agree with that. If we looked at a portfolio of fuels that was all done on spot, I think that the volatility or maximum volatility of that would, of course, be on the

most volatile fuel, which then is going to lead you to say that that's not going to have that -- that entire collection is not going to have less volatility than an individual fuel within that portfolio.

Q Okay. Could you explain what you mean by asset optimization? That's in line 16 of your supplemental testimony, page 2.

A Asset optimization is what Florida Power & Light tries to achieve or does achieve every day. Asset optimization includes economically dispatching your units with the lowest cost fuel, selling your excess generation when a gain can be made to give back to the customers, buying power when it's cheaper to buy power than to run your own generation. Asset optimization is really optimally running your system to first achieve reliability, and that's the number one concern. And then in addition to that, it's the economic dispatch of your system, the lowest cost dispatch, so that means running the right fuels in the right units, and it means buying and selling on the wholesale market as it warrants.

Q Okay. Would you turn to page 3 of your supplemental testimony, please, and look at lines 7 and 8?

A Okay.

Q Okay. You state there that FP&L has implemented numerous hedging strategies to achieve cost minimization.

A Yes.

Q Could you please explain this and provide some examples?

A Yes. And I believe this question refers to what we have done over the past year in light of the high fuel prices over the course of the winter.

Q Yes, that's correct. The question you were addressing in your testimony was what hedging strategies had FP&L implemented over the past year.

A Right. There's a pretty significant list. I think a lot of it pertains to operational hedging, but we can go through it.

FPL utilized natural gas storage in the winter of 2001. We injected gas at a lower cost in December of 2000, with the intent of withdrawing that gas in January to meet peak demand days. But overall, we did not want to run gas in base load units because it wasn't economical. We were able to utilize gas storage and achieve that goal, minimize gas burns on a daily basis and withdraw cheaper gas when needed to meet peak demand.

We maximized our oil storage. As we saw

natural gas prices running up, we were able to fill our oil tanks to make sure we had enough, since we knew oil was going to be the fuel of choice. It took the form of securing additional oil transport, which that became very tight in the winter of 2001, getting enough barging equipment in to get the oil to us. We secured additional transportation.

It meant selling off our excess oil-fired generation into a market that -- into a wholesale energy market that in December of 2000 was very lucrative for our customers, being able to sell much excess oil-fired generation to bring the gains back to our customers.

Over the course of the year, of course, it means fuel switching. It means managing a pipeline imbalance, a monthly pipeline imbalance on FGT's pipe correctly, making sure whatever the economics dictate, that we do that.

So it takes the form of a lot of operational hedging. Switching or swapping out our indexed gas in January for fixed price across the summer, that was a hedge. Locking in some fixed price gas in the summer of 2001 when the view of the market was very unstable and that prices could be extremely high in the summer, given the low amount of storage

levels coming out of the winter, we took a little bit of fixed price position in the summer. So it encompasses a lot of types of techniques, but that pretty much quantifies the list.

Q Okay. Would you turn to page 3 of your supplemental testimony and look at lines 10 through 14? Let me know when you --

A Okay.

Q Are you ready?

A Yes.

Q And I believe you've answered this question, but we're going to ask it to make sure.

Are you suggesting that stored gas was a hedge against gas price increases?

A Yes.

Q Was this storage hedge deliberate or by chance?

A Deliberate.

Q Okay. Was the stored gas a significant percentage of gas purchases for the year?

A It was not a significant amount of gas purchases when looked at compared to the entire year. It was a significant amount of storage when compared to the amount of natural gas that FPL was burning in January and February.

Q Okay. Was the storage used primarily for reliability purposes, not for a hedge on prices?

A Two parts to that answer. Everything we do to a certain extent is geared towards reliability. Our number one job is to keep our customers's lights on, so, yes.

Second to that, though, it was -- it ties together. Our goal in January was to burn the minimum amount of natural gas that we possibly could and still remain reliable.

Well, what does that mean? That means on peak days -- and that speaks to lower fuel costs. Gas was not the fuel of choice. We needed to limit the amount of gas we burned. On peak days, we needed to burn gas, obviously, to meets our peak loads and to be reliable. So what did storage do? It ensured reliability that on peak days, we could pull out lower cost natural gas, put it in our gas burning only units, and be able to meet peak demand. What did it do for the rest of the days? It made sure that that was -- it allowed us to minimize our gas burns on the rest of the days, and that was always sitting there for us to meet those peak demand days.

So it is twofold. The only objective, though, was not reliability. It also worked well in

lowering fuel costs, because with gas sitting in storage, we were able for most of that time period to really minimize our gas burns.

Q Okay. If prices for gas had moved in the opposite direction, would you have stored gas anyway?

A If prices had moved in the opposite direction where gas was going to be economically burned in our units, no.

Q Okay. You wouldn't have stored it. You would have burned it?

A We would have burned it; that's correct.

Q What's more expensive as a hedge, storage or locking in a price with futures or options?

A That's a pretty hard question to answer. Storage has a cost to it, obviously, and you've alluded to it in the dollars per MMBTU basis. Locking in gas at a fixed price on a futures contract has a cost to it, and that may be an opportunity cost that you locked in at a price, and the market has moved down, and now you can't capture that downside. So I really can't answer that one way or another. Each one is taken on its own individual merits, and I'm not sure that is -- that is probably comparing apples to oranges.

MS. STERN: Do you want to take a lunch

break?

MR. SJOSTROM: Let's go off the record.

(Short recess.)

BY MS. STERN:

Q I have some basic questions about hedging programs. Would a reasonable hedging program be one where the utility locks in a price with futures contracts on a rolling basis, for example, for about six months out?

A That could be reasonable, yes.

Q Okay. What are the criteria or considerations for deciding when and in what amount to hedge fuel purchases?

A For us, the criteria really will come in the form of the amount. Given the economics, our forecast of what the economics between natural gas and fuel oil will be, our hedging then is dictated by the amount of generation that we see running, or natural gas-fired generation. So our hedging may come in the form of our combined cycle units that we know are going to be baseloaded units that will run around the clock, given our fuel price forecasts. So we may want to fix the price of that amount of fuel on our system.

Intermediate units we may want to fix on a seasonal basis when we know they will run. The rest

we would want to, obviously, be able to capture in the spot market on what our needs may vary from day to day, utilizing our fuel switching capability. So I think the volumes that you hedge and what you do really are dictated by the type of units you have, what you see running all the time, what may be run seasonally, what is going to run in the spot market or on a more daily type basis.

Q Okay. What are the criteria or considerations for deciding between using a futures contract or an options contract for hedging?

A I think an options contract gives you the flexibility. Obviously, it caps your price. It locks in a capped price for fuel. That doesn't mean you have to take that fuel, and it leaves you the flexibility -- if the fuel market drops, then you're not locked in to that price, and you can go buy the lower cost fuel, but you have capped the high end.

A futures contract, whether it's physical delivery that you set up with somebody or a futures contract, locks you into that price unless in the financial market you unwind that position and get out of it. On the physical side, you would take delivery of it. So the call option gives you a little more flexibility. The long positions then or fixed price

positions are going to kind of lock you into a price.

Q Okay. Does the decision about whether to hedge boil down to the fuel buyer saying, "I think gas prices are going to rise above a certain level by a certain time, so I should lock in the future price now," or "I think gas prices will stay about where they are, so I won't hedge"?

A That's not the way it takes place at Florida Power & Light. For us it is a -- obviously, we're in the middle of studying our best strategy for hedging, given the large amount of fuel that we do burn. But more on a day-to-day basis, we're a collective team for the regulated utility, and that includes oil buying, gas buying, myself on wholesale energy, our forward trader, Mr. Ungar, who does our fuel price forecasting. We collectively talk about where we see the fuel market going, what will be the best strategy, what would be the best strategy in that situation. So it's not one person making a decision. It is a team saying what is the best thing that we can do in this situation. And by utilizing a team approach, I think we can get a lot better decision, because it's not just one person who may be a little off-base.

So that's how we determine what our

strategy is going to be. I think we're still in the middle of evaluating going forward the type of portfolio we will have, and I mean how much is fixed and how much isn't. So that is an ongoing effort, and that is a larger team looking at that. But on a day-to-day basis, what we are going to do monthly or what we are going to do intermonth is done by a collection of individuals, with the final outcome trying to be cost minimization and volatility minimization.

Q So your estimate of what the future price would be, would you say that's just one factor in your decision on whether to hedge or not to hedge, or --

A Right. For us it is. Go ahead. I didn't mean to interrupt you.

Q I just was wondering if you could clarify, identify some other factors. I know you've listed the other teams, but what other factors would determine whether or not you're going to hedge, aside from what you predict a future price to be?

A For us and the utility, obviously, a big part of it is what the future price is going to be. We make decisions on a monthly basis as far as quantifying what our needs are going to be for the month and then making a conscious decision at the

beginning of the month to say we think prices will fall during the months, so we will not procure as much base load as what we feel we'll need, and we'll do it on the spot market, because that's going to be the cheaper way to go. So price is a big factor.

But as a utility, we also have to look at overall schedules, what units are on, what units are off. We look at weather conditions, are we going to have a peak month. So there's a lot of other factors that go into how much fuel we're going to burn in any particular time period, and we have to take those into consideration too. Ultimately, price drives everything, but volume wise we have to look at weather and unit outages and transmission constraints. So there's a lot of other things to take into account.

Q Okay. I think you've answered this, but I'll just double-check. I'll read it. What is the basic information, for example, fuel prices, forecasts, current positions, that a utility needs to engage in the prudent use of hedging?

A I think first and foremost it needs to at least have a clear view of where it believes the market is going to go. And I think I spoke to that in the last example I gave on going into a month. How do you see prices moving -- and we'll just take a month

at a time. What do you think the daily price of natural gas will be versus the first of the month?

So, you know, the information that we need, of course, is all of our operational type information and our load data and everything, and then next a forecast of where we feel that the fuel markets will go, both natural gas and residual fuel oil.

Q Okay. Can derivative instruments be used to make the gas price forecast used in the fuel factor be realized?

A Not entirely, because, again, I think in any good procurement plan, I don't think you can hedge 100% of your fuel needs. And I know Florida Power & Light can't do that, and that speaks to load variations, unit outages, whatever it may be. So we don't really know the quantity of fuel that we're going to burn. We have a projection, but we cannot quantify it, so we cannot perfectly hedge all of our fuel needs, because our fuel needs may vary from what we project due to load and unit outages.

Also, I don't believe that 100% hedging -- and let's assume fixing the price of natural gas or fuel oil is really the prudent thing to do, because it does take out the down -- it does not allow you the flexibility to capture the downside of a market.

So to answer your question, if Florida Power & Light could go hedge its entire fuel needs, then, yes, you could say that what we tell the Commission and our customers their costs are going to be for 2002 if the market is there at that time -- and that's an important aspect also, if the market is there at that time. You could go lock in all your needs, and you would be set. But what you've done then is, you've taken away your flexibility to capitalize on a downturning market and to lower costs even further for your customers. So you would not do that, or we would not do that. I can't speak for anybody else.

Q Okay. To decide whether to lock in a price or not, is it correct that you compare your forecast to the market forecast?

A The market -- I'm not sure what you mean by market forecast. I don't think that we can take a look at the forward curve at any given time and say -- I don't know if that takes into account everything that we're looking at when we are forecasting. You know, we may try to figure out where prices are going to average on a daily basis. If we were to say right now that the forward market -- if we looked at the forward market for next year right now, we would

compare our forecasts to that to a certain extent. But I think we rely heavily on where our forecast is, because we're taking into account a lot of other factors in where we predict prices to go.

So I think you can compare your forecast to the market to see if you're in line. I think we compare our forecasts to what other publications are saying, where they feel fuel prices will be over any given period of time. So we do a lot of comparison, and ultimately we operate off of what we forecast the price to be.

Q Okay. So you do -- you said you do a lot of comparison.

A Yes.

Q Can a utility use derivative instruments to realize its gas price forecast within a certain range?

A Derivative instruments in the form of call options and put options can quantify a rage. Can you do enough volume to entirely put your portfolio in a range? I don't think so. But, yes, derivative instruments such as calls and puts can be utilized to quantify a range for a certain portion of your fuel.

Q Would the certainty about the forecast have value to the utility for planning purposes?

A I'm not sure what you mean by the certainty. That --

Q Well, you had said that you could use calls and puts to forecast a certain price within certain limits.

A Right.

Q Okay. So I assume that that forecast has a certain degree of certainty associated with it.

A Yes. If we could be assured that it was 100% certain, it would be a lot easier job. But, yes, the degree of certainty we feel in the forecast helps in procurement. If you have a high degree of certainty that you know where prices are going to be, it obviously will help. Obviously, you do the best job you can in forecasting, and it may go in either direction due to market conditions. But, you know, the higher degree of certainty, it helps you procure fuel, I guess is the ultimate answer to that.

Q Can a utility use derivative instruments to enhance its ability to make off-system sales?

A There I think it's less. Again, we make off-system sales when market conditions warrant and when we have excess generation. It's done more on a spot basis. The better you procure fuel or the lower cost that you procure fuel at, it helps you in a sales

market, obviously, to fit into the market so you're not above others' cost.

We do not do that, though. Derivative instruments or whatever type of hedging we're talking about relates to fuel. Our participation on the wholesale market is on more of a daily and spot basis, where do we fit in at any given time, hourly, daily, monthly. And if we can make an off-system sale, we will do it; and likewise, if we can purchase, we will do it. So there you're not going to see a lot of use of any kind of instrument, because, again, that we handle more on a real-time basis.

Q Okay. Would you please turn to page 3 of your supplemental testimony? And take whatever time you need to review lines 1 through 7.

A Okay.

Q On lines 1 through 7 you discuss techniques FPL has employed minimize fuel costs; is that correct?

A Yes.

Q Could derivative instruments be used to enhance or improve those techniques?

A I would say not. The techniques that I am speaking to here, it's more operational techniques that we do with fuel switching, selling excess gas, burning lower cost oil on any given day, optimizing

our gas transport when we don't need the gas transport by selling delivered natural gas. That's all more what I call operational type and day-to-day activities. I don't believe that any type of instrument, forward instruments or derivative type instruments would help that. That is something we continually do on a day-to-day basis.

Q Okay. Can you quantify the effects of the techniques you mention in lines 1 through 7?

A Off the top of my head, it's a little difficult. Rough estimates, I think when we answered Interrogatory 80, we showed gas and oil savings, and this is part of it.

But selling excess gas into the market, I know in December of 2000 it was roughly $10 million worth of added value to our customers by being able to fuel switch, burn oil and sell gas.

Overall, what is fuel switching worth? I don't know. I think the Commission staff has actually done some calculation on it, and I want to say it was around $100 million over the last year on what our fuel switching capability, what kind of value that adds to us.

Selling -- and I don't believe we have it in here, but even selling excess oil-fired generation

in December of 2000 was added value of $16 million back to our customers.

So I don't have exact numbers. Those are some rough estimates. Fuel switching obviously is the biggest value that we add back to our customers.

Q Okay. Are 100% of the benefits of the techniques mentioned in lines 1 through 7 passed on to ratepayers?

A Yes, they are.

Q Would you please turn now to page 4 of your supplemental testimony and look at the question and answer that starts on line 12? Just take whatever time you need to review that.

A Okay.

Q Does FPL currently have a risk management plan as a stated part of its fuel procurement practices?

A Yes.

Q Okay. What are the appropriate issues that a risk management plan should address?

A I think from our perspective, it's what we're trying to accomplish in the overall procurement plan. But our risk plan has bar limits set, you know, limits on the number of contracts, so to speak, that we can use in the financial markets. We're not there

speculating. We're trying to hedge, so we participate in those markets to gain some knowledge. But risk management, obviously, the main thing is to set some limits on what we can do.

And other than that -- I don't know. If you can repeat the question again. I kind of lost my train of thought.

Q Sure. What are the appropriate issues that a risk management plan should address?

A I think the limits are important. I think the risk management plan should be in sync with what the overall procurement plan is, which is to lower the volatility and cost. Risk management I guess takes a number of forms, and that comes in setting trading limits, credit limits. They're kind of behind the scene in the procurement plan, but ultimately that's what I would say, setting limits and being in sync with what the utility's overall procurement plan is.

Q Okay. Would a risk management plan that addresses the use of derivative instruments for hedging offer some assurance against sharp price increases in natural gas such as occurred in October 2000?

A I think it can. And if by risk management plan we mean a hedging plan that utilizes a number of

different types of hedging, yes, I think it can. I think it can eliminate some of those price spikes that we did experience last year.

Q Can FPL file a risk management plan with the Commission as a part of this proceeding that addresses the use of derivative instruments and prudent fuel procurement practices, hedging, speculation, regulatory treatment of hedging gains and losses, regulatory treatment of transaction costs, and goals for 2002?

A Can we get together with the Commission to cover all of that? And I need to go back to your first question on risk -- I guess I was a little confused. Not risk management, but on our hedging program.

Q Okay.

A But can we do that? Yes, and I think it is our intent to do that. I know Florida Power Corp. has mentioned some type of workshop. I think Florida Power & Light feels that a workshop would definitely be advantageous to all of us, to sit down together and to go through some of the issues, some of the questions that the Commission may have, some of the questions that we may have, and work out -- you know, FPL is currently looking into what their long-term

plan is going to be. We would like to share that with the Commission. So, yes, I think that -- in my opinion, it is a necessity to do that, to sit down and go through that with the Commission.

Q Can this plan explain how FPL intends to use derivatives to achieve fuel cost and volatility minimization to the customers?

A The plan would encompass that. Obviously, some of what our plan would be would be confidential information. But, yes, I think our plan would be to address what types of instruments we would use to hedge, to clarify with everybody what types of transactions are really taking place. But it would cover what types of instruments we plan to use, what our plan is for mixture, and how we -- that is the whole gist of what the plan would be, how it is going to help first to minimize or mitigate volatility, and secondly, minimize cost.

Q Are derivatives more than a supplement to operational hedging techniques?

A In the past, no. In the future they will be more than a supplement. And again, I don't know what types of derivatives we're talking about here. But, yes, hedging, whether that takes the form of fixed price physical delivery or some types of calls

or puts, or whatever it may be, yes, will be more than supplemental to operational hedging in the future.

Q Can operational hedging techniques do everything that exchange-traded derivatives can do?

A No.

Q Okay. Instead of using futures and options for hedging the price of gas purchases, would a mix of fixed price contracts and spot indexed contracts accomplish the same thing, that is, some insurance against volatility?

A What was the first part of that question?

Q Instead of using futures and options for hedging the price of gas purchases, would a mix of fixed price contracts and spot indexed contracts accomplish the same thing instead of futures and options for hedging?

A It could. I won't say definitely. It's a hard question to answer. I think it could, and I think that's what we're aiming for. When we talk about fixed price and a percentage of our portfolio fixed price, we're talking more on the physical side, which would then go back to utilizing contracts. So, yes, I think it could.

And can I just go -- I don't know if this is out of turn or not, but I would like to go back to

the last question.

Q Sure. Anytime you want to refer back to a question and add to it, or if you feel like you need to make a correction, feel free to do that.

A Well, I said in response to the last question no, that operational hedging can't accomplish everything exchange-traded can. I think there's a clarification. They're different types. I look at operational hedging for us on a day-to-day, real-time basis, how we can respond to changing fuel markets, spot fuel markets, how we can lower costs by utilizing that, and somewhat also in the future. In operational hedging, obviously, we use gas storage and everything. Exchange-traded or over-the-counter, or whatever it may be, I look at as more longer term type instruments to use for hedging. So that's just a little bit of clarification there.

Q Okay. Thank you.

Can clauses be inserted into bilateral contracts that accomplish the same thing as an exchange-traded derivative does?

A I don't know that I know the answer to that. I know we have -- I don't know if this is the intent of this. We have clauses in our contracts, as I mentioned before, that take an indexed contract and

allow us to fix the price of it. I don't know if that's what you're trying to ask here. I don't know how to answer that question, to be honest with you.

Q Okay. Could you turn to page 4 of your supplemental testimony and review lines 16 through 18?

A Okay.

Q Would it be less costly but more volatile for FPL to be completely unhedged?

A It would definitely be more volatile for FPL to be unhedged. Would it be more costly? I don't know. I think it speaks to volatility. It would obviously be more volatile to be unhedged. Would it be less costly? I don't know the answer to that. I don't believe so.

I think that the proper use of -- whether it's physical hedging or financial, or whatever we're talking about, it ultimately can remove volatility and minimize cost if it's done in the right percentage and you're still able to capture downsides in markets, if you leave your flexibility there to capture that. I think a fuel procurement portfolio that is properly hedged will have less volatility and lower cost than being completely unhedged.

MS. STERN: Do you mind if we go off the record?

MR. SJOSTROM: Not at all.

(Discussion off the record.)

(Recess from 12:57 to 1:54 p.m.)

BY MS. STERN:

Q Mr. Yupp, would you turn to your testimony, your original testimony filed in August of 2001, and turn to page 17 and review lines 17 through 23?

A Okay.

Q Oh, I'm sorry. Save your place there. I need to back up and come back to this question in a minute. I need to ask you some questions about the volatility of the gas supply portfolio of FPL.

A Okay.

Q Does FPL measure the volatility of its gas supply portfolio?

A I would answer that FPL would measure the volatility through its value-at-risk calculations on any of its positions that it has. On the entire portfolio of our indexed contracts, no, I don't believe so.

Q Okay. And what about for the fuel oil supply portfolio? Do you measure the volatility of that?

A Again, no.

Q Okay. Now I have a question about your

testimony on page 17.

A Okay.

Q You're talking about new purchased power agreements.

A Yes.

Q Could you explain why these agreements are necessary?

A FPL has contracted for the approximate total of a thousand megawatts that you see there in the question as part of its ongoing effort to keep its reserve margin, and also it agreed with the Commission to increase its reserve margin to 20%, I believe by next year or the year after. So this is all part of that. It was bought for reliability and also for our reserve margin.

Q Why are the purchased power arrangements the most cost-effective alternative?

A I don't know that to be true, and we're probably getting into an area that I probably can't speak to. I know for our needs for next summer and beyond, obviously, this is how we approached doing it. I was not involved in any additional discussions as to any other options, so all I can speak to is what we have purchased to date.

Q Okay. Do you know if FPL has any financial

interest in any of the parties that you entered into these purchased power agreements with?

A By financial interest you mean --

Q Any type of financial interest, ownership interest, stockholder.

A Not that I am aware of, no.

Q All right.

A I would answer no to that.

Q Okay. Now, you also discuss in there purchased power agreements you entered into for the year 2002. Were any of the purchased power agreements necessary for FPL to maintain its reliability criteria, or criterion?

A Well, I think as part of the reliability criteria, your reserve margin is part of your reliability criteria. And from that overall perspective, I would say yes, these purchased power agreements do help us meet our reliability criteria.

Q Okay. For each of the purchased power arrangements, did FPL perform a cost-effectiveness analysis?

A At the time that FPL entered into these agreements, the analysis was done versus the market price for similar products, especially on these having full dispatch rights to a combustion turbine. So the

evaluation was done on a market basis.

Additionally, I should state that FPL not only has looked to this option in meeting their needs, but as we allude to in this testimony, we are repowering some of our own units and adding additional megawatts through that means. But these were evaluated against where the market would be for this type of product.

Q Okay. I have some questions about Appendix 1 to your testimony, page 15.

A Okay.

Q All right. Is the FPC system purchase recallable by FPC for any reason?

A The FPC is equivalent to native load. It can -- FPC can cut that transaction in certain instances, and we will be made financially whole due to that. But essentially, it's equivalent to FPC's native load.

Q In what instances could FPC recall the purchase?

A If FPC were to get into a situation that they needed -- one of the stipulations in that agreement is that if they were to need emergency interchange from us, they then can bring that transaction back, so to speak. We would supply them

emergency interchange, but there are financial penalties associated with that. That is the only part of the agreement I know on a recalling instance. Otherwise, I would treat this as equivalent to native load, and it would be cut pro rata with native load.

Q Okay. The rest of the agreements referred to in this table, are they made with merchant plant companies?

A Yes.

Q Is there any instance where these merchant plant companies would not supply FPL with firm capacity and energy other than a unit outage?

A No.

Q If the units are unavailable, are the merchant entities responsible for providing replacement power?

A Off the top of my head, I would have to go back and look at the agreements, but I believe so. I'm not sure if it's all of them, but it may be. But I know replacement energy is usually part of the contract. I would have to go back and look at these.

Q Do you know at what cost -- what the replacement energy would cost or how you determine what the cost of the replacement energy would be?

A Specifically, no. Just to venture a guess,

it would be along the lines of what the unit would cost us to dispatch with our own fuel and our guaranteed heat rate. It should be within those limits, but I do not know that for sure.

Q Okay. Why do the capacity payments differ for the two Oleander Constellation purchases?

A Those are different time periods. In Oleander Unit 1, that is June 2nd through May 5th, and for Unit 2 it's June 2nd through April 3rd. And what happens is, it may be that it shows that the value in the closer to years, so to speak, closer to 2002 for that capacity is higher than it will be as time goes on out further.

Q Are these purchases made from identical types of generating units, Unit 1 and Unit 2?

A I would assume so. I would assume they are the same combustion turbines, same model combustion turbines.

Q The dollar per kilowatt capacity cost for the FPC system purchase appears to be much higher than the other four purchases in this table. Could you please explain why that is?

A I'm not sure why that is higher. That was done through a bid process with FPC, or an RFP process with FPC, and I really can't speak to why that is

higher than the rest.

Q Okay. What is the estimated amount of energy payments in 2002 for each of the power purchase agreements listed on this table?

A The energy payments are really not quantifiable right now because it is at a given heat rate with our own fuel, so it's really going to be whatever our fuel costs us in our own units, and that will be the energy component of at least four of these -- obviously, not the FPC system one, but of the combustion turbine output that we have purchased.

MS. STERN: Okay. That went faster than I thought. Those are our questions that don't touch on confidential information. At this time, if there's no objection, I would like to go off the record.

MR. SJOSTROM: No objection.

(Discussion off the record.)

BY MS. STERN:

Q Okay. I'm going to repeat a question. The dollar per kilowatt capacity cost for the FPC system purchase appears to be much higher than the other four purchases in this table. Could you please explain why that is?

A Yes. The dollar per kW capacity payment

would be higher in the Corp. transaction due to the fact that the underlying energy price that Florida Power & Light is paying Corp. when they do call on the energy is significantly less than the other four transactions that you see listed here.

MS. STERN: Okay. Thank you. I would like to go off the record now, please.

MR. SJOSTROM: Very well.

(Discussion off the record and short recess.)

CROSS EXAMINATION

BY MR. VANDIVER:

Q Good afternoon, Mr. Yupp.

A Good afternoon.

Q I'm Rob Vandiver with the Office of Public Counsel. I have a couple of questions for you.

Specifically, I wanted to talk a little bit about the -- I think it's the Dean study.

A Okay.

Q FPL is the largest electric investor-owned utility in the state; is that correct?

A Yes.

Q Hedging is an important issue to FPL and its ratepayers?

A Yes.

Q There's a lot of money on the table?
A That's correct.
Q FPL filed a total of four pages of testimony on the hedging issue in this docket?
A Yes, we did.
Q And will you accept subject to check that that's more testimony than any of the other IOUs filed on this subject?
A Subject to check, yes.
Q The Dean study is due in early November?
A Yes, it is.
Q How long has the Dean study been underway?
A Off the top of my head, I would say since August. I want to say since August, maybe July.
Q Can you walk me through just an outline of what's in that study?
A What we're trying to take a look at and evaluate with an unbiased third party, so to speak, is what are the proper hedging techniques that we should use, what's the right mix for us, if taking a historical look back, what would hedging have done for us for the last four years, what types of instruments can we use. So it's really to get an outside opinion, you know, this is what you can do, here's what you would have gained from what you had done in previous

years, including last year, and here's what you should do going forward, this is how much volatility you can remove and how much we feel you can minimize cost. That's what the study is to do, what hedging techniques are going to lead us to that ultimate objective of minimizing volatility and cost.

Q Hearing you describe it, that really sounds tremendously important for the issues in this docket. Would you agree with me?

A I agree it is important.

Q Tremendously important. Would you agree with that characterization?

A It is important, very important.

Q Very important?

A In this docket and in all future fuel dockets, yes. It's very important in the whole fuel procurement arena.

Q And I think I'm going back -- you know, these kind of blend together, but yesterday I think I heard you say that it was going to be completed early November.

A I honestly do not know the time frame of this. I know it was scheduled to be completed in early November. Whether we would have the time to get something ready by then and before the fuel hearing,

depending on whether we want to go into workshops with the Commission to give our findings out, to talk about hedging, what are the right strategies -- I don't know a time frame on it, to be honest.

Q I think I heard you say yesterday that you thought you might share the results of that after the November hearings with the Commission and the other parties. Is that correct?

A I may have said that, and that may be the case due to the workload that we have right now. But I don't think that lessens how important it is to this docket, because I think we want to make sure we get it right, and we want to make sure we give out the right findings and approach it from that aspect.

Q I couldn't agree with you more. Would you agree with me that a workshop process might be the appropriate way to go?

A Yes. Yes, I would agree with you on that.

Q And that's particularly with the paucity of testimony that we have, the little bit of testimony that we have on the record in this docket?

A Yes.

Q So would you agree with me that it might be appropriate for the Commission to perhaps go to a workshop process and address the hedging issue in the

next fuel adjustment proceeding?

A That may allow for a better period of time to really go through the issues and do a good job on it and not try to put something together so quickly that it's not the right answer. Yes, I agree with that.

Q Because the Dean study will ultimately be paid for by the ratepayers, won't it?

A Yes.

Q Let's see. There were some things earlier in your testimony that I was going to ask you about.

You referred to FPL as a net short utility?

A Yes.

Q Can you flesh that out a little bit for me? Do you refer to net short in terms of all your fuels?

A I will speak to natural gas and residual fuel oil. Coal mostly is done under long-term contracts. But we can just take natural gas and residual fuel oil. We do not have under contract, under long-term, mid-term, or short-term contract enough to cover what we feel our needs could be at any given time. Natural gas, for example, historically our long-term contracts were 30 to 40% of our needs. We then could fill in at any given time on a monthly

basis the remainder of what we needed, given the economics of fuel. So, yes, we are -- but even to that, yes, we are a net short utility. We do not have contracts to fulfill all of our fuel needs at any given time.

Q And net short refers to short in what time period? Is that on a monthly basis you're net short?

A Well, I look at it as overall. We are short -- that's harder to answer. Ultimately, our position is that we do not have enough fuel under contract to meet our needs, and that could be at any given time. If you want to say monthly, that's fine. For next month, do I have enough fuel, or can I buy enough fuel under my long-term contracts to meet what I project my needs are? No. How am I going to meet those needs? I'm going to go buy in the market. I'm going to go with counterparties and fill in the rest of my needs, and on a daily basis, as needs warrant, I'll buy in the spot market.

So that's where I was coming from. It's hard to put a time frame on it. But ultimately, we have demand to need. We have generating units that are going to meet that demand, and we need fuel to put in the generators to make megawatts. We don't have enough fuel under -- I don't want to say enough.

That's the wrong description of it. We don't have all of our fuel needs under contract.

Q Okay. Maybe a way that I could perhaps understand it a little bit better, maybe you could walk me through a typical load day.

A Okay.

Q Let's take a hot July day. It's 9:00 Monday morning, or 7:00 Monday morning, and the power plants are just ramping up, and I guess we've got some down for scheduled maintenance.

A Hopefully not in July, but maybe.

Q Well, I don't know what your -- you know this so much better than I do. I know that a hot July day -- walk me through a typical day from your perspective in buying that fuel and meeting the needs of your customers just very briefly.

A Okay. I would preface it by saying what we would have done prior to that. In June we would have made a decision for what our base load needs of natural gas would have been for the month of July. So if we had felt that -- let's just take hypotheticals here, 800,000 MMBTUs a day. When we ran it in our economic dispatch model, that was the average amount of gas we would burn, given the price relationship of all the fuels. And let's say we have contracted for

800,000 MMBTUs of firm transport, so it was exactly even.

We would have made a decision prior to going into July, do we want to go out and buy the 800,000 a day every day, or do we want to stay a little bit short, do we want to buy 700,000, because we think prices will go down during the month, so every day we'll go buy that incremental 100,000, leave a little bit of flexibility in case the load doesn't materialize and maybe we don't fully need the 800,000, because --

Q Better net short? Is that part of it?

A Right. That's all part of it. You just can't quantify to the molecule what you really need. So sometimes if you go procure everything that you feel is what you're going to burn base load and the load doesn't come in for you, now all of a sudden you have too much gas, so we leave ourselves a little flexibility.

So now we get to that Monday morning and we're at 700,000 on a base load schedule, and for the next day we project the load to be very high, that we'll even run some gas in our peaking units. And the economics dictate that we could burn -- that any incremental gas we buy beats oil on the margin, so we

go to the market, and we buy up to our firm transport, so we buy our 800,000. We feel we have some more needs, and what we'll do then is go into the IT market, try to procure some -- or secondary market, try to procure some more delivered gas to us if we feel we need it, or into an interruptible transport market. And, of course, there's a cost associated with that. Is it still economical? Yes. Then let's go ahead and buy it.

So that's how it goes day to day, and it's really a constant monitoring of fuel prices and what's the right thing to do. Sometimes when you get into the middle of summer, of course, you know, your loads are high, and you know you're going to burn gas, and so you're buying gas.

Where it really can be beneficial, our fuel switching and all of that, is in what I consider now the shoulder months, where your volumes could swing greatly on natural gas or fuel oil, depending on the economics of them. So that's where there's the real value, in those shoulder type months.

Q Thank you. You were asked some questions very early on about the effect of the September 11th terrorist attacks, I believe.

A Yes.

Q And I think your answer was that the September 11th attacks had no effect on your projections for natural gas or supply; is that correct?

A Yes, and probably I misspoke a little there. I was focusing more on where we feel it's going to have a very big impact, which is our load. But to a certain extent in fuel forecasting, due to the economy and what those attacks are doing to the economy and may continue to do, then, yes, it is a part of also where we see prices. To what extent I don't know, but, yes, it would impact your fuel price forecasts.

Q Have you quantified the effect on the load in sales?

A I have not. That had been done by Resource Planning. I do not have those exact numbers, what kind of impact they see. I believe we are still working on that and continuing to. So, no, I don't have the exact numbers on how it's going to impact. You know, what the projections are now from what we have heard is, you know, lower loads, obviously, less sales. I don't have a specific number for you.

Q Will those numbers have a finer point on them by the time of our hearings in November?

A Yes, they will.

Q So you will agree me that the hedging things could be deferred until the next fuel adjustment?

A Well, I don't know if I want to say deferred, and I don't know officially how everything will work out. I think we should start working on them as soon as we get our results and get our plan together.

I don't think that's going to -- when it comes up, we are still going to move forward with what we believe to be a good plan. We've seen these fuel markets come back down to a reasonable level, if we can define reasonable, and some of -- you know, a little less volatility with what we project next year. So I think it's a good plan. It gives us some more time, though, we do it right. I approach it from the standpoint of having enough time to make sure we do it right, to make sure we convey our points correctly, what we think is important.

So, ultimately, I think the answer is yes, I think we can wait until then. I think we will continue building our strategy and implementing it.

Q Do you have time to do it right before the hearing this November?

A I think that's a little tough, given the amount of workload that we have answering interrogatories and depositions and a lot of other things. So my feeling is not to short-change this effort, because I think a workshop environment would be important to make sure we're all talking about the same thing and we all understand the same thing.

Q If you had to answer my question yes or no --

A If I had to answer it, I would say no.

MR. VANDIVER: Thank you. That's all I have.

MS. STERN: Can we go off the record.

(Short recess.)

MS. STERN: Our deposition of Mr. Yupp is concluded.

(Deposition concluded at 3:21 p.m.)

CERTIFICATE OF ADMINISTERING OATH

STATE OF FLORIDA)
COUNTY OF LEON)

I, MARY ALLEN NEEL, Notary Public in and for the State of Florida at Large:

DO HEREBY CERTIFY that on the date and place indicated on the title page of the foregoing transcript, an oath was duly administered by me to the designated witness before testimony was taken.

WITNESS my hand and official seal this 30th day of October, 2001.

MARY ALLEN NEEL, RPR
100 Salem Court
Tallahassee, Florida 32301

Mary Allen Neel
MY COMMISSION # CC 782020
EXPIRES: October 10, 2002
Bonded Thru Troy Fain Insurance

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, MARY ALLEN NEEL, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter transcribed under my supervision; and that the foregoing pages numbered 51 through 142 are a true and correct transcription of my stenographic notes.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, or relative or employee of such attorney or counsel, or financially interested in the action.

DATED THIS 30th day of October, 2001.

MARY ALLEN NEEL, RPR
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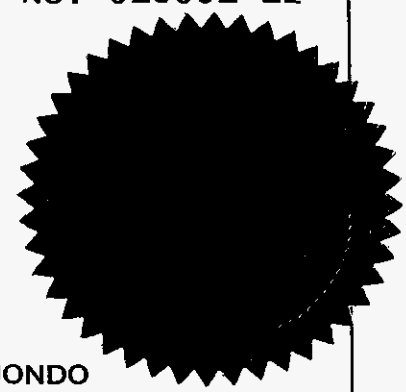
BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of

DOCKET NO. 010001-EI

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE AND GENERATING PERFORMANCE INCENTIVE FACTOR.

_____/



DEPOSITION OF:	JAVIER PORTUONDO
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
DATE:	Thursday, November 1, 2001
TIME:	Commenced at 12:17 p.m. Concluded at 1:56 p.m.
LOCATION:	Gerald L. Gunter Building Room 362 2540 Shumard Oak Boulevard Tallahassee, Florida
REPORTED BY:	MARY ALLEN NEEL, RPR Notary Public, State of Florida at Large

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APPEARANCES:

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WILLIAM COCHRAN KEATING, IV, Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0870, appearing on behalf of the Commission Staff.

ALSO PRESENT:

ROBERT SCHEFFEL WRIGHT, Landers & Parsons, 310 West College Avenue, 32301, Tallahassee, Florida 32301, on behalf of Johnson Controls.

DAVID GAMMON, ROBERT NIEKUM, and PAMELA MURPHY, Florida Power Corporation.

TODD BOHRMANN, Commission Staff.

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S T I P U L A T I O N S

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure; that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing is not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

PROCEEDINGS

MR. KEATING: I guess we'll go ahead and take appearances.

MR. McGEE: Jim McGee on behalf of Florida Power.

MR. VANDIVER: Rob Vandiver appearing on behalf of the citizens of the State of Florida.

MR. KEATING: And Cochran Keating appearing on behalf of the Commission staff.

* * *

Thereupon,

JAVIER PORTUONDO

the witness herein, having been first duly sworn on oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. KEATING:

Q Good morning.

A Good afternoon.

Q Good afternoon. Thank you. For the record, could you state your name and business address.

A Javier Portuondo, P.O. Box 14042, St. Petersburg, Florida.

Q Mr. Portuondo, do you have your prefiled testimony filed September 20th in this docket?

A I do.

Q I'm just going to ask you to reference to certain of the E schedules that are attached to your testimony. Were the data in Schedule E3 prepared or created by you or under your supervision?

A Yes.

Q Okay. Were the data shown in Schedule E4 created by you or under your supervision?

A Yes.

Q Would the same be true for the data shown on Schedule E5?

A Yes.

Q And E6?

A Yes.

Q And would the same be true for the data in Schedule E7?

A Yes.

Q And for Schedule E8?

A Yes.

Q And finally, would the same be true for the data shown in Schedule E9?

A Yes.

Q Do you also have with you your prefiled testimony that was filed October 8th? I'm sorry. I'm jumping ahead of myself. Let me stay on the September

20th testimony.

Is recovery of the amounts that Florida Power Corporation receives through the fuel adjustment clause any more certain than amounts received through base rates?

A I'm not sure I understand the essence of the question.

Q Is it correct that expenses that are recovered through base rates -- strike that. Expenses for fuel cost recovery are reviewed on an annual basis; correct?

A Correct.

Q And expenses that would be recovered through base rates are only reviewed in a rate proceeding; is that correct?

A Correct.

Q So based on that, is there any more certainty -- and maybe this goes to the timing of the recovery -- that you'll get recovery on a particular expense through fuel rather than through base rates absent a rate proceeding?

A The fuel clause does mitigate regulatory lag, yes.

Q In your opinion, should the rate of return for the unamortized balance of capital projects

recovered through the fuel clause be different than the rate of return that the capital project would have earned if the asset was part of rate base?

MR. McGEE: By rate of return are you referring to the equity return or the overall cost of capital?

MR. KEATING: The equity.

A The equity return should be the same in both cases.

Q Do you believe that there would be any obstacle to the Commission authorizing a utility to earn a rate of return on the unamortized balance of a capital project other than the rate of return that has been authorized, that is, the midpoint of the rate of return authorized for the utility?

A That sounds like more of a legal question, whether they have the authority to do that.

Q In your opinion, would there be any technical impediments to the Commission authorizing a rate of return for the unamortized balance of capital projects other than the rate of return midpoint?

A The technical application of a decision? Is that what you're referring to?

Q Right.

A No. The technical application would be

very simple to apply. Whether they have the authority to do so is a legal matter.

Q Do you believe that the utility would be fairly compensated if a different rate of return, that is, other than the utility's authorized rate of return midpoint, were applied to that unamortized balance?

A No. The utility would be harmed by that action.

Q How would the utility be harmed?

A Because it would not be permitted to earn its fair rate of return based on the Commission's actions in the last rate case.

Q For Florida Power Corporation, how much have fuel costs been reduced by capital projects over the last ten years?

A I don't have that information at my fingertips.

Q Okay. Is that information that you could obtain?

A Yes.

Q I may go back to that and see if that's something that could be provided as a late-filed exhibit.

A It may have already been provided in an interrogatory. The fuel savings associated with the

gas conversion project would be what your question is alluding to, and I do believe that we've provided that.

Q Are those the only projects that --

A That's the only projects that we are recovering through the fuel adjustment clause.

Q Okay. I may go back to that one. I'll think about that.

I don't suppose that you would have on the tip of your tongue any idea of, for every dollar of capital projects recovered through the fuel clause, how many dollars of savings there have been?

A No, but that interrogatory may have the return versus the savings.

Q Okay. I'll check on that as well.

Do you believe that absent -- well, let me step back. I know you stated it just a minute ago. What capital projects does Florida Power currently recover through the fuel clause?

A The conversion of a number of CTs to dual fuel capability. That would be gas and oil.

Q Absent approval for recovery of those projects through the fuel clause, do you believe that those projects would have been undertaken?

A I believe they would have, yes.

Q Were you involved in any of the decisions made with respect to those projects, or to that project?

A To the actual construction project or the recoverability of that?

Q The actual construction projects.

A No.

Q Were you involved in the recovery side?

A Yes.

Q How were you involved with that?

A In a support function of Carl Whelan as far as whether it was consistent with Commission practice to allow for the recovery of such costs.

Q Do you know who would have made the ultimate decision on whether to go forward with those projects?

A No. It spanned a number of years. I'm sure there were different individuals involved over the years.

Q When Florida Power is evaluating a particular capital project, is the potential for recovery through the fuel clause something that it considers?

A I think recovery is something that is considered, but it's not the primary focus of the

analysis.

Q So do you believe that the certainty of recovery through the fuel clause is not a deciding factor?

A No, I don't believe so.

Q Is the fuel clause the only mechanism for recovering prudently incurred fuel-related capital expenditures?

A No. The Commission's past practices and orders have incentivized the companies to implement new technologies which result in fuel savings and has encouraged the utilities to -- or has permitted the utilities to recover the cost of pursuing those technologies, the recoverability of those costs through the clause which receives the benefits of those projects.

Q Do you believe that the dollar amount associated with a capital project is an important consideration in Florida Power's decision on what cost recovery mechanism to pursue?

A I --

Q I guess stated differently, depending on the dollar amount of the project, would Florida Power Corporation look at one recovery mechanism versus another?

A I think the analysis that takes place is, is the project overall cost-effective, are you going to achieve the savings that it is your objective to achieve. I don't know that the magnitude of the dollars is the driving force for the type of recovery mechanism that you pursue.

Q Most of the remainder of my questions concern litigation between Lake Cogen and Florida Power. Are you familiar with that litigation?

A Yes.

Q And just to be clear, in the litigation, is the corporate name of the Lake entity NCP Lake Power?

A I believe that's true. I believe it has changed.

MR. McGEE: We may want to look at that. This question has come up before. The confusion that comes up, and it's apparent in this order, there's a distinction between Lake Power and Lake Cogen.

THE WITNESS: NCP Lake Power, Inc., according to the way it's presented in one of the orders, is the general partner of Lake Cogen, Ltd., referred to as Lake Cogen, if that clarifies that.

BY MR. KEATING:

Q Well, I can go through those later to get a better understanding.

Well, let me make sure I understand. Is Lake Cogen the party to the litigation, or is NCP Lake Power, or both?

MR. McGEE: We're reviewing a copy of an order that was issued in the court proceeding, and the language indicates that the general partner of Lake Cogen, and the general partner is Lake Power, was the plaintiff in the action. I believe the contract that we have, though, is with Lake Cogen, Ltd.

BY MR. KEATING:

Q Well, in my questions, and I hope this doesn't cause any confusion, I'm just with going to refer to them as Lake.

A That's fine. If that's all you were trying to do, I agree.

MR. McGEE: That's a compromise I think we can all agree on.

BY MR. KEATING:

Q What is your understanding of the source of the disagreement that led to the litigation between Florida Power and Lake?

A The source of the litigation was the

interpretation of the pricing mechanism.

Q Was that Section 9.1.2 of the contract?

A Yes.

Q What does that -- I realize that Florida Power Corporation has probably taken a position on the interpretation of that section, so I may be getting partly biased answers, but could you explain that provision of the contract?

A That provision of the contract explains how the energy payments will be calculated based on the avoided unit dispatch.

Q And how did Florida Power interpret this provision of the contract?

A Florida Power initially when the case -- or when the contract was first submitted to the PSC for approval assumed that the unit would run all the time, and therefore be paid for energy pricing. Upon further analysis of how that unit would operate, Florida Power concluded that there would be times when that unit would not be dispatched. The theoretical unit would not be dispatched, and therefore, in that period of time, the cogen customer would receive as-available pricing. We proceeded to implement that pricing mechanism, which prompted the litigation.

Q Just for clarification, would the price for

as-available energy be greater than or less than firm?

A It would be less than firm.

One moment.

MR. MCGEE: Just to make sure we understand the question, do you mean would the price of as-available be more or less than firm energy prices in all instances, or does the contract deal with that? I think there's a distinction he would want to make on that.

BY MR. KEATING:

Q Pursuant to the contract, would as-available energy be more or less pricy than firm?

A It would be less.

Q Based on your knowledge of the litigation, what is your understanding of Lake's interpretation of the provision, the pricing provision?

A My understanding of Lake's position is that it should have been priced at firm, and they believe that the unit would have run 100% of the time.

Q Was there also a disagreement regarding the coal prices upon which the energy payment was based?

A Yes, there was.

Q Could you explain the nature of that disagreement?

A Lake indicated that we had breached the

contract and we were manipulating the coal price at CR1 and 2. This was based on the fact that we had changed the method of transportation for getting that coal to the site from water transportation to rail. This was later -- this particular count of Lake's litigation was dismissed in the final appeals court.

Q That was the -- was that the Fifth District Court of Appeal decision?

A Yes.

Q Did the change in the transportation method that you mentioned result in a lower payment to Lake?

A Yes.

Q Were there any other points of disagreement between Lake and Florida Power with respect to that contract?

A There was a count in their litigation regarding the possible violation of the reg-out clause by Florida Power Corporation. And Florida Power had a count against Lake regarding possible breach of contract in the inability to generate during a gas pipeline outage. Both of those counts were dismissed.

Q Okay. And I want to go through some of the more specific litigation history with some other questions, but when you say they were dismissed, at what level were those two counts dismissed?

A Those two counts were dismissed at the Fifth Judicial Circuit Court.

Q That was at the appellate level?

MR. McGEE: Could we go off the record for a moment?

MR. KEATING: Sure.

(Discussion off the record.)

THE WITNESS: The dismissal of those two counts was in the trial court, the Fifth Judicial Circuit of Lake County.

BY MR. KEATING:

Q I guess for ease of reference and understanding, from here on out I'll try to distinguish. And to go ahead and get it on the record, the litigation at the trial level was in the Fifth Judicial Circuit in Lake County?

A Yes.

Q And then at the appellate level, it was at the Fifth District Court of Appeal?

A Correct.

Q Okay. I'll just try to refer to trial level and appellate level unless I need to be more specific.

What activities has Florida Power taken before the Public Service Commission with regard to

the Lake contract?

A Florida Power has sought interpretation of Section 9.1.2 from the PSC. It has also proposed a settlement for approval before the PSC. It has asked for a declaratory statement on their decisions.

Q What was the time frame for -- I guess the first one you mentioned was that an interpretation was sought before the Commission?

A For ease, I can provide you with a timeline, if you would like, that takes us from the beginning of the contract through its conclusion.

MR. KEATING: Okay. Should we just identify that as an exhibit?

THE WITNESS: This is my only copy, but we can share it.

MR. KEATING: We'll at some point make some copies and get one for the court reporter. We'll call it Exhibit 1, Lake Cogen Timeline.

(Deposition Exhibit 1 was marked for identification.)

BY MR. KEATING:

Q When did the litigation between Lake and Florida Power begin? Is that on the timeline?

A That's on the timeline. Around '94.

Q I'll tell you what. Let me look at the

timeline and see how many of my questions it might answer. I'll try to avoid any questions that may be covered in the timeline.

On page 19 of your September 20th testimony in this docket, beginning at line 21, you state that the litigation with Lake Cogen then proceeded to trial, which resulted in a ruling by the court generally favorable to Florida Power. What was that ruling that was generally favorable to Florida Power?

A The ruling by the trial court established payments for on-peak hours at a firm rate, and as-available for off-peak hours.

Q Did that ruling make any judgments with respect to the hours that the unit would run?

A If you'll give me a moment, I'll see if I can find -- the trial court really did not establish when the avoided unit would run.

Q Did the ruling of the trial court require any sort of payment from Florida Power to Lake Cogen? I'm probably not saying this as well as I can, but not on a going-forward basis, but as sort of -- any sort of make-whole payment or judgment against Florida Power Corporation?

A Yes.

Q Okay. And that's shown in the timeline?
A Yes, it is.
Q Okay. The timeline shows judgment setting damages at $4,480,247. Was that amount to be paid by Florida Power to Lake Cogen?
A Yes, it was, but it was never paid.
Q It was not paid?
A It was not paid.
Q Okay. That answered my next question.
Why was that amount not paid?
A Lake requested that we not make the payment.
Q Do you know why Lake made that request?
A It had to do with their legal position on the matter.
Q Can you explain that any further?
A No, I can't.
Q Are you at all familiar with Carl Whelan's testimony in the 990001 fuel cost recovery docket?
A I did not commit it to memory.
Q Okay. Was it your understanding that Mr. Whelan testified that that amount that we just discussed, the roughly $4.4 million, was included in the 1999 year-end estimated actual true-up balance as a result of -- or that that amount was included in

that balance?

A Subject to check, I would probably agree.

Q Okay. Do you know how this amount was treated with respect to the fuel clause?

A Since it was never paid, it was never charged to the fuel clause.

Q Would you agree subject to check that in Mr. Whelan's testimony, he stated that on a going-forward basis, the estimate of the energy payments pursuant to the pricing methodology established by the court was included in the true-up balance and projections for 2000?

A Subject to check, I would agree.

Q Based on the timeline that you gave me, the trial court's ruling was appealed by Lake; is that correct?

A Yes.

Q And that appeal went to the Fifth District Court of Appeal?

A Let's make sure. I believe so, yes.

Q Given that the order was appealed, did Florida Power pay for energy based upon the trial court's ruling or upon another interpretation of the contract?

A Florida Power -- we paid under the trial

court's ruling.

Q You paid under the interpretation of the provision that the trial court --

A That's correct.

Q How were the energy payments treated in the fuel clause as a result of the appeal?

A The actual payments where recovered through the fuel clause.

Q Is it correct that the Fifth District Court of Appeal, the appellate court, overturned the trial court's decision?

A Correct.

Q Were there any particular portions of -- or what particular portions of the trial court's decision were overturned?

A The pricing mechanism, the portion on the coal pricing -- oh, affirmed. They affirmed the trial court's dismissal of the pricing of the coal portion of the payments.

Q So the trial court's decision was overturned only with respect to --

A The energy payment calculation.

Q Okay. And earlier you stated that payments for on-peak energy would be at the firm rate, and then for off-peak would be as-available?

A Correct.

Q That's the interpretation that was overturned?

A Correct.

Q What is your understanding of the appellate court's reasoning for -- well, let me step back. What interpretation did the appellate court uphold or support?

A The appellate court ruled that the unit would run all the -- would run except for 45 days, which was a negotiated period of time for maintenance outages, would run 100% absent those days, and the payments should based on a firm rate during that period and as-available during the period that the unit would have been in an outage for maintenance.

Q Was that 45 days something that was part of the original contract between Florida Power and Lake Cogen?

A No. It was a negotiated period of time.

Q Okay. When you say it was negotiated, it was negotiated as part of the litigation?

A Yes.

Q Was that negotiated while the case was at the trial court level or after the appeal?

A The appellate court referenced a

maintenance period, but did not define the period. So it was negotiated after the appellate court ruled and provided to the lower court.

Q Do you believe that that negotiated provision constituted an amendment to the contract?

A I don't believe so, on the basis that Section 9.1.2 goes to the period that the avoided unit would run, and maintenance is an integral part of the operation of any facility.

Q Based on your understanding of the appellate court's decision, what was the reason it offered for its decision?

MR. MCGEE: Cochran, since the witness is simply going to have to read the appellate court decision to get that, and since we have provided -- I think we've provided you a copy of that opinion.

THE WITNESS: Well, we are willing to provide you copies of all the orders from which you could extract that information.

MR. KEATING: That will suffice. I won't make you go through that.

THE WITNESS: Thank you.

MR. KEATING: Okay. You prepared these documents concerning the litigation between

Florida Power and Lake, and I guess we can go ahead and identify this as a deposition exhibit. It will be Exhibit Number 2, documents regarding litigation between Florida Power and Lake. And we'll get copies of that as well.

(Deposition Exhibit 2 was marked for identification.)

BY MR. KEATING:

Q Based on the appellate court's ruling, was Florida Power required to make any additional payments to Lake?

A Florida Power was required to true up the payments from the point in time that they altered the interpretation of 9.1.2.

Q And what time was that?

A From -- it goes back to the original date of the contract. It just so happens that the payment stream finally approved by the appellate court is identical to the first-year payment stream to Lake County, so it's the same payment stream that the Commission originally approved. So really, from the inception of the contract, it goes back to '93, although there was no real impact until August of '94. So the 19, almost $20 million in back payments really addressed the '94 period forward, August of '94

forward, and it was 19,860,307.

Q I believe that's -- yes, it's reflected on the timeline.

Has Florida Power paid that amount?

A Yes, they have.

Q When was that payment made, or was it made in smaller payments or as one lump sum?

A No, it was made in one payment. September 24th. I'm sorry.

Q I'm just going to look at this before I ask a question.

Has that payment been recovered through the fuel clause?

A It was projected in this current docket at $20 million, so it will be included in the fuel factor which will be set on 1/1/2002 for recovery from customers.

Q Was it exactly 20 million that was projected?

A Yes, it was.

Q On page 8 of your testimony, you state that the case was remanded by the appellate court back to the trial court?

A Yes.

Q For entry of a final order consistent with

the appellate court's decision?

A Yes.

Q Do you know what the current status of the litigation is now?

A It had been provided to you in Late-Filed Exhibit 2.

Q Okay. So according to this exhibit, final judgment from the Circuit Court, the trial court, on remand was issued September 24th?

A (Indicating.)

Q Is that correct?

A Correct.

Q Were there any additional amounts required for Florida Power to pay to Lake after the remand?

A Yes. There are still pending court costs.

Q You say still pending. As --

A Well, we don't have the numbers from Lake, the final numbers from Lake.

Q Okay. So when Lake provides those final numbers, Florida Power will be required to pay those costs?

A Correct.

Q Okay. Is Florida Power projecting any of those costs in its projections for 2002?

A No, we did not.

Q That is in the fuel clause? Just to clarify, that's in the fuel clause?

A It's in the fuel clause; correct.

Q Does Florida Power anticipate that it would seek to recover those costs through the fuel clause?

A I still need to do some research on whether it's applicable for recovery through the fuel clause.

Q So that has not been decided yet?

A No, it hasn't.

MR. KEATING: Can we go off the record for a moment?

MR. MCGEE: Sure.

(Discussion off the record.)

BY MR. KEATING:

Q Did the appellate court find that Florida Power was -- did the court find that Florida Power had violated or breached any of the terms of the contract, the appellate court?

A To the best of my knowledge, I don't believe so.

Q Did the court find any wrongdoing on Florida Power Corporation's part, or did it simply disagree with Florida Power's interpretation of the contract?

A I think it was just a disagreement on the

interpretation of that section of the contract.

Q There's a document that's cited in the appellate court's opinion that's entitled "Cogeneration and Purchased Power Cogen Strategic Proposal." Are you familiar with that document at all?

A No, I'm not.

Q Are you familiar with the requirements for a utility such as Florida Power to purchase power from cogenerators such as Lake?

A Yes.

Q And are you familiar with the concept of avoided cost?

A Yes.

Q What's your understanding of what avoided cost means?

A It's the avoidance of having to build a generating facility through the purchase from another entity.

Q What is an avoided unit intended to represent?

A The embedded cost that the utility would incur from having to build such a facility and would recover from its customers.

Q Is it intended to be a real unit?

A No. For purposes of evaluation, it's the theoretical next unit built.

Q So would you agree that an avoided unit is merely numbers that are intended to mimic a real unit in a sense?

A It's a simulation.

Q Do you know if Florida Power has cogen contracts in which it has dispatch rights?

A I believe we do.

Q Does the Lake contract give Florida Power dispatch rights?

A No.

Q Under the Lake contract, does Florida Power have to purchase energy from Lake when it is provided?

A Yes.

Q If system conditions changed such that it was less economical to purchase from a cogenerator, would a contract with dispatch rights give Florida Power more flexibility to lower purchases from a cogenerator than a contract without dispatch rights?

A Say that again.

Q If system conditions changed so that it was less economical to purchase from a cogenerator, would a contract with dispatch rights give Florida Power more flexibility to lower purchases from a cogenerator

compared to a contract without dispatch rights?

A Yes.

Q When the Florida Power/Lake Cogen contract was approved by the Commission, were the costs of the contract projected to be below Florida Power's avoided cost?

A I believe it was projected to be at the avoided cost.

I stand corrected. It was below avoided cost.

Q When Florida Power modified the energy payments pursuant to Section 9.1.2 of the contract, were those payments in Florida Power's opinion at or below avoided cost?

A Our attempts to modify the contract produced payments lower than the payments previously paid to Lake Cogen.

Q So it would be below avoided cost?

A Correct.

Q Will the payments Florida Power is required to make to Lake on a going-forward basis, that is, not any damages or costs assessed from the litigation, result in payments at or below avoided cost?

A Since they would be based on the original assumptions, it would be below avoided cost.

Q I believe in a discussion that you had with a staff member prior to the deposition, that staff person had expressed an interest in having some data provided concerning the historical and forecasted energy payments made to Lake Cogen since July 1, 1993, to the end of the contract. Have you by chance prepared a table that provides that information?

A Yes, I have.

Q Okay. You've handed me three pages. The first page is Lake Cogen Payment Comparison, sheet 1 of 2, and the second page is sheet 2 of 2 of that document, and there's a third page, Summary of Forecasted Positions for Lake Cogen.

Does this document include historical and forecasted annual energy payments made to Lake since July 1, '93?

A Yes.

Q Through the end of the contract?

A Yes.

Q Does this document also include the energy payments as interpreted by Florida Power Corporation, or as Florida Power Corporation interpreted Section 9.1.2 of the contract?

A Yes, it does.

Q And does it also include the energy

payments as Lake interpreted Section 9.1.2 of the contract?

A Yes, it does.

Q And it provides what those payments would have been from the beginning to the end of the contract under each interpretation?

A Correct.

Q And does this document also include the energy payments as required, as interpreted by the courts? And when I say the courts, it was ultimately decided by the appellate court.

A Yes, it does.

MR. KEATING: Could we mark this as Exhibit 3, Lake Cogen Payment Comparison. And we'll get copies of this as well.

(Deposition Exhibit 3 was marked for identification.)

BY MR. KEATING:

Q Are you familiar with the settlement agreement with Lake that Florida Power submitted for Commission approval in 1996?

A Yes.

Q Could you briefly summarize or hit the high points of that settlement agreement?

A The settlement agreement moved the O&M

portion of the energy payment to the capacity cost recovery, or the capacity payment, resulting in energy payments that would be the fuel cost times the heat rate for all hours. It also contemplated the termination of the contract 43 months earlier than scheduled.

Q Were the costs of the proposed settlement projected to be at or below avoided cost?

A Below avoided cost.

Q Did Florida Power make any payments to Lake as a result of the settlement agreement?

A Yes, we did.

Q What was the amount of that payment? Would that be in the timeline?

A I believe so.

No, the dollar amount is not here. It was approximately -- I believe 5.5 million, if I recollect correctly.

Q What was the number again?

A I think 5.5 million. I'll be glad to provide exact amount.

Q Was that amount recovered through the fuel clause?

A It was recovered in a later -- paid back to customers. Once the settlement expired and was not

approved by the Commission, we collected the funds back from Lake Cogen that had been paid.

Q Lake returned --

A The funds.

Q And that amount was credited --

A To the fuel clause.

Q Was there any interest associated with that transaction?

A I believe there was. Subject to check, I believe there was.

Q There's another item that I believe a staff member had discussed with you prior to the deposition. We had asked if you could provide a comparison beginning in November '96 of the annual cost of the Lake settlement agreement, the annual cost as interpreted by Florida Power, the annual cost as interpreted by Lake, and the annual cost as ordered by the court. Is that something you've been able to prepare?

A We combined that with the other request for the same information from the beginning of the contract, so it's all on one exhibit.

Q And is that what has been identified as Exhibit 3?

A Yes, it is.

MR. KEATING: Can we go off the record for just a moment?

MR. McGEE: Sure.

(Discussion off the record.)

BY MR. KEATING:

Q Do you have an opinion as to whether the Commission can allow recovery of an amount less than that paid by Florida Power to Lake Cogen?

MR. McGEE: To the extent that's asking for his legal conclusion, I think he probably lacks the qualifications for that. He's a policy witness for Florida Power. He will be happy to respond to a question in terms of regulatory practice or policy.

BY MR. KEATING:

Q *Do you* believe that there's any policy that the Commission has which would allow it or require it to allow recovery of the total amount paid to Lake Cogen?

A I believe the Commission has already ruled when the contract was first submitted to them for approval that the payment stream was recoverable. And it so happens that we are now, based on the appellate court decision, back to that same payment stream. So therefore, I think they've already ruled.

Q So the damage amount that was ordered by the appellate court --

A Simply brought the payments to date back to what they should have been based on their decision.

Q If the Commission were to disallow recovery of any amount of the payment made to Lake Cogen, what is your understanding of how the regulatory out clause in the contract would operate?

A Florida Power would exercise the regulatory out which, to the best of my knowledge, functions on the basis that if the utility is not allowed full recovery of the cost, then the contract, in essence, can be terminated.

There are differing interpretations on whether the reg-out clause could be enforced or not, so I believe there would be extensive litigation on that matter.

Q Do you have any knowledge of what the litigation costs are associated with the Florida Power/Lake litigation?

A I do not have those numbers available at this time.

Q Do you know if those costs have been recovered, any litigation costs have been recovered through the fuel clause?

A To the best of my knowledge, they have not.

Q Are any of the litigation costs included in the 2002 projections for the fuel clause?

A No, they are not.

Q Do you know if any of the litigation costs have been recovered through any other cost recovery clause or by any other means?

A That is what we're currently reviewing. I don't have that answer for you at the moment.

Q You're reviewing to see if any of those costs have been recovered through another clause?

A Based on a conversation with staff, we are going back to the beginning of the litigation to identify where these costs have been charged, and we are prepared to provide a late-filed exhibit showing that.

MR. KEATING: If you could do that, that would be great. That would be Late-Filed Exhibit Number 4. We'll just call that Recovery of Litigation Costs.

(Late-Filed Deposition Exhibit 4 was identified.)

BY MR. KEATING:

Q And if you could include in that any amounts recovered and what time it was recovered and

through which cost recovery mechanism it was recovered, or whether -- obviously, one of those cost recovery mechanisms could be base rates.

A Correct. Yes.

MR. KEATING: That's all the questions I have. Thank you.

THE WITNESS: You're welcome.

CROSS EXAMINATION

BY MR. VANDIVER:

Q Good afternoon, Mr. Portuondo.

A Good afternoon.

Q Could you turn to page 11, please, of your September 20th testimony. Down at the bottom of the page, you indicate that the forecast was prepared in June 2001?

A Correct.

Q So none of the forecasted data takes into account the terrorist attacks of September 11th; is that correct?

A That's correct.

Q In your opinion, would the September 11th terrorist attacks affect demand?

A To the best of my knowledge, it has not affected the demand.

Q So the September terrorist attacks will

have no effect on the forecast at all?

A It may have an effect on customer usage, but not the demand. The energy --

Q What effect would it have on usage?

A It would be a declining usage.

Q Would it be necessary to change anything in your forecast or projections for the November hearing?

A Given the uncertainty of all the variables that would have an impact on the fuel adjustment clause, we do not believe it prudent for us at this moment to make such a change. But the company is monitoring the situation and is prepared to submit a revision once we feel comfortable with our assumptions on the other variables, such as the impact of the ongoing events on oil, oil prices, transportation. There are a number of variables that need to be considered before we take that action to revise the forecast, and we're in the process of evaluating all those factors.

Q Do you have September numbers yet?

A September actuals?

Q Yes.

A Yes.

Q How do they compare to the September 2000 numbers?

A I have not done that analysis, or at least I don't have that with me to be able to give you an answer. It's too early. That would be too early to really be reflective of the future effects of what happened on September 11th, to be honest.

Q Okay. Fair enough.

I would like to turn now to your -- I get my dates confused. I guess it's your later testimony that was filed in October.

A Yes.

Q On the hedging issues, would Florida Power Corporation object to a delay of the hedging issues and bumping those to the 2002 time frame?

A No, we would not.

MR. VANDIVER: That's all the questions I have. Thank you.

MR. McGEE: Let me have a moment here.

CROSS EXAMINATION

BY MR. McGEE:

Q Earlier on you were asked some questions about the treatment of the costs of the Florida Power gas conversion projects through the fuel adjustment clause, and I think you indicated that you didn't believe that the projects would have been -- that you believed that the project would have been undertaken

even if there hadn't been fuel cost recovery, and you had also indicated that you were only involved in certain aspects of the project planning. Is that an opinion on your part, or do you know whether that would have had an effect on the company's decision to go forward with those conversion projects?

A That's an opinion on my part.

Q Do you know whether or not the absence of fuel cost recovery for the cost of those projects could have -- even if they had gone forward, could the absence of that recovery have affected the timing under which those projects were undertaken?

A That is a possibility.

MR. McGEE: Cochran, I also wanted to mention to you that on the subject of the gas conversion projects, as it happens, by coincidence, Mr. Niekum, who will be testifying later on, was involved in those projects in his former life.

MR. KEATING: Thank you.

BY MR. McGEE:

Q There were some discussions regarding the Lake Cogen contract on the actions that are currently underway in the -- or have been recently underway in the trial court proceedings on remand after the

appellate court's decision, and you referred to a 45-day negotiated maintenance period. Do you know whether that 45-day maintenance period was ultimately reflected in the final judgment issued by the trial court?

A Yes, it was.

Q Okay. You were asked some questions about the dispatchability of QF contracts, and I believe you indicated in response to a question from Mr. Keating that Florida Power had QF contracts with dispatch rights. Do you know whether Florida Power has any contracts with QFs that are fully dispatchable in the same sense that one of our own generating units would be dispatchable?

A No, I believe it's limited dispatch rights.

Q Things that would include low load periods?

A Correct.

Q Mr. Vandiver asked you a question about the possibility of revising the energy forecast -- excuse me, the sales forecast that the fuel adjustment filing is on, in light of the events of September 11th. If the forecast were to be revised, what effect would that have on the fuel adjustment factor?

A The usage -- due to the usage decreasing,

and depending on the impact on the unit price of the commodity, it could produce a higher factor than we currently have.

MR. McGEE: That's all I have.

MR. KEATING: If there's nothing else, that should conclude the deposition.

(Deposition concluded at 1:56 p.m.)

CERTIFICATE OF ADMINISTERING OATH

STATE OF FLORIDA)
COUNTY OF LEON)

I, MARY ALLEN NEEL, Notary Public in and for the State of Florida at Large:

DO HEREBY CERTIFY that on the date and place indicated on the title page of the foregoing transcript, an oath was duly administered by me to the designated witness before testimony was taken.

WITNESS my hand and official seal this 8th day of November, 2001.

MARY ALLEN NEEL, RPR
100 Salem Court
Tallahassee, Florida 32301

Mary Allen Neel
MY COMMISSION # CC 782020
EXPIRES: October 10, 2002
Bonded Thru Troy Fain Insurance

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, MARY ALLEN NEEL, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter transcribed under my supervision; and that the foregoing pages numbered 1 through 45 are a true and correct transcription of my stenographic notes.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, or relative or employee of such attorney or counsel, or financially interested in the action.

DATED THIS 8th day of November, 2001.

MARY ALLEN NEEL, RPR
100 Salem Court
Tallahassee, Florida 32301
(850) 878-2221

Lake Cogen Timeline

July 1, 1991	FPSC approves the Lake Cogen contract for cost recovery.
July 1, 1993	FPC begins capacity payments and firm energy payments
July 18, 1994	FPC notifies Lake Cogen that it will begin implementation of its energy pricing interpretation
July 21, 1994	FPC filed a petition at the FPSC seeking a declaratory statement that Section 9.1.2 of the negotiated contracts is consistent with FPSC rules
August 8, 1994	FPC begins paying the as-available rate for energy when the avoided unit would be turned off using the four parameters in the contract and sends letter to QFs clarifying its position.
October 7, 1994	Lake Cogen, Ltd. by its general partner NCP Lake Power Incorporated brought suit in the Circuit Court of the Fifth Judicial Circuit in and for Lake County. Amended on October 19, 1994.
November 1, 1994	FPC amends its petition with the FPSC and asked the FPSC to determine if its implementation of Section 9.1.2 is lawful and consistent with FPSC Rule 25-17.0832(4)b *(Standard Offer Pricing)*
February 15, 1995	FPSC dismisses FPC's petition stating "[W]e have made it clear that we will not revisit our cost recovery determination absent a showing of fraud, misrepresentation, or mistake". The FPSC also stated "[W]e defer to the courts to answer the question of contract interpretation raised in this case".
January 23, 1996	Circuit Court issues a partial summary judgement ruling that FPC's implementation of the energy pricing mechanism was inadequate. FPC should model "the operation of a real, operable 1991 Pulverized Coal Unit, having the characteristics required by law to be installed on such a unit as well as all other characteristics associated with such unit."
November 25, 1996	FPC files a petition for the approval of a settlement agreement between FPC and Lake Cogen
August 18, 1997	FPSC votes to approve the settlement agreement. The staff recommendation is attached. The FPSC later rescinded its approval.
November 14, 1997	FPSC issues Order PSC-97-1437-FOF-EQ denying FPC's petition for the approval of the settlement agreement because it determined its jurisdiction was greater than it previously concluded. This order states "[E]nergy payments under the modified contract reflect Lake's court position of 100% firm energy, which clearly exceeds avoided cost". However, the order is declared null because the settlement expired.

April 9, 1998	FPC files a petition for a declaratory statement that defines the type of payment that the FPSC intended when it approved the cogen contracts.
May 5, 1998	Lake Cogen files its second amended complaint. This complaint added a count charging FPC with manipulation of coal prices to Crystal River 1 and 2.
August 10, 1998	Lake Cogen files its third amended complaint. This amendment added a count charging FPC with violating "Reg-out" clause by filing for a second declaratory statement on April 9.
November 2, 1998	Trial begins in the Circuit Court of the Fifth Judicial Circuit in Tavares, FL. Trial goes for two weeks and restarts for another week on November 30.
December 4, 1998	FPSC denies FPC's petition for a declaratory statement saying that it had previously ruled on a similar petition.
April 6, 1999	Fifth Circuit Court issues its Non-Final Trial Order in which its states that Lake Cogen should be paid at the firm rate during on-peak hours and at the as-available rate during off-peak hours.
August 26, 1999	Fifth Circuit Court issues it final judgement setting the damages at $4,480,247.
August 26, 1999	Lake Cogen Appeals the Fifth Circuit Court order.
August, 1999	Payments calculated according to Fifth Circuit Court ruling
September 5, 2000	Case is heard before the Fifth District Court of Appeals in Daytona Beach, FL.
March 1, 2001	Supreme Court of Florida issues Order No. SC94665 regarding FPC's appeal of FPSC's denial of its second declaratory statement. The Court states that "the PSC's prior, unappealed ruling regarding its jurisdiction to entertain the controversy addressed in FPC's petitions—even if erroneous—operates as a bar to a subsequent determination that that jurisdiction over the same claim".
April 6, 2001	Fifth District Court of Appeals issues its clarifying order that states "the Contract requires that Lake be paid the firm energy rate for all hours that the avoided unit operates and that it operates all of the time except for periods it is turned completely off for maintenance and repairs".
July, 2001	Payments calculated according to Fifth Circuit Court of Appeals ruling. The damages are estimated at $20,000,000.

September 24, 2001	Fifth District Court approves the stipulation agreed to between FPC and Lake Cogen. The agreed to damages are $19,860,307 and the maintenance periods are to be 45 days per year.

Florida Power Corporation
Docket No. 010001-EI
Late Filed Deposition Exhibit No. 2
Witness: J. Portuondo

This Late-Filed Deposition Exhibit contains the following documents regarding the litigation between Florida Power Corporation and NCP Lake Power, Inc.

- Order Granting Partial Summary Judgement from the Fifth Judicial Circuit Court
- Non-Final Trial Order from the Fifth Judicial Circuit Court
- Final Judgement from the Fifth Judicial Circuit Court (8/26/99)
- Final Judgment Fifth District Court of Appeals
- On Motion for Clarification from the District Court of Appeal
- Final Judgement from the Fifth Judicial Circuit Court (9/24/01)
- Florida Supreme Court Ruling

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IN THE CIRCUIT COURT OF THE FIFTH JUDICIAL CIRCUIT
IN AND FOR LAKE COUNTY, FLORIDA

NCP LAKE POWER, INCORPORATED,
a Delaware corporation,
as General Partner of LAKE
COGEN LTD., a Florida
limited partnership,

Plaintiff,

vs.

FLORIDA POWER CORPORATION,

Defendant.
_____/

CASE NO. 94-2354-CA-01

DIVISION NO. 8

ORDER GRANTING PARTIAL SUMMARY JUDGMENT FOR THE PLAINTIFF AND AGAINST THE DEFENDANT

This cause came on to be heard on Plaintiff, NCP LAKE POWER, INCORPORATED's, a Delaware corporation, as General Partner of LAKE COGEN, LTD., a Florida limited partnership ("LAKE COGEN"), Motion for Partial Summary Judgment and Defendant, FLORIDA POWER CORPORATION's ("FPC"), Motion for Partial Summary Judgment and the Court having heard argument from counsel for both parties hereto and otherwise being fully advised in these premises,* the Court finds as follows:

A. The pleadings, depositions, answers to interrogatories, admissions, and the affidavits filed in support of the Plaintiff's Motion for Partial Summary Judgment show that there are no genuine issues of material fact concerning the interpretation of Section 9.1.2 of the Negotiated Contract for the Purchase of Firm Capacity and Energy From a Qualifying

* Defendant's proposed order was Considered by the Court. DFB

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Facility Between Lake Cogen Limited and Florida Power Corporation (the "Lake Cogen-FPC Agreement") which is attached to the Plaintiff's Amended Complaint filed herein.

B. Section 9.1.2 of the Agreement between the parties, read in conjunction with the entire Agreement is unambiguous as it relates to the type of unit used to model the calculation of the electric energy payments to the Plaintiff.

C. Section 9.1.2 of the Agreement, together with the other pertinent sections of the Agreement, requires the Defendant FPC to make electric energy payments to the Plaintiff with reference to modeling the operation of a real, operable 1991 Pulverized Coal Unit, having the characteristics required by law to be installed on such a unit as well as all other characteristics associated with such a unit, as selected by the Plaintiff in Section 8.2.1 of the Agreement and described in Appendix "C", Schedules 3 and 4 of the Agreement.

D. The Court has also considered the Defendant's Motion for Partial Summary Judgment and finds that the terms of the Agreement at issue are unambiguous and do not require the Court to look outside its four corners for its interpretation of Section 9.1.2 of the Agreement. However, the Court disagrees with the Defendant's conclusions regarding the interpretation of the Agreement at issue before the Court.

IT IS THEREFORE, ORDERED AND ADJUDGED that:

1. A Partial Summary Judgment is hereby entered for LAKE COGEN and against FPC on the issue of liability for FPC's failure to pay LAKE COGEN at the firm energy cost rate when the avoided unit with operational characteristics of an operable 1991 Pulverized Coal Unit contemplated by the Lake Cogen-FPC Agreement would have been operating and

at the as-available energy cost rate during those times when said avoided unit would not have been operating.

2. The Defendant's Motion for Partial Summary Judgment is denied to the extent that it is inconsistent with this Order.

DONE AND ORDERED in Chambers at Tavares, Lake County, Florida this 23 day of January, 1996.

DON F. BRIGGS
CIRCUIT JUDGE

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy hereof has been furnished by U.S. Mail this 23 day of January, 1996 to:

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Judy A. Shafer
~~JUDICIAL ASSISTANT~~ DC

IN THE CIRCUIT COURT OF THE FIFTH JUDICIAL CIRCUIT OF FLORIDA IN AND FOR LAKE COUNTY

RECEIVED
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NCP LAKE POWER, INCORPORATED, a Delaware Corporation, as General Partner of LAKE COGEN, LTD., a Florida limited partnership,

Plaintiff,

v.

Case No.:94-2354-CA

FLORIDA POWER CORPORATION,

Defendant.

NON-FINAL TRIAL ORDER

THIS CAUSE came on to be tried before the Court. On the evidence presented the Court makes the following findings of fact and adjudications.

The Plaintiff, NCP LAKE POWER, INC., a Delaware corporation, as General Partner of LAKE COGEN, LTD, hereinafter "LAKE COGEN", is a qualifying cogeneration facility ("QF") within the meaning of the applicable federal and state statutes and regulations. The Defendant, FLORIDA POWER CORPORATION, hereinafter, "FPC", is a public utility within the meaning of §366.02(1) of the Florida Statutes. On March 13, 1991, LAKE COGEN and FPC entered into an agreement for the purchase of electrical capacity and energy by FPC from LAKE COGEN. This agreement, entitled "Negotiated Contract for the Purchase of Firm Capacity and Energy from a Qualifying Facility", the "contract", was drafted by FPC, and the interpretation of this document is the gravamen of the present lawsuit.

The contract required payment by FPC for capacity and energy delivered to FPC from the

LAKE COGEN facility in two components: capacity payments, pursuant to Article VIII of the contract, and energy payments, pursuant to Article IX of the contract. Attached to the contract were a number of different schedules. These schedules were offered by FPC to allow the QF to project payment plans based on various models of the avoided unit[1]. The QF had the option of choosing the schedule it preferred. The effect of the choice was to define the characteristics of the avoided unit for which the QF was substituted, and the payment schedule the QF would be paid on for its energy payments. The method of calculating energy payments is dependent upon whether the Avoided Unit, as selected by the QF in the contract, would have been operating, (thus the QF would be paid firm payments), or not operating, (thus the QF would be paid as-available payments). Most of the issues litigated concern a difference of opinion as to how the energy payments (pursuant to Article IX and in conjunction with the schedule LAKE COGEN chose), should be calculated.

This Court had previously concluded that Section 9.1.2 of the contract was unambiguous in the order on partial summary judgment. This conclusion applies to each of the terms of the contract which were litigated during the thirteen day trial. Each party presented their own interpretation of the contract, but a difference of opinion does not render the contract ambiguous. The parties proffered a tremendous amount of evidence and testimony which this Court admitted. The evidence was not admitted as parole evidence to vary ambiguous terms of the contract, but to explain to the Court the meaning of the contract. Southeast Banks Trust Co., N.A. v. Higginbotham Chevrolet-Oldsmobile, Inc., 445 So.2d 347, 349 (Fla. 5th DCA 1984).

> "In Chase Manhattan Bank v. First Marion Bank, 437 F.2d 1040, 1048 (5th Cir. 1971), it was stated that evidence to 'show the

[1]"Avoided Unit" is a term of art used throughout the electric generating industry which refers to the generating unit the utility would have built and purchased energy from but for the availability to purchase power from the QFs.

> meaning of technical terms, and the like, is not regarded as an exception to the ... [parol evidence rule], because it does not contradict or vary the written instrument, but simply places the court in the position of the parties when they made the contract, and enables it to appreciate the force of the words they used in reducing ... [the agreement] to writing.'"

Id. at 348.

Given this general background, the Court chooses to address each count of the complaint, and each counterclaim, individually.

Count I of the Complaint, Breach of Contract

The schedule LAKE COGEN chose to be incorporated into the contract with FPC, Appendix "C", schedules three (3) and four (4), describes Lake Cogen's chosen avoided unit as a 1991 Pulverized Coal Unit with a minimum on-peak capacity factor of 83.0%[2]. Section 9.1.2 of the contract provides, "the QF will receive electric energy payments based upon the Firm Energy Cost ... for each hour that the Company would have had **a unit with these characteristics** operating, ..."

Each party went to great lengths, and presumably great expense, to provide the Court with modeling[3] of the 1991 Pulverized Coal Unit in an effort to show what "these characteristics" would have been had FPC built a pulverized coal unit. According to LAKE COGEN's model, the avoided unit would have been running all the time. Hence, LAKE COGEN should be paid at the firm energy rate all the time. Conversely, FPC's model indicated that the avoided unit would be in operation

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[2]The on-peak capacity factor is the electric energy actually received by FPC at the point of delivery during the on-peak hours divided by the product of the Committed Capacity and the number of on-peak hours during the applicable period.

[3]Modeling is a common practice in the industry whereby a computer simulation is used to determine if a given unit, in this case the avoided unit, would be operational or not. Like every computer simulation, whatever result the program calculates is directly tied to the values the operator of the program has entered.

much less frequently. Hence, LAKE COGEN would be paid at an as-available rate much of the time.

FPC astutely pointed out to the Court that the LAKE COGEN model was fatally flawed because LAKE COGEN had used parameters, (input data), outside the four corners of the contract. Likewise, LAKE COGEN, adeptly pointed out to the Court that FPC'S model was fatally flawed because while FPC used only the four parameters listed in the contract, their input included zeros as input for data which had to be entered in order for the simulation program to run. The zeros which FPC input have value: They are not just "place holders."

Each party argued so zealously and convincingly that the other party's interpretation of the contract was misplaced, the Court is quite persuaded by both arguments. Neither party's interpretation of the contract gives meaning to each provision of the contract in a reasonable manner.

For the reasons pointed out by the experts, the Court finds the modeling is susceptible to being skewed in favor of the proponent of the model. For this reason alone, the modeling would not be afforded a great deal of consideration, but as the Court has determined the contract is unambiguous, and the modeling goes beyond the four corners of the contract, the modeling is irrelevant. This leaves the plain language of the contract.

The contract specifies that LAKE COGEN should be paid either "firm" or "as-available"[4] energy payments for all energy it provides to FPC. Section 9.1.2 of the contract states not only how FPC must calculate firm energy prices, but also when FPC must make firm energy payments. Specifically, Section 9.1.2 provides

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[4]Section 1.3 of the contract defines as-available energy costs as the energy rate calculated in accordance with PSC Rule 25-17.0825. The method of calculating as-available energy payment is not at issue here.

> The QF will receive electric energy payments based upon the Firm Energy Cost calculated on an hour-by-hour basis as follows: (I) the product of the average monthly inventory charge out price of the fuel burned at the Avoided Unit Fuel Reference Plant, the Fuel Multiplier, and the Avoided Unit Heat Rate, plus the Avoided Unit Variable O&M, if applicable for each hour that the Company would have had a unit with these characteristics operating; and during all other hours, the energy cost shall be equal to the As-Available Energy Cost.

From Section 9.1.2, one can only determine the properties of the "unit" by referring to the attached schedule in which LAKE COGEN chose the avoided unit they wanted. Applying the four characteristics in Section 9.1.2 to the avoided unit in schedule 4, the contract specifies how the firm energy payments are to be calculated. The when is also determined by looking to the selected schedule, schedule 3. This schedule, entitled "Rates For Purchase Of Firm Capacity and Energy From A Qualifying Facility," provides not only the operating data of the avoided unit, including the On-Peak Capacity Factor, but also the On-Peak Hours. To reach an On-Peak Capacity Factor of 83.0%, which is what the schedule calls for, the testimony showed the avoided unit would have to run continuously during the On-Peak hours, barring down-time for maintenance and repairs. Hence, the avoided unit would be running during the On-Peak Hours as set forth in Appendix "C" schedule 3.

Section 1.35 defines "On-Peak Hours" to mean the lesser of those daily time periods specified in Appendix C or the hours that the company would have operated a unit with the characteristics defined in section 9.1.2 (I). The characteristics defined in section 9.1.2 (I) only have meaning when applied to the avoided unit chosen by the QF in the schedules. The schedule LAKE COGEN chose provided for an avoided unit with an 83.0% On-Peak Capacity Factor. Therefore, the avoided unit would be running continuously during the On-Peak hours. The daily time periods that the avoided unit would be running are the same as the On-Peak hours, in this instance. It is the

only way the 83.0% On-Peak Capacity Factor can be achieved. While the definition of On-Peak hours reads as a "lesser of" provision, by virtue of the avoided unit LAKE COGEN chose, the daily time periods are the same in this contract. Ironically, FPC's own witness testified that this is not a "lessor of" contract.

Neither of the two modeling efforts accurately reflect only the provisions of the contract and the schedules. Modeling is not envisioned by the terms of the contract. Indeed, FPC did not model during the first contract year, an action they now call a "mistake". If the proposed modeling is accepted, the contract terms lack reason and become susceptible to manipulation. When possible, courts should give effect to each provision of a written instrument in order to ascertain the true meaning of the instrument. Inter-Active Services, Inc. v. Heathrow Master Association, Inc., 721 So.2d 433, 435 (Fla. 5th DCA 1998). Where the contract is susceptible to an interpretation that gives effect to all of its provisions, the court should select that interpretation over an alternative interpretation that relies on negation of some of the contractual provisions. Id. This Court chooses to read the contract in its entirety and to give meaning to all of the provisions. When section 9.1.2 is read together with the attached schedule, and meaning is given to terms On-Peak Hours and On-Peak Capacity Factor, the contract reasonably states that FPC must pay firm-energy payments to LAKE COGEN during the On-Peak Hours, as set out in Appendix C, schedule 3. For all other hours, i.e., Off-Peak Hours, FPC must pay the as-available rate calculated in accordance with PSC Rule 25-17.0825. Based upon the foregoing analysis and the evidence presented it is hereby

ORDERED AND ADJUDGED that LAKE COGEN's claim for breach of contract, count I of the complaint, is **granted.** The Court reserves jurisdiction on this issue to enable the parties to present evidence to support an award of damages calculated in accordance with the Court's ruling. Plaintiff shall schedule an appropriate amount of court time to present both parties' evidence on this

issue.

Count II of the Complaint, Declaratory Judgment

LAKE COGEN has asked the Court to declare that FPC has no right to implement the payment methodology based upon the four parameter modeling, and declare FPC must pay LAKE COGEN at the firm energy cost rate for all power provided to FPC by LAKE COGEN. The Court has determined that the modeling proposed by FPC does not accurately reflect the terms of the contract. However, the contract does not contemplate LAKE COGEN being paid firm energy cost rate at all times regardless of any other consideration. Therefore, it is hereby

ORDERED AND ADJUDGED that FPC does not have the right to calculate its payments to LAKE COGEN on the four parameter model, but shall calculate the payments in accordance with this Court's current order.

Count III of the Complaint, Breach of Contract Re: Coal Pricing

LAKE COGEN has alleged that FPC has breached both the express terms of the contract, and the implied covenant of good faith by manipulating the price of coal burned at its Crystal River facilities 1 and 2. FPC operates four coal-fired generating plants in the vicinity of Crystal River which are commonly known as CR 1&2, and CR 4&5. Under section 9.1.2 of the contract, the energy payments FPC is obligated to make to LAKE COGEN are tied to the monthly inventory charge out price of fuel burned at the Avoided Unit Reference Plant. The contract expressly defines the Avoided Unit Fuel Reference Plant as the FPC unit(s) whose delivered price of fuel shall be used as a proxy for the fuel associated with the avoided unit type selected in section 8.2.1 of the contract as such unit(s) are defined in Appendix C. To determine which FPC unit the Avoided Unit Fuel Reference Plant is based upon, one must again refer to Appendix C. In this instance, LAKE COGEN chose CR 1&2 to be the Avoided Unit Fuel Reference Plants. Historically, coal has been delivered

to CR 1&2 and CR 4&5 by a combination of barge and rail. The transportation cost of delivering the coal by barge is generally more expensive than delivering the coal by rail. LAKE COGEN alleges that some time after it executed the contract, FPC began manipulating the price of coal delivered to CR 1&2 by transporting a greater percentage of coal via rail instead of barge, thus, lowering the delivered price of coal at CR 1&2.

LAKE COGEN's argument that FPC breached the express terms of the contract is belied by the very terms of the contract. The definition of Avoided Unit Fuel Reference Plant is the FPC unit whose **delivered** price of fuel shall be used as a proxy. There is no section of the contract that LAKE COGEN can point to which delineates what the transportation mix of rail and barge delivery of coal to CR 1&2 had to be. LAKE COGEN argues they relied on the historic transportation costs, but there is no section which states the historic mix had to remain static. Further, LAKE COGEN has not alleged fraud in the inducement.

LAKE COGEN also argues that even if FPC did not breach an express term of the contract, FPC breached the implied covenant of good faith and fair dealing, and commercial reasonableness. FPC offered several explanations for the change in the transportation mix to CR 1&2 including 1) the coal delivery is governed by the PSC's fuel procurement policy, 2) natural forces mandate the transportation mix, and 3) the change in the transportation mix occurred independently from any request by FPC.

One of the implied contract terms recognized in Florida law is the implied covenant of good faith. Cox v. CSX Intermodal, Inc., 1999 WL 9764 (Fla. 1st DCA Jan. 13, 1999). Where the terms of the contract afford a party substantial discretion to promote that party's self interest, the duty to act in good faith nevertheless limits that party's ability to act capriciously to contravene the reasonable contractual expectations of the other party. Id. Assuming, arguendo, LAKE COGEN

met their burden of showing FPC acted capriciously so as to contravene LAKE COGEN's reasonable contractual expectations, the claim would still fail because LAKE COGEN failed to present any evidence concerning damages. For the foregoing reasons, it is hereby

ORDERED AND ADJUDGED that LAKE COGEN's third cause of action, breach of contract regarding coal pricing, is **dismissed.**

Count IV of the Complaint, Declaratory and Injunctive Relief re: FPC petitioning the PSC

The final cause of action pleaded by LAKE COGEN is for declaratory relief and a prayer for injunctive relief. FPC has previously petitioned the PSC to interpret its 1991 order approving the FPC/LAKE COGEN contract. LAKE COGEN argues the purpose the previous petitions was to encourage the PSC to reduce the rates and charges that FPC may charge the ratepayers. LAKE COGEN then argues, should the PSC reduce the rates, the FPC will attempt to use Article XX of the contract to reduce its payments to LAKE COGEN. LAKE COGEN is asking this Court to restrict FPC's access to the PSC, and to enjoin FPC from employing Article XX of the contract.

The Court ruled at trial that LAKE COGEN failed to produce any evidence that it was damaged by FPC petitioning the PSC. This Court does not see that LAKE COGEN's complaint for declaratory relief in this lawsuit is in any way distinguishable from FPC petitioning the PSC for declaratory relief. FPC has as much right to petition the PSC as LAKE COGEN has to file the instant lawsuit. Finally, allegations of what FPC might do if the PCS were to reduce rates is too speculative to show the future irreparable harm necessary for an injunction to issue. Accordingly, it is hereby

ORDERED AND ADJUDGED that LAKE COGEN's fourth cause of action, declaratory and injunctive relief regarding FPC's petitioning the PSC, is **dismissed.**

FPC'S COUNTERCLAIMS

FPC's Count II, Breach of Section 3.3 re: Lake Cogen's inability to deliver committed capacity

Section 3.3 of the contract provides

> Except for Force Majeure Events declared by the Facility's fuel supplier(s) or fuel transporter(s) which comply with the definition of of Force Majeure Events as specified in this Agreement and occur after the Contract In-Service Date, the Facility's ability to deliver its Committed Capacity[5] shall not be encumbered by interruptions in its fuel supply.

FPC argues LAKE COGEN breached the contract in two ways. First, FPC alleges that because LAKE COGEN did not maintain the required fuel back up, its ability to deliver its Committed Capacity was encumbered from March 3, 1994 to October , 1998. FPC seeks damages for the entire 56 month period. Second, FPC seeks damages because LAKE COGEN did not deliver energy during the period of August 14 through August 17, 1998.

Although FPC argues that the QF was "required" to have back up fuel on premises, the contract simply does not support that assertion. The contract requires that the QF's committed capacity shall not be encumbered by interruptions in its fuel supply. The testimony showed the QFs had wide latitude in how to comply with section 3.3.

The testimony further showed that LAKE COGEN does have a curtailment plan in place. The gas that LAKE COGEN purchases from its fuel supplier, UP Fuels, travels across the lines of Florida Gas Transmission. People Gas Systems (PSG) is responsible for ensuring that the gas is transported across those lines. LAKE COGEN's gas transportation agreement with PSG is

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[5]The term committed capacity is defined as the kilo-watt capacity which the QF has agreed to make available on a firm basis during the On-Peak Hours at the point of delivery.

interruptible. The unrebutted testimony showed that LAKE COGEN could not have negotiated an un-interruptible contract with PSG. Instead of having an un-interruptible gas transportation contract, LAKE COGEN has a curtailment plan whereby, in the event PSG interrupts LAKE COGEN's gas supply, BP Oil would bring fuel to the site within two to three hours. According to the testimony, this plan is preferable to LAKE COGEN storing the oil on the premises in the fuel tank because the oil could spoil if not used on a regular basis.

Even assuming that LAKE COGEN's failure to store the back up fuel on the premises was a material breach of contract as FPC argues, section 15.3.5 of the contract provides that if the QF fails to perform or comply with any material term or condition of the contract, and fails to conform to said term or condition within sixty (60) days after a demand by FPC, FPC may exercise any of the remedies in section 15.4, which includes remedies at law, i.e. suing LAKE COGEN for breach of contract. The evidence showed that, notwithstanding the fact FPC had the ability to inspect LAKE COGEN's facility, FPC never made a demand on LAKE COGEN to store its back up fuel on the premises during the 56 month period. The contract does not require the QF to store back up fuel on the premises, and even assuming, arguendo, it did, FPC was required to give notice to LAKE COGEN of the material breach, and allow LAKE COGEN sixty days to cure the breach.

Additionally, FPC argues LAKE COGEN failed to deliver its committed capacity due to an interruption in its gas supply for the dates August 14, 1998 through August 17, 1998. The testimony was undisputed that the cause of the interruption was a lightning strike. The lightning strike caused a fire that disabled all of Florida Gas Transmission's, (FGT's) lines, so that no gas was flowing into the state of Florida over FGT's lines. FPC points specifically to the three days in August 1998 to support its position that LAKE COGEN failed to deliver its committed capacity. FPC argues that section 3.3 imposes upon LAKE COGEN an obligation to be able to deliver its committed capacity

every hour of the day. However, the contract calls for LAKE COGEN to meet a 90% Committed On-Peak Capacity Factor over a rolling 12 month average. If LAKE COGEN fails to meet this average, it is subject to the contract's performance adjustment and reduced capacity payment. Under section 15.3.3, only if the QF fails to qualify for capacity payments under Article VIII for any consecutive twenty-four (24) month period will the failure constitute an operational events default. FPC has failed to meet its burden of showing that LAKE COGEN failed to deliver its committed capacity. Based on the foregoing analysis, it is hereby

ORDERED AND ADJUDGED that FPC's counterclaim for breach of contract re: capacity payments is **dismissed.**

DONE AND ORDERED in chambers at Tavares, Florida this 6 day of April, 1999.

Don F. Briggs, Circuit Judge

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that the following has been forwarded by mail this 6 day of April, 1999 to the following parties:

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Judicial Assistant/Clerk

IN THE CIRCUIT COURT OF THE FIFTH JUDICIAL CIRCUIT
OF FLORIDA IN AND FOR LAKE COUNTY

NCP LAKE POWER, INCORPORATED,
a Delaware Corporation,
as General Partner of LAKE
COGEN, LTD., a Florida
limited partnership,

Plaintiff,

v. Case No.:94-2354-CA

FLORIDA POWER CORPORATION,

Defendant.

FINAL JUDGMENT

THIS CAUSE came before the Court for final disposition on July 29, 1999. A complete trial of all issues concluded in December, 1998. Counsel was directed by the Court to submit written closing arguments which were received by the Court at the end of February, 1999. This Court entered a Non-Final Trial Order in April, 1999, which adjudicated liability, but reserved ruling on damages as the Court's interpretation of the contract at issue did not comport with the interpretations given by the respective Parties. The Parties were left to calculate damages in accordance with the Court's interpretation of the contract. Two issues arose concerning 1) the date of breach; and 2) whether as-available energy payments were capped at the firm rate, and these issues were argued before the Court in July, 1999. An order was entered in August, which brought the Parties closer to agreeing on the amount of damages. It appears there is only one issue remaining to be addressed in this, the Final Judgment. The Court, being fully advised in the premises, and having considered both Parties respective proposed Final Judgments and correspondence, it is thereupon:

ORDERED AND ADJUDGED AS FOLLOWS:

1. The address of the Defendant, Florida Power Corporation (FEIN 59-0247770) is One Progress Plaza, Suite 1500, St. Petersburg, Florida 33701.

2. The address of the Plaintiff, NCP Lake Power, Incorporated, as General Partner of Lake Cogen Ltd., is One Upper Pond Road, Parsippany, New Jersey 07054.

3. The Plaintiff, NCP Lake Power, Incorporated, as General Partner of Lake Cogen, Ltd., shall recover from the Defendant, Florida Power Corporation, the amount of Four Million Four-Hundred Eighty Thousand Two-Hundred Forty-Seven and no/100 Dollars ($4,480,247.00) which includes pre-judgment interest and all other damages for FPC's breach of contract. The Judgment shall accrue interest at the post-judgment legal rate pursuant to Section 55.03, Florida Statutes.[1]

4. This Court specifically incorporates by reference its Non-Final Trial Order dated April 6, 1999; Order dated May 3, 1999; and Order Specifying As-Available Energy Payments Not Capped at Firm Energy Payments, dated August 5, 1999, into this Final Judgment as if such rulings were fully set forth herein.

5. Each party shall bear its own attorney's fees. This Court reserves jurisdiction to determine entitlement to costs.

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[1]The Parties were in disagreement as to the proper rate of interest to be applied post-judgment. Specifically, Florida Power submitted a partial transcript of the trial dated 12/2/98, in which Florida Power and NCP stipulated on the record that "in the event that the Court would determine damages, that the damages would be at the contract rate, which is the commercial paper rate rather than the statutory interest rate." This stipulation spoke to the calculation of damages, pre-judgment interest, and not to the interest rate to be applied to a judgment. The Court finds Florida law controls this issue as the contract does not address the rate of interest to be applied post-judgment. Therefore Section 55.03, Florida Statutes sets the rate of interest to be applied to this judgment.

FOR ALL OF WHICH LET EXECUTION ISSUE.

DONE AND ORDERED in chambers at Tavares, Florida this 26 day of August, 1999.

Don F. Briggs, Circuit Judge

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that the following has been forwarded by mail this 26 day of August, 1999 to the following parties:

Marylin E. Culp/ Ellen Koehler
ANNIS, MITCHELL, COCKEY,
EDWARDS & ROEHN, P.A.
Post Office Box 3433
Tampa, FL 33601

Rodney E. Gaddy
Florida Power Corporation
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Robert Scheffel Wright
LANDERS & PARSONS
310 West College Avenue
Tallahassee, FL 32302

Judicial Assistant/Clerk

IN THE DISTRICT COURT OF APPEAL OF THE STATE OF FLORIDA
FIFTH DISTRICT JANUARY TERM 2001

NOT FINAL UNTIL THE TIME EXPIRES TO FILE REHEARING MOTION, AND, IF FILED, DISPOSED OF.

NCP LAKE POWER, INC., etc.,

Appellant/Cross-Appellee,

v.

Case No. 5D99-2401

FLORIDA POWER CORPORATION,

Appellee/Cross-Appellant.

Opinion filed April 6, 2001

Appeal from the Circuit Court
for Lake County,
Don F. Briggs, Judge.

Phillip S. Smith and Christopher V. Carlyle of McLin, Burnsed, Morrison, Johnson, Newman & Roy, P.A., Leesburg, and John Beranek of Ausley & McMullen, Tallahassee, and Robert Scheffel Wright of Landers & Parsons, Tallahassee, for Appellant/Cross-Appellee.

Jodi L. Corrigan and A. Alexander Rhodes and Ellen L. Koehler of Annis, Mitchell, Cockey, Edwards & Roehn, P.A., Tampa, and Rodney E. Gaddy and Jeffrey A. Froeschle, St. Petersburg, for Appellee/Cross-Appellant.

PER CURIAM.

ON MOTION FOR CLARIFICATION

We grant Florida Power Corporation's motion for clarification, withdraw our previous opinion dated January 26, 2001, and substitute the following opinion.

We are here confronted with the arduous task of interpreting contractual provisions relating to the intricate and complicated process of producing and selling electrical energy;

arduous because we must grapple with terminology utilized by electrical engineers and physicists whose education and training provide them the ability to readily understand this process. However, we undertake our judicial duty assured by the knowledge that enduring legal principles formulated long ago continue to provide courts today with accurate guidance to ascertain the meaning of such technical terminology and the intent of the parties who incorporate it into their agreements.

NCP Lake Power, Inc., (Lake) appeals a final judgment entered in a breach of contract action it filed against Florida Power Corporation (FPC).[1] The trial court entered judgment in favor of Lake for $4.48 million in damages finding that FPC did breach the contract. Lake claims that this amount is not adequate to compensate it for its damages and that the trial court erred in calculating the amount of damages pursuant to the contract provisions that specify the rate Lake is to be paid by FPC for energy it produces and sells to FPC. The primary issue in this case is what rate Lake is to be paid for energy pursuant to its contract with FPC. We reverse because the trial court incorrectly determined the rate that Lake is to receive for its energy and thus incorrectly determined the damages under the contract.

Two other issues are presented by the parties. One is whether the trial court erred

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[1] FPC filed a cross appeal contending that the trial court rejected the plain meaning of the contract and erred by admitting extrinsic evidence to explain the terms and conditions of the agreement. Although we agree that the trial court did not properly construe the rate provisions of the contract, we reject the arguments made by FPC regarding how the rate should be calculated for the energy produced by Lake. The contract provisions relating to calculation of the payment rate will be discussed in a separate section of this opinion. We find that the arguments made by FPC concerning introduction of the extrinsic evidence are without merit. The issues relating to the extrinsic evidence will also be discussed in a separate section of this opinion.

in dismissing count III of Lake's complaint seeking damages for FPC's alleged improper manipulation of the coal price which determines the amount of the per-hour "firm energy rate" Lake contends it is entitled to receive for its energy. Specifically, Lake contends that FPC artificially manipulated the price of coal in an effort to reduce its energy payments by altering its method of coal transportation in order to lower the delivered price of coal to its proxy plants (the avoided unit of measure) which are FPC's Crystal River 1 and 2 plants. We find that substantial competent evidence supports the trial court's decision to dismiss this count of the complaint and affirm that decision without further discussion.

The other issue is whether the trial court erred in ruling that the breach of contract by FPC commenced the first day the contract was implemented resulting in damages that were calculated to include a set-off for the first thirteen months of energy payments which were paid at the "firm rate" for all energy Lake delivered to FPC. Lake contends that FPC failed to properly plead set-off as an affirmative defense or as a counterclaim. We conclude that this issue is rendered moot by our decision regarding the rate that Lake is entitled to be paid for its energy.

Thus the only issue we will address in the remainder of this opinion is the issue regarding rate and calculation of damages. We will first discuss the factual and procedural history of this case to provide an overview of how it evolved. We will next address the standard of review that we will apply in resolving this issue and then examine the legal basis for admitting and considering the extrinsic evidence that was admitted by the trial judge. Our discussion will conclude with an examination of the extrinsic evidence which provides us the necessary information to understand the terms and conditions of the contract.

Factual And Procedural Background

FPC is a public utility that supplies electrical power to millions of rate payers across the State of Florida. In order to meet its increasing energy and capacity needs, FPC solicited bids from "qualifying facilities" to purchase firm capacity and energy which FPC would in turn distribute to its customers. A qualifying facility is a cogeneration facility that meets certain energy efficiency and ownership criteria pursuant to regulations promulgated by the Federal Energy Regulatory Commission. Lake, a qualifying facility under these regulations, builds power plants to produce and supply electrical energy and generating capacity to entities like FPC.

Several qualifying facilities, including Lake, responded to FPC's solicitation for bids. FPC and Lake eventually entered into a detailed and extensive contract formally referred to by the parties as the "Negotiated Contract for the Purchase of Firm Capacity and Energy from a Qualifying Facility" (the Contract). Pursuant to the Contract, Lake agreed to construct and operate an electrical generating plant and sell its electricity to FPC. The provisions of the Contract relating to the rate that Lake is to be paid by FPC for its energy are central to resolution of the issue in this case and those provisions will be quoted later in this opinion. We find that other provisions of the Contract required Lake to choose what type of processing facility would be used as a model or proxy for determining payment, which was to be based on an "avoided unit" of measure and not on the power plant which was actually supplying the energy. These facilities are referred to as "avoided units" because FPC, by entering into a contract with a qualified facility to produce energy for it, avoids having to expend its own funds to construct and operate the facility itself. Thus an avoided unit is the generating facility that FPC would have built and operated but for the

contractual commitments of Lake and other qualified facilities. Lake selected a 1991 Pulverized Coal Unit as the avoided unit pursuant to the Contract. FPC and Lake anticipated that this avoided unit would be similar to FPC's Crystal River coal plants. The record reveals that FPC already had four large pulverized coal units in its system which were similar to the avoided unit Lake selected pursuant to the Contract.

On July 1, 1993, Lake began providing electrical energy and capacity to FPC pursuant to the Contract. From the commencement date until August 8, 1994 (thirteen months), it is undisputed that FPC paid Lake the "firm rate" as if the avoided unit were operating all of the time. Lee G. Schuster, Manager of Special Products for FPC, testified that an internal audit was conducted by FPC in 1993, revealing that the prices for fuel other than coal had changed such that the avoided coal plant was no longer the cheapest unit to run. Based on this assessment, Schuster testified that FPC then developed a mechanism pursuant to 9.1.2 of the Contract, implementing a procedure wherein the avoided unit would not be dispatched on a continuous basis as it had been during the initial thirteen months.

After the audit, FPC formed a strategy team to address the impact the new system would have on the contracts entered into with qualifying facilities such as Lake and to reduce payments based on the results of the audit.[2] The strategy team set forth a number of specific strategies in an internal document entitled "Cogeneration and Purchased Power

[2]According to Robert Dolan, a manager of the co-generation department of FPC at the time of contracting as well as at the time of testifying, the strategy team was assembled to determine what should be done with the contracts entered into with the qualifying facilities. He testified that the "avoided unit" of the qualifying facilities was based on similar units Crystal River 4 and 5, which are "base-load" units, meaning that they are not cycled on and off, because they are the cheapest to run.

Cogen Strategic Proposal." The mission statement contained in that document was:

> Enhance Florida Power Corporation's (FPC) competitive position by improving the cost effectiveness of purchased power contracts and mitigate impacts of purchased power to FPC's and Florida Progress's credit ratings.

The documented proposed strategies for accomplishing that mission were: (1) "[r]educe the capacity and energy costs of FPC's purchased power contracts" by "[r]educ[ing] and maintain[ing] the cost of QF purchased power to a level comparable to competitive market alternatives, defined as a gas-fired combined cycle unit"; (2) "[m]itigate the negative impacts to FPC's and Florida Progress's credit ratings caused by purchased power contracts" by "reduc[ing] and maintain[ing] purchased power to a level below 15% of FPC's supply side capacity resources"; (3) "[o]btain generation reduction capabilities from the 'QFs' to reduce total system cost and maintain proper system reliability" by "[o]btain[ing] an additional 500 MWs of generation reduction capabilities from 'QFs' by the end of first quarter 1995."

On July 18, 1994, FPC notified Lake and other qualifying facilities that it would begin paying the as-available prices for energy provided when the avoided unit was off. The record supports the fact that the scheduled shut down of the avoided unit on a daily basis is hypothetical and does not reflect actual shut down of the reference facilities – FPC's Crystal River plants, which although cycled, are apparently never shut off except for maintenance. After sending this letter to Lake and the other qualifying facilities, FPC petitioned the Public Service Commission (PSC) for a declaration that FPC's intended actions were consistent with the PSC's contract approval. While the petition was still pending with the PSC, Lake filed its lawsuit in October 1994. On February 15, 1995, the PSC dismissed the Petition for Declaration, apparently on the ground that they did not have

jurisdiction to adjudicate a dispute over a provision in a negotiated contract.

Pertinent Provisions Of The Contract And Legal Issues Raised Therefrom

The term of the Contract is twenty years, and it requires FPC to pay Lake for its energy pursuant to Article 9 which details the energy pricing methodology as follows:

> 9.1.2 Except as otherwise provided in section 9.1.1 hereof, for each billing month beginning with the Contract In-Service Date, the QF will receive electric energy payments based upon the Firm Energy Cost calculated on an hour-by-hour basis as follows: (i) the product of the average monthly inventory chargeout price of fuel burned at the Avoided Unit Fuel Reference Plant, the Fuel Multiplier, and the Avoided Unit Heat Rate, plus the Avoided Unit Variable O & M, if applicable, for each hour that the Company would have had a unit with these characteristics operating; and (ii) during all other hours, the energy cost shall be equal to the As-Available Energy Cost.

Both parties agree that this section of the Contract requires payment of either firm or as-available energy prices depending on the operational status of the avoided unit. The firm rate is calculated pursuant to a formula which is based on the product of the average monthly inventory chargeout price of fuel burned at the avoided fuel reference plant, the fuel multiplier, and the avoided unit heat rate, plus the avoided unit variable O & M, if applicable. The hourly firm rate calculated pursuant to this formula must be paid for each hour that FPC would have had a unit with these characteristics operating. When FPC would not have had the unit operating, it would be obligated to pay the as-available energy cost which is less than the firm energy cost.

The dispute in these proceedings is not with the formula for calculating the hour-by-hour firm energy rate or the amount of the hourly rate calculated pursuant to this formula. Rather, the dispute concerns when the avoided unit would have been operating to entitle Lake to receive payment based on this hourly rate. This issue was framed by the trial court

when it entered partial summary judgment in favor of Lake on the issue of liability. The judgment provides that FPC failed "to pay Lake Cogen at the firm energy cost rate when the avoided unit with operational characteristics of an operable 1991 Pulverized Coal Unit contemplated by the Lake Cogen-FPC Agreement would have been operating and at the as-available energy cost rate during those times when said avoided unit would not have been operating." The trial court did not determine the issue of when the unit would have been operating and indicated that this was an issue relating to the amount of damages. In this posture, the parties subsequently tried the case.

The trial was conducted over a three week period and both sides presented expert testimony to define and clarify the technical terms of the Contract and to attempt to explain when the avoided unit would have been in operation. After the trial concluded, the trial court resolved the issue of when the avoided unit would be operating by holding that it would operate during all on-peak hours,[3] but not during off-peak hours. The parties to these proceedings indicate that this approach was not advanced, argued, or expected by either party and Lake refers to this methodology as an unsupportable "Solomonic" attempt to "split

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[3]Appendix C, Schedule 3, of the Contract, entitled "Rates For Purchase of Firm Capacity and Energy From Qualifying Facility," sets forth the following:

> ON-PEAK HOURS
> (1) FOR THE CALENDAR MONTHS OF NOVEMBER THROUGH MARCH,
> ALL DAYS: 6:00 A.M. TO 12:00 NOON, AND
> 5:00 P.M. TO 10:00 P.M.
>
> (2) FOR THE CALENDAR MONTHS OF APRIL THROUGH OCTOBER
> ALL DAYS: 11:00 A.M. TO 10:00 P.M.

the baby." The trial court essentially found that the minimum number of hours of operation of a 1991 Pulverized Coal Unit was equal to the on-peak hours of Schedule 3 and that Lake was entitled to the firm rate during those hours and to the as-available rate for the off-peak hours. However, we find that the contract does not specifically state when the avoided unit does and does not operate. Thus the problem with the result reached by the trial court is that it assumes that the avoided unit is shut down and does not operate during the off-peak hours. Furthermore, we find nothing in the Contract that states that the on-peak hours are the only operating hours of the avoided unit. Moreover, this approach is not supported by the extrinsic evidence which explains the physical operating characteristics of a 1991 Pulverized Coal Unit.

The Standard Of Review

The interpretation of a contract is a question of law and, therefore, we are not bound by the conclusions reached by the trial court regarding construction of the Contract. See Inter-Active Servs., Inc. v. Heathrow Master Assoc., Inc., 721 So. 2d 433, 434 (Fla. 5th DCA 1998). Thus decisions which construe a contract are generally subject to review on appeal by the de novo standard of review. See Gilman Yacht Sales, Inc. v. FMB Invs., Inc., 766 So. 2d 294 (Fla. 4th DCA 2000); Gibbs Constr. Co. v. S.L. Page Corp., 755 So. 2d 787 (Fla. 2d DCA 2000); Powertel, Inc. v. Bexley, 743 So. 2d 570 (Fla. 1st DCA 1999), rev. denied, 763 So. 2d 1044 (Fla. 2000); Management Computer Controls, Inc. v. Charles Perry Constr., Inc., 743 So. 2d 627 (Fla. 1st DCA 1999). Therefore, we review the trial court's decision in this case pursuant to that standard.

FPC argues that because the trial court admitted and considered extrinsic evidence,

the de novo standard should not be applied. We disagree because the Contract is unambiguous: both parties agree that the contract is unambiguous, the trial court found it is unambiguous, and so do we. Furthermore, the evidence admitted only explains technical terms contained in the Contract and does not alter or amend the provisions of the agreement. Moreover, even if we were to apply the substantial evidence standard to this case, considering the evidence that may support the trial court's finding that the avoided unit only operates during the designated on-peak hours, we find that such evidence is far from substantial in light of all of the other evidence and testimony contained in this record. See Elmore v. Enterprise Developers, Inc., 418 So. 2d 1078, 1079 (Fla. 4th DCA 1982) ("In such cases, where the provisions of the contract are susceptible of two or more meanings and there is substantial competent evidence in the record to support the meaning adopted by the trial court, we are bound to affirm that ruling just as we would be bound to sustain a finding of fact made by the trial court on disputed issues of fact.").

Legal Basis For Admitting Extrinsic Evidence

As a general rule, when the terms and provisions of a contract are unambiguous and complete, parol evidence is not admissible to define or explain them. See McKay v. State Farm Fire & Cas. Co., 731 So. 2d 852 (Fla. 4th DCA 1999); Kraft v. Mason, 668 So. 2d 679 (Fla. 4th DCA), rev. dismissed, 679 So. 2d 773 (Fla. 1996). This court has held, however, that if an unambiguous contract contains technical terminology that may not be understood by the court, extrinsic evidence may be introduced to explain it. In Southeast Banks Trust Co., N.A. v. Higginbotham Chevrolet-Oldsmobile, Inc., 445 So. 2d 347 (Fla. 5th DCA 1984) this court explained:

> [W]here words or phrases used in a contract have acquired a definite meaning generally or by local usage, or, where used in reference to certain things or commodities, have acquired a definite meaning among those dealing with such things or commodities, and the language used in the writing is such that the court does not understand it, oral testimony is admissible to explain the meaning of such words or phrases.

Id. at 348 (quoting Hinote v. Brigman, 44 Fla. 589, 33 So. 303, 305 (Fla. 1902)).

As we have previously indicated, the Contract in the instant case, although unambiguous, is replete with technical terminology intended for electrical engineers and scientists engaged in the process of producing and selling electrical energy: not for laymen, lawyers, and judges. The trial court properly admitted extrinsic evidence to explain that terminology. For example, "Fuel Multiplier," "Avoided Unit Heat Rate," "Avoided Unit Variable O & M," "Firm Energy Cost," "As-Available Energy Cost," "83% On Peak Capacity Factor," are some of the terms contained in the Contract that, even when defined in the definitions section of the Contract, are not easily understood by judges or juries without explanation by experts. Furthermore, the central issue in this case is when does a Pulverized Coal Unit operate. We find that the Contract under review does not contain all of the variables involved in the operation of a real Pulverized Coal Unit, which was Lake's contractual choice for the avoided unit. Thus extrinsic evidence was necessary to explain the technical terminology in the contract and to explain what a Pulverized Coal Unit is and how and when it operates.

Moreover, the Contract does not specifically provide the hours of operation of the avoided unit in the instant case. Therefore, in instances such as this, extrinsic evidence of custom and trade usage may be introduced to "annex incidents to a written contract" regarding matters to which the contract is silent. See Carr v. Stockton, 84 Fla. 69, 92 So.

814, 815 (Fla. 1922); Vanater v. Tom Lilly Constr., 483 So. 2d 506, 508 (Fla. 4th DCA 1986) ("Where a term is missing, it may be supplied in accordance with usual, reasonable, and customary practices in the locality."); Fred S. Conrad Constr. Co. v. Exchange Bank of St. Augustine, 178 So. 2d 217 (Fla. 1st DCA 1965); Orange City Hills, Inc. v. Florida Realty Bureau, Inc., 119 So. 2d 43, 47 (Fla. 1st DCA 1960) (noting the listing agreement "did state most of the terms and conditions of the contemplated sale, including the purchase price and amount to be paid at time of closing; and the above missing elements are suppliable in accordance with the usual reasonable and customary practices in the locality.").

The same rule applies to introduction of the parties' course of dealing. In Cox v. CSX Intermodal, Inc., 732 So. 2d 1092 (Fla. 1st DCA), rev. denied, 744 So. 2d 453 (1999), for example, the court, in a case involving an unambiguous contract, stated:

> [W]hen the language of a contract does not deal in express terms with all aspects of the rights and duties of the parties to the agreement, the language used 'should be interpreted as reasonable persons, knowledgable about the business or industry, would likely interpret them-*not* some strained interpretation put forth by the drafter.'

Id. at 1096 (quoting Hussmann Corp. v. UPS Truck Leasing, Inc., 549 So. 2d 215, 217 (Fla. 5th DCA 1989)). We, therefore, conclude that the trial court correctly decided to introduce extrinsic evidence in this case.

The Extrinsic Evidence Admitted By The Trial Court

Now that we have determined that there is a sound legal basis for us to consider the extrinsic evidence admitted by the trial court, we will first examine the expert testimony, some of which relates to custom and trade usage, which explains what a 1991 Pulverized Coal Unit is and how and when such units operate. We will next examine the testimony

relating to the provision in the Contract that requires Lake's avoided unit to achieve an on-peak capacity factor of eighty-three percent and what that means in terms of how and when the avoided unit must operate in order to comply with that requirement. We will then discuss the evidence relating to the parties' course of dealing when the Contract was presented to the PSC for approval and how the parties conducted themselves in relation to the Contract after it was approved and implemented.

Much of the extrinsic evidence demonstrates that the avoided unit, a 1991 Pulverized Coal Unit, is intended to be a baseload unit. This means that the unit is intended to operate at all times when it is available except when it is shut down for maintenance or required repairs. FPC contends that this evidence is inadmissible because the Contract does not specify that the avoided unit is a baseload unit. The testimony presented shows, however, that a Pulverized Coal Unit is currently dispatched as a baseload unit. We find that this evidence is not inconsistent with the Contract and is admissible to explain the dynamics of an actual Pulverized Coal Unit which is not apparent in the Contract. Furthermore, FPC and Lake disagree whether a Pulverized Coal Unit operates all of the time, and the Contract does not specify that the unit would not be in operation during any off-peak hours as the trial court concluded. Thus the trial court properly admitted the testimony of experts and other witnesses to explain the industry's knowledge of the operation of a Pulverized Coal Unit as a baseload unit which we find to be helpful in determining whether or not the avoided unit in the instant case operates at all times as Lake suggests.

The evidence established that all of FPC's existing coal plants are baseload units including the Crystal River Units that are listed in Schedule 3 of the Contract as the "avoided unit fuel reference plant." As mentioned earlier, the avoided unit selected by Lake is similar

to these avoided unit fuel reference plants. The testimony and evidence revealed that none of FPC's similar coal plants are shut down on a regular scheduled basis, although they may be cycled down during off-peak time.[4] John Seelke, the former Cogeneration Manager for FPC who participated in the negotiation of the Contract with Lake, testified that of FPC's four existing coal units, only one had been turned off one time for reasons other than maintenance or repairs. According to the Contract with Lake, the firm rate is to be paid when a unit with the same characteristics is operating. Thus, only complete shut-down of the avoided unit would evoke the as-available rate as opposed to the firm rate of payment. Based on the evidence and testimony that Lake's avoided unit functions as a baseload unit that operates all the time it is available, Lake should be paid the firm rate.

Testimony was also admitted concerning the requirement in the Contract that the avoided unit achieve a minimum on-peak capacity factor of eighty-three percent.[5] The testimony of both FPC's and Lake's experts establishes that the avoided 1991 Pulverized Coal Unit, because of its fundamental engineering design and operational characteristics, must necessarily run all the time that it is available at its highest output in order to achieve a minimum on-peak capacity factor of eighty-three percent. While the minimum on-peak capacity factor only relates to on-peak hours of operation, the testimony of the experts

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[4]Although testimony revealed that the avoided coal plant was no longer the cheapest to operate, there was no further evidence or testimony presented to support the notion that FPC's currently operating coal plants are actually shut down based on this. Moreover, Dolan testified that although the avoided unit could be cycled on and off, FPC does not practice this procedure on a daily basis.

[5]The avoided unit chosen by Lake pursuant to Article 8.2.1 of the contract was the 1991 Pulverized Coal Unit described in Appendix C, Schedule 4. Appendix C, Schedule 3 of the Contract specifically provides that this avoided unit would achieve a minimum eighty-three percent on-peak capacity factor.

demonstrated that a coal unit could not be shut down and re-started during the off-peak hours and still reach its maximum output during all of the on-peak hours.

For example, John Tucker Day, FPC's expert witness, testified that the avoided unit "would have to run essentially full out for every hour that it was available in general in order to achieve 83% capacity factor." He was also asked whether operating the avoided unit for eleven hours a day during the on-peak hours specified in Appendix C, Schedule 3 of the Contract would satisfy the minimum eighty-three percent capacity factor and he testified that "I would agree that you cannot–you cannot operate those hours and get an 83% capacity factor." Lake's expert, Kenneth John Slater, testified regarding the eighty-three percent capacity factor that the avoided unit is "really going to be running all the time that it's available. It may cycle down in megawatts to allow a level overnight, but it would still be running."

The evidence further revealed that FPC petitioned the PSC for approval of the Contract. FPC provided the PSC with data and projections of its avoided costs and of payments to be made under its contract with Lake and the other qualified facilities to demonstrate the cost effectiveness of the Contract. It is undisputed that FPC used only firm prices for the estimates, thus representing to the PSC that the contract would pay the firm rate at all times. FPC subsequently submitted a letter to the PSC correcting some of its previously submitted data but did not alter the use of the firm pricing estimates. Shortly thereafter, the PSC approved the contract.

FPC paid Lake the firm rate at all times during the first thirteen months of energy delivery which spanned the period from July 1, 1993, through August 8, 1994. Lake argues that this evidence of course of dealing shows that FPC intended to pay the firm rate during

all times the unit operated. FPC objected to the introduction of this evidence as improper parol evidence. Under the circumstances of this case, we conclude that this evidence was properly introduced. See Cox.

Even though the title of the Contract states that it is a "Negotiated Contract," the record is clear that the Contract was drafted by FPC. If it intended that firm energy rates only be paid during the on-peak hours as the trial court held, FPC could have easily inserted that provision in the Contract in place of the provision that the firm rate will be paid for "each hour that the Company would have had a unit with these characteristics operating . . . ." We conclude that the Contract requires that Lake be paid the firm energy rate for all hours that the avoided unit operates and that it operates all of the time except for periods it is turned completely off for maintenance and repairs.

Conclusion

We affirm the trial court's dismissal of count III of the complaint. We find that the issue relating to set-off has been rendered moot. Regarding the rate and damages issue, we conclude that the trial court erred in failing to determine damages based on the actual operating hours of Lake's avoided unit. Therefore, that portion of the final judgment is reversed. We conclude our judicial duty in this matter by remanding this case back to the trial court for a new trial to determine the amount of damages based on the firm energy rate for all hours the avoided unit operates, which is all of the time, minus any maintenance shut-down hours.

AFFIRMED in part; REVERSED in part; and REMANDED.

COBB, PETERSON and SAWAYA, JJ., concur.

IN THE CIRCUIT COURT OF THE FIFTH JUDICIAL CIRCUIT
IN AND FOR LAKE COUNTY, FLORIDA

NCP LAKE POWER, INCORPORATED,
a Delaware corporation, as General
Partner of LAKE COGEN LTD., a
Florida limited partnership,

Plaintiff,

vs.

FLORIDA POWER CORPORATION,

Defendant.
_____/

CASE NO. 94-2354-CA-01

DIVISION NO. 8

FINAL JUDGMENT

This action was presented to the trial court on remand and the parties stipulated to the remaining factual issues consistent with the ruling of the 5th DCA. After hearing from counsel of the respective parties, and otherwise being duly advised, the Court finds and orders as follows:

1. The Court adopts the parties Stipulation of Facts as its own and incorporates those facts into this Final Judgment. A true and correct copy of the Stipulation of Facts is attached hereto as Exhibit "A."

It is therefore, ORDERED and ADJUDGED that Plaintiff, NCP Lake Power, Incorporated, a Delaware corporation, as General Partner of Lake Cogen Ltd., a Florida limited partnership, is due from Defendant, Florida Power Corporation, $19,860,307.00 for damages through and including August 31, 2001, and prejudgment interest through and including September 24, 2001.

It is further ORDERED that this Court reserves jurisdiction to determine the taxable costs in this matter.

FOR WHICH LET EXECUTION ISSUE FORTHWITH.

ORDERED at Tavares, Florida on the 24 day of Sept, 2001.

/s/ Don F. Briggs

DON F. BRIGGS, Circuit Judge

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy hereof has been furnished by U.S. Mail this 24 day of Sept, 2001, to:

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Attorneys For Defendant

JUDICIAL ASSISTANT

IN THE CIRCUIT COURT OF THE FIFTH JUDICIAL CIRCUIT
IN AND FOR LAKE COUNTY, FLORIDA

NCP LAKE POWER, INCORPORATED,
a Delaware corporation, as General
Partner of LAKE COGEN LTD., a
Florida limited partnership,

Plaintiff,

vs.

FLORIDA POWER CORPORATION,

Defendant.
_____/

CASE NO. 94-2354-CA-01

DIVISION NO. 8

STIPULATION OF FACTS

Pursuant to the Fifth District Court of Appeal ruling dated April 25, 2001, this cause was remanded to the trial court for further proceedings consistent with the opinion. The parties having reviewed the Court's ruling, hereby stipulate to the following facts consistent with such ruling:

1. The Appellate Court ruled that Lake Cogen would be entitled to the firm energy cost rate for all hours of energy production minus any maintenance hours of a 1991 pulverized coal plant.

2. A 1991 pulverized coal unit is similar to Crystal River units 4 and 5, with the added addition of air scrubbers.

3. A 1991 pulverized coal unit would have two (2) scheduled outages totaling forty-five (45) days per year where it would be turned completely off for maintenance and repairs.

4. The required maintenance of a 1991 pulverized coal unit would be scheduled in two (2) outages per year, to be coordinated in advance by Florida Power. Florida Power would normally schedule outages in blocks occurring in March 1st through April 30th and October15th through December 15th each year. No outage would be less than fifteen (15) days.

5. Consistent with the operation of a 1991 pulverized coal unit, Florida Power and Lake Cogen could agree to alter a previously schedule maintenance outage, to a mutually agreeable time.

6. The total dollars owed to Lake Cogen by FPC including energy costs, and the performance adjustment up through and including August 31, 2001 and interest up through and including September 24, 2001, equals $19,860,307.00.

7. The per diem interest amount on the total amount owed is $ 1,884.00 and should be added to the total amount for every day the Final Judgment date exceeds September 24, 2001.

8. Finally, the parties agree that a final judgment consistent with the Appellate Court's ruling and these stipulations is appropriate.

FLORIDA POWER CORPORATION

By:_____
Its_____

Dated: the _____ day of _____, 2001

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Florida Bar No. 901570
JODI CORRIGAN, P.A.
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Largo, FL 33770
Attorney for Defendant

NCP LAKE POWER, INC.

By:_____
Its

Dated: the _____ day of _____, 2001

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Lake Cogen Energy Pricing

Historically the Lake Cogen energy payments have been calculated using three different methods.

From July 1, 1993 to July 31, 1999 – The energy payment was calculated using FPC's method. That is, a dispatch model was used to determine when the avoided unit would be either cycled on or off. If the unit was cycled on then the firm energy rate was used; otherwise the as-available rate was used.

August 1, 1999 to June 30, 2001 – The energy payment was calculated using the lower court ruling. The firm energy rate was used during the on-peak hours and the as-available rate was used during the off-peak hours.

July 1, 2001 to present – The energy payment is calculated at the firm rate all the time except for 45 days per year of maintenance. During the maintenance periods the as-available rate is used.

The spreadsheet column labeled "As Paid by FPC" reflects the first two of the payment methods. The next column labeled "Per September 2001 Stipulation" reflects these payments recalculated using the stipulation methodology that has been used since July 1. The next column is the difference between the older methodology and the stipulated methodology. The interest rate is the 30-day commercial rate as quoted in the WSJ on the first business day of the month. This is the interest rate specified in the contract. The last column shows the days that the as-available rate was used. The stipulation states that no maintenance period shall be shorter that 15 days but for the historic calculation of damages. This requirement was waived because Lake Cogen took short outages and it would have been unfair to require that they get forced into 15-day outages when they took outages of a few days here and there.

Supreme Court of Florida

No. SC94665

FLORIDA POWER CORPORATION,
Appellant,

vs.

JOE GARCIA,
etc., et al.,
Appellees.

[March 1, 2001]

LEWIS, J.

This case involves an appeal from a decision of the Public Service Commission (the "Commission," or the "PSC") denying Florida Power Corporation's petition for declaratory statement on the basis of res judicata. In re Petition of Florida Power Corp., 98 F. P. S. C. 12:65 (1998) (Docket No. 980509-EQ, Order No. PSC-98-1621-FOF-EQ, Dec. 4, 1998). We have jurisdiction. See art. V, § 3(b)(2), Fla. Const. The narrow question presented is whether the 1995 determination by the Florida Public Service Commission regarding its

jurisdiction to entertain a certain petition for declaratory statement filed in 1994 by appellant, Florida Power Corporation (FPC), had a preclusive effect as applied to its later determination of jurisdiction to entertain a substantially similar petition for declaratory statement filed by FPC in 1998. Based upon the unique circumstances of this case, we affirm the PSC's determination that it did because the concept of administrative finality applies.

I. MATERIAL FACTS AND PROCEEDINGS BELOW

In March, 1991, FPC and certain qualifying facilities[1] ("QF"s) entered into negotiated contracts for the purchase of electrical power. One of these contracts involved the cogenerator who is the appellee here, Lake Cogen, Limited ("Lake Cogen"). All of the contracts contain the following provision, set forth as section 9.1.2:

> Except as otherwise provided in Section 9.1.1 hereof, for each billing month beginning with the Contract In-Service Date, the QF will receive electric energy payments based on the Firm Energy Cost calculated on an hour-by-hour basis as follows: (i) the product of the average monthly inventory chargeout price of fuel burned at the Avoided Unit Fuel Reference Plant, the Fuel Multiplier, and the Avoided Unit Heat Rate, plus the Avoided Unit Variable Q&M, if applicable, for each hour that the Company would have had a unit with these

[1] "Qualifying Facilities" are those small power generators and cogenerators who meet the qualifying criteria set forth in Rule 25-17.080 ("Definitions and Qualifying Criteria"), Florida Administrative Code, enabling them to contract with power companies for the purchase and sale of electrical power which they generate.

characteristics operating; and (ii) during all other hours, the energy cost shall be equal to the As-Available Energy Cost.

This provision makes apparent allowance for the fact that electric utilities such as FPC typically have a number of electricity-generating facilities, not all of which may be "on line" at the same time, but which may be cycled into operation as appropriate to meet the customers' fluctuating energy demands. See generally Leonard S. Hyman, America's Electric Utilities: Past, Present and Future 22-30 (4th ed. 1992). Thus, the contract provision establishes the method to determine, on a monthly basis, when the cogenerator will be entitled to receive higher "firm" energy payments for electricity pursuant to subsection (i) (when FPC would have operated the "avoided unit"--the facility which a utility such as FPC, by purchasing electrical power from a QF, avoids having to build to meet customer demand for electricity) or lower "as-available" payments pursuant to subsection (ii) (when such unit would not have been operated).

On July 1, 1991, in In re Petition for Approval of Contracts, 91 F.P.S.C. 7:60 (1991) (Docket No. 910401-EQ, Order No. 24734, July 1, 1991), the PSC reviewed the negotiated contracts and found them to be cost-effective for FPC's ratepayers (that is, not requiring payment to the cogenerators in excess of FPC's "avoided cost") under the criteria established in Rules 25-17.082 and

25-17.0832(2), Florida Administrative Code (providing that "[n]egotiated contracts will be considered prudent for cost recovery purposes if it is demonstrated by the utility that the purchase of firm capacity and energy from the qualifying facility pursuant to the rates, terms, and other conditions of the contract can reasonably be expected to contribute towards the deferral or avoidance of additional capacity construction or other capacity-related costs by the purchasing utility at a cost to the utility's ratepayers which does not exceed full avoided costs, giving consideration to the characteristics of the capacity and energy to be delivered by the qualifying facility under the contract"). As stated by this Court in Panda-Kathleen, L.P. v. Clark, 701 So. 2d 322, 324 (Fla. 1997), "'[a]voided cost' is the cost that a utility avoids by purchasing electrical power from a QF rather than generating the electrical power itself or purchasing the power from another source." In arriving at the estimated energy payment structure which the Commission approved, the contract used simplified assumptions regarding the "avoided unit."

During the first three years of the contract, FPC paid cogenerators firm energy prices at all hours of the day (thus, at the very least, implying that FPC would have operated the "avoided unit" at all times). However, thereafter (according to representations made to the Commission by FPC), FPC reviewed the operational status of the "avoided unit" described in section 9.1.2 of the contracts

during minimum load conditions (that is, times of minimum customer demand for energy), and determined that the "avoided unit" would be scheduled off during certain minimum load hours of the day.

Based upon this review, on July 18, 1994, FPC unilaterally notified the parties to the contracts that, effective August 1, 1994, FPC would begin implementing section 9.1.2 as a basis for making certain "as available" energy payments for electricity (i.e., assuming that the "avoided unit" would not be operating during those hours) instead of the "firm" energy payments which it had previously been making (i.e., assuming, at least by implication, that the "avoided unit" would be operating during those hours). Three days later, on July 21, 1994, in an apparent attempt to justify its planned change in payments, FPC filed a petition with the Commission seeking a declaratory statement that section 9.1.2 of its negotiated cogeneration contracts (including the contract with appellee here) was consistent with Rule 25-17.0832(4)(b), Florida Administrative Code.[2]

---

[2]Subsections (a) and (b) of Rule 25-17.0832(4) provide:

> (4) Avoided energy payments.
>
> (a) For the purpose of this rule, avoided energy costs associated with firm energy sold to a utility by a qualifying facility pursuant to a utility's standard offer contract shall commence with the in-service date of the avoided unit specified in the contract. Prior to the in-service date of the avoided unit, the qualifying facility may sell as-available energy to the utility pursuant to Rule 25-17.0825(2)(a).
>
> (b) To the extent that the avoided unit would have been operated, had that unit

The appellee cogenerator, Lake Cogen, petitioned for leave to intervene and questioned whether the declaratory statement procedure was appropriate. In addition, Lake Cogen filed a motion to dismiss on the ground that the PSC did not have jurisdiction to consider FPC's petition. Lake Cogen also initiated a lawsuit in state court at this time, alleging breach of contract based upon FPC's planned change in payments, and seeking declaratory judgment.

On November 1, 1994, FPC amended its petition, asking the PSC to determine whether its manner of implementing the pricing mechanism set forth in section 9.1.2 of the negotiated contracts for the purchase of firm capacity and energy from certain QFs (to determine the period when as-available energy payments were to be substituted for firm energy payments), which would result in a planned change in payments, was lawful under section 366.051, Florida Statutes (1993), and complied with Rule 25-17.0832(4)(b), Florida Administrative Code, and the orders of the Commission approving the negotiated contracts. Thereafter, Lake Cogen filed an additional motion to dismiss the amended petition.

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been installed, avoided energy costs associated with firm energy shall be the energy cost of this unit. To the extent that the avoided unit would not have been operated, firm energy purchased from qualifying facilities shall be treated as as-available energy for the purposes of determining the megawatt block size in Rule 25-17.0825 (2)(a).

In In re Petition by Florida Power Corp., 95 F.P.S.C. 2:263 (1995) (Docket no. 940771-EQ, Order No. PSC-95-0210-FOF-EQ, Feb. 15, 1995), the Commission granted the motion to dismiss. In so ruling, the Commission found that, although FPC had phrased its petition in terms of seeking a rule interpretation, it was really asking the Commission to adjudicate a contractual dispute,[3] a matter over which the Commission did not have jurisdiction. The order provided, in pertinent part:

> FPC has asked us to determine if its implementation of the pricing provision is lawful and consistent with Commission Rule 25-17.0832(4), Florida Administrative Code. We believe that FPC's request is really a request to interpret the meaning of the contract term. FPC is not asking us to interpret the rule. It is asking us to decide that its interpretation of the contract's pricing provision is correct. We believe that endeavor would be inconsistent with the intent of PURPA to limit our involvement in negotiated contracts once they have been established. Furthermore, we agree with the cogenerators that the pricing methodology outlined in Rule 25-17.0832(4), Florida Administrative Code, is intended to apply to standard offer contracts, not negotiated contracts. We have clearly said that we would not require any standard provisions, pricing or otherwise, for negotiated contracts. Therefore, whether FPC's implementation of the pricing provision is consistent with the rule is really irrelevant to the parties' dispute over the meaning of the negotiated provision. In this case, we will defer to the courts to resolve that dispute. We note however, that

[3] The Commission, in later summarizing its decision, stated: "The Commission found that FPC was asking the Commission to adjudicate a contract dispute. The Commission held that it had no jurisdiction to adjudicate contract disputes involving negotiated cogeneration contracts." In re Petition of Florida Power Corp., 98 F.P.S.C. at 12:66.

courts have the discretion to refer matters to us for consideration to maintain uniformity and to bring the Commission's specialized expertise to bear upon the issues at hand.

We disagree with FPC's proposition that when the Commission issues an order approving negotiated cogeneration contracts for cost recovery, the contracts themselves become an order of the Commission that we have continuing jurisdiction to interpret. . . .

Under certain circumstances we will exercise continuing regulatory supervision over power purchases made pursuant to negotiated contracts. We have made it clear that we will not revisit our cost recovery determinations absent a showing of fraud, misrepresentation or mistake; but if it is determined that any of those facts existed when we approved a contract for cost recovery, we will review our initial decision. That power has been clearly recognized by the parties through the "regulatory out" provisions of those contracts. We do not think, however, that the regulatory out provisions of negotiated contracts somehow confer continuing responsibility or authority to resolve contract interpretation disputes. Our authority derives from the statutes. United Telephone Company v. Public Service Commission, 496 So. 2d 116 (Fla.1986). It cannot be conferred or inferred from the provisions of a contract.

For these reasons we find that the motions to dismiss should be granted. FPC's petition fails to set forth any claim that the Commission should resolve. We defer to the courts to answer the question of contract interpretation raised in this case. Thus, FPC's petition is dismissed.

In re Petition by Florida Power Corp., 95 F.P.S.C. at 2:269-70 (footnote omitted) (emphasis supplied).

With the PSC having refused to intervene in the dispute, the parties involved in the Lake Cogen litigation pending in state court then proceeded to enter into a proposed settlement agreement attempting to resolve all issues between them. Because this agreement included modifications to the power purchase contract, it

required Commission approval pursuant to Rule 25-17.082, Florida Administrative Code. Accordingly, FPC filed with the Commission a "Petition for Approval of a Settlement Agreement." Upon considering the petition, the Commission, in a proposed agency action order, determined that the PSC had jurisdiction (in the context of reviewing the modifications to the original contract proposed in the settlement agreement before it) to construe the meaning of the contract as originally approved,[4] citing In re Orange & Rockland Utilities, Inc., No. 96-E-0728 (N.Y.P.S.C. Nov. 29, 1996)). It further found that the exercise of such jurisdiction was not barred by the doctrine of administrative finality. Based upon its review of the petition, the PSC concluded that the proposed modifications, when compared with the original contract which the Commission had approved, would result in payments to the cogenerators in excess of current avoided energy costs:

> If as FPC contends, the contract contemplates that the "avoided unit" would cycle in FPC's system economic dispatch and if as we believe and FPC contends, the contract provides for the use of actual

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[4]Commissioner Clark dissented, observing that "[t]he Order originally approving the contract had no specific amplification as to how the payments due under section 9.1.2 would be calculated, and when asked for clarification with respect to the calculation in the Petition for Declaratory Statement, it which the contract was approved for cost recovery." In re Petition for Expedited Approval of Settlement Agreement, 97 F.P.S.C. 11:202, 11:216 (1997) (Docket No. 961477-EQ; Order No. PSC-97-1437-FOF-EQ, Nov. 14, 1997) (emphasis supplied).

fuel prices and not projected fuel prices, then Lake's assertion in the circuit that it is entitled to firm energy payments 100% of the time is suspect. If this assertion is suspect, then the "savings" associated with the buy out are overstated. If the Commission does in fact have the jurisdiction to resolve the question of what was contemplated at the time of approval, the uncertainty of the outcome of the circuit court litigation would not be a factor in the decision to approve the buy out.

. . . .

. . . Florida Power Corporation argues that, given the Commission's previous determination that it would defer to the circuit court, the Commission cannot revisit that question in the guise of a cost recovery approval/disallowance.

However, we are not, at this juncture, "revisiting" anything. What is before the Commission is a contract modification that we believe is based on an erroneous assumption. That is, that the cost effectiveness of the modification is based on the "litigation risk" associated with a circuit court determination of the operating characteristics of the "avoided unit" in a manner not contemplated or intended when the contract was approved. If, as FPC suggests (and Crossroads [Orange & Rockland Utilities] supports), this Commission has the jurisdiction to interpret and clarify its approval, there is no "risk" associated with an erroneous circuit court interpretation. The modification/buy-out then is clearly not cost-effective when measured by the standard of Rule 25-17.0836, Florida Administrative Code.

. . . .

When the Commission initially approves a negotiated contract, the determination of avoided costs is based on the utility's next identified capacity addition. At that point in time, the contract is evaluated for cost recovery purposes in accordance with the above referenced rules. However, in evaluating contract modifications, continued cost recovery is based on savings compared to the existing contract.

Rule 25-17.036(6) requires that:

> The modifications and concessions of the utility and developer shall be evaluated against both the existing contract and the

current value of the purchasing utility's avoided cost. (Emphasis added)

Absent a modification, the utility's ratepayers remain obligated to pay costs as specified within the current contract. Therefore, modifications which result in costs above the existing contract are not appropriate for approval.

. . . .

The Settlement Agreement achieves benefits in the form of curtailment savings and reduced capacity and variable O&M payments. However, compared to the more appropriate method of determining energy payments under the existing contract, the Settlement Agreement increases costs to FPC's ratepayers by approximately $17.1 million NPV. Furthermore, contrary to Section 366.051, Florida Statutes, Section 210 of PURPA, and this Commission's rules, approval of the Settlement Agreement commits FPC's ratepayers to costs in excess of current avoided energy costs. For these reasons, we find that the Settlement Agreement should be denied.

In re Petition for Expedited Approval, 97 F. P. S. C. at 11:209-12 (emphasis added).[5]

On April 10, 1998, FPC filed with the PSC the petition for declaratory statement which is at issue here. Pursuant to "Rule 25-22.020, et. seq., F.A.C.," FPC petitioned the Commission as follows:

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[5] The cogenerator, Lake Cogen, timely protested this order, and subsequently moved to dismiss the proceeding on grounds of mootness. On March 30, 1998, the Commission, pursuant to a unanimous vote, issued an order holding that the Lake Cogen Order was a nullity (because the settlement agreement which the order had disapproved had, by its own terms, expired for lack of such approval), and dismissing FPC's petition in the Lake Cogen-FPC Settlement Docket. See In re Petition for Expedited Approval of Settlement Agreement, 98 F.P.S.C. 3:392 (1998) (Docket No. 961477-EQ, Order No. PSC-98-0450, FOF-EQ, Mar. 30, 1998).

FOR A DECLARATORY STATEMENT that, under Order no. PSC-97-1437-FOF-EQ entered in Dkt. 961477-EQ, Nov. 14, 1997 (the "Lake Docket"), [PURPA], Fla. Stat. § 366.051, and Rule 25-17.0832, F.A.C., the Commission interprets its Order No. 24734 entered in Dkt. 910401-EQ, July 1, 1991 [originally approving the negotiated contracts between FPC and respondents] to require that FPC:

(A) Pay for energy based upon avoided energy costs, strictly as reflected in the Contract;

(B) Use only the avoided unit's contractually-specified characteristics in § 9.1.2, and not other or additional unspecified characteristics that might have been applicable had the avoided unit actually been built, to assess its operational status for the purpose of determining when [respondents are] entitled to receive firm or as-available energy payments;

(C) Use the actual chargeout price of coal to FPC's Crystal River ("CR") plants 1 and 2, resulting from FPC's prevailing mix of transportation, rather than the mix of transportation in effect at the time the Contract was executed or some other mix, to compute the level of firm energy payments to Dade.

The Commission denied this petition on the basis of administrative res judicata:

Subsequent to the filing of FPC's petition in Docket No. 940771-EQ, Lake and other QFs, filed lawsuits in the state courts for breach of contract. On January 23, 1996, the Fifth Judicial Circuit Court issued a Partial Summary Judgement for Lake in Case No. 94-2354-CA-01.

On April 9, 1998, FPC filed a Petition for a Declaratory Statement arguing that Order No. 24734, issued July 1, 1991, in Docket No. 901401-EQ, together with Orders Nos. PSC-97-1437-

FOF-EQ and 24989, PURPA, Section 366.051, Florida Statutes, and Rule 25-17.082, F.A.C., establish that its contractual energy payments to Lake, including when firm or as-available payment is due, are limited to the analysis of avoided costs based upon the avoided unit's contractually-specified characteristics.

On April 30, 1998, Lake filed a motion to dismiss FPC's request for a Declaratory Statement, a petition to intervene and a request for Oral Argument on the topics of res judicata, collateral estoppel and administrative finality. . . .

. . . .

In its current petition, FPC asks us to consider certain authorities which post-date Order 0210 in determining whether the Commission can nonetheless exercise jurisdiction to issue the declaratory statement that FPC now petitions for. Those cases include the New York Public Service Commission's opinion in Orange and Rockland Utilities, Inc. (Crossroads), Case 96-E-0728; the Florida Supreme Court's decision in Panda-Kathleen, L.P. v. Clark, et al. (Panda), 701 So. 2d 322 (Fla. 1997) and our own Order Denying Approval of Proposed Settlement (Lake), Order No. PSC-97-1437-FOF-EQ in Docket No. 961477-EQ.

In Crossroads, which concerned a negotiated power purchase agreement between a utility and a cogenerator, the NYPSC held that it is within our authority to interpret our power purchase contract approvals[6] . . . . The precedents involving interpretation of past policies and approvals, and not the contract non-interference policy that Crossroads cites, control here. [e.s.] Crossroads, p. 5

While Panda involved a standard offer contract, FPC interprets the Florida Supreme Court's opinion to provide that

> the Commission has jurisdiction to clarify its orders and to construe its rules in order to ensure that contracts and payments thereunder do not exceed avoided cost.

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[6] See Orange & Rockland Utilities, No. 96-E-0728, 1996 WL 707459 (stating, specifically, that, "[a]s was recently reaffirmed, it is within our authority to interpret our power purchase contract approvals, and that jurisdiction has been upheld by the courts") (citing Matter of Indeck-Yerkes Energy Servs. v. Public Serv. Comm'n. of State of N.Y., 164 A.D.2d 618 (N.Y. App. Div. 1991)).

Petition, at p. 14.

Finally, FPC points out that, consistent with Crossroads and other like holdings of the NYPSC, our Lake order reasoned that the cited New York cases

> involve a question that turns on what was meant when the contract was approved, and not on the determination of disputed facts and the application of those facts to an unambiguous provision.

Petition, p. 13-14.

In the adjudication of the instant petition, however, we find that we are unable to apply these more recent cases as directly to the case at hand as FPC argues we should. First, this case is distinguishable from both Crossroads and Panda in that neither of those cases involved a prior determination which could be claimed to be, in effect res judicata as to the current controversy concerning pricing between FPC and parties (including Lake) to the negotiated cogeneration contracts containing these identical pricing provisions. The cogenerators, during oral argument, asserted that, however we may decide to reflect such holdings as Crossroads or Panda in our future dispositions as to negotiated cogeneration contract issues, this controversy has already been determined in our dismissal of FPC's prior petitions in Order 0210 and may not be re-adjudicated now. We agree with that point and find that the doctrine of administrative finality precludes such re-adjudication as a matter of fairness to those who prevailed in the litigation of this issue previously. Peoples Gas System v. Mason, 187 So. 2d 335 (Fla. 1966). Moreover, our Lake order was only proposed agency action (PAA), which then became a legal nullity when the settlement proposal considered therein lapsed. Therefore, it never matured into a final order so as to constitute this Commission's precedent.

In thus denying FPC's petition, we need not reach today the issue of whether such cases as Crossroads, the reasoning in our Lake order or FPC's interpretation of Panda will or will not play a role in our consideration of future cases concerning negotiated cogeneration contracts post-approval. We only decide that, having resolved this

pricing controversy previously in Order 0210, the prior resolution must stand, consistent with the principles of administrative finality.

In re: Petition of Florida Power Corp., 98 F.P.S.C. at 12:66-68 (footnote added) (emphasis supplied).

On appeal, FPC argues that the PSC erred in giving preclusive effect to its 1995 dismissal of FPC's prior petitions, by Order 0210, in the present controversy. FPC also argues that the PSC's dismissal of the current petition on the ground that the same matter is pending in state court is not proper.

II. ANALYSIS

Despite the fact that all of the parties present arguments directed to whether (absent the unique procedural history involved in this case) the Commission does or does not have jurisdiction over some aspect of a contractual controversy such as theirs, that issue is not before the Court at this time. What is before the Court is the question of whether the Commission's 1995 determination of its own subject matter jurisdiction over the present controversy is a bar to the Commission's subsequent determination of jurisdiction over the same claim. To resolve that issue, the Court must decide whether the jurisdictional issue posed by the 1998 petitions was either actually raised and determined, or could have been raised and determined, in the 1994-95 proceedings.

In reviewing the PSC's determination of its own subject matter jurisdiction, this Court has applied the standard established in Pan American World Airways, Inc. v. Florida Public Service Commission, 427 So. 2d 716 (Fla.1983). See Panda, 701 So. 2d at 325 (applying Pan American standard of review to, inter alia, PSC's determination of its jurisdiction to construe terms of standard offer contract). Pursuant to that review standard, the Court presumes "orders of the Commission to be correct, and . . . only determine[s] whether the Commission's action comports with the essential requirements of law and is supported by competent, substantial evidence." Id. at 325-26 (citing Pan American, 427 So. 2d at 717).

Applying this standard, under the circumstances of this case, the PSC's prior, unappealed ruling regarding its jurisdiction to entertain the controversy addressed in FPC's petitions--even if erroneous[7]--operates as a bar to a subsequent determination of that jurisdiction over the same claim. Cf. State Dep't of Transp. v. Bailey, 603 So. 2d 1384, 1387 (Fla. 1st DCA 1992) (acknowledging that "even an erroneous determination on the question of subject matter jurisdiction may become res judicata on that issue if the jurisdictional question was actually litigated and

[7]The narrow issue addressed here is the preclusive effect of the PSC's prior determination in this case as applied to FPC's 1998 petitions for declaratory relief. We do not address the substantive issue of whether, absent the unique circumstances presented here, the Commission would have jurisdiction to entertain such a petition.

decided, or if a party had an opportunity to contest subject matter jurisdiction and failed to do so," although finding it inapplicable under the facts of the case) (citing 11 Charles Alan Wright & Arthur R. Miller, Federal Practice and Procedure, § 2862, (Supp.1992) (reflecting cases in which an erroneous exercise of jurisdiction was not challenged by appeal)); Oglala Sioux Tribe v. Homestake Mining Co., 722 F. 2d 1407, 1411-13 (8th Cir. 1983) (holding that dismissal of a suit for lack of federal subject-matter jurisdiction precludes relitigation of the same issue of subject-matter jurisdiction in a second federal suit on the same claim). This result is unchanged even if there has been a subsequent change in case law potentially affecting the scope of the Commission's jurisdiction over the controversy--particularly where (as here) such subsequent case law is not directly on point[8] and irrefutably controlling. Cf. Plymouth Citrus Products Co-op. v. Williamson, 71 So. 2d 162 (Fla. 1954) (involving workers' compensation claim barred by prior determination that claimant had not suffered an accident based upon case law prevailing at the time of the first determination, even though statute of limitations period had not expired, and controlling case law developed in interim would have

[8]This Court's intervening Panda decision involved a "standard offer" contract. The issue of whether the Panda reasoning could (or could not) be applied broadly to suggest that the exercise of jurisdiction would also be appropriate where Commission rules have been incorporated into a negotiated contract is not properly before us, and therefore we do not address it here.

provided a basis for the claim); Sugarmill Woods Civic Ass'n, Inc. v. Southern States Utilities, 687 So. 2d 1346, 1349 (Fla. 1st DCA 1997) (holding that intervening PSC order reflecting that PSC had jurisdiction over certain facilities should not be retroactively applied because "[a] subsequent order by the body which rendered the order under review is not the kind of 'change in the law' which the appellate court is bound to apply to pending cases"); Hillhaven Corp. v. Department of Health and Rehab. Servs., 625 So. 2d 1299 (Fla. 1st DCA 1993) (holding that a Supreme Court decision which invalidated a statute related to certain rules, and which was rendered after adoption of the rules but before commencement of the proceeding challenging them, applied to invalidate the rules at issue), review denied, 634 So. 2d 623 (Fla. 1994).

In Plymouth Citrus Products, this Court considered whether res judicata applied to bar a workers' compensation claim where the Deputy Commissioner had previously made a determination (on the merits) based upon the then-prevailing case law, the claimant had not sought appellate review, and, thereafter, the controlling precedent changed, so that the claimant would have been entitled to recover from the employer under the changed case law. The statute of limitations had not expired when the case law changed, and the claimant again filed his claim, in the form of a petition for modification. The full Commission accepted this

petition "as the filing of a new claim by the claimant," determining, based upon the current case law, that "the claimant suffered a compensable accident for which claim had been filed within the proper time limit" and that "the previous adjudication between the parties is not res judicata to this present claim." 71 So. 2d at 163.

In reversing this order, this Court disagreed with the Commission's analysis:

> There must be an end to litigation sometime. As to the facts in this particular case, the doctrine of res adjudicata applies.
>
> The case of Wagner v. Baron, Fla., 64 So. 2d 267, was strongly relied upon by petitioner in this case but it is not applicable. In that case we were dealing with a statute which imposed certain additional liabilities upon the father of a bastard child in the nature of support for the said child during a certain period of time and for the determination of the question of fatherhood. There was no question involved in that case of an intervening decision which changed the rule of law or the responsibilities, duties and liabilities of the father of the bastard child. The change in that case was effected by a statute.
>
> After a judgment, order or decree has become final and the time for appeal has expired, an intervening decision which may change the liability or the rule of law applicable to a case is not sufficient ground to open the case up for the filing of a new claim under the same facts.
>
> It appears that the Full Commission did not proceed in accordance with the essential requirements of the law in this matter. The writ of certiorari should be granted and the order of the Full Commission, affirming the Deputy Commissioner, should be quashed and set aside and a proper order entered by the Full Commission, reversing and setting aside the order of the Deputy Commissioner.

Plymouth Citrus Products, 71 So. 2d at 163 (emphasis supplied) (citations omitted). Applying these principles to the present case, the Commission's determination of its jurisdiction to entertain the 1998 petition for declaratory

statement regarding the parties' negotiated contract was governed by the doctrine of administrative finality.

Further, even if the jurisdictional issue raised by appellant in its 1998 petition was not actually determined by the PSC's prior decision regarding jurisdiction over the 1994 petition, it appears that it could have been resolved by the PSC at that time. In reviewing the two petitions, there is no question that they are substantively the same, despite the semantical difference.[9] That semantical difference is "what the contract terms mean" (1994) (i.e., an interpretation of the contract itself) versus "what the contract terms meant to the PSC when it approved the contract" (1998) (i.e., an interpretation of the Commission's contract approval order). Although the wording of the 1994 and 1998 jurisdictional issues is not identical, because FPC could have challenged the Commission's jurisdictional analysis in an appeal from the denial of its 1994 petition (but did not), the doctrine of decisional finality still applies. Cf. Albrecht v. State, 444 So. 2d 8, 11-12 (Fla. 1984) (reflecting that, for

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[9]Focusing on the same technical distinction which is urged by FPC here, the New York Public Service Commission in Orange & Rockland Utilities suggested that, while a commission may not (as the Florida PSC determined) resolve a contractual dispute between parties to a negotiated contract, it may properly entertain a petition for declaratory statement seeking clarification of how the commission first interpreted that contract at the time it was approved. See Orange & Rockland Utilities, No. 96-E-0728 (providing that it "is within [the commission's] authority to interpret our power purchase contract approvals, and that jurisdiction has been upheld by the courts[; therefore,] the approval of the original contract for the Crossroads site may be explained and interpreted, and O&R's petition may be construed as requesting that relief").

the counterpart of administrative finality--res judicata--to apply, several conditions must occur simultaneously, one of which is an identity of the cause of action, and that the "determining factor in deciding whether the cause of action is the same is whether the facts or evidence necessary to maintain the suit are the same in both actions") (citations omitted); accord, Youngblood v. Taylor, 89 So. 2d 503, 505 (Fla. 1956) (observing that "the test of the identity of the causes of action, for the purpose of determining the question of res adjudicata, is the identity of the facts essential to the maintenance of the actions") (citing Gordon v. Gordon, 36 So. 2d 774, 777 (Fla. 1948) (quoting Bagwell v. Bagwell, 14 So. 2d 841, 843 (Fla. 1943)).

The doctrine of decisional finality provides that there must be a "terminal point in every proceeding both administrative and judicial, at which the parties and the public may rely on a decision as being final and dispositive of the rights and issues involved therein." Austin Tupler Trucking, Inc. v. Hawkins, 377 So. 2d 679, 681 (Fla.1979). Here, because there is an identity of essential facts common to FPC's 1994 and 1998 petitions, along with an identity of the substance of the issue presented, the same issue of subject matter jurisdiction implicated by the 1998 petition, even if not actually raised in 1994, could have been raised at that time. A decision, once final, may only be modified if there is a significant change in circumstances or if modification is required in the public interest. See Austin

Tupler Trucking, 377 So. 2d at 681. Although the Court will avoid "too doctrinaire" an application of the rule, see Peoples Gas System, Inc. v. Mason, 187 So. 2d 335, 339 (Fla. 1966), the circumstances here do not compel a different result.

Even assuming arguendo (as appellant urges) that a change in law could qualify as "changed circumstances" for purposes of this analysis, the theory does not apply. At the time FPC filed its first petition, there was already an out-of-state ruling reflecting that it was properly within the ambit of a public service commission's authority to interpret the scope of its contract approval. See Indeck-Yerkes Energy Servs. v. Public Serv. Comm'n, 564 N.Y.S.2d 841 (N.Y. App. Div. 1991). Indeed, this was the opinion cited by the New York Public Service Commission in Orange & Rockland Utilities when it stated that its jurisdiction to interpret the scope of its original contract approvals "has been upheld by the courts."

In Indeck-Yerkes, the New York Supreme Court, Appellate Division, in approving the public service commission's declaratory statement interpreting the scope of its original approval of a cogeneration contract, carefully framed the issue which had been addressed by the commission:

> The issue in this proceeding is not one of pure interpretation of the language of the agreement between petitioner and NiMo by application of common-law principles of contract. Rather, it is whether there was a rational basis to the PSC's determination of the scope of its prior approval of the parties' agreement, particularly the price structure contained therein, as not covering other than insignificant deviations from the contract's stated initial output of approximately 49 MW.

564 N.Y.S.2d at 843.[10] The distinction stated by the Indeck-Yerkes court in framing the issue before it (involving an interpretation of the scope of the commission's order approving the subject agreement, rather than a "pure interpretation" of the agreement itself) is the same basis upon which FPC relies to differentiate its 1998 petition from its 1994 petition.

Thus, it is clear that FPC could have pursued this theory of jurisdiction throughout the proceedings involving its 1994 petition. Given its failure to do so, including its failure to appeal from dismissal of the 1994 petition, under the unique circumstances presented here, decisional finality applies.[11] The PSC's decision is affirmed.

It is so ordered.

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[10] Although the Indeck-Yerkes opinion does not reflect whether the subject contract was

Id. at 842.

[11] Based upon this conclusion, we need not reach the alternative issue raised on this appeal (that it was proper for the Commission to deny FPC's petition for declaratory statement where, as here, the matter in controversy was pending in state court).

WELLS, C.J., and SHAW, HARDING, ANSTEAD, PARIENTE and QUINCE, JJ., concur.

NOT FINAL UNTIL TIME EXPIRES TO FILE REHEARING MOTION, AND IF FILED, DETERMINED.

An Appeal from the Public Service Commission

Rodney Gaddy and James A. McGee, Florida Power Corporation, St. Petersburg, Florida; Jodi L. Corrigan and Marylin E. Culp of Annis, Mitchell, Cockey, Edwards & Roehn, P.A., Tampa, Florida; and Sylvia H. Walbolt, Chris S. Coutroulis, Robert L. Ciotti, and Joseph H. Lang, Jr. of Carlton, Fields, Ward, Emmanuel, Smith & Cutler, P.A.,

for Appellant

Robert D. Vandiver, General Counsel, and Richard C. Bellak, Associate General Counsel, Florida Public Service Commission, Tallahassee, Florida,

for Appellee

John Beranek and Lee L. Willis of Ausley & McMullen, Tallahassee, Florida,

for Lake Cogen, Ltd., Intervenor/Appellee

Robert Scheffel Wright and John T. Lavia, III, Tallahassee, Florida; and Gail P. Fels, Office of the County Attorney, Miami, Florida,

for Miami-Dade County, Florida, and Montenay-Dade, Ltd., Intervenors/Appellees

Lake Cogen Payment Comparison

	FPC Interpretation	Lake Interpretation	Nov. '96 Settlement Energy	Nov. '96 Settlement Incremental Capacity	Total Incremental Impact of Nov. '96 Settlement including Energy	Trial Court Ruling	Court of Appeals Ruling
Jul-93	1,697,894.34	1,697,894.34			1,697,894.34	1,777,642.96	1,697,894.34
Aug-93	1,634,381.19	1,634,381.19			1,634,381.19	1,546,073.00	1,634,381.19
Sep-93	1,582,340.69	1,634,557.93			1,582,340.69	1,483,780.45	1,582,340.69
Oct-93	1,752,653.17	1,752,653.17			1,752,653.17	1,754,252.93	1,752,653.17
Nov-93	1,666,819.60	1,666,819.60			1,666,819.60	1,653,549.72	1,666,819.60
Dec-93	1,674,073.60	1,674,073.60			1,674,073.60	1,411,909.51	1,674,073.60
Jan-94	1,623,351.55	1,626,154.16			1,623,351.55	1,389,009.72	1,623,351.55
Feb-94	1,422,918.64	1,425,213.84			1,422,918.64	1,212,136.32	1,422,918.64
Mar-94	1,742,014.87	1,744,883.68			1,742,014.87	1,546,952.35	1,742,014.87
Apr-94	1,524,660.40	1,527,130.67			1,524,660.40	1,406,942.18	1,524,660.40
May-94	1,850,688.13	1,853,657.26			1,850,688.13	1,765,399.44	1,850,688.13
Jun-94	1,770,794.18	1,773,664.56			1,770,794.18	1,637,583.78	1,770,794.18
Jul-94	1,778,985.23	1,781,879.87			1,778,985.23	1,605,994.28	1,778,985.23
Aug-94	1,564,738.61	1,749,107.14			1,564,738.61	1,528,148.16	1,746,257.80
Sep-94	1,476,078.29	1,748,460.29			1,476,078.29	1,514,261.52	1,747,544.39
Oct-94	1,582,187.38	1,824,572.93			1,582,187.38	1,626,047.96	1,769,069.41
Nov-94	1,268,371.73	1,512,697.16			1,268,371.73	1,366,213.79	1,386,983.14
Dec-94	1,520,746.33	1,799,267.00			1,520,746.33	1,625,660.79	1,790,391.58
Jan-95	1,275,667.09	1,435,842.82			1,275,667.09	1,312,733.33	1,359,762.98
Feb-95	1,430,402.61	1,576,826.56			1,430,402.61	1,477,667.47	1,527,861.91
Mar-95	1,415,105.62	1,578,051.75			1,415,105.62	1,447,880.81	1,557,395.26
Apr-95	1,495,617.81	1,750,417.50			1,495,617.81	1,539,053.77	1,698,228.45
May-95	1,627,505.29	1,743,014.98			1,627,505.29	1,647,277.25	1,739,255.98
Jun-95	1,497,456.98	1,676,331.93			1,497,456.98	1,517,877.42	1,668,485.78
Jul-95	1,520,319.98	1,704,853.58			1,520,319.98	1,537,851.78	1,701,096.38
Aug-95	1,183,697.59	1,382,583.14			1,183,697.59	1,213,082.35	1,379,897.63
Sep-95	1,422,322.16	1,665,160.95			1,422,322.16	1,456,200.20	1,655,587.75
Oct-95	1,473,420.98	1,787,243.97			1,473,420.98	1,554,549.56	1,721,191.83
Nov-95	1,217,629.01	1,608,480.41			1,217,629.01	1,384,840.25	1,517,112.29
Dec-95	1,489,889.35	1,733,376.14			1,489,889.35	1,572,401.45	1,729,685.91
Jan-96	1,500,243.88	1,763,859.86			1,500,243.88	1,616,492.06	1,759,302.07
Feb-96	1,336,944.96	1,655,625.76			1,336,944.96	1,487,066.84	1,651,522.57
Mar-96	1,462,873.87	1,582,801.41			1,462,873.87	1,535,397.95	1,562,447.98
Apr-96	1,503,136.90	1,576,166.67			1,503,136.90	1,535,149.37	1,545,454.69
May-96	1,665,900.33	1,708,284.34			1,665,900.33	1,714,751.43	1,703,916.92
Jun-96	1,502,038.30	1,622,473.22			1,502,038.30	1,523,467.06	1,618,236.91
Jul-96	1,512,608.27	1,649,765.88			1,512,608.27	1,533,257.83	1,645,409.84
Aug-96	1,546,461.92	1,708,239.39			1,546,461.92	1,553,205.63	1,703,731.13
Sep-96	1,571,342.59	1,661,200.51			1,571,342.59	1,589,728.59	1,656,860.08
Oct-96	1,381,577.58	1,491,321.68			6,893,633.58	1,463,634.93	1,545,565.22
Nov-96	1,569,390.41	1,688,480.05	1,319,584.15	1,204,349.40	2,523,933.55	1,747,432.32	1,684,265.45
Dec-96	1,273,121.08	1,400,386.16	1,093,209.49	1,204,349.40	2,297,558.89	1,479,125.71	1,515,832.80
Jan-97	1,523,284.73	1,712,915.19	1,319,908.83	814,236.73	2,134,145.56	1,697,617.86	1,703,969.27
Feb-97	1,388,737.61	1,493,919.89	1,139,095.58	814,236.73	1,953,332.31	1,492,102.64	1,485,464.75
Mar-97	1,470,064.98	1,705,792.66	1,304,111.94	814,236.73	2,118,348.67	1,599,728.75	1,699,973.27
Apr-97	1,369,359.46	1,509,312.01	1,123,654.62	814,236.73	1,937,891.35	1,419,695.84	1,629,324.66
May-97	1,554,268.33	1,726,979.43	1,317,523.30	814,236.73	2,131,760.03	1,593,187.38	1,721,931.91
Jun-97	647,503.14	719,502.28	425,974.63	814,236.73	1,240,211.36	669,308.05	712,139.03
Jul-97	1,703,192.50	1,741,798.65	1,344,527.02	814,236.73	2,158,763.75	1,773,803.98	1,732,532.25
Aug-97	892,507.71	926,544.62	627,923.00	1,153,247.53	1,781,170.53	926,239.62	906,642.10
Sep-97	1,658,614.41	1,705,679.38	1,336,319.25	1,155,757.68	2,492,076.93	1,665,231.98	1,698,944.88
Oct-97	1,537,599.71	1,678,662.12	1,311,744.04	1,169,587.49	2,481,331.53	1,593,895.13	1,906,094.98
Nov-97	1,237,329.63	1,641,278.06	1,266,758.43	1,170,758.20	2,437,516.63	1,435,759.64	1,635,514.49
Dec-97	1,418,595.76	1,715,073.60	1,324,070.23	814,236.73	2,138,306.96	1,549,469.24	1,709,360.55
Jan-98	1,239,716.52	1,696,165.23	1,280,493.51	773,672.62	2,054,166.13	1,449,148.83	1,690,348.16
Feb-98	1,002,725.88	1,374,711.63	1,048,117.63	773,672.62	1,821,790.25	1,171,753.69	1,291,916.65

	FPC Interpretation	Lake Interpretation	Nov. '96 Settlement Energy	Nov. '96 Settlement Incremental Capacity	Total Incremental Impact of Nov. '96 Settlement including Energy	Trial Court Ruling	Court of Appeals Ruling
Mar-98	1,146,936.65	1,714,505.80	1,286,507.32	773,672.62	2,060,179.94	1,[illegible],565.67	1,708,574.77
Apr-98	1,057,584.03	1,412,164.63	1,060,200.29	773,672.62	1,833,872.91	1,203,413.03	1,405,859.22
May-98	1,258,456.09	1,591,158.63	1,211,621.75	773,672.62	1,985,294.37	1,356,295.01	1,585,650.44
Jun-98	1,454,604.04	1,586,677.37	1,233,337.58	773,672.62	2,007,010.20	1,530,664.86	1,657,521.70
Jul-98	1,390,733.99	1,564,301.37	1,199,796.27	773,672.62	1,973,468.89	1,430,566.73	1,558,890.49
Aug-98	1,130,262.51	1,368,072.24	993,523.81	773,672.62	1,767,196.43	1,169,410.91	1,363,252.52
Sep-98	1,171,188.73	1,513,391.13	1,148,071.41	773,672.62	1,921,744.03	1,287,964.77	1,508,166.03
Oct-98	1,069,309.25	1,317,966.55	994,624.11	773,672.62	1,768,296.73	1,141,234.85	1,259,413.96
Nov-98	1,164,319.73	1,597,238.29	1,210,389.24	773,672.62	1,984,061.86	1,376,493.65	1,592,004.14
Dec-98	1,173,112.50	1,663,031.96	1,251,572.23	773,672.62	2,025,244.85	1,403,929.59	1,657,521.70
Jan-99	1,033,403.07	1,681,856.62	1,243,045.58	855,104.26	2,098,149.84	1,393,818.77	1,676,120.67
Feb-99	873,057.37	1,518,138.59	1,117,781.48	855,104.26	1,972,885.74	1,208,923.97	1,512,970.46
Mar-99	1,052,353.95	1,627,090.28	1,229,151.97	855,104.26	2,084,256.23	1,372,002.19	1,667,495.53
Apr-99	1,015,421.16	1,335,413.94	937,517.57	855,104.26	1,792,621.83	1,105,281.42	1,319,025.15
May-99	1,118,317.49	1,505,492.35	1,060,190.55	855,104.26	1,915,294.82	1,248,560.91	1,449,036.68
Jun-99	1,041,006.52	1,429,121.48	1,009,254.89	855,104.26	1,864,359.15	1,190,394.01	1,433,168.43
Jul-99	1,151,549.52	1,465,315.08	1,025,531.81	855,104.26	1,880,636.07	1,233,427.59	1,451,807.47
Aug-99	1,096,073.43	1,275,677.42	898,973.75	855,104.26	1,754,078.01	1,107,517.53	1,270,982.23
Sep-99	1,334,835.64	1,573,906.81	1,077,166.88	855,104.26	1,932,271.15	1,377,268.19	1,568,590.75
Oct-99	1,434,658.35	1,581,050.25	1,079,259.30	855,104.26	1,934,363.56	1,504,704.47	1,575,647.20
Nov-99	1,088,406.09	1,517,398.64	1,055,470.96	855,104.26	1,910,575.22	1,299,261.05	1,512,285.07
Dec-99	1,019,282.94	1,469,389.14	1,035,805.67	855,104.26	1,890,909.94	1,256,860.78	1,092,717.89
Jan-00	1,019,150.19	1,513,223.78	1,038,917.37	914,030.45	1,952,947.82	1,302,979.68	1,508,265.73
Feb-00	936,841.84	1,428,025.27	982,752.03	914,030.45	1,896,782.49	1,209,563.25	1,423,260.62
Mar-00	1,158,882.26	1,490,848.22	1,032,997.24	914,030.45	1,947,027.69	1,363,979.77	1,485,550.68
Apr-00	925,106.55	1,208,019.42	837,493.63	914,030.45	1,751,524.08	1,069,745.11	1,077,198.55
May-00	1,138,243.79	1,371,445.38	941,342.66	914,030.45	1,855,373.12	1,182,528.47	1,366,747.94
Jun-00	1,279,315.59	1,368,807.34	899,338.79	914,030.45	1,813,369.25	1,365,649.77	1,364,828.94
Jul-00	1,275,916.59	1,399,483.26	923,275.27	914,030.45	1,837,305.72	1,372,727.18	1,394,962.44
Aug-00	1,052,588.06	1,164,471.69	848,654.30	914,030.45	1,762,684.75	1,124,991.60	1,160,300.86
Sep-00	1,150,041.72	1,261,490.08	835,507.01	914,030.45	1,749,537.46	1,232,508.65	1,257,299.16
Oct-00	1,015,193.24	1,224,210.83	856,412.49	914,030.45	1,770,442.95	1,174,039.29	1,378,740.19
Nov-00	1,084,188.66	1,399,039.81	968,596.56	914,030.45	1,882,627.02	1,334,949.77	1,395,931.45
Dec-00	1,302,481.65	1,380,151.53	989,284.98	914,030.45	1,903,315.44	1,525,951.70	1,535,828.95
Jan-01	1,566,335.00	1,486,185.57	1,033,633.52	872,656.76	1,906,290.27	1,763,022.61	1,749,037.92
Feb-01	930,889.64	1,281,800.82	889,966.62	872,656.76	1,762,623.37	1,157,460.03	1,278,163.75
Mar-01	1,120,029.01	1,419,574.87	980,187.20	871,987.73	1,852,174.92	1,299,163.28	1,415,295.80
Apr-01	1,203,829.67	1,378,370.50	955,149.46	872,656.76	1,827,806.22	1,274,403.93	1,374,099.29
May-01	1,253,423.57	1,283,114.09	900,518.51	872,656.76	1,773,175.27	1,366,338.88	1,279,732.96
Jun-01	1,302,889.72	1,339,456.07	923,926.48	871,463.01	1,795,389.49	1,329,186.00	,335,256
Jul-01	1,416,697.74	1,425,982.44	984,851.10	869,823.99	1,854,675.09	1,466,056.73	1,421,533.64
Aug-01	1,343,084.08	1,388,030.97	966,492.20	872,656.76	1,839,148.96	1,352,513.75	1,383,674.95
Sep-01	1,300,569.03	1,477,362.48	1,059,406.02	872,656.76	1,932,062.78	1,345,656.12	1,473,066.87

Historic Total	132,765,394	152,923,645		181,403,277	140,551,703	152,419,566
NPV of Forecasted Payments	397,581,000	451,209,000		320,358,000	412,120,000	437,992,000
Total	530,346,394	604,132,645		501,761,277	552,671,703	590,411,566

Notes: The shaded areas reflect the actual payments made to Lake Cogen by FPC excluding the damages of $19,860,307. The payments shown as FPC's interpretation for the period between July 1993 and July 1994 do not reflect the four parameter method used in the remainder of the data in this column. The four parameter calculation of these months is not available.

Florida Power Corporation
Docket No. 010001_EI
Late Filed Deposition Exhibit No._____
Witness: J. Portuondo

Summary of Forecasted Positions for Lake Cogen

Year	FPC's Position	Lake's Position	Settlement	Trail Court Order	Appeals Court Order
2001	11,624	13,211	12,369	12,055	12,808
2002	50,059	57,657	53,014	52,057	55,813
2003	47,761	53,666	50,587	49,275	52,109
2004	48,697	54,806	51,688	50,408	53,245
2005	49,521	56,099	52,754	51,247	54,432
2006	51,569	58,314	54,828	53,375	56,627
2007	53,047	60,537	56,952	55,101	58,731
2008	56,722	64,240	59,064	58,776	62,426
2009	57,453	65,139	16,942	59,573	63,266
2010	59,376	67,370	17,142	61,593	65,438
2011	61,286	69,585	17,329	63,598	67,594
2012	63,226	71,925	17,540	65,638	69,868
2013	65,184	74,124	17,763	67,698	72,011
NPV @ 8.94%	**$397,581**	**$451,209**	**$320,358**	**$412,120**	**$437,992**
Historical Total	**$132,765**	**$152,924**	**$181,403**	**$140,552**	**$152,420**
Total	**$530,346**	**$604,133**	**$501,761**	**$552,672**	**$590,412**

"Journal Voucher to Correct Overstatement Of Emission Allowance Costs"

The following adjustment was made in July 2001and included in the calculation of recoverable fuel expense.

Debit	555-00101	Recoverable Purchased Power Expense – Emission Allowances	$385,796.01	
Credit		555-00400 Non-recoverable Purchased Power Expense		$385,796.01

Due to the overstatement of emission allowances related to Interchange sales in August 2000, the Company understated the net recoverable fuel expense. The above adjustment increased the net recoverable fuel expense in July 2001 by the same amount.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause and generating performance incentive factor.	DOCKET NO. 010001-EI DATED: OCTOBER 9, 2001

STAFF'S FIRST SET OF INTERROGATORIES TO
FLORIDA PUBLIC UTILITIES COMPANY (NOS. 1 - 6)

The Staff of the Florida Public Service Commission, by and through its undersigned attorney, propounds the following interrogatories, pursuant to Rule 1.340, Florida Rules of Civil Procedure, to Florida Public Utilities Company ("FPUC"). These interrogatories shall be answered under oath by you or your agent, who is qualified and who will be identified, with the answers being served as provided by the Rules of Civil Procedure. As provided by Rule 1.340(a), Florida Rules of Civil Procedure, each interrogatory shall be answered separately and fully in writing under oath unless it is objected to. Each answer shall be signed by the person making it.

Give the name, address and relationship to Florida Public Utilities Company of those persons providing the answers to each of the following interrogatories.

If an interrogatory contained herein asks for information that has already been provided or is in the process of being provided to

the Commission through a Commission audit, please so state, indicating the date provided and the audit document/record request number.

INTERROGATORIES

1. According to Audit Disclosure No. 1 from the Florida Public Service Commission staff's Fuel Audit for FPUC for the period ended December 31, 2000 (Audit Control No. 01-053-4-2), FPUC underbilled several customers in late 2000. Please indicate whether FPUC agrees with Audit Disclosure No. 1. If FPUC does not agree, please explain the basis for FPUC's opinion.

(See response attached)

2. For each rate schedule that was affected by the billing error referenced in Audit Disclosure Nc. 1, please provide the following information:

   a. The specific time period or periods during which the billing error occurred;

   b. The type of rate that was incorrectly applied (i.e., fuel charge, base rate, etc.);

   c. The Commission-approved rate;

   d. The erroneously billed rate; and

   e. The total revenue shortfall that resulted from the erroneous billing.

(See response attached)

3. Please explain the cause of the billing error referenced in Audit Disclosure No. 1.

(See response attached)

4. Please indicate what steps FPUC has undertaken to correct the billing error referenced in Audit Disclosure No. 1.

(See response attached)

5. Audit Disclosure No. 1 indicates that FPUC decided not to backbill customers affected by the billing error. Please explain why FPUC chose not to backbill those customers.

(See response attached)

6. Please explain how FPUC proposes to recover the total revenue shortfall that resulted from the billing error referenced in Audit Disclosure No. 1.

(See response attached)

WM. COCHRAN KEATING IV
Staff Counsel
FLORIDA PUBLIC SERVICE COMMISSION
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850
(850) 413-6193

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause and generating performance incentive factor.	DOCKET NO. 010001-EI DATED: OCTOBER 9, 2001

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that the original and one copy of STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA PUBLIC UTILITIES COMPANY (NOS. 1 - 6) has been served by hand-delivery to Norman H. Horton, Jr., Messer Law Firm, 215 South Monroe Street, Suite 701, Tallahassee, Florida, 32301, on behalf of Florida Public Utilities Company, and that a true and correct copy thereof has been furnished to the following by U. S. Mail this 9th day of October 2001:

Jeffrey Stone/Russell Badders
Beggs and Lane Law Firm
P. O. Box 12950
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James A. McGee
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St. Petersburg, FL 33733

Susan D. Ritenour
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0780

Joseph McGlothlin/Vicki Kaufman
McWhirter Law Firm
117 South Gadsden Street
Tallahassee, FL 32301

Fla. Industrial Power
Users Group
c/o John McWhirter, Jr.
McWhirter, Reeves Law Firm
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Tampa, FL 33601-3350

R. Wade Litchfield
Florida Power & Light Company
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Juno Beach, FL 33408

Robert Vandiver
Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, #812
Tallahassee, FL 32399-1400

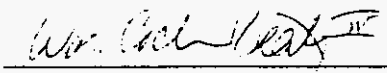
Florida Public Utilities Co.
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Angela Llewellyn
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Florida Power & Light Company
Bill Walker
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(850) 413-6193

Florida Public Utilities Company
Responses to Interrogatory (Nos. 1-6) Docket No. 010001-EI

1. The company agrees that they under billed 13 customers in October, November and December of 2000. This occurred in our Marianna Division only.
2. Rate Schedule MPD51 (GSD)
    a. Several billing errors occurred with this group of customers ranging over a period from October 2000 through September 2001.
    b. During the October though December 2000 period, the fuel charge was billed at the incorrect rate; the SL customer fuel rate was used for these GSD customers in our Marianna Division.
    c. The Commission approved rate for these GSD customers was $ .03599 per KWH.
    d. The rate used for billing purposes for these customers during the October through December 2000 period was $ .02608 per KWH.
    e. The total revenue shortfall in 2000 that resulted from this incorrect billing was $4,854.49.

3. The incorrect fuel charge rate was used in our new billing system that was implemented October 1, 2000. Because of some implementation issues and lack of required reports for analysis, we were not able to discover or correct this billing problem until 2001.

4. We have corrected the rates used for these customers and are currently billing at the correct fuel rates. We plan to send out a billing adjustment to correct the previous fuel billing errors by the end of 2001 to each customer. In addition to correcting the bills for the incorrect fuel charge, we have implemented rate reviews and have written reports for revenue analysis to avoid this type of problem in the future.

5. Originally we were discussing the possibility of not correcting these billing errors due to the cost/benefit of making the correction; however, we have since determined that the amount is material and we will be making corrections for the entire period that these customers were incorrectly billed for fuel.

6. We are going to bill each of these customers for the shortfall through an adjustment on their future bills for the fuel rate correction. There will be no net shortfall resulting from fuel rates after the adjustment is billed.

LAW OFFICES
MESSER, CAPARELLO & SELF
A PROFESSIONAL ASSOCIATION

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POST OFFICE BOX 1876
TALLAHASSEE, FLORIDA 32302-1876
TELEPHONE: (850) 222-0720
TELECOPIER: (850) 224-4359
INTERNET: www.lawfla.com

October 30, 2001

RECEIVED
OCT 30 2001

BY HAND DELIVERY
Ms. Blanca Bayo, Director
Division of Records and Reporting
Room 110, Easley Building
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Florida Public Utilities Company; Docket No. 010001-EI

Dear Ms. Bayo:

Enclosed for filing on behalf of Florida Public Utilities Company in this docket are an original and one copy of Florida Public Utilities Company's Notice of Service of Responses to FPSC Staff's First Set of Interrogatories in the above referenced docket.

Please acknowledge receipt of these documents by stamping the enclosed extra copy of this letter.

Thank you for your assistance.

Sincerely,

Norman H. Horton, Jr.

NHH/amb
Enclosures
cc: Mr. George Bachman
Parties of Record

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause	)	Docket No. 010001-EI Filed: October 30, 2001

FLORIDA PUBLIC UTILITIES COMPANY'S NOTICE OF SERVICE OF RESPONSES TO FPSC STAFF'S FIRST SET OF INTERROGATORIES

Florida Public Utilities Company ("FPU") by and through its undersigned counsel, hereby files and serves Notice that it has served its Responses to FPSC Staff's First Set of Interrogatories by hand delivery on Cochran Keating, Esq., Division of Legal Services, Florida Public Service Commission, 2540 Shumard Oak Blvd., Tallahassee, Florida 32399-0850 on this 30th day of October, 2001.

NORMAN H. HORTON, JR.
MESSER, CAPARELLO & SELF, P. A.
Post Office Box 1876
Tallahassee, FL 32302-1876
(850) 222-0720

Attorneys for Florida Public Utilities Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that true and correct copies of Florida Public Utilities Company's Notice of Service of Responses to FPSC Staff's First Set of Interrogatories in Docket No. 010001-EI have been served by hand delivery (*) and/or U. S. Mail this 30th day of October, 2001 upon the following:

Cochran Keating, Esq.*
Division of Legal Services
Florida Public Service Commission
2540 Shumard Oak Blvd., Room 370
Tallahassee, FL 32399-0850

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Tallahassee, FL 32302

Jeffrey A. Stone, Esq.
Russell Badders, Esq.
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Gulf Power Company
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Steel Hector & Davis, LLP
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Tallahassee, FL 32301

Mr. David H. Bowdle
Vastar Resources, Inc.
15375 Memorial Drive
Houston, TX 77079

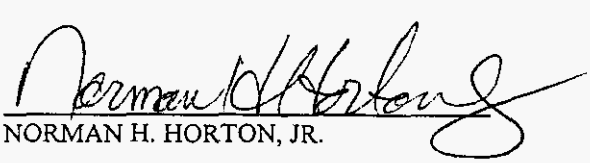
Wayne L. Schiefelbein, Esq.
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MacFarlane, Ferguson, Allison &Kelly
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William G. Walker, III
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Miami, FL 33174

James McGee
Florida Power Corporation
P.O. Box 14042 (A5A)
St. Petersburg, FL 33733-4042



NORMAN H. HORTON, JR.

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Norman H. Horton, Jr.

NHH/amb
Enclosures
cc: Mr. George Bachman
Parties of Record

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause	)))	Docket No. 010001-EI Filed: October 30, 2001

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NORMAN H. HORTON, JR.
MESSER, CAPARELLO & SELF, P. A.
Post Office Box 1876
Tallahassee, FL 32302-1876
(850) 222-0720

Attorneys for Florida Public Utilities Company

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Florida Power Corporation
P.O. Box 14042 (A5A)
St. Petersburg, FL 33733-4042

NORMAN H. HORTON, JR.

Florida Power Corporation
Docket No. 010001-EI
Witness: Jacob
Exhibit No. _____ (MFJ-1)

GPIF REWARD/PENALTY SCHEDULES

Descriptive Title	Sheet
• Reward/Penalty Table (Actual)	1
• Calculation of Maximum Incentive Dollars (Actual)	2
• Calculation of System Actual GPIF Points	3
• GPIF Unit Performance Summary	4
• Actual Unit Performance Data	5
• Adjustments to EAF Actual	6
• Adjustments to ANOHR Actual	7
• Generating Performance Incentive Points Table	8-16
• Actual Unit Performance Data	17-25
• Planned Outage Schedules (Actual)	26-27

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. _____ EXHIBIT NO. 18
COMPANY/
WITNESS: Jacobs
DATE: 11-20-21-01

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ACTUAL

Florida Power Corporation
January 2000 - December 2000

	Generating Performance Incentive Points (GPIF)	Fuel Savings/Loss ($)	Generating Performance Incentive Factor ($)
	10	$24,864,477	$7,700,337
	9	$22,378,029	$6,930,303
	8	$19,891,582	$6,160,269
	7	$17,405,134	$5,390,236
	6	$14,918,686	$4,620,202
	5	$12,432,238	$3,850,168
	4	$9,945,791	$3,080,135
	3	$7,459,343	$2,310,101
	2	$4,972,895	$1,540,067
	1	$2,486,448	$770,034
****	0.347	$861,883	$266,919
	0	$0	$0
	-1	($4,354,348)	($770,034)
	-2	($8,708,695)	($1,540,067)
	-3	($13,063,043)	($2,310,101)
	-4	($17,417,391)	($3,080,135)
	-5	($21,771,738)	($3,850,168)
	-6	($26,126,086)	($4,620,202)
	-7	($30,480,434)	($5,390,236)
	-8	($34,834,782)	($6,160,269)
	-9	($39,189,129)	($6,930,303)
	-10	($43,543,477)	($7,700,337)

Issued by: FPC

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

Florida Power Corporation
January 2000 - December 2000

1	Beginning of period balance of common equity	1,885,007,000	
2	END OF MONTH BALANCE OF COMMON EQUITY:		
	Month of JANUARY 2000	$1,908,560,828	
3	Month of FEBRUARY 2000	$1,922,506,509	
4	Month of MARCH 2000	$1,897,178,875	
5	Month of APRIL 2000	$1,909,412,280	
6	Month of MAY 2000	$1,942,334,135	
7	Month of JUNE 2000	$1,925,429,467	
8	Month of JULY 2000	$1,965,679,137	
9	Month of AUGUST 2000	$2,002,046,817	
10	Month of SEPTEMBER 2000	$1,996,157,910	
11	Month of OCTOBER 2000	$2,013,161,633	
12	Month of NOVEMBER 2000	$2,031,735,989	
13	Month of DECEMBER 2000	$1,965,028,205	
14	Average common equity for the period	1,951,095,291	
15	25 Basis Points	0.0025	
16	Revenue Expansion Factor	61.3808%	
17	Maximum allowed incentive dollars	$7,946,684	
18	Jurisdictional Sales *	34,817,196	MWH
19	Total Sales *	35,931,290	MWH
20	Jurisdictional Separation Factor	96.90%	
21	Maximum allowed jurisdictional incentive dollars	$7,700,337	

* Net sales (Sales - Interruptible)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF SYSTEM ACTUAL GPIF POINTS

Florida Power Corporation
January 2000 - December 2000

Plant/Unit	Performance Indicator EAF or ANOHR	Weighting Factor %	Unit Points	Weighted Unit Points
Anclote 1	EAF	4.71	-10.000	-0.471
	ANOHR	5.16	-3.949	-0.204
Anclote 2	EAF	5.88	9.131	0.537
	ANOHR	4.42	0.000	0.000
Crystal River 1	EAF	3.46	-1.358	-0.047
	ANOHR	3.24	0.000	0.000
Crystal River 2	EAF	10.80	-10.000	-1.080
	ANOHR	2.63	4.578	0.120
Crystal River 3	EAF	10.49	10.000	1.049
	ANOHR	10.50	0.000	0.000
Crystal River 4	EAF	9.68	4.305	0.417
	ANOHR	6.36	3.928	0.250
Crystal River 5	EAF	3.60	-7.275	-0.262
	ANOHR	8.66	0.478	0.041
Bartow 3	EAF	1.68	-2.720	-0.046
	ANOHR	2.15	0.000	0.000
Tiger Bay	EAF	1.26	5.782	0.073
	ANOHR	5.31	-0.588	-0.031
GPIF System		100.00		0.347

Issued by: FPC

Filed:
Suspended:
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GENERATION PERFORMANCE INCENTIVE FACTOR
GPIF UNIT PERFORMANCE SUMMARY

Florida Power Corporation
January 2000 - December 2000

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE Max. (%)	EAF RANGE Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)	EAF Adjusted Actual (%)	Estimated Fuel Savings/ Loss ($000)
ANC. 1	4.71	92.36	94.15	88.68	$1,172	($2,142)	84.51	($2,142.0)
ANC. 2	5.88	83.94	86.98	77.78	$1,463	($1,990)	86.72	$1,335.8
C.R. 1	3.46	90.28	94.81	81.24	$860	($3,595)	89.06	($488.2)
C.R. 2	10.80	75.25	79.85	66.34	$2,685	($4,532)	53.41	($4,532.0)
C.R. 3	10.49	93.43	96.52	87.09	$2,608	($7,700)	96.77	$2,608.0
C.R. 4	9.68	75.65	78.97	69.01	$2,407	($5,122)	77.08	$1,036.3
C.R. 5	3.60	94.04	95.95	90.09	$896	($2,695)	91.17	($1,960.7)
BA 3	1.68	82.84	86.39	75.71	$418	($2,026)	80.90	($551.0)
TB	1.26	79.13	82.32	75.96	$314	($1,700)	80.98	$181.6
GPIF System	51.57				$12,823	($31,502)		($4,512.2)

Plant/Unit	Weighting Factor (%)	ANOHR Target (BTU/KWH)	NOF	ANOHR RANGE Min. (Btu/kwh)	ANOHR RANGE Max. (Btu/kwh)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)	ANOHR Adjusted Actual (Btu/kwh)	Estimated Fuel Savings/ Loss ($000)
ANC. 1	5.16	10022	52.0	9744	10300	$1,282	($1,282)	10177	($506.2)
ANC. 2	4.42	10025	53.2	9767	10283	$1,100	($1,100)	10085	$0.0
C.R. 1	3.24	9851	82.4	9671	10032	$806	($806)	9840	$0.0
C.R. 2	2.63	9851	68.7	9687	10014	$653	($653)	9735	$299.1
C.R. 3	10.50	10357	100.2	10207	10507	$2,610	($2,610)	10333	$0.0
C.R. 4	6.36	9422	89.6	9248	9596	$1,582	($1,582)	9308	$621.3
C.R. 5	8.66	9394	91.5	9205	9582	$2,154	($2,154)	9313	$103.0
BA 3	2.15	10140	61.1	9860	10420	$534	($534)	10201	$0.0
TB	5.31	7590	90.0	7000	8180	$1,321	($1,321)	7695	($77.7)
GPIF System	48.43					$12,041	($12,041)		$439.5

Issued by: FPC

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATION PERFORMANCE INCENTIVE FACTOR
ACTUAL UNIT PERFORMANCE DATA

Florida Power Corporation
January 2000 - December 2000

PLANT/UNIT	ACTUAL EAF %	ADJUSTMENTS (1) TO EAF %	EAF ADJUSTED ACTUAL %
CRYSTAL RIVER 1	89.06	0.00	89.06
CRYSTAL RIVER 2	62.66	-9.25	53.41
CRYSTAL RIVER 3	96.77	0.00	96.77
CRYSTAL RIVER 4	84.04	-6.96	77.08
CRYSTAL RIVER 5	92.95	-1.78	91.17
ANCLOTE UNIT 1	87.87	-3.36	84.51
ANCLOTE UNIT 2	83.85	2.87	86.72
BARTOW 3	81.09	-0.19	80.90
TIGER BAY	83.97	-2.99	80.98

PLANT/UNIT	ACTUAL ANOHR BTU/KWH	ADJUSTMENTS (2) TO ANOHR BTU/KWH	ANOHR ADJUSTED ACTUAL BTU/KWH
CRYSTAL RIVER 1	9833.2	6.6	9839.8
CRYSTAL RIVER 2	9687.8	47.4	9735.3
CRYSTAL RIVER 3	10257.9	74.9	10332.8
CRYSTAL RIVER 4	9316.0	-8.1	9307.9
CRYSTAL RIVER 5	9332.0	-18.9	9313.2
ANCLOTE UNIT 1	10113.7	63.5	10177.2
ANCLOTE UNIT 2	10063.1	22.2	10085.3
BARTOW 3	10126.6	74.7	10201.3
TIGER BAY	7657.8	37.6	7695.4

(1) For documentation of adjustments to actual EAF, see sheet 6.
(2) For documentation of adjustments to actual ANOHR, see sheet 7.

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GENERATION PERFORMANCE INCENTIVE FACTOR
ADJUSTMENTS TO EAF ACTUAL

Florida Power Corporation
January 2000 - December 2000

EAF ADJUSTMENTS FOR PLANNED OUTAGE HOURS		AN1	AN2	CR1	CR2	CR3	CR4	CR5	BA3	TB
1. ACTUAL POH	HRS.	0.00	1102.40	0.00	0.00	0.00	855.00	0.00	821.48	1068.9
2. TARGET POH	HRS.	336.00	840.00	0.00	1296.00	0.00	1512.00	168.00	840	1344
3. ADJ. FACTOR (PH-POHT/PH-POHA)		0.96	1.03	1.00	0.85	1.00	0.92	0.98	1.00	0.96
4. ACTUAL EUOH	HRS.	1065.46	316.13	961.29	3280.16	283.95	546.52	619.55	839.85	339.12
5. ADJ. EUOH (3*4)	HRS.	1024.70	326.93	961.29	2796.21	283.95	501.24	607.70	837.90	327.03
6. ACTUAL EAF	%	87.87	83.85	89.06	62.66	96.77	84.04	92.95	81.09	83.97
7. ADJUSTED EAF (using 2 & 5)	%	84.51	86.72	89.06	53.41	96.77	77.08	91.17	80.90	80.98
8. DIFFERENCE	%	-3.36	2.87	0.00	-9.25	0.00	-6.96	-1.78	-0.19	-2.99
9. TOTAL ADJ TO EAF (6 + 8)	%	-3.36	2.87	0.00	-9.25	0.00	-6.96	-1.78	-0.19	-2.99

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ADJUSTMENTS TO ANOHR ACTUAL

Florida Power Corporation
January 2000 - December 2000

ANOHR adj for Target NOF		CR 1	CR 2	CR 3	CR 4	CR 5	AN 1	AN 2	BA3	TB
1. Target NOF	%	82.4	68.7	100.2	89.6	91.5	52.0	53.2	61.1	90.0
2. Target ANOHR	Btu/kwh	9851.5	9850.8	10357.0	9421.8	9393.6	10021.9	10024.8	10140.1	7590.1
3. Actual NOF	%	83.0	81.0	102.4	88.6	87.9	58.6	54.8	67.0	90.7
4. Calc. ANOHR (using 3)	Btu/kwh	9844.9	9803.4	10282.0	9429.9	9412.5	9958.4	10002.6	10065.4	7552.5
5. Total adj. to ANOHR (2-4)	Btu/kwh	6.6	47.4	74.9	-8.1	-18.9	63.5	22.2	74.7	37.6

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation
January 2000 - December 2000
Unit: Crystal River 1

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$860,000	94.81	10	$805,537	9670.7	
	9	$774,000	94.36	9	$724,983	9681.3	
	8	$688,000	93.91	8	$644,429	9691.9	
	7	$602,000	93.45	7	$563,876	9702.5	
	6	$516,000	93.00	6	$483,322	9713.0	
	5	$430,000	92.55	5	$402,768	9723.6	
	4	$344,000	92.10	4	$322,215	9734.2	
	3	$258,000	91.64	3	$241,661	9744.8	
	2	$172,000	91.19	2	$161,107	9755.3	
	1	$86,000	90.74	1	$80,554	9765.9	
		$0	90.28	0	$0	9776.5	
	0	$0	90.28	0	$0	9839.8	****
		$0	90.28	0	$0	9851.5	
	-1	($359,500)	89.38	0	$0	9926.5	
****	-1.358	($488,153)	89.06	-1	($80,554)	9937.1	
	-2	($719,000)	88.48	-2	($161,107)	9947.6	
	-3	($1,078,500)	87.57	-3	($241,661)	9958.2	
	-4	($1,438,000)	86.67	-4	($322,215)	9968.8	
	-5	($1,797,500)	85.76	-5	($402,768)	9979.4	
	-6	($2,157,000)	84.86	-6	($483,322)	9989.9	
	-7	($2,516,500)	83.96	-7	($563,876)	10000.5	
	-8	($2,876,000)	83.05	-8	($644,429)	10011.1	
	-9	($3,235,500)	82.15	-9	($724,983)	10021.7	
	-10	($3,595,000)	81.24	-10	($805,537)	10032.3	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.46%	3.24%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation
January 2000 - December 2000
Unit: Crystal River 2

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$2,685,000	79.85	10	$653,492	9687.2	
	9	$2,416,500	79.39	9	$588,143	9696.1	
	8	$2,148,000	78.93	8	$522,794	9704.9	
	7	$1,879,500	78.47	7	$457,445	9713.8	
	6	$1,611,000	78.01	6	$392,095	9722.7	
	5	$1,342,500	77.55	5	$326,746	9731.5	
	4	$1,074,000	77.09	4.578	$299,141	9735.3	****
	3	$805,500	76.63	4	$261,397	9740.4	
	2	$537,000	76.17	3	$196,048	9749.3	
	1	$268,500	75.71	2	$130,698	9758.1	
		$0	75.25	1	$65,349	9767.0	
	0	$0	75.25	0	$0	9775.8	
		$0	75.25	0	$0	9850.8	
	-1	($453,200)	74.36	0	$0	9925.8	
	-2	($906,400)	73.47	-1	($65,349)	9934.7	
	-3	($1,359,600)	72.58	-2	($130,698)	9943.6	
	-4	($1,812,800)	71.69	-3	($196,048)	9952.4	
	-5	($2,266,000)	70.80	-4	($261,397)	9961.3	
	-6	($2,719,200)	69.91	-5	($326,746)	9970.2	
	-7	($3,172,400)	69.02	-6	($392,095)	9979.0	
	-8	($3,625,600)	68.13	-7	($457,445)	9987.9	
	-9	($4,078,800)	67.24	-8	($522,794)	9996.7	
	-10	($4,532,000)	66.34	-9	($588,143)	10005.6	
****	-10.000	($4,532,000)	53.41	-10	($653,492)	10014.5	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
10.80%	2.63%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation
January 2000 - December 2000
Unit: Crystal River 3

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10.000	$2,608,000	96.77	10	$2,610,155	10207.0	
	10	$2,608,000	96.52	9	$2,349,139	10214.5	
	9	$2,347,200	96.21	8	$2,088,124	10222.0	
	8	$2,086,400	95.90	7	$1,827,108	10229.5	
	7	$1,825,600	95.60	6	$1,566,093	10237.0	
	6	$1,564,800	95.29	5	$1,305,077	10244.5	
	5	$1,304,000	94.98	4	$1,044,062	10252.0	
	4	$1,043,200	94.67	3	$783,046	10259.5	
	3	$782,400	94.36	2	$522,031	10267.0	
	2	$521,600	94.05	1	$261,015	10274.5	
	1	$260,800	93.74	0	$0	10282.0	
		$0	93.43	0	$0	10332.8	****
	0	$0	93.43	0	$0	10357.0	
		$0	93.43	0	$0	10432.0	
	-1	($770,000)	92.80	-1	($261,015)	10439.5	
	-2	($1,540,000)	92.16	-2	($522,031)	10447.0	
	-3	($2,310,000)	91.53	-3	($783,046)	10454.5	
	-4	($3,080,000)	90.90	-4	($1,044,062)	10462.0	
	-5	($3,850,000)	90.26	-5	($1,305,077)	10469.5	
	-6	($4,620,000)	89.63	-6	($1,566,093)	10477.0	
	-7	($5,390,000)	88.99	-7	($1,827,108)	10484.5	
	-8	($6,160,000)	88.36	-8	($2,088,124)	10492.0	
	-9	($6,930,000)	87.73	-9	($2,349,139)	10499.5	
	-10	($7,700,000)	87.09	-10	($2,610,155)	10507.0	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
10.49%	10.50%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation
January 2000 - December 2000
Unit: Crystal River 4

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$2,407,000	78.97	10	$1,581,607	9247.8	
	9	$2,166,300	78.64	9	$1,423,446	9257.7	
	8	$1,925,600	78.31	8	$1,265,285	9267.6	
	7	$1,684,900	77.98	7	$1,107,125	9277.5	
	6	$1,444,200	77.64	6	$948,964	9287.4	
	5	$1,203,500	77.31	5	$790,803	9297.3	
****	4.305	$1,036,299	77.08	4	$632,643	9307.2	
	4	$962,800	76.98	3.928	$621,334	9307.9	****
	3	$722,100	76.65	3	$474,482	9317.1	
	2	$481,400	76.31	2	$316,321	9327.0	
	1	$240,700	75.98	1	$158,161	9336.9	
		$0	75.65	0	$0	9346.8	
	0	$0	75.65	0	$0	9421.8	
		$0	75.65	0	$0	9496.8	
	-1	($512,200)	74.98	-1	($158,161)	9506.7	
	-2	($1,024,400)	74.32	-2	($316,321)	9516.6	
	-3	($1,536,600)	73.66	-3	($474,482)	9526.5	
	-4	($2,048,800)	72.99	-4	($632,643)	9536.4	
	-5	($2,561,000)	72.33	-5	($790,803)	9546.3	
	-6	($3,073,200)	71.66	-6	($948,964)	9556.2	
	-7	($3,585,400)	71.00	-7	($1,107,125)	9566.1	
	-8	($4,097,600)	70.34	-8	($1,265,285)	9576.0	
	-9	($4,609,800)	69.67	-9	($1,423,446)	9585.9	
	-10	($5,122,000)	69.01	-10	($1,581,607)	9595.8	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
9.68%	6.36%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation
January 2000 - December 2000
Unit: Crystal River 5

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$896,000	95.95	10	$2,154,370	9204.8	
	9	$806,400	95.76	9	$1,938,933	9216.2	
	8	$716,800	95.57	8	$1,723,496	9227.6	
	7	$627,200	95.38	7	$1,508,059	9238.9	
	6	$537,600	95.19	6	$1,292,622	9250.3	
	5	$448,000	94.99	5	$1,077,185	9261.7	
	4	$358,400	94.80	4	$861,748	9273.1	
	3	$268,800	94.61	3	$646,311	9284.5	
	2	$179,200	94.42	2	$430,874	9295.9	
	1	$89,600	94.23	1	$215,437	9307.2	
		$0	94.04	0.478	$102,963	9313.2	****
	0	$0	94.04	0	$0	9318.6	
		$0	94.04	0	$0	9393.6	
	-1	($269,500)	93.64	0	$0	9468.6	
	-2	($539,000)	93.25	-1	($215,437)	9480.0	
	-3	($808,500)	92.86	-2	($430,874)	9491.4	
	-4	($1,078,000)	92.46	-3	($646,311)	9502.8	
	-5	($1,347,500)	92.07	-4	($861,748)	9514.2	
	-6	($1,617,000)	91.67	-5	($1,077,185)	9525.5	
	-7	($1,886,500)	91.28	-6	($1,292,622)	9536.9	
****	-7.275	($1,960,674)	91.17	-7	($1,508,059)	9548.3	
	-8	($2,156,000)	90.88	-8	($1,723,496)	9559.7	
	-9	($2,425,500)	90.49	-9	($1,938,933)	9571.1	
	-10	($2,695,000)	90.09	-10	($2,154,370)	9582.5	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.60%	8.66%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation
January 2000 - December 2000
Unit: Anclote 1

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$1,172,000	94.15	10	$1,281,848	9743.5	
	9	$1,054,800	93.97	9	$1,153,664	9763.9	
	8	$937,600	93.79	8	$1,025,479	9784.2	
	7	$820,400	93.61	7	$897,294	9804.6	
	6	$703,200	93.43	6	$769,109	9824.9	
	5	$586,000	93.25	5	$640,924	9845.2	
	4	$468,800	93.07	4	$512,739	9865.6	
	3	$351,600	92.89	3	$384,555	9885.9	
	2	$234,400	92.71	2	$256,370	9906.2	
	1	$117,200	92.54	1	$128,185	9926.6	
		$0	92.36	0	$0	9946.9	
	0	$0	92.36	0	$0	10021.9	
		$0	92.36	0	$0	10096.9	
	-1	($214,200)	91.99	-1	($128,185)	10117.3	
	-2	($428,400)	91.62	-2	($256,370)	10137.6	
	-3	($642,600)	91.25	-3	($384,555)	10157.9	
	-4	($856,800)	90.89	-3.949	($506,199)	10177.2	****
	-5	($1,071,000)	90.52	-4	($512,739)	10178.3	
	-6	($1,285,200)	90.15	-5	($640,924)	10198.6	
	-7	($1,499,400)	89.78	-6	($769,109)	10218.9	
	-8	($1,713,600)	89.41	-7	($897,294)	10239.3	
	-9	($1,927,800)	89.05	-8	($1,025,479)	10259.6	
	-10	($2,142,000)	88.68	-9	($1,153,664)	10280.0	
****	-10.000	($2,142,000)	84.51	-10	($1,281,848)	10300.3	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
4.71%	5.16%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation
January 2000 - December 2000
Unit: Anclote 2

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$1,463,000	86.98	10	$1,100,183	9766.8	
****	9.131	$1,335,815	86.72	9	$990,165	9785.1	
	9	$1,316,700	86.68	8	$880,147	9803.4	
	8	$1,170,400	86.37	7	$770,128	9821.7	
	7	$1,024,100	86.07	6	$660,110	9840.0	
	6	$877,800	85.76	5	$550,092	9858.3	
	5	$731,500	85.46	4	$440,073	9876.6	
	4	$585,200	85.15	3	$330,055	9894.9	
	3	$438,900	84.85	2	$220,037	9913.2	
	2	$292,600	84.54	1	$110,018	9931.5	
	1	$146,300	84.24	0	$0	9949.8	
		$0	83.94	0	$0	10024.8	
	0	$0	83.94	0	$0	10085.3	****
		$0	83.94	0	$0	10099.8	
	-1	($199,000)	83.32	-1	($110,018)	10118.1	
	-2	($398,000)	82.70	-2	($220,037)	10136.4	
	-3	($597,000)	82.09	-3	($330,055)	10154.7	
	-4	($796,000)	81.47	-4	($440,073)	10173.0	
	-5	($995,000)	80.86	-5	($550,092)	10191.3	
	-6	($1,194,000)	80.24	-6	($660,110)	10209.6	
	-7	($1,393,000)	79.63	-7	($770,128)	10227.9	
	-8	($1,592,000)	79.01	-8	($880,147)	10246.2	
	-9	($1,791,000)	78.40	-9	($990,165)	10264.5	
	-10	($1,990,000)	77.78	-10	($1,100,183)	10282.8	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
5.88%	4.42%

Issued by: FPC

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation
January 2000 - December 2000
Unit: Bartow 3

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$418,000	86.39	10	$533,778	9860.1	
	9	$376,200	86.03	9	$480,401	9880.6	
	8	$334,400	85.68	8	$427,023	9901.1	
	7	$292,600	85.32	7	$373,645	9921.6	
	6	$250,800	84.97	6	$320,267	9942.1	
	5	$209,000	84.61	5	$266,889	9962.6	
	4	$167,200	84.26	4	$213,511	9983.1	
	3	$125,400	83.90	3	$160,134	10003.6	
	2	$83,600	83.55	2	$106,756	10024.1	
	1	$41,800	83.19	1	$53,378	10044.6	
		$0	82.84	0	$0	10065.1	
	0	$0	82.84	0	$0	10140.1	
		$0	82.84	0	$0	10201.3	****
	-1	($202,600)	82.12	0	$0	10215.1	
	-2	($405,200)	81.41	-1	($53,378)	10235.6	
****	-2.720	($551,043)	80.90	-2	($106,756)	10256.1	
	-3	($607,800)	80.70	-3	($160,134)	10276.5	
	-4	($810,400)	79.99	-4	($213,511)	10297.0	
	-5	($1,013,000)	79.27	-5	($266,889)	10317.5	
	-6	($1,215,600)	78.56	-6	($320,267)	10338.0	
	-7	($1,418,200)	77.85	-7	($373,645)	10358.5	
	-8	($1,620,800)	77.13	-8	($427,023)	10379.0	
	-9	($1,823,400)	76.42	-9	($480,401)	10399.5	
	-10	($2,026,000)	75.71	-10	($533,778)	10420.0	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
1.68%	2.15%

Issued by: FPC

Filed:
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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation
January 2000 - December 2000
Unit: Tiger Bay

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$314,000	82.32	10	$1,320,507	6999.8	
	9	$282,600	82.00	9	$1,188,456	7051.4	
	8	$251,200	81.69	8	$1,056,406	7102.9	
	7	$219,800	81.37	7	$924,355	7154.4	
	6	$188,400	81.05	6	$792,304	7206.0	
****	5.782	$181,550	80.98	5	$660,253	7257.5	
	5	$157,000	80.73	4	$528,203	7309.0	
	4	$125,600	80.41	3	$396,152	7360.5	
	3	$94,200	80.09	2	$264,101	7412.1	
	2	$62,800	79.77	1	$132,051	7463.6	
	1	$31,400	79.45	0	$0	7515.1	
		$0	79.13	0	$0	7590.1	
	0	$0	79.13	0	$0	7665.1	
		$0	79.13	-0.588	($77,693)	7695.4	****
	-1	($170,000)	78.81	-1	($132,051)	7716.6	
	-2	($340,000)	78.50	-2	($264,101)	7768.2	
	-3	($510,000)	78.18	-3	($396,152)	7819.7	
	-4	($680,000)	77.86	-4	($528,203)	7871.2	
	-5	($850,000)	77.54	-5	($660,253)	7922.7	
	-6	($1,020,000)	77.23	-6	($792,304)	7974.3	
	-7	($1,190,000)	76.91	-7	($924,355)	8025.8	
	-8	($1,360,000)	76.59	-8	($1,056,406)	8077.3	
	-9	($1,530,000)	76.28	-9	($1,188,456)	8128.9	
	-10	($1,700,000)	75.96	-10	($1,320,507)	8180.4	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
1.26%	5.31%

Issued by: FPC

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

CRYSTAL RIVER 1	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-Dec Period
1. EAF	97.24	91.29	95.75	72.87	99.06	78.15	84.15	96.67	84.05	87.78	98.56	82.50	89.06
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	744.0	641.5	735.1	528.2	744.0	628.9	656.0	744.0	627.2	673.2	720.0	619.0	8061.1
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	54.5	8.9	190.8	0.0	91.1	88.0	0.0	92.8	71.8	0.0	125.1	722.9
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	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	91.1	1.9	0.0	19.3	0.8	0.0	2.4	115.6
8. MOH	0.0	54.5	8.9	190.8	0.0	0.0	86.1	0.0	73.5	70.9	0.0	122.7	607.3
9. PFOH	41.1	6.3	24.4	4.1	12.1	119.0	73.8	22.6	0.0	2.1	12.6	3.0	321.2
10. LR PF (MW)	119.0	83.1	92.3	158.6	143.8	153.6	99.3	86.0	0.0	193.8	9.2	175.2	120.4
11. PMOH	14.6	20.9	31.7	9.2	8.2	31.8	20.6	36.0	42.0	61.6	31.0	17.7	325.2
12. LR PM (MW)	184.6	83.0	193.7	101.5	101.4	193.7	180.4	199.8	193.7	108.8	119.9	78.1	151.7
13. NSC (MW)	369	369	369	369	369	369	369	369	369	369	369	369	369
14. OPER MBTU	2068155	1699973	2189693	1686245	2336717	1915443	2106160	2469655	1892878	1929060	2113995	1871049	24279023
15. NET GEN (MWH)	211475	173907	225292	172867	237527	190842	209901	245732	191666	198379	218738	192752	2469078
16. ANOHR (BTU/KWH)	9779.7	9775.2	9719.4	9754.6	9837.7	10036.8	10034.1	10050.2	9875.9	9724.1	9664.5	9707.0	9833.2
17. NOF (%)	77.03	73.47	83.05	88.69	86.52	82.24	86.71	89.51	82.82	79.86	82.33	84.40	83.01
18. NPC (MW)	369	369	369	369	369	369	369	369	369	369	369	369	369

ANOHR EQUATION: ANOHR = -10.689 * NOF + 10732.1

ISSUED BY: FLORIDA POWER CORPORATION

ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

CRYSTAL RIVER 2	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-Dec Period
1. EAF	73.59	94.95	87.40	76.87	65.79	3.10	0.00	0.00	72.11	91.21	96.95	91.93	62.66
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	616.5	696.0	678.5	589.9	505.9	22.3	0.0	0.0	596.6	745.0	720.0	695.1	5865.8
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	127.5	0.0	65.5	129.1	238.1	697.7	744.0	744.0	123.5	0.0	0.0	49.0	2918.3
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	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	697.7	0.0	0.0	3.9	0.0	0.0	0.0	701.6
8. MOH	127.5	0.0	65.5	129.1	238.1	0.0	744.0	744.0	119.6	0.0	0.0	49.0	2216.7
9. PFOH	17.6	3.7	5.5	150.0	15.5	0.0	0.0	0.0	412.0	120.2	11.8	5.8	741.8
10. LR PF (MW)	192.2	269.3	9.3	65.5	152.4	0.0	0.0	0.0	87.1	174.9	232.6	193.3	104.3
11. PMOH	516.7	149.4	75.3	43.6	41.1	0.0	0.0	0.0	0.0	49.6	39.2	29.0	943.9
12. LR PM (MW)	55.5	102.6	173.0	170.3	128.6	0.0	0.0	0.0	0.0	188.9	190.1	139.4	96.0
13. NSC (MW)	464	464	464	464	464	464	464	464	464	464	464	464	464
14. OPER MBTU	1997863	2236921	2517080	2166041	1890178	80744	0	7896	2019704	2814453	2808774	2810923	21350577
15. NET GEN (MWH)	205720	230733	260025	222721	192685	7985	0	0	206612	292143	292936	292297	2203857
16. ANOHR (BTU/KWH)	9711.6	9694.8	9680.1	9725.4	9809.7	10111.9	0.0	0.0	9775.3	9633.8	9588.4	9616.7	9687.8
17. NOF (%)	71.92	71.45	82.60	81.37	82.08	77.10	0.00	0.00	74.64	84.51	87.68	90.63	80.97
18. NPC (MW)	464	464	464	464	464	464	464	464	464	464	464	464	464

ANOHR EQUATION: ANOHR = -3.865 * NOF + 10116.3

ISSUED BY: FLORIDA POWER CORPORATION

ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

CRYSTAL RIVER 3	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-Dec Period
1. EAF	99.98	99.36	98.35	90.71	100.00	100.00	100.00	99.12	74.64	98.51	100.00	100.00	96.77
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	744.0	696.0	744.0	664.1	744.0	720.0	744.0	744.0	546.6	745.0	720.0	744.0	8555.7
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	0.0	54.9	0.0	0.0	0.0	0.0	173.4	0.0	0.0	0.0	228.3
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	0.0	0.0	0.0	0.0	0.0
8. MOH	0.0	0.0	0.0	54.9	0.0	0.0	0.0	0.0	173.4	0.0	0.0	0.0	228.3
9. PFOH	0.0	0.0	33.3	0.0	0.0	0.0	0.0	34.2	0.0	30.3	0.0	0.0	97.8
10. LR PF (MW)	0.0	0.0	278.3	0.0	0.0	0.0	0.0	144.5	0.0	4.7	0.0	0.0	146.9
11. PMOH	3.0	29.5	0.0	26.3	0.0	0.0	0.0	0.0	23.5	56.3	0.0	0.0	138.6
12. LR PM (MW)	31.0	113.8	0.0	340.4	0.0	0.0	0.0	0.0	295.5	146.7	0.0	0.0	199.2
13. NSC (MW)	754	754	754	754	754	754	754	754	754	754	754	754	754
14. OPER MBTU	5914409	5507551	5840388	5233671	5926032	5733894	5926806	5883897	4304603	5843289	5735370	5922667	67772577
15. NET GEN (MWH)	582026	542369	575239	511129	577564	554181	567083	559742	418174	573908	563682	581772	6606869
16. ANOHR (BTU/KWH)	10161.8	10154.6	10153.0	10239.4	10260.4	10346.6	10451.4	10511.8	10293.8	10181.6	10174.8	10180.4	10257.9
17. NOF (%)	103.75	103.35	102.54	102.07	102.96	102.08	101.09	99.78	101.47	102.17	103.83	103.71	102.42
18. NPC (MW)	754	754	754	754	754	754	754	754	754	754	754	754	754

ANOHR EQUATION: ANOHR = -34.186 * NOF + 13783.3

ISSUED BY: FLORIDA POWER CORPORATION

ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

CRYSTAL RIVER 4	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-Dec Period
1. EAF	99.50	99.95	35.64	47.65	99.16	93.47	99.91	99.21	100.00	80.73	76.79	76.90	84.04
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	744.0	696.0	265.2	342.8	744.0	720.0	744.0	744.0	720.0	611.7	589.3	575.9	7496.9
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	478.8	376.2	0.0	0.0	0.0	0.0	0.0	133.3	130.7	168.1	1287.1
6. POH	0.0	0.0	478.8	376.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	855.0
7. FOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	103.7	50.0	80.6	234.3
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.7	80.7	87.5	197.9
9. PFOH	21.5	2.2	0.0	1.7	5.2	83.4	4.8	36.7	0.0	21.1	86.1	0.0	262.6
10. LR PF (MW)	119.6	66.8	0.0	95.5	66.8	389.1	93.0	84.7	0.0	337.4	227.1	0.0	250.9
11. PMOH	0.0	0.3	0.0	0.0	46.6	3.4	0.0	11.5	0.0	0.0	68.0	5.0	134.8
12. LR PM (MW)	0.0	255.1	0.0	0.0	85.9	85.8	0.0	85.9	0.0	0.0	85.9	525.2	102.6
13. NSC (MW)	697	697	697	697	697	697	697	697	697	697	697	697	697
14. OPER MBTU	4194091	3750550	1364380	1815491	4297539	4242572	4607028	4617685	4308389	3512591	3064322	3342004	43116641
15. NET GEN (MWH)	448754	401080	147359	191665	469127	453753	489629	491511	461658	376025	335169	362518	4628248
16. ANOHR (BTU/KWH)	9346.1	9351.1	9258.9	9472.2	9160.7	9350.0	9409.2	9394.9	9332.4	9341.4	9142.6	9218.9	9316.0
17. NOF (%)	86.54	82.68	79.73	80.21	90.47	90.42	94.42	94.78	91.99	88.20	81.60	90.31	88.57
18. NPC (MW)	697	697	697	697	697	697	697	697	697	697	697	697	697

ANOHR EQUATION: ANOHR = -8.030 * NOF + 10141.2

ISSUED BY: FLORIDA POWER CORPORATION

ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

CRYSTAL RIVER 5	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-Dec Period
1. EAF	99.01	97.69	99.07	99.65	100.00	99.45	98.93	99.58	99.68	90.44	84.19	48.35	92.95
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	744.0	696.0	744.0	719.0	744.0	720.0	738.7	741.6	718.5	743.0	638.8	359.7	8307.2
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	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	5.3	2.5	1.5	2.0	81.2	384.3	476.8
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	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	5.3	2.5	1.5	2.0	8.3	22.8	42.4
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	72.9	361.5	434.4
9. PFOH	6.3	0.0	2.8	3.0	0.0	10.1	22.9	3.5	2.1	507.7	63.8	0.0	622.0
10. LR PF (MW)	427.3	0.0	65.1	590.7	0.0	280.4	46.7	141.4	282.4	97.3	93.7	0.0	104.4
11. PMOH	34.7	153.9	8.2	0.0	0.0	0.0	8.0	0.0	0.0	0.0	238.4	0.0	443.1
12. LR PM (MW)	74.6	74.6	581.4	0.0	0.0	0.0	103.2	0.0	0.0	0.0	72.6	0.0	83.4
13. NSC (MW)	714	714	714	714	714	714	714	714	714	714	714	714	714
14. OPER MBTU	4249963	3642045	4438929	4147208	4330003	4531684	4604297	4668024	4336312	3995607	3641818	2080594	48666482
15. NET GEN (MWH)	464837	399482	480364	447156	468982	482582	482450	491354	459267	426692	392015	219806	5214987
16. ANOHR (BTU/KWH)	9142.9	9116.9	9240.8	9274.6	9232.8	9390.5	9543.6	9500.3	9441.8	9364.1	9290.0	9465.6	9332.0
17. NOF (%)	87.50	80.39	90.43	87.10	88.28	93.87	91.48	92.80	89.52	80.43	85.95	85.59	87.92
18. NPC (MW)	714	714	714	714	714	714	714	714	714	714	714	714	714

ANOHR EQUATION: ANOHR = -5.341 * NOF + 9882.1

ISSUED BY: FLORIDA POWER CORPORATION

ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

ANCLOTE 1	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-Dec Period
1. EAF	77.05	61.19	92.03	75.01	96.32	96.73	90.62	84.92	91.13	91.78	97.78	98.44	87.87
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	513.4	258.1	532.1	432.2	739.3	720.0	699.5	718.8	690.9	641.7	720.0	739.0	7404.9
4. RSH	59.9	173.9	169.2	124.0	4.7	0.0	0.0	0.0	0.0	62.7	0.0	0.0	594.4
5. UH	170.7	264.0	42.8	162.8	0.0	0.0	44.5	25.2	29.1	40.6	0.0	5.0	784.7
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	170.7	0.0	12.5	0.0	0.0	0.0	44.5	25.2	0.0	0.0	0.0	5.0	257.9
8. MOH	0.0	264.0	30.3	162.8	0.0	0.0	0.0	0.0	29.1	40.6	0.0	0.0	526.8
9. PFOH	0.1	0.0	4.2	30.2	5.7	38.8	42.3	0.0	167.7	1.9	0.0	0.0	290.8
10. LR PF (MW)	496.7	0.0	40.4	146.2	50.0	31.8	96.2	0.0	56.4	170.7	0.0	0.0	68.7
11. PMOH	0.0	18.0	48.0	23.8	80.6	66.2	54.6	279.4	49.7	59.2	47.3	18.4	745.0
12. LR PM (MW)	0.0	170.2	170.2	170.2	167.6	160.3	158.2	156.6	161.7	170.2	170.2	181.8	162.8
13. NSC (MW)	503	503	503	503	503	503	503	503	503	503	503	503	503
14. OPER MBTU	1120289	524699	1679864	1356637	2022995	2276983	2375973	2630030	2304901	1694587	1865682	2236905	22089544
15. NET GEN (MWH)	108154	50838	165325	135518	196685	227378	236095	265967	236902	164028	184808	212418	2184116
16. ANOHR (BTU/KWH)	10358.3	10321.0	10161.0	10010.7	10285.5	10014.1	10063.6	9888.6	9729.3	10331.1	10095.2	10530.7	10113.7
17. NOF (%)	41.88	39.16	61.77	62.34	52.89	62.78	67.10	73.56	68.17	50.82	51.03	57.15	58.64
18. NPC (MW)	503	503	503	503	503	503	503	503	503	503	503	503	503

ANOHR EQUATION: ANOHR = -9.610 * NOF + 10521.9

ISSUED BY: FLORIDA POWER CORPORATION

ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

ANCLOTE 2	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-Dec Period
1. EAF	93.63	99.46	98.84	91.26	97.38	92.13	97.04	97.98	98.01	70.11	0.00	69.66	83.85
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	419.3	695.1	744.0	671.2	744.0	676.0	744.0	744.0	720.0	371.5	0.0	411.8	6940.8
4. RSH	285.4	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	156.0	0.0	106.8	549.1
5. UH	39.4	0.0	0.0	47.9	0.0	44.0	0.0	0.0	0.0	217.6	720.0	225.4	1294.2
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	157.0	720.0	225.4	1102.4
7. FOH	6.9	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	0.0	0.0	0.0	50.9
8. MOH	32.5	0.0	0.0	47.9	0.0	0.0	0.0	0.0	0.0	60.6	0.0	0.0	140.9
9. PFOH	28.2	1.8	0.0	16.1	0.0	4.5	4.6	3.7	6.2	0.0	0.0	1.9	67.0
10. LR PF (MW)	79.3	14.3	0.0	52.9	0.0	264.6	52.9	287.8	52.9	0.0	0.0	84.4	91.0
11. PMOH	10.8	11.2	25.8	39.6	58.4	30.7	66.9	38.5	41.7	15.4	0.0	0.0	338.8
12. LR PM (MW)	166.4	168.2	168.3	168.3	168.3	168.3	162.0	168.3	164.9	168.3	0.0	0.0	166.6
13. NSC (MW)	503	503	503	503	503	503	503	503	503	503	503	503	503
14. OPER MBTU	905108	1188220	1971227	1732889	2089794	2110833	2288650	2503744	2123294	945871	0	1404108	19263737
15. NET GEN (MWH)	88738	106824	193588	166744	205649	212615	231372	257482	220315	91328	0	139646	1914301
16. ANOHR (BTU/KWH)	10199.8	11123.2	10182.6	10392.5	10161.9	9928.0	9891.6	9724.0	9637.5	10356.9	0.0	10054.8	10063.1
17. NOF (%)	42.08	30.55	51.73	49.39	54.95	62.53	61.83	68.80	60.83	48.87	0.00	67.41	54.83
18. NPC (MW)	503	503	503	503	503	503	503	503	503	503	503	503	503

ANOHR EQUATION: ANOHR = -13.676 * NOF + 10752.5

ISSUED BY: FLORIDA POWER CORPORATION

ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

BARTOW 3	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-Dec Period
1. EAF	99.33	70.37	16.38	77.52	96.77	97.73	91.93	88.85	71.05	79.68	99.84	83.59	81.09
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	475.7	391.0	121.9	561.6	727.3	719.5	744.0	681.9	581.1	518.1	360.1	567.2	6449.4
4. RSH	268.3	105.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	226.9	359.9	54.8	1015.4
5. UH	0.0	199.4	622.1	157.4	16.7	0.5	0.0	62.1	139.0	0.0	0.0	122.1	1319.2
6. POH	0.0	199.4	622.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	821.5
7. FOH	0.0	0.0	0.0	105.5	16.7	0.5	0.0	62.1	15.2	0.0	0.0	0.0	200.0
8. MOH	0.0	0.0	0.0	51.9	0.0	0.0	0.0	0.0	123.7	0.0	0.0	122.1	297.7
9. PFOH	3.9	0.0	0.0	0.0	0.0	3.1	17.3	0.0	116.4	7.6	0.0	0.0	148.2
10. LR PF (MW)	113.0	0.0	0.0	0.0	0.0	159.8	111.9	0.0	99.6	69.3	0.0	0.0	101.1
11. PMOH	5.0	11.2	0.0	7.5	12.8	23.5	82.7	35.4	29.4	367.5	2.0	0.0	576.8
12. LR PM (MW)	120.9	127.3	0.0	118.4	119.0	119.0	127.5	122.8	97.4	84.2	119.0	0.0	97.4
13. NSC (MW)	208	208	208	208	208	208	208	208	208	208	208	208	208
14. OPER MBTU	599475	410385	192333	759553	1008465	1130041	1122458	1063562	821320	645788	504378	838797	9096556
15. NET GEN (MWH)	59779	38680	18029	72390	101360	111373	111947	105720	81057	62971	50973	84005	898284
16. ANOHR (BTU/KWH)	10028.2	10609.8	10668.0	10492.5	9949.3	10146.5	10026.7	10060.2	10132.6	10255.3	9895.0	9985.1	10126.6
17. NOF (%)	60.42	47.56	71.11	61.97	67.01	74.42	72.34	74.53	67.07	58.43	68.05	71.21	66.96
18. NPC (MW)	208	208	208	208	208	208	208	208	208	208	208	208	208

ANOHR EQUATION: ANOHR = -12.673 * NOF + 10914.0

ISSUED BY: FLORIDA POWER CORPORATION

ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

TIGER BAY	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-Dec Period
1. EAF	95.40	100.00	37.99	49.75	100.00	99.70	100.00	87.63	100.00	90.07	55.05	92.02	83.97
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	636.9	696.0	282.7	357.9	744.0	720.0	744.0	652.0	720.0	574.1	396.4	684.6	7208.6
4. RSH	72.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	96.9	0.0	0.0	169.8
5. UH	34.2	0.0	461.3	361.1	0.0	0.0	0.0	92.0	0.0	74.0	323.6	59.4	1405.6
6. POH	0.0	0.0	461.3	361.1	0.0	0.0	0.0	0.0	0.0	0.0	246.5	0.0	1068.9
7. FOH	34.2	0.0	0.0	0.0	0.0	0.0	0.0	92.0	0.0	74.0	77.1	0.0	277.3
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	59.4	59.4
9. PFOH	0.0	0.0	0.0	0.8	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	3.9
10. LR PF (MW)	0.0	0.0	0.0	60.0	0.0	145.9	0.0	0.0	0.0	0.0	0.0	0.0	127.7
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13. NSC (MW)	206	206	206	206	206	206	206	206	206	206	206	206	206
14. OPER MBTU	928891	953611	392732	514898	1065807	1043286	1064768	969815	1035370	812621	527688	1008982	10318469
15. NET GEN (MWH)	117030	125545	51647	65769	141853	132279	141804	126070	136094	108855	65969	134533	1347448
16. ANOHR (BTU/KWH)	7937.2	7595.8	7604.2	7828.9	7513.5	7887.0	7508.7	7692.7	7607.8	7465.2	7999.0	7499.9	7657.8
17. NOF (%)	89.20	87.56	88.69	89.20	92.55	89.18	92.52	93.87	91.76	92.04	80.79	95.39	90.74
18. NPC (MW)	206	206	206	206	206	206	206	206	206	206	206	206	206

ANOHR EQUATION: ANOHR = -49.416 * NOF + 12036.4

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PLANNED OUTAGE SCHEDULES
ACTUAL

Florida Power Corporation
January 2000 - December 2000

Plant/Unit	Planned Outage Dates	Reason for Outage
Anclote 2	10/25 (0001) - 12/10 (2400)	Boiler Overhaul
Bartow 3	02/21 (0001) - 03/26 (2400)	Boiler Overhaul
Crystal River 4	03/12 (0001) - 04/16 (2400)	Boiler Overhaul
Tiger Bay	03/12 (0001) - 04/15 (2400)	Combustion Inspection/Generator Field
Tiger Bay	11/01 (0001) - 11/11 (2400)	Cycle Off

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Planned Outage Schedule - Actual

Florida Power Corporation
January 2000 - December 2000

	January	February	March	April	May	June	July	August	September	October	November	December
Anclote 2											Boiler Overhaul 10/25 [redacted] 12/10 47 days	
Bartow 3			Boiler Overhaul 2/21 [redacted] 3/26 35 days									
Crystal River 4				Boiler Overhaul 3/12 [redacted] 4/16 36 days								
Tiger Bay				Combustion Inspection/Gen. Field 3/12 [redacted] 4/15 35 days								
Tiger Bay											Cycle Off 11/1 [redacted] 11/11 11 days	

EXHIBITS TO THE TESTIMONY OF MICHAEL F. JACOB

GPIF Targets and Ranges for January through December 2002

STANDARD FORM GPIF SCHEDULES

Description	Page
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GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ESTIMATED

Company: Florida Power Corporation
Period of: January, 2002- December, 2002

Generating Performance Incentive Points (GPIF)	Fuel Saving/Loss ($)	Generating Performance Incentive Factor ($)
10	$50,391,526	$8,218,782
9	$45,352,373	$7,396,904
8	$40,313,220	$6,575,026
7	$35,274,068	$5,753,147
6	$30,234,915	$4,931,269
5	$25,195,763	$4,109,391
4	$20,156,610	$3,287,513
3	$15,117,458	$2,465,635
2	$10,078,305	$1,643,756
1	$5,039,153	$821,878
0	$0	$0
-1	($6,352,053)	($821,878)
-2	($12,704,105)	($1,643,756)
-3	($19,056,158)	($2,465,635)
-4	($25,408,210)	($3,287,513)
-5	($31,760,263)	($4,109,391)
-6	($38,112,315)	($4,931,269)
-7	($44,464,368)	($5,753,147)
-8	($50,816,420)	($6,575,026)
-9	($57,168,473)	($7,396,904)
-10	($63,520,526)	($8,218,782)

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Suspended:
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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ESTIMATED

Company: Florida Power Corporation
Period of: January, 2002- December, 2002

1	Beginning of period balance of common equity	$2,040,786,932	
	END OF MONTH BALANCE OF COMMON EQUITY:		
2	Month of JANUARY 2002	$2,068,599,375	
3	Month of FEBRUARY 2002	$2,023,977,108	
4	Month of MARCH 2002	$2,047,764,004	
5	Month of APRIL 2002	$2,058,508,726	
6	Month of MAY 2002	$2,023,727,250	
7	Month of JUNE 2002	$2,058,930,803	
8	Month of JULY 2002	$2,099,863,320	
9	Month of AUGUST 2002	$2,079,537,717	
10	Month of SEPTEMBER 2002	$2,114,167,636	
11	Month of OCTOBER 2002	$2,135,799,911	
12	Month of NOVEMBER 2002	$2,087,164,729	
13	Month of DECEMBER 2002	$2,110,753,261	
14	Average common equity for the period (Summation of LINE 1 through LINE 13 divided by 13)	$2,073,044,675	
15	25 Basis Points	0.0025	
16	Revenue Expansion Factor	61.3808%	
17	Maximum allowed incentive dollars (LINE 14 times LINE 15 divided by LINE 16)	$8,443,376	
18	Jurisdictional Sales *	37,116,108	MWH
19	Total Sales *	38,130,585	MWH
20	Jurisdictional Separation Factor *(LINE 18 divided by LINE 19)*	97.34%	
21	Maximum allowed jurisdictional incentive dollars (LINE 17 times LINE 20)	$8,218,782	

* Net sales (Sales - Interruptible)

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Docket No.:
Order No.:

GPIF TARGET AND RANGE SUMMARY

Company: Florida Power Corporation
Period of: January, 2002- December, 2002

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE Max. (%)	EAF RANGE Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
ANCLOTE 1	8.78	91.71	95.57	84.05	4426	(3,269)
ANCLOTE 2	3.13	81.68	84.11	76.72	1579	(2,672)
BARTOW 3	2.67	80.12	84.02	72.41	1344	(750)
C.R. 1	3.51	86.75	92.87	74.82	1770	(7,066)
C.R. 2	13.39	65.14	71.66	52.88	6745	(8,834)
C.R. 3	7.81	96.21	98.00	92.51	3938	(6,718)
C.R. 4	5.19	76.48	78.14	73.10	2615	(4,740)
C.R. 5	5.62	94.52	97.09	89.30	2833	(6,760)
TIGER BAY	6.76	80.31	83.22	74.49	3404	(974)
GPIF System	56.86				28654	(41,783)

Plant/Unit	Weighting Factor (%)	ANOHR Target (BTU/KWH)	NOF	ANOHR RANGE Min. (BTU/KWH)	ANOHR RANGE Max. (BTU/KWH)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
ANCLOTE 1	4.46	10183	48.9	9833	10534	2249.2	(2,249.2)
ANCLOTE 2	3.91	10090	53.1	9783	10396	1969.8	(1,969.8)
BARTOW 3	1.39	10053	71.7	9832	10275	701.4	(701.4)
C.R. 1	2.71	9750	93.5	9529	9972	1365.1	(1,365.1)
C.R. 2	3.51	9619	93.0	9323	9915	1771.2	(1,771.2)
C.R. 3	10.89	10283	101.1	10096	10470	5485.7	(5,485.7)
C.R. 4	5.36	9413	85.7	9187	9639	2703.5	(2,703.5)
C.R. 5	7.28	9376	90.2	9137	9614	3668.4	(3,668.4)
TIGER BAY	3.62	8267	71.9	7782	8751	1823.4	(1,823.4)
GPIF System	43.14					21737.5	(21,737.5)

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Suspended:
Effective:
Docket No.:
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COMPARISON OF GPIF TARGETS VS. PRIOR PERIODS' ACTUAL PERFORMANCE AVAILABILITY

Company: Florida Power Corporation
Period of: January, 2002- December, 2002

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Target POF	Target EUOF	Target EUOR	Actual Performance 1st Prior Period Jan.-June 2001 POF	Actual Performance 1st Prior Period Jan.-June 2001 EUOF	Actual Performance 1st Prior Period Jan.-June 2001 EUOR	Actual Performance 2nd Prior Period Jan.-Dec. 2000 POF	Actual Performance 2nd Prior Period Jan.-Dec. 2000 EUOF	Actual Performance 2nd Prior Period Jan.-Dec. 2000 EUOR
ANCLOTE 1	8.78	15.45	0.00	8.29	8.98	24.28	4.34	6.10	0.00	12.13	13.01
ANCLOTE 2	3.13	5.51	13.15	5.17	6.15	0.00	5.56	6.29	12.55	3.60	4.43
BARTOW 3	2.67	4.69	11.51	8.37	9.59	2.85	14.65	16.03	9.35	9.56	12.09
C.R. 1	3.51	6.18	0.00	13.25	13.25	0.00	11.56	11.67	0.00	10.94	10.94
C.R. 2	13.39	23.54	20.55	14.32	18.03	19.55	10.25	12.74	0.00	37.25	37.25
C.R. 3	7.81	13.74	0.00	3.79	3.79	0.00	8.31	8.31	0.00	3.23	3.23
C.R. 4	5.19	9.13	20.00	3.52	4.40	0.00	1.50	1.50	9.73	6.22	6.89
C.R. 5	5.62	9.89	0.00	5.48	5.48	20.68	3.74	4.72	0.00	7.05	7.05
TIGER BAY	6.76	11.88	13.42	6.27	8.64	15.80	4.38	5.20	12.17	3.86	4.49
GPIF System Wghtd. Avg.	56.86	100.00	9.52	8.27	9.73	12.41	6.96	8.12	3.46	14.13	14.57

Plant/Unit	Actual Performance 3rd Prior Period Jan.-Dec. 1999 POF	Actual Performance 3rd Prior Period Jan.-Dec. 1999 EUOF	Actual Performance 3rd Prior Period Jan.-Dec. 1999 EUOR	Actual Performance 4th Prior Period Jan.-Dec. 1998 POF	Actual Performance 4th Prior Period Jan.-Dec. 1998 EUOF	Actual Performance 4th Prior Period Jan.-Dec. 1998 EUOR	Actual Performance 5th Prior Period Jan.-Dec. 1997 POF	Actual Performance 5th Prior Period Jan.-Dec. 1997 EUOF	Actual Performance 5th Prior Period Jan.-Dec. 1997 EUOR
ANCLOTE 1	14.40	6.66	8.56	6.36	2.50	2.89	7.18	3.23	4.47
ANCLOTE 2	0.00	7.88	8.25	15.88	8.78	10.92	4.02	4.80	5.62
BARTOW 3	0.00	6.19	6.24	8.12	4.30	4.75	11.00	10.65	12.14
C.R. 1	14.15	12.39	15.27	7.81	10.66	12.05	0.00	5.97	5.97
C.R. 2	0.00	7.35	7.52	0.00	15.45	15.45	9.75	11.43	12.67
C.R. 3	11.55	2.86	3.23	0.00	12.50	12.50	0.00	100.00	100.00
C.R. 4	0.00	4.09	4.22	12.59	3.58	4.10	0.00	12.47	12.47
C.R. 5	15.82	4.14	4.93	0.00	3.64	3.67	8.99	1.44	1.58
TIGER BAY	10.09	6.00	7.50	4.55	11.28	12.78	0.00	0.36	0.39
GPIF System Wghtd. Avg.	7.45	6.14	6.99	4.41	9.11	9.62	5.03	19.39	20.01

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Filed:
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COMPARISON OF GPIF TARGETS VS. PRIOR PERIODS' ACTUAL PERFORMANCE
AVERAGE NET OPERATING HEAT RATE

Company: Florida Power Corporation
Period of: January, 2002- December, 2002

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Average Heat Rate Target	1st Prior HR Jan. 2000 - Dec. 2000	2nd Prior HR Jan. 1999 - Dec. 1999	3rd Prior HR Jan. 1998 - Dec. 1998
ANCLOTE 1	4.46	10.35	10183	10269	10240	10103
ANCLOTE 2	3.91	9.06	10090	10164	10057	10074
BARTOW 3	1.39	3.23	10053	10130	10115	9931
C.R. 1	2.71	6.28	9750	9747	9797	9748
C.R. 2	3.51	8.15	9619	9586	9614	9665
C.R. 3	10.89	25.24	10283	10248	10273	10306
C.R. 4	5.36	12.44	9413	9312	9512	9464
C.R. 5	7.28	16.88	9376	9316	9385	9433
TIGER BAY	3.62	8.39	8267	8211	8338	8213
GPIF System Weighted Avg.	43.14	100.00	9730	9709	9755	9748

NOTE: Crystal River Unit 3 was in an extended major design issues outage from Sept. 1996 through February 1998; therefore, its 3rd prior heat rate is from February 1998 through December 1998.

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DERIVATION OF WEIGHTING FACTORS

Company: Florida Power Corporation
Period of: January, 2002- December, 2002

Unit Performance Indicator	Production Costing Simulation Fuel Cost ($000) At Target (1)	At Maximum Improvement (2)	Savings (3)	Weighting Factor (% of Savings)
ANC. 1 EA	1363984	1359558	4426	8.78
ANC. 1 HR	1363984	1361735	2249	4.46
ANC. 2 EA	1363984	1362405	1579	3.13
ANC. 2 HR	1363984	1362014	1970	3.91
BARTOW 3 EA	1363984	1362640	1344	2.67
BARTOW 3 HR	1363984	1363283	701	1.39
C.R. 1 EA	1363984	1362214	1770	3.51
C.R. 1 HR	1363984	1362619	1365	2.71
C.R. 2 EA	1363984	1357239	6745	13.39
C.R. 2 HR	1363984	1362213	1771	3.51
C.R. 3 EA	1363984	1360046	3938	7.81
C.R. 3 HR	1363984	1358498	5486	10.89
C.R. 4 EA	1363984	1361369	2615	5.19
C.R. 4 HR	1363984	1361280	2704	5.36
C.R. 5 EA	1363984	1361151	2833	5.62
C.R. 5 HR	1363984	1360316	3668	7.28
TIGER BAY EA	1363984	1360580	3404	6.76
TIGER BAY HR	1363984	1362161	1823	3.62

1. Fuel Adjustment Base Case - all unit performance indicators at Target.
2. All other unit performance indicators at Target.
3. Expressed in replacement costs.

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INCENTIVE POINTS TABLES

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation
Period of: January, 2002- December, 2002

Anclote 1

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$4,426,000	95.57	10	$2,249,192	9832.5
9	$3,983,400	95.18	9	$2,024,273	9860.1
8	$3,540,800	94.80	8	$1,799,354	9887.7
7	$3,098,200	94.41	7	$1,574,435	9915.2
6	$2,655,600	94.03	6	$1,349,515	9942.8
5	$2,213,000	93.64	5	$1,124,596	9970.3
4	$1,770,400	93.25	4	$899,677	9997.9
3	$1,327,800	92.87	3	$674,758	10025.4
2	$885,200	92.48	2	$449,838	10053.0
1	$442,600	92.10	1	$224,919	10080.6
					10108.1
0	$0	91.71	0	$0	10183.1
					10258.1
-1	($326,900)	90.95	-1	($224,919)	10285.7
-2	($653,800)	90.18	-2	($449,838)	10313.2
-3	($980,700)	89.41	-3	($674,758)	10340.8
-4	($1,307,600)	88.65	-4	($899,677)	10368.4
-5	($1,634,500)	87.88	-5	($1,124,596)	10395.9
-6	($1,961,400)	87.12	-6	($1,349,515)	10423.5
-7	($2,288,300)	86.35	-7	($1,574,435)	10451.0
-8	($2,615,200)	85.58	-8	($1,799,354)	10478.6
-9	($2,942,100)	84.82	-9	($2,024,273)	10506.2
-10	($3,269,000)	84.05	-10	($2,249,192)	10533.7

Equivalent Availability *Weighting Factor:*	Heat Rate *Weighting Factor:*
8.78%	4.46%

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Suspended:
Effective:
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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation
Period of: January, 2002- December, 2002

Unit: Anclote 2

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$1,579,000	84.11	10	$1,969,775	9783.1
9	$1,421,100	83.87	9	$1,772,797	9806.3
8	$1,263,200	83.62	8	$1,575,820	9829.4
7	$1,105,300	83.38	7	$1,378,842	9852.6
6	$947,400	83.14	6	$1,181,865	9875.8
5	$789,500	82.90	5	$984,887	9898.9
4	$631,600	82.65	4	$787,910	9922.1
3	$473,700	82.41	3	$590,932	9945.3
2	$315,800	82.17	2	$393,955	9968.5
1	$157,900	81.92	1	$196,977	9991.6
					10014.8
0	$0	81.68	0	$0	10089.8
					10164.8
-1	($267,200)	81.18	-1	($196,977)	10188.0
-2	($534,400)	80.69	-2	($393,955)	10211.1
-3	($801,600)	80.19	-3	($590,932)	10234.3
-4	($1,068,800)	79.69	-4	($787,910)	10257.5
-5	($1,336,000)	79.20	-5	($984,887)	10280.6
-6	($1,603,200)	78.70	-6	($1,181,865)	10303.8
-7	($1,870,400)	78.21	-7	($1,378,842)	10327.0
-8	($2,137,600)	77.71	-8	($1,575,820)	10350.1
-9	($2,404,800)	77.21	-9	($1,772,797)	10373.3
-10	($2,672,000)	76.72	-10	($1,969,775)	10396.5

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.13%	3.91%

Issued by: FPC

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation
Period of: January, 2002- December, 2002

Unit: Bartow 3

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$1,344,000	84.02	10	$701,404	9831.5
9	$1,209,600	83.63	9	$631,263	9846.2
8	$1,075,200	83.24	8	$561,123	9860.9
7	$940,800	82.85	7	$490,983	9875.5
6	$806,400	82.46	6	$420,842	9890.2
5	$672,000	82.07	5	$350,702	9904.9
4	$537,600	81.68	4	$280,561	9919.6
3	$403,200	81.29	3	$210,421	9934.2
2	$268,800	80.90	2	$140,281	9948.9
1	$134,400	80.51	1	$70,140	9963.6
					9978.3
0	$0	80.12	0	$0	10053.3
					10128.3
-1	($75,000)	79.35	-1	($70,140)	10142.9
-2	($150,000)	78.58	-2	($140,281)	10157.6
-3	($225,000)	77.81	-3	($210,421)	10172.3
-4	($300,000)	77.04	-4	($280,561)	10187.0
-5	($375,000)	76.27	-5	($350,702)	10201.6
-6	($450,000)	75.49	-6	($420,842)	10216.3
-7	($525,000)	74.72	-7	($490,983)	10231.0
-8	($600,000)	73.95	-8	($561,123)	10245.7
-9	($675,000)	73.18	-9	($631,263)	10260.3
-10	($750,000)	72.41	-10	($701,404)	10275.0

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
2.67%	1.39%

Issued by: FPC

Filed:
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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation
Period of: January, 2002- December, 2002

Unit: Crystal River 1

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$1,770,000	92.87	10	$1,365,059	9528.7
9	$1,593,000	92.26	9	$1,228,553	9543.3
8	$1,416,000	91.65	8	$1,092,047	9558.0
7	$1,239,000	91.04	7	$955,541	9572.6
6	$1,062,000	90.43	6	$819,035	9587.3
5	$885,000	89.81	5	$682,530	9602.0
4	$708,000	89.20	4	$546,024	9616.6
3	$531,000	88.59	3	$409,518	9631.3
2	$354,000	87.98	2	$273,012	9645.9
1	$177,000	87.37	1	$136,506	9660.6
					9675.2
0	$0	86.75	0	$0	9750.2
					9825.2
-1	($706,600)	85.56	-1	($136,506)	9839.9
-2	($1,413,200)	84.37	-2	($273,012)	9854.6
-3	($2,119,800)	83.17	-3	($409,518)	9869.2
-4	($2,826,400)	81.98	-4	($546,024)	9883.9
-5	($3,533,000)	80.78	-5	($682,530)	9898.5
-6	($4,239,600)	79.59	-6	($819,035)	9913.2
-7	($4,946,200)	78.40	-7	($955,541)	9927.8
-8	($5,652,800)	77.20	-8	($1,092,047)	9942.5
-9	($6,359,400)	76.01	-9	($1,228,553)	9957.2
-10	($7,066,000)	74.82	-10	($1,365,059)	9971.8

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.51%	2.71%

Issued by: FPC

Filed:
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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation
Period of: January, 2002- December, 2002

Unit: Crystal River 2

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$6,745,000	71.66	10	$1,771,167	9323.1
9	$6,070,500	71.00	9	$1,594,051	9345.2
8	$5,396,000	70.35	8	$1,416,934	9367.3
7	$4,721,500	69.70	7	$1,239,817	9389.4
6	$4,047,000	69.05	6	$1,062,700	9411.5
5	$3,372,500	68.40	5	$885,584	9433.6
4	$2,698,000	67.74	4	$708,467	9455.7
3	$2,023,500	67.09	3	$531,350	9477.8
2	$1,349,000	66.44	2	$354,233	9499.9
1	$674,500	65.79	1	$177,117	9522.0
					9544.1
0	$0	65.14	0	$0	9619.1
					9694.1
-1	($883,400)	63.91	-1	($177,117)	9716.2
-2	($1,766,800)	62.69	-2	($354,233)	9738.3
-3	($2,650,200)	61.46	-3	($531,350)	9760.4
-4	($3,533,600)	60.23	-4	($708,467)	9782.5
-5	($4,417,000)	59.01	-5	($885,584)	9804.6
-6	($5,300,400)	57.78	-6	($1,062,700)	9826.7
-7	($6,183,800)	56.56	-7	($1,239,817)	9848.8
-8	($7,067,200)	55.33	-8	($1,416,934)	9870.9
-9	($7,950,600)	54.11	-9	($1,594,051)	9893.0
-10	($8,834,000)	52.88	-10	($1,771,167)	9915.1

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
13.39%	3.51%

Issued by: FPC

Filed:
Suspended:
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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation
Period of: January, 2002- December, 2002

Unit: Crystal River 3

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$3,938,000	98.00	10	$5,485,663	10095.9
9	$3,544,200	97.82	9	$4,937,097	10107.1
8	$3,150,400	97.64	8	$4,388,531	10118.3
7	$2,756,600	97.46	7	$3,839,964	10129.5
6	$2,362,800	97.28	6	$3,291,398	10140.8
5	$1,969,000	97.10	5	$2,742,832	10152.0
4	$1,575,200	96.92	4	$2,194,265	10163.2
3	$1,181,400	96.74	3	$1,645,699	10174.4
2	$787,600	96.56	2	$1,097,133	10185.6
1	$393,800	96.39	1	$548,566	10196.8
					10208.1
0	$0	96.21	0	$0	10283.1
					10358.1
-1	($671,800)	95.84	-1	($548,566)	10369.3
-2	($1,343,600)	95.47	-2	($1,097,133)	10380.5
-3	($2,015,400)	95.10	-3	($1,645,699)	10391.7
-4	($2,687,200)	94.73	-4	($2,194,265)	10402.9
-5	($3,359,000)	94.36	-5	($2,742,832)	10414.1
-6	($4,030,800)	93.99	-6	($3,291,398)	10425.4
-7	($4,702,600)	93.62	-7	($3,839,964)	10436.6
-8	($5,374,400)	93.25	-8	($4,388,531)	10447.8
-9	($6,046,200)	92.88	-9	($4,937,097)	10459.0
-10	($6,718,000)	92.51	-10	($5,485,663)	10470.2

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
7.81%	10.89%

Issued by: FPC

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation
Period of: January, 2002- December, 2002

Unit: Crystal River 4

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$2,615,000	78.14	10	$2,703,503	9186.9
9	$2,353,500	77.97	9	$2,433,153	9202.0
8	$2,092,000	77.81	8	$2,162,802	9217.1
7	$1,830,500	77.64	7	$1,892,452	9232.2
6	$1,569,000	77.48	6	$1,622,102	9247.3
5	$1,307,500	77.31	5	$1,351,751	9262.4
4	$1,046,000	77.15	4	$1,081,401	9277.5
3	$784,500	76.98	3	$811,051	9292.7
2	$523,000	76.82	2	$540,701	9307.8
1	$261,500	76.65	1	$270,350	9322.9
					9338.0
0	$0	76.48	0	$0	9413.0
					9488.0
-1	($474,000)	76.15	-1	($270,350)	9503.1
-2	($948,000)	75.81	-2	($540,701)	9518.2
-3	($1,422,000)	75.47	-3	($811,051)	9533.3
-4	($1,896,000)	75.13	-4	($1,081,401)	9548.5
-5	($2,370,000)	74.79	-5	($1,351,751)	9563.6
-6	($2,844,000)	74.45	-6	($1,622,102)	9578.7
-7	($3,318,000)	74.11	-7	($1,892,452)	9593.8
-8	($3,792,000)	73.77	-8	($2,162,802)	9608.9
-9	($4,266,000)	73.44	-9	($2,433,153)	9624.0
-10	($4,740,000)	73.10	-10	($2,703,503)	9639.1

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
5.19%	5.36%

Issued by: FPC

Filed:
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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation
Period of: January, 2002- December, 2002

Unit: Crystal River 5

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$2,833,000	97.09	10	$3,668,376	9137.1
9	$2,549,700	96.83	9	$3,301,539	9153.5
8	$2,266,400	96.58	8	$2,934,701	9169.9
7	$1,983,100	96.32	7	$2,567,864	9186.2
6	$1,699,800	96.06	6	$2,201,026	9202.6
5	$1,416,500	95.81	5	$1,834,188	9218.9
4	$1,133,200	95.55	4	$1,467,351	9235.3
3	$849,900	95.29	3	$1,100,513	9251.6
2	$566,600	95.04	2	$733,675	9268.0
1	$283,300	94.78	1	$366,838	9284.3
					9300.7
0	$0	94.52	0	$0	9375.7
					9450.7
-1	($676,000)	94.00	-1	($366,838)	9467.0
-2	($1,352,000)	93.48	-2	($733,675)	9483.4
-3	($2,028,000)	92.95	-3	($1,100,513)	9499.7
-4	($2,704,000)	92.43	-4	($1,467,351)	9516.1
-5	($3,380,000)	91.91	-5	($1,834,188)	9532.5
-6	($4,056,000)	91.39	-6	($2,201,026)	9548.8
-7	($4,732,000)	90.86	-7	($2,567,864)	9565.2
-8	($5,408,000)	90.34	-8	($2,934,701)	9581.5
-9	($6,084,000)	89.82	-9	($3,301,539)	9597.9
-10	($6,760,000)	89.30	-10	($3,668,376)	9614.2

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
5.62%	7.28%

Issued by: FPC

Filed:
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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation
Period of: January, 2002- December, 2002

Unit: Tiger Bay

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$3,404,000	83.22	10	$1,823,386	7782.5
9	$3,063,600	82.93	9	$1,641,047	7823.4
8	$2,723,200	82.64	8	$1,458,708	7864.3
7	$2,382,800	82.35	7	$1,276,370	7905.3
6	$2,042,400	82.06	6	$1,094,031	7946.2
5	$1,702,000	81.76	5	$911,693	7987.1
4	$1,361,600	81.47	4	$729,354	8028.1
3	$1,021,200	81.18	3	$547,016	8069.0
2	$680,800	80.89	2	$364,677	8109.9
1	$340,400	80.60	1	$182,339	8150.9
					8191.8
0	$0	80.31	0	$0	8266.8
					8341.8
-1	($97,400)	79.72	-1	($182,339)	8382.7
-2	($194,800)	79.14	-2	($364,677)	8423.7
-3	($292,200)	78.56	-3	($547,016)	8464.6
-4	($389,600)	77.98	-4	($729,354)	8505.5
-5	($487,000)	77.40	-5	($911,693)	8546.5
-6	($584,400)	76.82	-6	($1,094,031)	8587.4
-7	($681,800)	76.24	-7	($1,276,370)	8628.3
-8	($779,200)	75.66	-8	($1,458,708)	8669.3
-9	($876,600)	75.08	-9	($1,641,047)	8710.2
-10	($974,000)	74.49	-10	($1,823,386)	8751.1

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
6.76%	3.62%

Issued by: FPC

Filed:
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UNIT PERFORMANCE DATA

ESTIMATED UNIT PERFORMANCE DATA
Florida Power Corporation

Period of: January, 2002- December, 2002

PLANT/UNIT Anclote 1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	93.88	95.99	91.03	91.08	91.02	91.07	91.02	91.02	91.02	91.20	91.02	91.53	91.71
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. EUOF	6.12	4.01	8.97	8.92	8.98	8.93	8.98	8.98	8.98	8.80	8.98	8.47	8.29
4. EUOR	8.98	8.98	8.98	8.98	8.98	8.98	8.98	8.98	8.98	8.98	8.98	8.98	8.98
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	476.1	281.7	697.7	671.4	698.6	672.3	698.6	698.6	676.1	684.5	676.1	659.2	7590.6
7. RSH	237.0	372.0	1.0	5.0	0.0	4.0	0.0	0.0	0.0	15.0	0.0	42.0	676.0
8. UH	30.9	18.3	45.3	43.6	45.4	43.7	45.4	45.4	43.9	44.5	43.9	42.8	493.4
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. FOH & PFOH	14.4	8.5	21.1	20.3	21.1	20.3	21.1	21.1	20.4	20.7	20.4	19.9	229.2
11. MOH & PMOH	31.2	18.4	45.7	43.9	45.7	44.0	45.7	45.7	44.2	44.8	44.2	43.1	496.8
12. Oper. Btu(MBtu)	692132	631982	1454191	1481296	1759849	1635600	2183471	2283856	2155452	1343142	1470487	1644278	18805799
13. Net Gen. (MWH)	65859.9	61599.0	141033.9	144212.4	173053.6	160387.2	219124.6	230353.1	216785.5	129772.4	143019.2	161559.9	1846760.7
14. ANOHR (Btu/KWH)	10509	10260	10311	10272	10169	10198	9965	9915	9943	10350	10282	10178	10183
15. NOF (%)	27.8	43.9	40.6	43.1	49.7	47.9	63.0	66.2	64.4	38.1	42.5	49.2	48.9
16. NSC (MW)	498	498	498	498	498	498	498	498	498	498	498	498	498
17. ANOHR Equation	ANOHR=	-15.471 x NOF +		10938.9									

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ESTIMATED UNIT PERFORMANCE DATA
Florida Power Corporation

Period of: January, 2002- December, 2002

PLANT/UNIT **Anclote 2**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	94.40	95.50	93.85	93.85	93.85	93.86	93.85	93.85	93.85	54.49	0.00	78.71	81.68
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41.94	100.00	16.13	13.15
3. EUOF	5.60	4.50	6.15	6.15	6.15	6.14	6.15	6.15	6.15	3.57	0.00	5.16	5.17
4. EUOR	6.15	6.15	6.15	6.15	6.15	6.15	6.15	6.15	6.15	6.15	0.00	6.15	6.15
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	650.8	472.0	715.3	692.2	715.3	691.2	715.3	715.3	692.2	415.3	0.0	599.9	7074.7
7. RSH	67.0	181.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	249.0
8. UH	26.2	19.0	28.7	27.8	28.7	27.8	28.7	28.7	27.8	328.7	720.0	144.1	1436.3
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	312.0	720.0	120.0	1152.0
10. FOH & PFOH	7.9	5.8	8.7	8.4	8.7	8.4	8.7	8.7	8.4	5.1	0.0	7.3	86.2
11. MOH & PMOH	33.7	24.5	37.1	35.9	37.1	35.8	37.1	37.1	35.9	21.5	0.0	31.1	366.6
12. Oper. Btu(MBtu)	812288	888684	1818280	1888856	1961615	1786690	2305441	2313668	2221538	1190501	0	1467895	18753512
13. Net Gen. (MWH)	76430.3	85517.9	179428.7	187796.7	195139.5	176611.3	234030.8	234983.6	225378.7	119034.6	0.0	144309.4	1858661.5
14. ANOHR (Btu/KWH)	10628	10392	10134	10058	10052	10117	9851	9846	9857	10001	0	10172	10090
15. NOF (%)	23.7	36.6	50.7	54.8	55.1	51.6	66.1	66.4	65.8	57.9	0.0	48.6	53.1
16. NSC (MW)	495	495	495	495	495	495	495	495	495	495	495	495	495
17. ANOHR Equation	ANOHR=	-18.331 x NOF +		11062.7									

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ESTIMATED UNIT PERFORMANCE DATA
Florida Power Corporation

Period of: January, 2002- December, 2002

PLANT/UNIT **Bartow 3**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	90.50	90.41	2.94	54.85	90.41	90.41	90.41	90.41	90.41	90.41	90.41	91.11	80.12
2. POF	0.00	0.00	96.77	40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.51
3. EUOF	9.50	9.59	0.28	5.15	9.59	9.59	9.59	9.59	9.59	9.59	9.59	8.89	8.37
4. EUOR	9.59	9.59	9.59	9.59	9.59	9.59	9.59	9.59	9.59	9.59	9.59	9.59	9.59
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	688.4	627.7	20.5	361.5	695.0	672.5	695.0	695.0	672.5	695.0	672.5	644.5	7140.1
7. RSH	7.0	0.0	2.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.0	108.0
8. UH	48.6	44.3	721.5	313.5	49.0	47.5	49.0	49.0	47.5	49.0	47.5	45.5	1511.9
9. POH	0.0	0.0	720.0	288.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1008.0
10. FOH & PFOH	40.3	36.7	1.2	21.1	40.6	39.3	40.6	40.6	39.3	40.6	39.3	37.7	417.6
11. MOH & PMOH	30.4	27.7	0.9	16.0	30.7	29.7	30.7	30.7	29.7	30.7	29.7	28.5	315.5
12. Oper. Btu(MBtu)	618481	800249	25217	599020	1094421	1106244	1138174	870400	952667	1167478	1057761	1046747	10502829
13. Net Gen. (MWH)	59482.8	78656.1	2471.5	60290.1	109573.5	111253.6	114412.5	85436.8	94444.0	117677.6	105889.5	105129.7	1044717.7
14. ANOHR (Btu/KWH)	10398	10174	10203	9936	9988	9943	9948	10188	10087	9921	9989	9957	10053
15. NOF (%)	42.4	61.4	59.0	81.8	77.3	81.1	80.7	60.3	68.8	83.0	77.2	80.0	71.7
16. NSC (MW)	204	204	204	204	204	204	204	204	204	204	204	204	204
17. ANOHR Equation	ANOHR=	-11.726 x NOF +		10894.3									

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ESTIMATED UNIT PERFORMANCE DATA
Florida Power Corporation

Period of: January, 2002- December, 2002

PLANT/UNIT Crystal River 1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	86.84	86.75	86.75	86.75	86.75	86.75	86.75	86.75	86.75	86.75	86.75	86.75	86.75
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. EUOF	13.16	13.25	13.25	13.25	13.25	13.25	13.25	13.25	13.25	13.25	13.25	13.25	13.25
4. EUOR	13.25	13.25	13.25	13.25	13.25	13.25	13.25	13.25	13.25	13.25	13.25	13.25	13.25
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	665.8	605.4	670.3	648.7	670.3	648.7	670.3	670.3	648.7	670.3	648.7	670.3	7887.8
7. RSH	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0
8. UH	73.2	66.6	73.7	71.3	73.7	71.3	73.7	73.7	71.3	73.7	71.3	73.7	867.2
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. FOH & PFOH	29.9	27.2	30.1	29.2	30.1	29.2	30.1	30.1	29.2	30.1	29.2	30.1	354.5
11. MOH & PMOH	68.0	61.8	68.5	66.3	68.5	66.3	68.5	68.5	66.3	68.5	66.3	68.5	805.8
12. Oper. Btu(MBtu)	2178952	2383645	1997891	2497651	2102029	2177838	1987330	2663200	2491433	2104179	2139423	2520759	27265758
13. Net Gen. (MWH)	222712.2	246710.7	203113.1	258080.1	214308.5	222948.5	201981.5	275836.7	257390.3	214540.3	218775.0	260021.4	2796418.3
14. ANOHR (Btu/KWH)	9784	9662	9836	9678	9808	9768	9839	9655	9680	9808	9779	9694	9750
15. NOF (%)	88.3	107.5	80.0	105.0	84.4	90.7	79.5	108.6	104.7	84.4	89.0	102.4	93.5
16. NSC (MW)	379	379	379	379	379	379	379	379	379	379	379	379	379
17. ANOHR Equation	ANOHR=	-6.335 x NOF +		10342.9									

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ESTIMATED UNIT PERFORMANCE DATA
Florida Power Corporation

Period of: January, 2002- December, 2002

PLANT/UNIT **Crystal River 2**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	81.97	81.97	81.97	82.12	81.97	81.97	81.97	81.97	73.77	0.00	0.00	52.88	65.14
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.00	100.00	100.00	35.48	20.55
3. EUOF	18.03	18.03	18.03	17.88	18.03	18.03	18.03	18.03	16.23	0.00	0.00	11.63	14.32
4. EUOR	18.03	18.03	18.03	18.03	18.03	18.03	18.03	18.03	18.03	0.00	0.00	18.03	18.03
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	643.5	581.2	643.5	617.5	643.5	622.7	643.5	643.5	560.4	0.0	0.0	415.1	6014.3
7. RSH	0.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0
8. UH	100.5	90.8	100.5	96.5	100.5	97.3	100.5	100.5	159.6	744.0	720.0	328.9	2739.7
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	72.0	744.0	720.0	264.0	1800.0
10. FOH & PFOH	42.3	38.2	42.3	40.6	42.3	41.0	42.3	42.3	36.9	0.0	0.0	27.3	395.8
11. MOH & PMOH	91.8	82.9	91.8	88.1	91.8	88.9	91.8	91.8	80.0	0.0	0.0	59.2	858.2
12. Oper. Btu(MBtu)	3396179	2967615	3175104	2038594	3121066	2338109	2394465	3324293	1095143	0	0	2134993	26149597
13. Net Gen. (MWH)	361586.7	314524.0	335011.6	206737.0	328597.4	239617.2	245199.0	352885.5	107849.9	0.0	0.0	226497.2	2718505.5
14. ANOHR (Btu/KWH)	9392	9435	9478	9861	9498	9758	9765	9420	10154	0	0	9426	9619
15. NOF (%)	115.6	111.4	107.1	68.9	105.1	79.2	78.4	112.8	39.6	0.0	0.0	112.3	93.0
16. NSC (MW)	486	486	486	486	486	486	486	486	486	486	486	486	486
17. ANOHR Equation	ANOHR=	-10.021 x NOF +		10551.1									

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ESTIMATED UNIT PERFORMANCE DATA
Florida Power Corporation

Period of: January, 2002- December, 2002

PLANT/UNIT **Crystal River 3**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	96.21	96.21	96.21	96.21	96.21	96.21	96.21	96.21	96.21	96.21	96.21	96.21	96.21
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. EUOF	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79
4. EUOR	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	724.0	654.0	724.0	700.7	724.0	700.7	724.0	724.0	700.7	724.0	700.7	724.0	8524.9
7. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8. UH	20.0	18.0	20.0	19.3	20.0	19.3	20.0	20.0	19.3	20.0	19.3	20.0	235.1
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. FOH & PFOH	7.2	6.5	7.2	7.0	7.2	7.0	7.2	7.2	7.0	7.2	7.0	7.2	85.3
11. MOH & PMOH	21.0	18.9	21.0	20.3	21.0	20.3	21.0	21.0	20.3	21.0	20.3	21.0	246.9
12. Oper. Btu(MBtu)	5964059	5386892	5964059	5771670	5844993	5161658	5844993	5844993	5656445	5386981	4989982	5964059	67795406
13. Net Gen. (MWH)	581808.0	525504.0	581808.0	563040.0	569160.0	498780.0	569160.0	569160.0	550800.0	520965.0	480930.0	581808.0	6592923.0
14. ANOHR (Btu/KWH)	10251	10251	10251	10251	10270	10349	10270	10270	10270	10340	10376	10251	10283
15. NOF (%)	105.0	105.0	105.0	105.0	102.8	93.1	102.8	102.8	102.8	94.1	89.7	105.0	101.1
16. NSC (MW)	765	765	765	765	765	765	765	765	765	765	765	765	765
17. ANOHR Equation	ANOHR=	-8.146 x NOF +		11106.6									

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Suspended:
Effective:
Docket No.:
Order No.:

ESTIMATED UNIT PERFORMANCE DATA
Florida Power Corporation

Period of: January, 2002- December, 2002

PLANT/UNIT Crystal River 4	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	95.60	95.60	3.08	0.00	55.51	95.60	95.60	95.60	95.60	95.60	95.60	95.62	76.48
2. POF	0.00	0.00	96.77	100.00	41.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.00
3. EUOF	4.40	4.40	0.14	0.00	2.55	4.40	4.40	4.40	4.40	4.40	4.40	4.38	3.52
4. EUOR	4.40	4.40	4.40	0.00	4.40	4.40	4.40	4.40	4.40	4.40	4.40	4.40	4.40
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	723.9	653.8	23.4	0.0	420.3	700.5	723.9	723.9	700.5	723.9	700.5	721.9	6816.5
7. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.0
8. UH	20.1	18.2	720.6	720.0	323.7	19.5	20.1	20.1	19.5	20.1	19.5	20.1	1941.5
9. POH	0.0	0.0	720.0	720.0	312.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1752.0
10. FOH & PFOH	21.3	19.2	0.7	0.0	12.4	20.6	21.3	21.3	20.6	21.3	20.6	21.3	200.7
11. MOH & PMOH	11.4	10.3	0.4	0.0	6.6	11.0	11.4	11.4	11.0	11.4	11.0	11.4	107.3
12. Oper. Btu(MBtu)	4099504	3710201	152398	0	2302270	4054664	4269326	4211561	4359589	4265191	4647055	3508286	39591744
13. Net Gen. (MWH)	434991.2	393720.0	16288.1	0.0	243914.7	430679.2	453895.3	447456.4	464756.8	453434.0	497124.4	369811.1	4206071.2
14. ANOHR (Btu/KWH)	9424	9423	9356	0	9439	9415	9406	9412	9380	9406	9348	9487	9413
15. NOF (%)	83.5	83.6	96.9	0.0	80.6	85.4	87.1	85.9	92.1	87.0	98.6	71.1	85.7
16. NSC (MW)	720	720	720	720	720	720	720	720	720	720	720	720	720
17. ANOHR Equation	ANOHR=	-5.064 x NOF +		9847.0									

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Docket No.:
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ESTIMATED UNIT PERFORMANCE DATA
Florida Power Corporation

Period of: January, 2002- December, 2002

PLANT/UNIT Crystal River 5	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	94.52	94.52	94.54	94.52	94.52	94.52	94.52	94.52	94.52	94.52	94.52	94.52	94.52
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. EUOF	5.48	5.48	5.46	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48
4. EUOR	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	710.8	642.0	708.9	687.9	710.8	687.9	710.8	710.8	687.9	710.8	687.9	710.8	8367.0
7. RSH	0.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0
8. UH	33.2	30.0	33.1	32.1	33.2	32.1	33.2	33.2	32.1	33.2	32.1	33.2	391.0
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. FOH & PFOH	14.7	13.3	14.7	14.2	14.7	14.2	14.7	14.7	14.2	14.7	14.2	14.7	173.0
11. MOH & PMOH	26.1	23.5	26.0	25.2	26.1	25.2	26.1	26.1	25.2	26.1	25.2	26.1	306.9
12. Oper. Btu(MBtu)	4291349	2812307	4597430	4444977	4251009	4306423	4511948	4621971	4257871	4586725	4195349	3821714	50721155
13. Net Gen. (MWH)	457622.3	296104.1	491997.1	475593.7	453119.0	460036.2	482323.3	494690.4	454596.8	490725.1	447601.7	405452.2	5409861.9
14. ANOHR (Btu/KWH)	9377	9498	9344	9346	9382	9361	9355	9343	9366	9347	9373	9426	9376
15. NOF (%)	89.8	64.3	96.8	96.4	88.9	93.3	94.6	97.1	92.2	96.3	90.8	79.6	90.2
16. NSC (MW)	717	717	717	717	717	717	717	717	717	717	717	717	717
17. ANOHR Equation	ANOHR=	-4.720 x NOF +		9801.3									

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Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ESTIMATED UNIT PERFORMANCE DATA
Florida Power Corporation

Period of: January, 2002- December, 2002

PLANT/UNIT **Tiger Bay**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	95.46	72.86	6.14	92.51	92.83	92.41	92.07	92.36	91.90	50.51	92.43	93.02	80.31
2. POF	0.00	21.43	93.55	0.00	0.00	0.00	0.00	0.00	0.00	45.16	0.00	0.00	13.42
3. EUOF	4.54	5.71	0.31	7.49	7.17	7.59	7.93	7.64	8.10	4.33	7.57	6.98	6.27
4. EUOR	8.64	8.64	8.64	8.64	8.64	8.64	8.64	8.64	8.64	8.64	8.64	8.64	8.64
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	357.5	406.0	24.7	570.6	564.2	577.9	624.6	601.7	617.2	341.1	577.0	549.6	5812.1
7. RSH	353.0	84.0	21.0	96.0	127.0	88.0	61.0	86.0	45.0	35.0	89.0	143.0	1228.0
8. UH	33.5	182.0	698.3	53.4	52.8	54.1	58.4	56.3	57.8	367.9	54.0	51.4	1719.9
9. POH	0.0	144.0	696.0	0.0	0.0	0.0	0.0	0.0	0.0	336.0	0.0	0.0	1176.0
10. FOH & PFOH	22.6	25.7	1.6	36.1	35.7	36.6	39.6	38.1	39.1	21.6	36.5	34.8	368.2
11. MOH & PMOH	11.1	12.7	0.8	17.8	17.6	18.0	19.5	18.7	19.2	10.6	18.0	17.1	181.1
12. Oper. Btu(MBtu)	426019	488799	30693	567125	739084	801565	868915	851580	832599	322761	596692	531751	7154594
13. Net Gen. (MWH)	50785.6	58532.7	3730.2	63473.0	92320.1	103799.5	112765.7	111922.0	105840.8	35647.7	67568.7	59074.6	865460.6
14. ANOHR (Btu/KWH)	8389	8351	8228	8935	8006	7722	7705	7609	7867	9054	8831	9001	8267
15. NOF (%)	68.6	69.6	73.0	53.7	79.0	86.8	87.2	89.9	82.8	50.5	56.6	51.9	71.9
16. NSC (MW)	207	207	207	207	207	207	207	207	207	207	207	207	207
17. ANOHR Equation	ANOHR=	-36.715 x NOF +		10907.9									

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PLANNED OUTAGE SCHEDULES

Company: Florida Power Corporation
Period of: January 2002 - December 2002

Plant/Unit	Planned Outage Dates	Reason for Outage
Anclote 2	10/19 (0001) - 12/06 (2400)	Boiler/Turb./Gen. major inspection
Bartow 3	03/02 (0001) - 04/12 (2400)	Boiler/Turb./Gen. major inspection
Crystal River 2	09/28 (0001) - 12/13 (2400)	Boiler/Turb./Gen. major inspection
Crystal River 4	03/02 (0001) - 05/13 (2400)	Condenser retube, Cooling Tower repairs
Tiger Bay	02/23 (0001) - 03/29 (2400)	Steam Turbine major outage
Tiger Bay	10/12 (0001) - 10/25 (2400)	Balance of Plant maintenance

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AVERAGE NET OPERATING HEAT RATE CURVES

FLORIDA POWER CORPORATION

ANCLOTE UNIT 1

ANOHR -15.471 * NOF + 10938.93

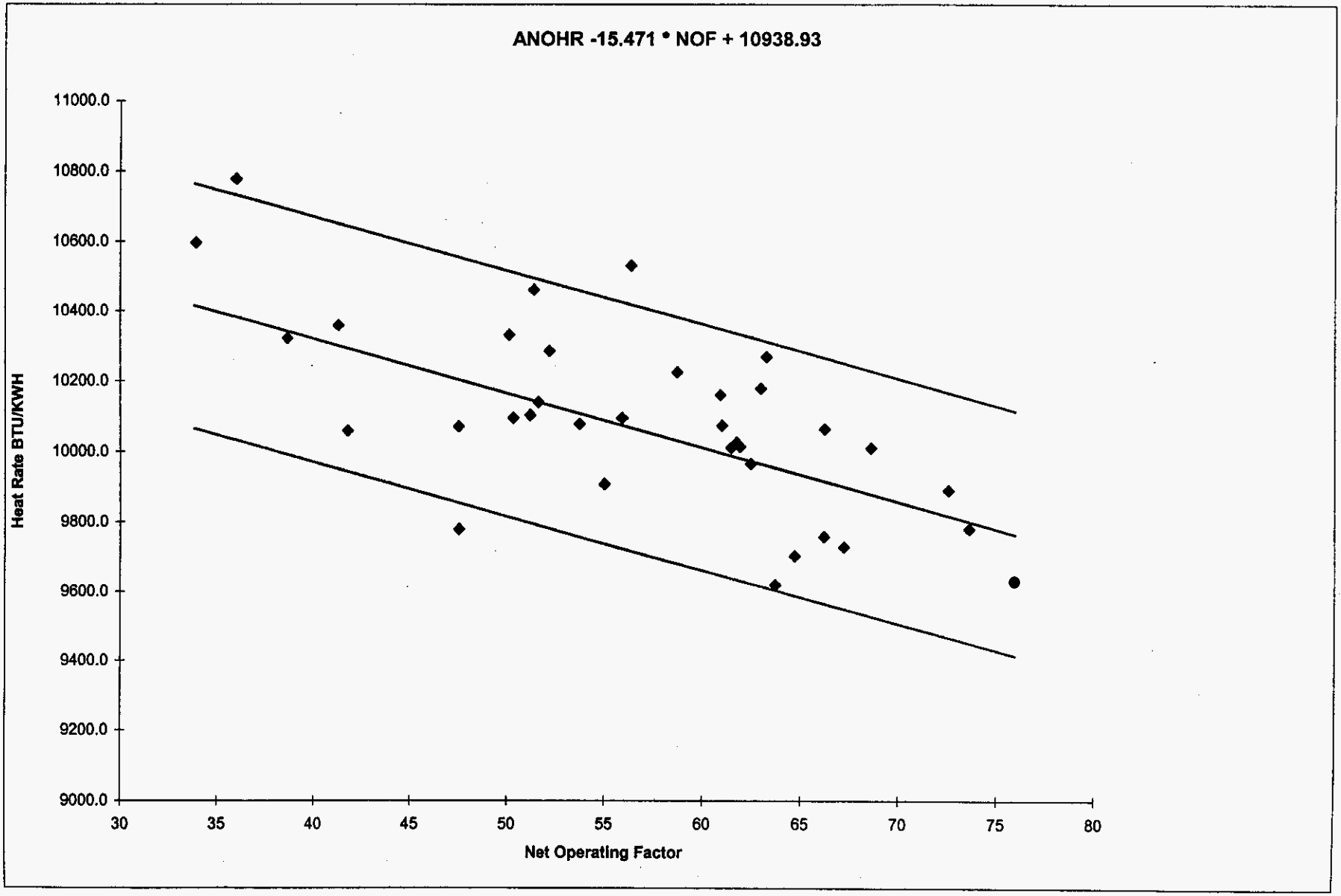
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-98	68.6	10010.8	9877.7	133.1	350.6
Aug-98	66.2	9758.6	9914.8	-156.2	350.6
Sep-98	58.7	10224.7	10030.8	193.9	350.6
Oct-98	51.2	10103.3	10146.8	-43.5	350.6
Nov-98	64.7	9703.2	9938.0	-234.8	350.6
Dec-98	75.9	9630.3	9764.7	-134.4	350.6
Jan-99	61.0	10074.0	9995.2	78.8	350.6
Feb-99	73.6	9780.5	9800.3	-19.8	350.6
Mar-99	63.7	9618.8	9953.5	-334.7	350.6
May-99	55.9	10094.9	10074.1	20.7	350.6
Jun-99	51.4	10461.3	10143.7	317.6	350.6
Jul-99	63.3	10268.0	9960.3	307.7	350.6
Aug-99	63.0	10179.0	9964.8	214.2	350.6
Sep-99	51.6	10140.0	10140.3	-0.3	350.6
Oct-99	62.5	9965.0	9972.5	-7.5	350.6
Nov-99	47.5	10071.0	10203.6	-132.6	350.6
Dec-99	33.9	10597.0	10414.0	183.0	350.6
Jan-00	41.3	10358.0	10300.0	58.0	350.6
Feb-00	38.6	10321.0	10341.3	-20.3	350.6
Mar-00	60.9	10161.0	9996.5	164.5	350.6
Apr-00	61.5	10011.0	9987.8	23.2	350.6
May-00	52.2	10285.0	10131.5	153.5	350.6
Jun-00	61.9	10014.0	9981.0	33.0	350.6
Jul-00	66.2	10064.0	9914.3	149.7	350.6
Aug-00	72.6	9889.0	9816.5	72.5	350.6
Sep-00	67.2	9729.0	9899.0	-170.0	350.6
Oct-00	50.1	10331.0	10163.6	167.4	350.6
Nov-00	50.3	10095.0	10160.3	-65.3	350.6
Dec-00	56.4	10531.0	10067.0	464.0	350.6
Jan-01	55.0	9907.0	10088.0	-181.0	350.6
Feb-01	41.8	10059.0	10292.4	-233.4	350.6
Mar-01	36.0	10779.0	10382.4	396.6	350.6
Apr-01	47.6	9779.0	10203.2	-424.2	350.6
May-01	61.8	10026.0	9983.5	42.5	350.6
Jun-01	53.7	10079.0	10107.6	-28.6	350.6

Regression Output:

Constant	10938.93
Std Err of Y Est	216.2372062
R Squared	0.369969544
No. of Observations	35
Degrees of Freedom	34
X Coefficient	-15.47054546
Std Err of Coef.	3.514361568

Anclote Unit 1



FLORIDA POWER CORPORATION

ANCLOTE UNIT 2

ANOHR -18.331 * NOF + 11062.71

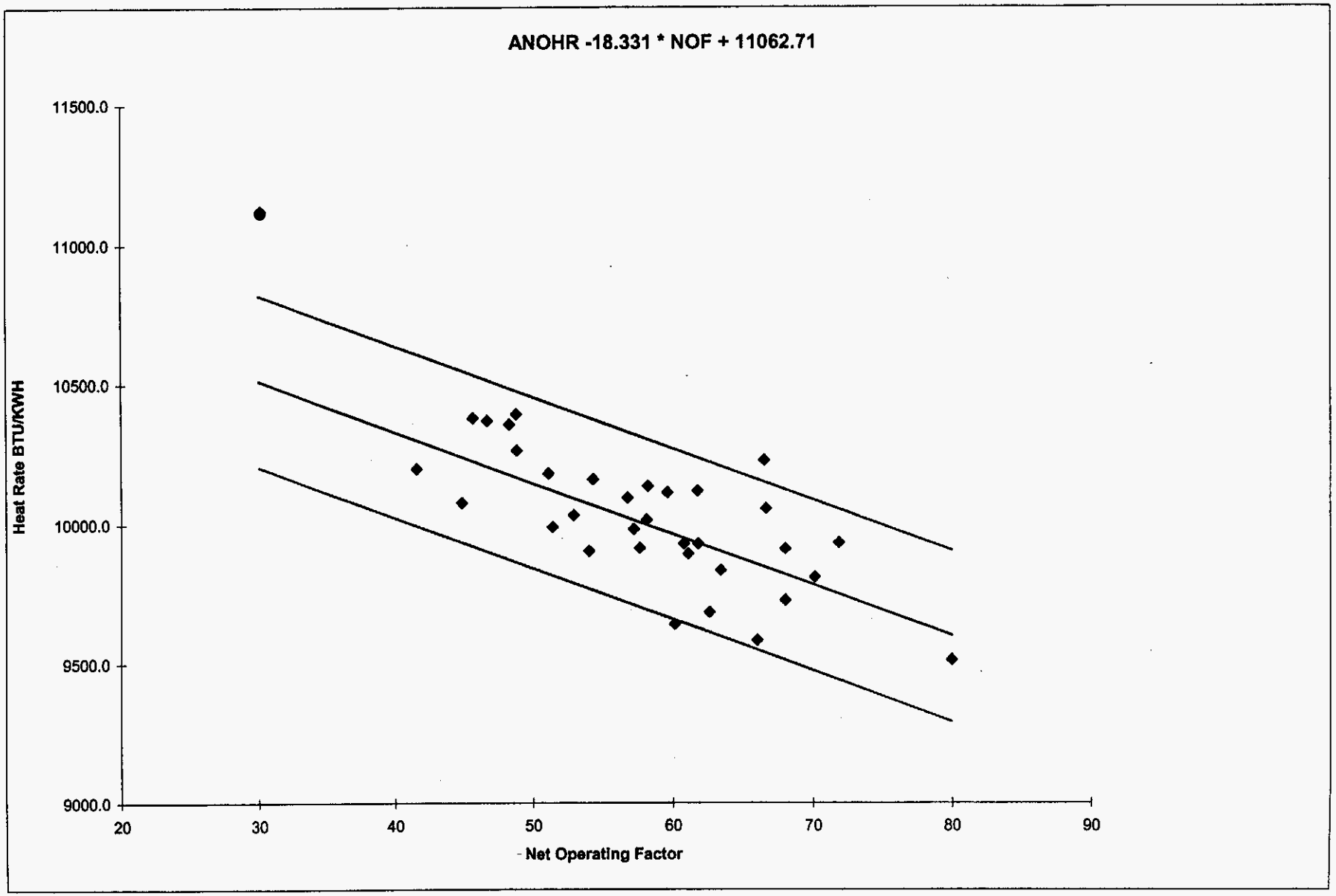
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-98	68.0	9909.5	9816.2	93.3	306.7
Aug-98	66.5	10227.9	9843.7	384.2	306.7
Sep-98	57.2	9982.5	10014.2	-31.7	306.7
Oct-98	60.8	9928.6	9948.9	-20.3	306.7
Dec-98	80.0	9510.5	9596.6	-86.1	306.7
Jan-99	62.6	9682.3	9915.2	-232.9	306.7
Feb-99	66.0	9580.4	9852.9	-272.5	306.7
Mar-99	63.4	9832.5	9900.5	-68.0	306.7
Apr-99	70.1	9807.5	9777.7	29.8	306.7
May-99	54.0	9902.6	10072.8	-170.2	306.7
Jun-99	46.7	10369.9	10206.7	163.2	306.7
Jul-99	59.6	10114.0	9970.0	144.0	306.7
Aug-99	61.8	10120.0	9930.6	189.4	306.7
Sep-99	51.4	9990.0	10120.3	-130.3	306.7
Oct-99	58.1	10015.0	9997.1	17.9	306.7
Nov-99	48.8	10264.0	10167.4	96.6	306.7
Dec-99	44.9	10078.0	10240.6	-162.6	306.7
Jan-00	41.6	10200.0	10300.5	-100.5	306.7
Feb-00	30.2	11123.0	10509.1	613.9	306.7
Mar-00	51.1	10183.0	10125.6	57.4	306.7
Apr-00	48.8	10393.0	10168.0	225.0	306.7
May-00	54.3	10162.0	10067.2	94.8	306.7
Jun-00	61.8	9928.0	9930.0	-2.0	306.7
Jul-00	61.1	9892.0	9942.7	-50.7	306.7
Aug-00	68.0	9724.0	9816.4	-92.4	306.7
Sep-00	60.1	9638.0	9960.7	-322.7	306.7
Oct-00	48.3	10357.0	10177.4	179.6	306.7
Dec-00	66.6	10055.0	9841.5	213.5	306.7
Jan-01	56.8	10095.0	10022.3	72.7	306.7
Feb-01	52.9	10032.0	10092.8	-60.8	306.7
Mar-01	45.7	10379.0	10225.4	153.6	306.7
Apr-01	57.6	9913.0	10006.2	-93.2	306.7
May-01	71.8	9932.0	9745.9	186.1	306.7
Jun-01	58.2	10136.0	9995.5	140.5	306.7

Regression Output:

Constant	11062.71
Std Err of Y Est	189.2422985
R Squared	0.486550824
No. of Observations	34
Degrees of Freedom	33
X Coefficient	-18.33094142
Std Err of Coef.	3.32885137

Anclote Unit 2



FLORIDA POWER CORPORATION

BARTOW UNIT 3

ANOHR -11.726 * NOF + 10894.30

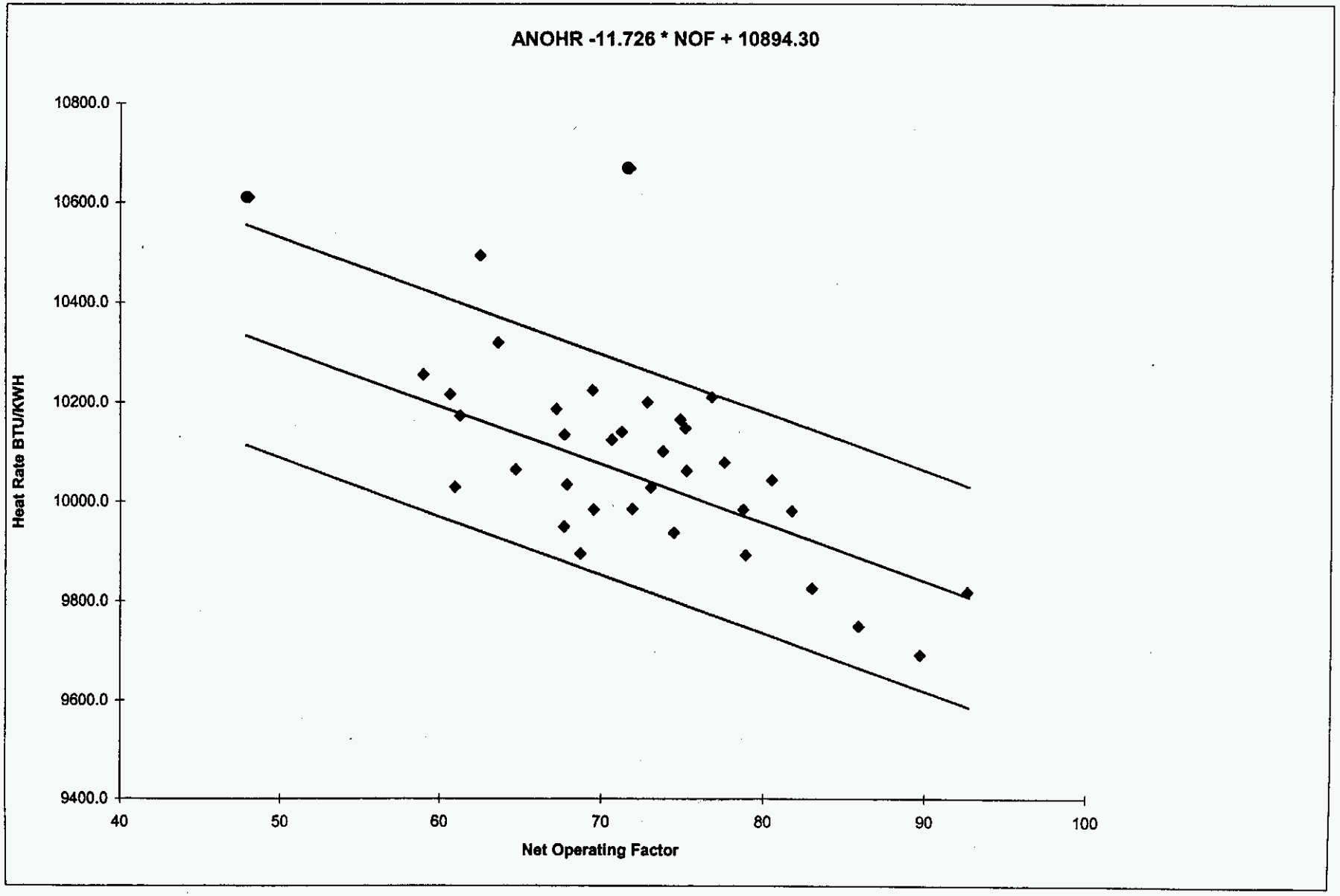
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-98	81.7	9981.0	9935.8	45.2	221.7
Aug-98	83.0	9825.0	9921.2	-96.2	221.7
Sep-98	78.9	9892.0	9969.4	-77.4	221.7
Oct-98	73.8	10099.0	10028.9	70.1	221.7
Nov-98	74.5	9937.0	10021.1	-84.1	221.7
Dec-98	89.7	9692.0	9842.6	-150.6	221.7
Jan-99	85.9	9749.0	9887.3	-138.3	221.7
Feb-99	92.6	9818.0	9808.2	9.8	221.7
Mar-99	78.7	9984.0	9971.2	12.8	221.7
Apr-99	80.5	10042.0	9950.5	91.5	221.7
May-99	69.5	10223.0	10079.8	143.2	221.7
Jun-99	70.7	10122.0	10065.9	56.1	221.7
Jul-99	74.9	10163.0	10016.3	146.7	221.7
Aug-99	77.6	10077.0	9984.4	92.6	221.7
Sep-99	69.5	9984.0	10079.1	-95.1	221.7
Oct-99	76.8	10209.0	9993.5	215.5	221.7
Nov-99	63.6	10319.0	10148.1	170.9	221.7
Dec-99	60.7	10215.0	10183.0	32.0	221.7
Jan-00	61.0	10028.0	10179.5	-151.5	221.7
Feb-00	48.0	10610.0	10331.2	278.8	221.7
Mar-00	71.7	10668.0	10053.1	614.9	221.7
Apr-00	62.5	10493.0	10161.1	331.9	221.7
May-00	67.7	9949.0	10100.7	-151.7	221.7
Jun-00	75.2	10146.0	10012.6	133.4	221.7
Jul-00	73.0	10027.0	10037.8	-10.8	221.7
Aug-00	75.3	10060.0	10011.8	48.2	221.7
Sep-00	67.7	10133.0	10100.2	32.8	221.7
Oct-00	59.0	10255.0	10202.5	52.5	221.7
Nov-00	68.7	9895.0	10088.6	-193.6	221.7
Dec-00	71.9	9985.0	10051.2	-66.2	221.7
Jan-01	67.9	10033.0	10098.5	-65.5	221.7
Feb-01	64.7	10063.0	10135.4	-72.4	221.7
Mar-01	61.3	10171.0	10175.8	-4.8	221.7
Apr-01	67.2	10185.0	10106.0	79.0	221.7
May-01	71.3	10138.0	10058.7	79.3	221.7
Jun-01	72.8	10199.0	10040.2	158.8	221.7

Regression Output:

Constant	10894.30
Std Err of Y Est	136.712798
R Squared	0.379825501
No. of Observations	36
Degrees of Freedom	35
X Coefficient	-11.72587458
Std Err of Coef.	2.5696305

Bartow Unit 3



FLORIDA POWER CORPORATION

CRYSTAL RIVER UNIT 1

ANOHR -6.335 * NOF + 10342.87

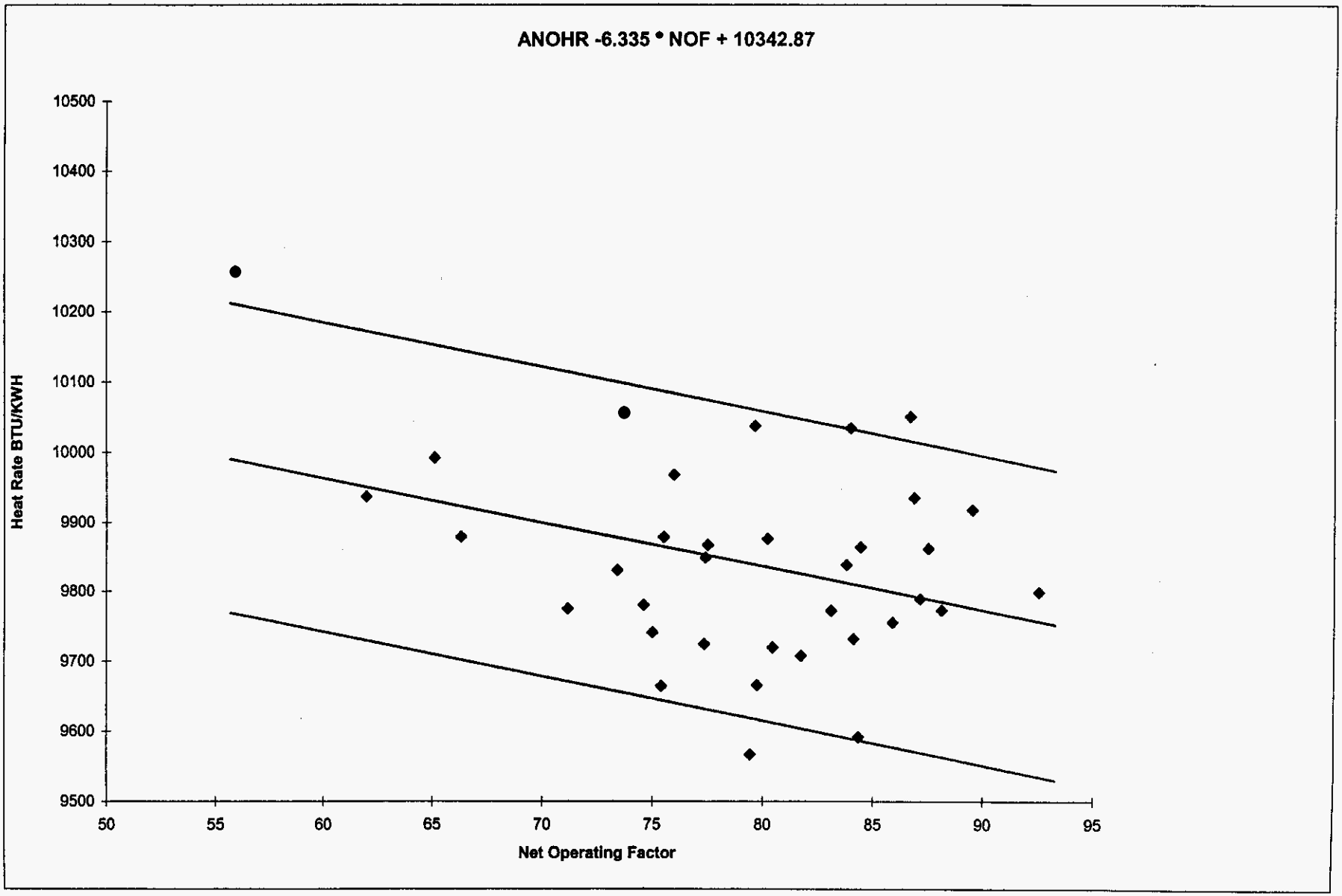
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-98	73.7	10056.0	9876.0	180.0	221.6
Aug-98	89.5	9918.0	9775.9	142.1	221.6
Sep-98	83.1	9772.1	9816.4	-44.3	221.6
Oct-98	88.1	9772.9	9784.7	-11.8	221.6
Nov-98	75.0	9740.3	9867.7	-127.4	221.6
Dec-98	73.4	9830.3	9877.9	-47.6	221.6
Jan-99	66.3	9879.2	9922.8	-43.6	221.6
Feb-99	55.9	10257.6	9988.7	268.9	221.6
Mar-99	77.4	9848.6	9852.5	-3.9	221.6
Apr-99	87.5	9861.8	9788.5	73.3	221.6
May-99	65.1	9992.0	9930.4	61.6	221.6
Jun-99	75.5	9878.7	9864.5	14.2	221.6
Jul-99	84.4	9864.0	9808.0	56.0	221.6
Aug-99	86.9	9935.0	9792.5	142.5	221.6
Sep-99	84.1	9731.0	9810.0	-79.0	221.6
Oct-99	92.5	9799.0	9756.7	42.3	221.6
Dec-99	62.0	9937.0	9950.2	-13.2	221.6
Jan-00	74.6	9780.0	9870.2	-90.2	221.6
Feb-00	71.2	9775.0	9892.1	-117.1	221.6
Mar-00	80.4	9719.0	9833.2	-114.2	221.6
Apr-00	85.9	9755.0	9798.7	-43.7	221.6
May-00	83.8	9838.0	9812.0	26.0	221.6
Jun-00	79.7	10037.0	9838.3	198.7	221.6
Jul-00	84.0	10034.0	9810.8	223.2	221.6
Aug-00	86.7	10050.0	9793.7	256.3	221.6
Sep-00	80.2	9876.0	9834.7	41.3	221.6
Oct-00	77.3	9724.0	9852.9	-128.9	221.6
Nov-00	79.7	9665.0	9837.7	-172.7	221.6
Dec-00	81.7	9707.0	9825.0	-118.0	221.6
Jan-01	79.4	9567.0	9839.6	-272.6	221.6
Feb-01	75.4	9664.0	9865.2	-201.2	221.6
Mar-01	77.5	9867.0	9851.8	15.2	221.6
Apr-01	84.3	9592.0	9808.6	-216.6	221.6
May-01	87.1	9789.0	9790.8	-1.8	221.6
Jun-01	76.0	9968.0	9861.5	106.5	221.6

Regression Output:

Constant	10342.87
Std Err of Y Est	136.6586001
R Squared	0.12629535
No. of Observations	35
Degrees of Freedom	34
X Coefficient	-6.335437343
Std Err of Coef.	2.900736455

Crystal River Unit 1



FLORIDA POWER CORPORATION

CRYSTAL RIVER UNIT 2

ANOHR -10.021 * NOF + 10551.12

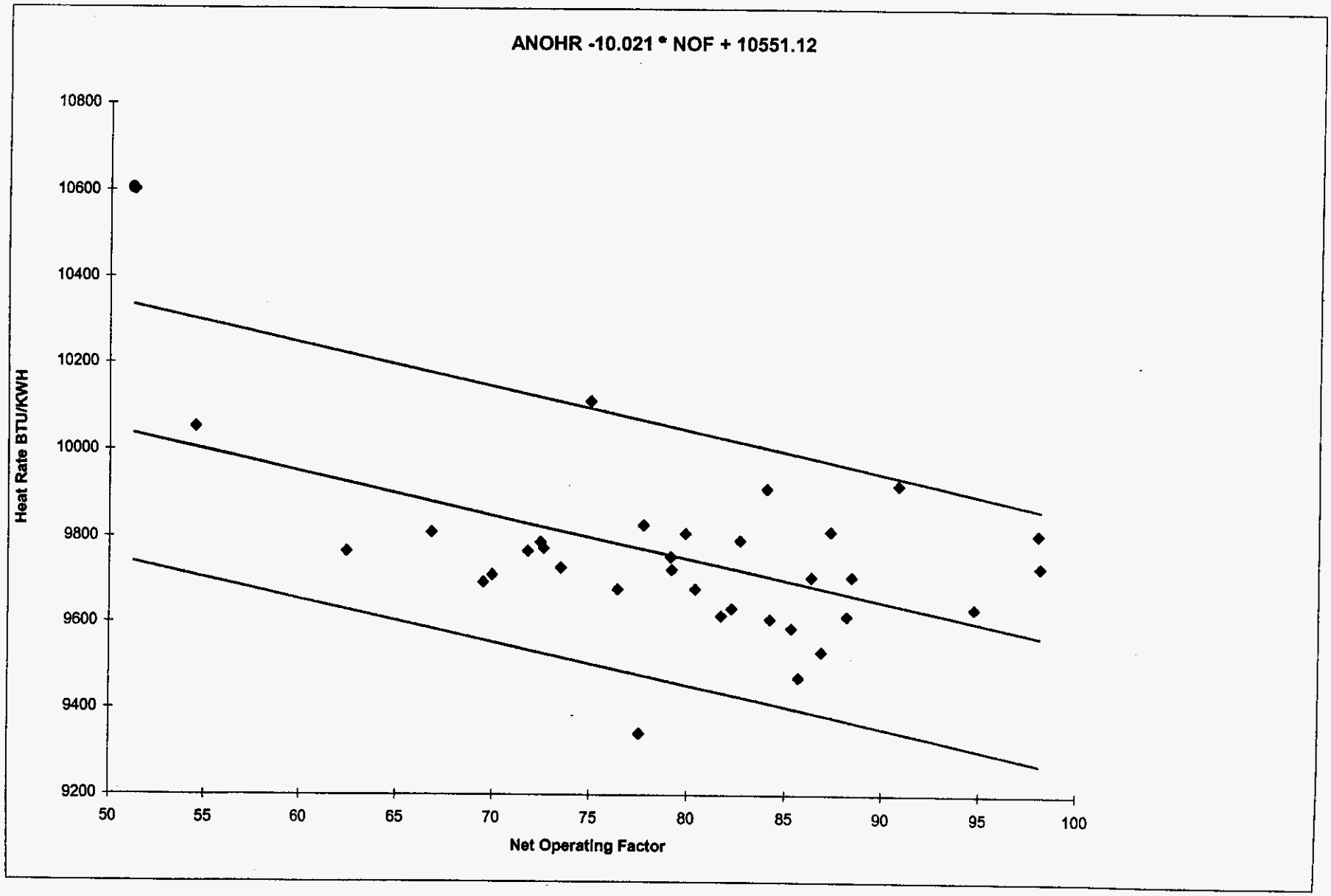
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-98	98.1	9732.3	9568.1	164.2	296.0
Aug-98	98.0	9809.2	9569.1	240.1	296.0
Sep-98	88.4	9708.8	9665.3	43.5	296.0
Oct-98	71.8	9767.8	9831.6	-63.8	296.0
Nov-98	73.5	9729.1	9814.6	-85.5	296.0
Dec-98	66.8	9812.3	9881.7	-69.4	296.0
Jan-99	62.4	9767.0	9925.8	-158.8	296.0
Feb-99	54.5	10053.1	10005.0	48.1	296.0
Mar-99	76.4	9678.6	9785.5	-106.9	296.0
Apr-99	94.7	9635.0	9602.1	32.9	296.0
May-99	90.8	9920.5	9641.2	279.3	296.0
Jun-99	87.3	9815.0	9676.3	138.7	296.0
Jul-99	82.6	9794.0	9723.2	70.8	296.0
Aug-99	84.0	9912.0	9709.5	202.5	296.0
Sep-99	79.1	9755.0	9758.6	-3.6	296.0
Oct-99	84.2	9609.0	9707.5	-98.5	296.0
Nov-99	77.5	9342.0	9774.1	-432.1	296.0
Dec-99	72.5	9789.0	9825.0	-36.0	296.0
Jan-00	70.0	9712.0	9850.1	-138.1	296.0
Feb-00	69.5	9695.0	9854.7	-159.7	296.0
Mar-00	80.4	9680.0	9745.9	-65.9	296.0
Apr-00	79.2	9725.0	9757.9	-32.9	296.0
May-00	79.9	9810.0	9750.9	59.1	296.0
Jun-00	75.0	10112.0	9799.5	312.5	296.0
Sep-00	72.6	9775.0	9823.5	-48.5	296.0
Oct-00	82.2	9634.0	9727.3	-93.3	296.0
Nov-00	85.3	9588.0	9696.4	-108.4	296.0
Dec-00	88.2	9616.0	9667.6	-51.6	296.0
Jan-01	85.7	9473.0	9692.6	-219.6	296.0
Feb-01	81.7	9617.0	9732.6	-115.6	296.0
Mar-01	51.3	10603.0	10037.3	565.7	296.0
Apr-01	86.9	9533.0	9680.8	-147.8	296.0
May-01	86.3	9708.0	9686.2	21.8	296.0
Jun-01	77.7	9829.0	9772.3	56.7	296.0

Regression Output:

Constant	10551.12
Std Err of Y Est	182.6466088
R Squared	0.262944474
No. of Observations	34
Degrees of Freedom	33
X Coefficient	-10.0209748
Std Err of Coef.	2.965876485

Crystal River Unit 2



FLORIDA POWER CORPORATION

CRYSTAL RIVER UNIT 3

ANOHR -8.146 * NOF + 11106.59

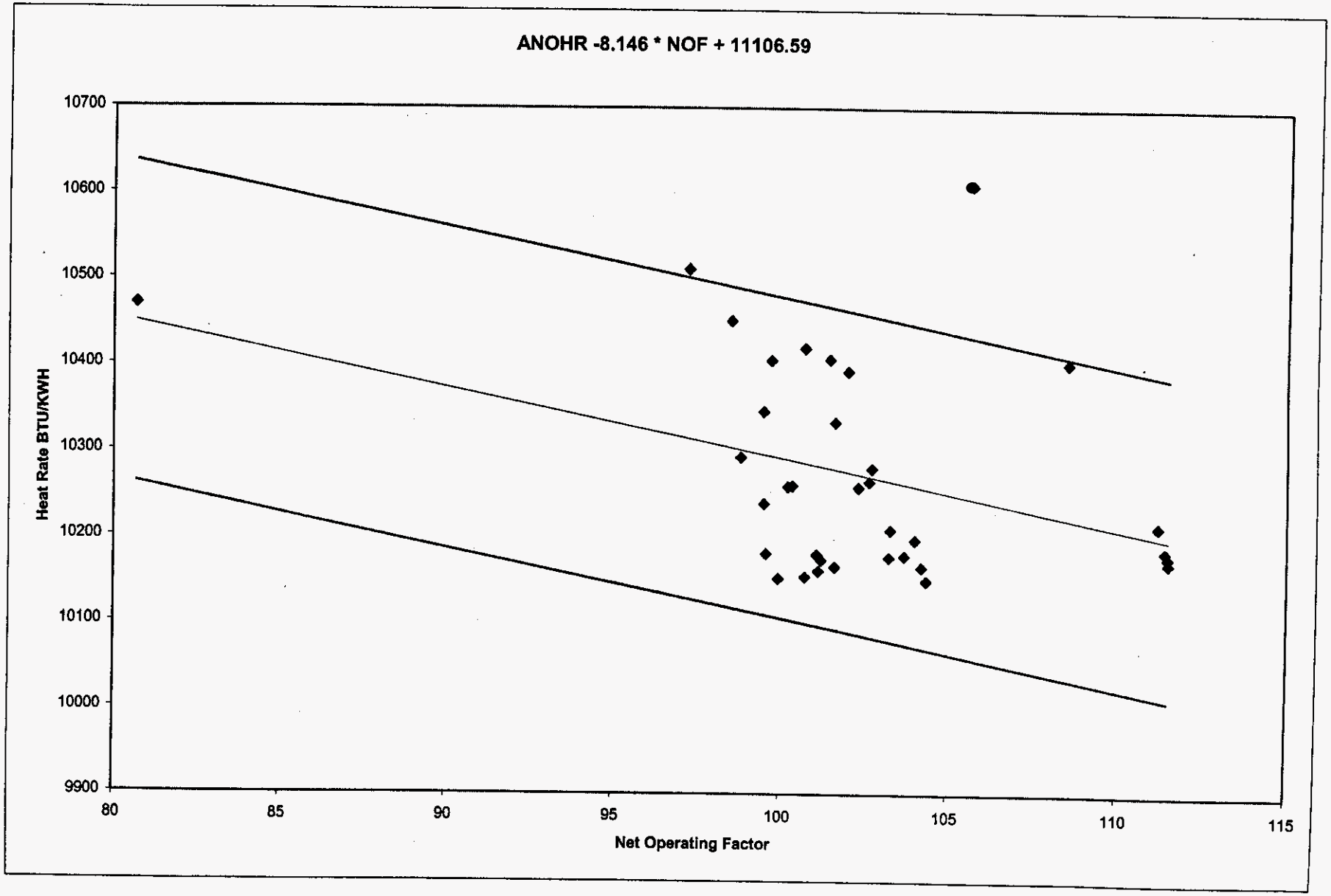
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-98	99.7	10405.5	10294.4	111.1	187.2
Aug-98	100.7	10419.5	10286.3	133.2	187.2
Sep-98	102.7	10280.6	10270.0	10.6	187.2
Oct-98	103.3	10209.4	10265.4	-56.0	187.2
Nov-98	103.2	10177.3	10265.7	-88.4	187.2
Dec-98	103.7	10179.2	10262.0	-82.8	187.2
Jan-99	104.0	10198.0	10259.4	-61.4	187.2
Feb-99	101.6	10166.1	10278.9	-112.9	187.2
Mar-99	104.2	10165.7	10257.8	-92.1	187.2
Apr-99	100.2	10259.0	10290.3	-31.3	187.2
May-99	102.3	10258.5	10273.2	-14.7	187.2
Jun-99	101.6	10333.8	10278.9	54.9	187.2
Jul-99	102.0	10393.0	10275.8	117.2	187.2
Aug-99	101.4	10407.0	10280.3	126.7	187.2
Sep-99	102.6	10265.0	10270.6	-5.6	187.2
Nov-99	80.7	10470.0	10449.3	20.7	187.2
Dec-99	104.4	10150.0	10256.5	-106.5	187.2
Jan-00	101.1	10161.0	10282.9	-121.9	187.2
Feb-00	100.7	10154.0	10286.1	-132.1	187.2
Mar-00	99.9	10152.0	10292.5	-140.5	187.2
Apr-00	99.5	10239.0	10296.1	-57.1	187.2
May-00	100.3	10260.0	10289.3	-29.3	187.2
Jun-00	99.5	10346.0	10296.2	49.8	187.2
Jul-00	98.5	10451.0	10304.1	146.9	187.2
Aug-00	97.2	10511.0	10314.5	196.5	187.2
Sep-00	98.8	10293.0	10301.7	-8.7	187.2
Oct-00	99.6	10181.0	10295.5	-114.5	187.2
Nov-00	101.2	10174.0	10282.3	-108.3	187.2
Dec-00	101.1	10180.0	10283.3	-103.3	187.2
Jan-01	111.4	10186.0	10199.1	-13.1	187.2
Feb-01	111.5	10172.0	10198.2	-26.2	187.2
Mar-01	111.5	10179.0	10198.4	-19.4	187.2
Apr-01	111.2	10215.0	10200.7	14.3	187.2
May-01	105.6	10610.0	10246.0	364.0	187.2
Jun-01	108.5	10403.0	10222.5	180.5	187.2

Regression Output:

Constant	11106.59
Std Err of Y Est	115.4416233
R Squared	0.127624159
No. of Observations	35
Degrees of Freedom	34
X Coefficient	-8.146173087
Std Err of Coef.	3.70750745

Crystal River Unit 3



FLORIDA POWER CORPORATION

CRYSTAL RIVER UNIT 4

ANOHR -5.064 * NOF + 9846.97

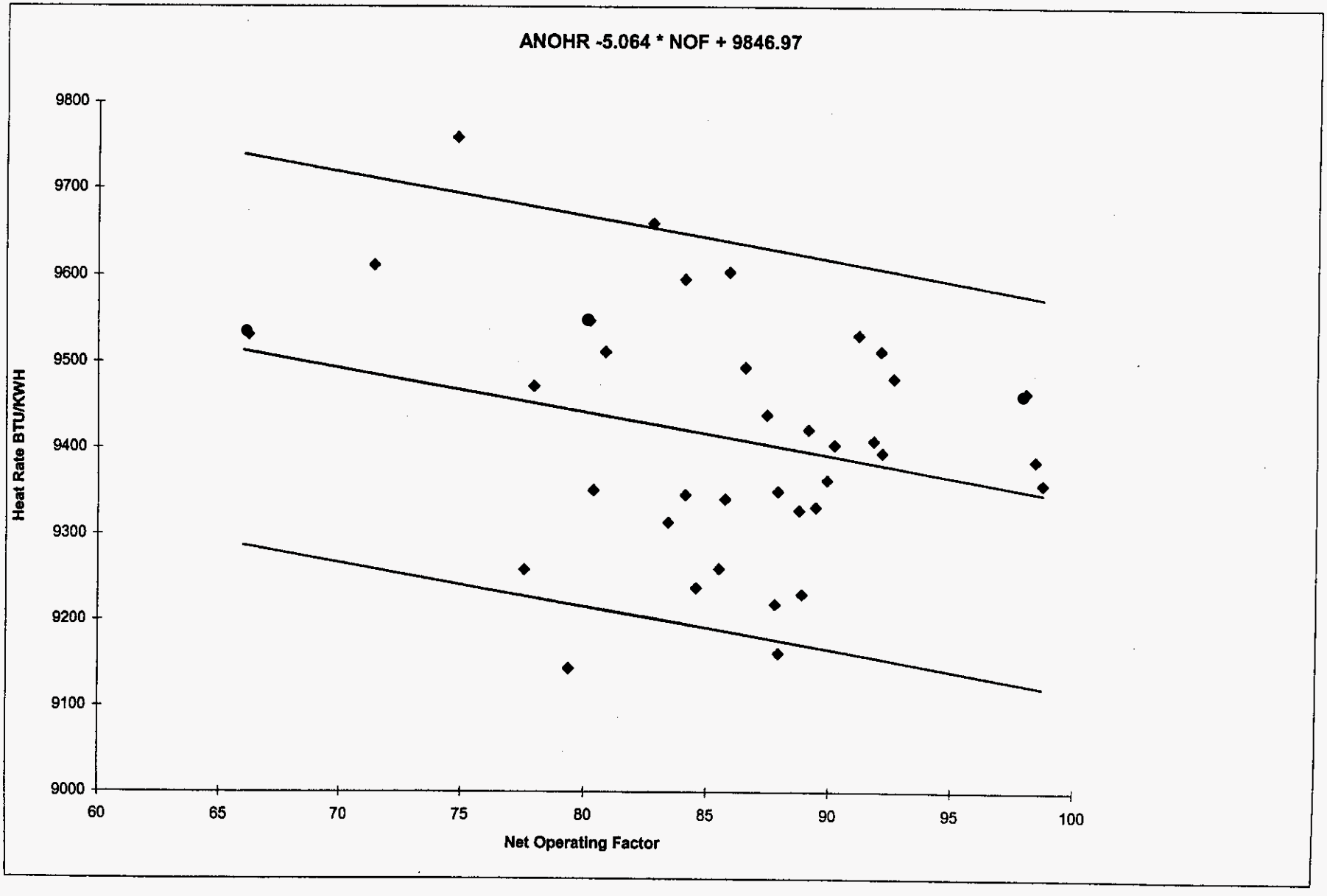
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-98	98.4	9385.7	9348.7	37.0	226.1
Aug-98	98.0	9464.7	9350.7	114.0	226.1
Sep-98	92.6	9481.7	9378.1	103.6	226.1
Oct-98	89.9	9363.2	9391.8	-28.6	226.1
Nov-98	80.9	9512.0	9437.6	74.4	226.1
Dec-98	71.4	9611.2	9485.4	125.8	226.1
Jan-99	74.8	9759.2	9468.2	291.0	226.1
Feb-99	66.2	9531.4	9511.7	19.7	226.1
Mar-99	85.5	9260.3	9414.0	-153.7	226.1
Apr-99	98.7	9358.5	9347.2	11.3	226.1
May-99	84.1	9595.2	9421.1	174.1	226.1
Jun-99	85.9	9603.6	9412.0	191.6	226.1
Jul-99	91.2	9531.0	9385.4	145.6	226.1
Aug-99	86.6	9494.0	9408.6	85.4	226.1
Sep-99	82.8	9659.0	9427.8	231.2	226.1
Oct-99	92.1	9513.0	9380.7	132.3	226.1
Nov-99	89.1	9422.0	9395.6	26.4	226.1
Dec-99	87.4	9439.0	9404.2	34.8	226.1
Jan-00	84.1	9346.0	9421.0	-75.0	226.1
Feb-00	80.4	9351.0	9440.0	-89.0	226.1
Mar-00	77.6	9259.0	9454.2	-195.2	226.1
Apr-00	77.9	9472.0	9452.3	19.7	226.1
May-00	87.9	9161.0	9401.7	-240.7	226.1
Jun-00	87.9	9350.0	9401.9	-51.9	226.1
Jul-00	91.8	9409.0	9382.2	26.8	226.1
Aug-00	92.1	9395.0	9380.4	14.6	226.1
Sep-00	89.4	9332.0	9394.1	-62.1	226.1
Oct-00	85.7	9341.0	9412.8	-71.8	226.1
Nov-00	79.4	9143.0	9445.1	-302.1	226.1
Dec-00	87.8	9219.0	9402.4	-183.4	226.1
Jan-01	88.9	9231.0	9396.9	-165.9	226.1
Feb-01	84.6	9238.0	9418.8	-180.8	226.1
Mar-01	83.4	9314.0	9424.6	-110.6	226.1
Apr-01	88.8	9328.0	9397.5	-69.5	226.1
May-01	90.2	9404.0	9390.3	13.7	226.1
Jun-01	80.2	9548.0	9440.8	107.2	226.1

Regression Output:

Constant	9846.97
Std Err of Y Est	139.4255444
R Squared	0.063557253
No. of Observations	36
Degrees of Freedom	35
X Coefficient	-5.063780653
Std Err of Coef.	3.333446456

Crystal River Unit 4



FLORIDA POWER CORPORATION

CRYSTAL RIVER UNIT 5

ANOHR -4.720 * NOF + 9801.31

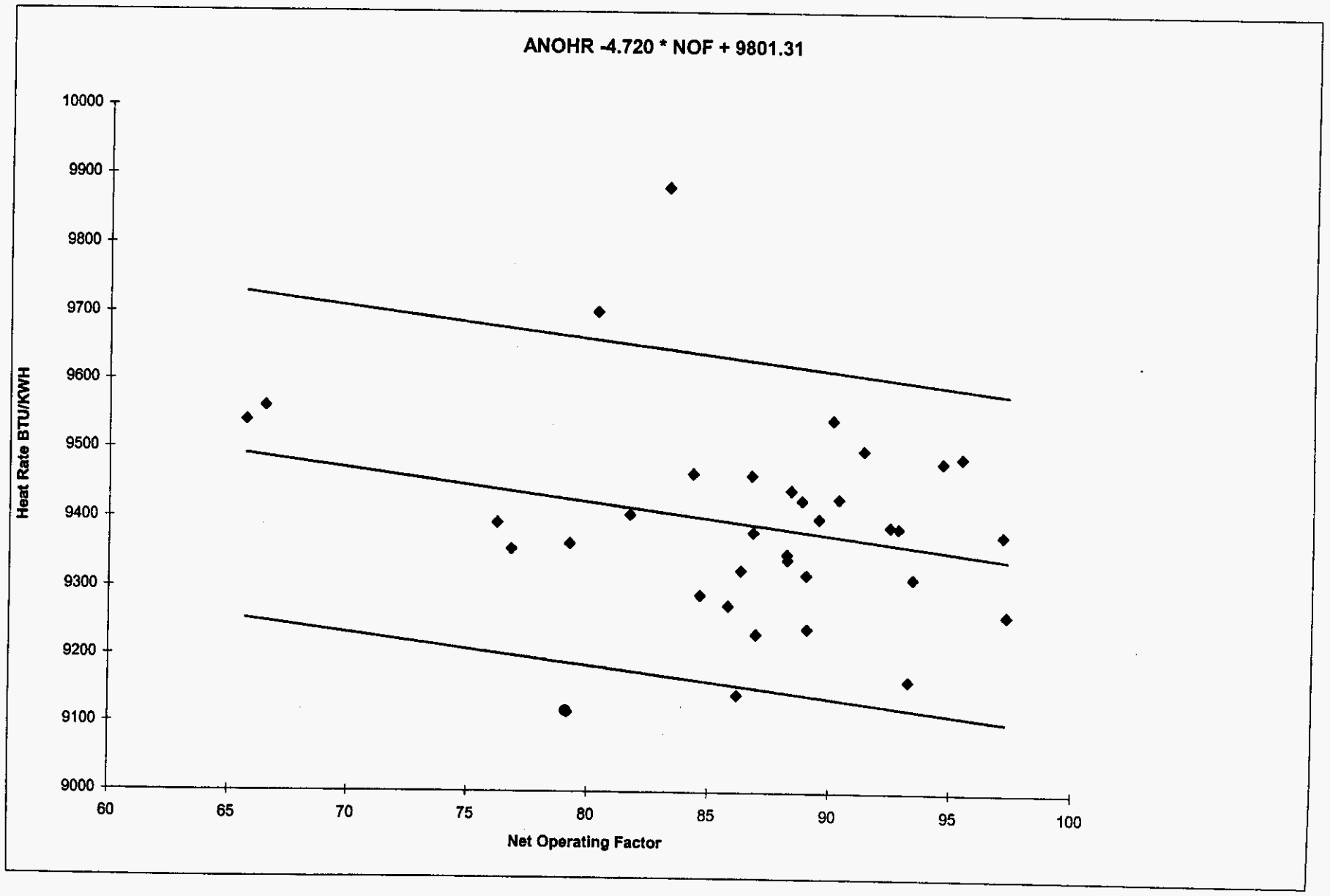
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-98	94.6	9482.6	9354.8	127.8	238.5
Aug-98	95.4	9489.6	9351.0	138.6	238.5
Sep-98	89.5	9401.2	9378.9	22.3	238.5
Oct-98	89.0	9319.9	9381.2	-61.3	238.5
Nov-98	81.7	9405.8	9415.7	-9.9	238.5
Dec-98	66.5	9561.1	9487.4	73.7	238.5
Jan-99	76.2	9393.5	9441.7	-48.2	238.5
Feb-99	65.7	9540.5	9491.2	49.3	238.5
Mar-99	76.8	9355.7	9438.8	-83.1	238.5
May-99	83.2	9882.0	9408.6	473.4	238.5
Jun-99	88.8	9427.5	9382.2	45.3	238.5
Jul-99	93.4	9315.0	9360.4	-45.4	238.5
Aug-99	97.3	9262.0	9342.1	-80.1	238.5
Sep-99	92.8	9388.0	9363.3	24.7	238.5
Oct-99	97.1	9378.0	9342.9	35.1	238.5
Nov-99	93.3	9165.0	9361.1	-196.1	238.5
Dec-99	86.3	9326.0	9394.0	-68.0	238.5
Jan-00	86.2	9143.0	9394.6	-251.6	238.5
Feb-00	79.2	9117.0	9427.6	-310.6	238.5
Mar-00	89.1	9241.0	9381.0	-140.0	238.5
Apr-00	85.8	9275.0	9396.4	-121.4	238.5
May-00	87.0	9233.0	9390.9	-157.9	238.5
Jun-00	92.5	9390.0	9365.0	25.0	238.5
Jul-00	90.0	9544.0	9376.3	167.7	238.5
Aug-00	91.3	9500.0	9370.2	129.8	238.5
Sep-00	88.4	9442.0	9384.3	57.7	238.5
Oct-00	79.2	9364.0	9427.4	-63.4	238.5
Nov-00	84.6	9290.0	9401.9	-111.9	238.5
Dec-00	84.3	9465.0	9403.5	61.5	238.5
Jan-01	88.2	9342.0	9384.9	-42.9	238.5
Feb-01	86.8	9381.0	9391.6	-10.6	238.5
Mar-01	86.7	9463.0	9392.0	71.0	238.5
Apr-01	90.3	9430.0	9375.0	55.0	238.5
May-01	80.3	9702.0	9422.3	279.7	238.5
Jun-01	88.2	9350.0	9385.0	-35.0	238.5

Regression Output:

Constant	9801.31
Std Err of Y Est	147.1259496
R Squared	0.054580171
No. of Observations	35
Degrees of Freedom	34
X Coefficient	-4.719911101
Std Err of Coef.	3.419572018

Crystal River Unit 5



FLORIDA POWER CORPORATION

TIGER BAY

ANOHR -36.715 * NOF + 10907.89

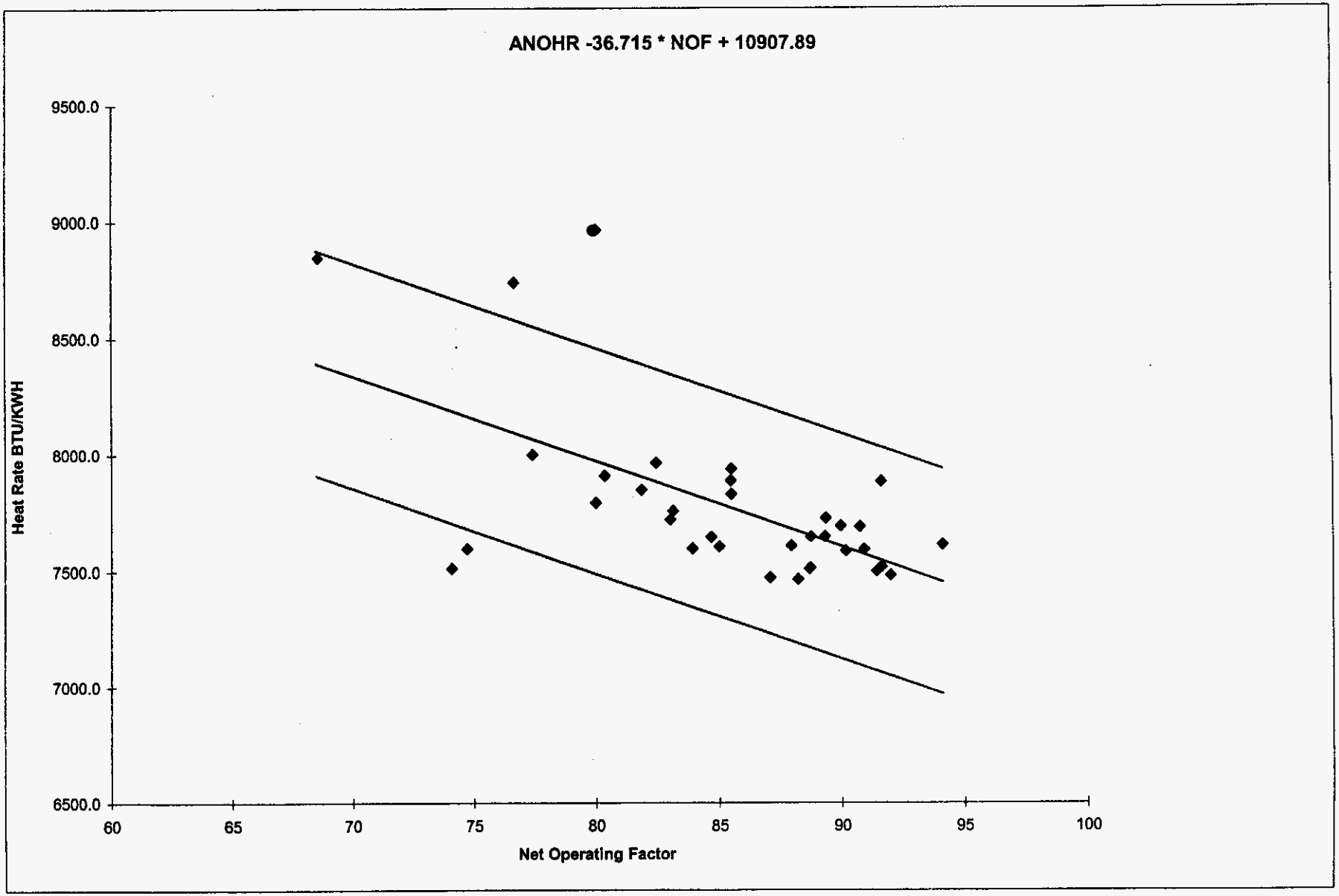
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-98	89.3	7648.0	7630.0	18.0	484.3
Aug-98	82.4	7963.0	7881.9	81.1	484.3
Sep-98	80.3	7908.0	7958.2	-50.2	484.3
Oct-98	81.8	7848.0	7903.9	-55.9	484.3
Nov-98	74.1	7512.0	8188.4	-676.4	484.3
Jan-99	80.0	8962.0	7970.7	991.3	484.3
Feb-99	68.6	8847.0	8389.6	457.4	484.3
Mar-99	74.7	7596.0	8165.3	-569.3	484.3
Apr-99	76.7	8739.0	8093.7	645.3	484.3
May-99	87.1	7472.0	7711.9	-239.9	484.3
Jun-99	83.1	7757.0	7856.5	-99.5	484.3
Jul-99	83.0	7721.0	7860.6	-139.6	484.3
Aug-99	84.7	7646.0	7800.0	-154.0	484.3
Sep-99	80.0	7792.0	7971.5	-179.5	484.3
Oct-99	90.1	7586.0	7598.4	-12.4	484.3
Nov-99	94.1	7612.0	7453.0	159.0	484.3
Dec-99	88.7	7647.0	7650.9	-3.9	484.3
Jan-00	85.5	7937.0	7769.9	167.1	484.3
Feb-00	83.9	7596.0	7827.5	-231.5	484.3
Mar-00	85.0	7604.0	7787.9	-183.9	484.3
Apr-00	85.5	7829.0	7769.9	59.1	484.3
May-00	88.7	7513.0	7652.0	-139.0	484.3
Jun-00	85.5	7887.0	7770.6	116.4	484.3
Jul-00	88.7	7509.0	7653.1	-144.1	484.3
Aug-00	89.9	7693.0	7605.8	87.2	484.3
Sep-00	87.9	7608.0	7680.1	-72.1	484.3
Oct-00	88.2	7465.0	7670.2	-205.2	484.3
Nov-00	77.4	7999.0	8065.8	-66.8	484.3
Dec-00	91.4	7500.0	7552.1	-52.1	484.3
Jan-01	91.6	7519.0	7545.3	-26.3	484.3
Feb-01	89.3	7726.0	7628.7	97.3	484.3
Mar-01	92.0	7482.0	7531.5	-49.5	484.3
Apr-01	91.6	7883.0	7545.7	337.3	484.3
May-01	90.9	7593.0	7570.8	22.2	484.3
Jun-01	90.7	7690.0	7577.4	112.6	484.3

Regression Output:

Constant	10907.89
Std Err of Y Est	298.7291354
R Squared	0.353869604
No. of Observations	35
Degrees of Freedom	34
X Coefficient	-36.71471223
Std Err of Coef.	8.636178594

Tiger Bay


ANOHR -36.715 * NOF + 10907.89
Heat Rate BTU/KWH
9500.0
9000.0
8500.0
8000.0
7500.0
7000.0
6500.0
60
65
70
75
80
85
90
95
100
Net Operating Factor

UNPLANNED OUTAGE RATE TABLES AND GRAPHS

UNIT UNAVAILABLE OUTAGE RATE SUMMARY

Company: Florida Power Corporation
Period of: January, 2002- December, 2002

UNIT	RATE	LOW RANGE	HIGH RANGE	TARGET
Anclote 1	FOR	1.15	4.36	2.18
	MOR	2.15	8.19	4.09
	FOR&MOR	3.30	12.55	6.28
	PFOR	0.41	1.58	0.79
	PMOR	1.19	4.55	2.28
	EUOR	4.80	17.28	8.98
	EUOF	4.43	15.95	8.29
Anclote 2	FOR	0.25	0.96	0.48
	MOR	1.79	6.83	3.41
	FOR&MOR	2.05	7.79	3.90
	PFOR	0.39	1.47	0.73
	PMOR	0.86	3.29	1.65
	EUOR	3.26	12.06	6.15
	EUOF	2.74	10.13	5.17
Crystal River 1	FOR	1.18	4.49	2.25
	MOR	4.20	16.00	8.00
	FOR&MOR	5.38	20.49	10.25
	PFOR	1.15	4.39	2.20
	PMOR	0.80	3.04	1.52
	EUOR	7.13	25.20	13.25
	EUOF	7.13	25.18	13.25
Crystal River 2	FOR	2.07	7.89	3.95
	MOR	5.42	20.65	10.33
	FOR&MOR	7.49	28.55	14.27
	PFOR	1.30	4.94	2.47
	PMOR	1.45	5.51	2.75
	EUOR	9.82	33.47	18.03
	EUOF	7.80	26.57	14.32
Crystal River 3	FOR	0.24	0.91	0.45
	MOR	1.18	4.50	2.25
	FOR&MOR	1.42	5.41	2.70
	PFOR	0.29	1.09	0.54
	PMOR	0.31	1.19	0.60
	EUOR	2.00	7.49	3.79
	EUOF	2.00	7.49	3.79
Crystal River 4	FOR	0.88	3.36	1.68
	MOR	0.56	2.12	1.06
	FOR&MOR	1.44	5.48	2.74
	PFOR	0.65	2.47	1.23
	PMOR	0.26	1.01	0.50
	EUOR	2.33	8.63	4.40
	EUOF	1.86	6.90	3.52
Crystal River 5	FOR	0.72	2.72	1.36
	MOR	1.67	6.38	3.19
	FOR&MOR	2.39	9.10	4.55
	PFOR	0.36	1.37	0.69
	PMOR	0.20	0.75	0.38
	EUOR	2.91	10.70	5.48
	EUOF	2.91	10.70	5.48
Bartow 3	FOR	2.51	9.57	4.79
	MOR	1.04	3.98	1.99
	FOR&MOR	3.56	13.55	6.78
	PFOR	0.43	1.64	0.82
	PMOR	1.25	4.77	2.39
	EUOR	5.13	18.43	9.59
	EUOF	4.48	16.09	8.37
Tiger Bay	FOR	3.11	11.83	5.92
	MOR	1.56	5.96	2.98
	FOR&MOR	4.67	17.79	8.89
	PFOR	0.02	0.09	0.05
	PMOR	0.02	0.09	0.05
	EUOR	4.62	16.65	8.64
	EUOF	3.35	12.08	6.27

Anclote
Unit 1

	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	703.30	744.00	720.00	385.48	720.00	744.00	583.98	672.00	292.20	0.00	652.97	615.83	742.20	744.00	683.10	740.80	428.80	225.80
RSH	0.00	0.00	0.00	0.00	0.00	0.00	160.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	226.20	302.70
UH	40.70	0.00	0.00	359.52	0.00	0.00	0.00	0.00	451.80	719.00	91.03	104.17	1.80	0.00	36.90	4.30	65.00	215.50
POH	0.00	0.00	0.00	342.45	0.00	0.00	0.00	0.00	451.80	719.00	91.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	40.70	0.00	0.00	17.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	37.03	1.80	0.00	36.90	4.30	0.00	15.60
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	67.13	0.00	0.00	0.00	0.00	65.00	200.00
PFOH	187.10	3.30	0.00	146.80	24.66	13.98	3.00	0.00	0.00	0.00	32.67	9.85	0.00	133.00	201.20	39.10	0.00	0.00
LRPF	18.00	156.90	0.00	14.63	165.77	319.10	257.30	0.00	0.00	0.00	109.40	197.71	0.00	43.60	15.00	174.00	0.00	0.00
EFOH	6.59	1.01	0.00	4.20	8.00	8.73	1.51	0.00	0.00	0.00	6.99	3.81	0.00	11.35	5.91	13.31	0.00	0.00
PMOH	96.90	76.60	48.50	10.17	24.10	0.00	0.00	23.00	0.00	0.00	22.65	55.58	73.50	61.00	45.00	60.60	12.50	0.00
LRPM	95.80	149.30	165.50	155.01	163.39	0.00	0.00	169.65	0.00	0.00	173.54	132.80	172.30	163.10	164.30	166.20	169.70	0.00
EMOH	18.17	22.38	15.71	3.09	7.71	0.00	0.00	7.64	0.00	0.00	7.69	14.44	24.78	19.47	14.47	19.71	4.15	0.00
NPC	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00

MONTHLY	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
FOR	5.47	0.00	0.00	4.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.67	0.24	0.00	5.13	0.58	0.00	6.46
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.83	0.00	0.00	0.00	0.00	13.16	46.97
PFOR	0.94	0.14	0.00	1.09	1.11	1.17	0.26	0.00	0.00	0.00	1.07	0.62	0.00	1.53	0.86	1.80	0.00	0.00
PMOR	2.58	3.01	2.18	0.80	1.07	0.00	0.00	1.14	0.00	0.00	1.18	2.35	3.34	2.62	2.12	2.66	0.97	0.00
EUOR	8.80	3.14	2.18	6.05	2.18	1.17	0.26	1.14	0.00	0.00	2.25	17.00	3.57	4.14	7.95	5.01	14.00	48.84
EUOF	8.80	3.14	2.18	3.27	2.18	1.17	0.20	1.14	0.00	0.00	1.97	17.00	3.57	4.14	7.95	5.01	9.60	28.98
POF	0.00	0.00	0.00	45.97	0.00	0.00	0.00	0.00	60.73	100.00	12.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	91.20	96.86	97.82	50.76	97.82	98.83	99.80	98.86	39.27	0.00	85.79	83.00	96.43	95.86	92.05	94.99	90.40	71.02

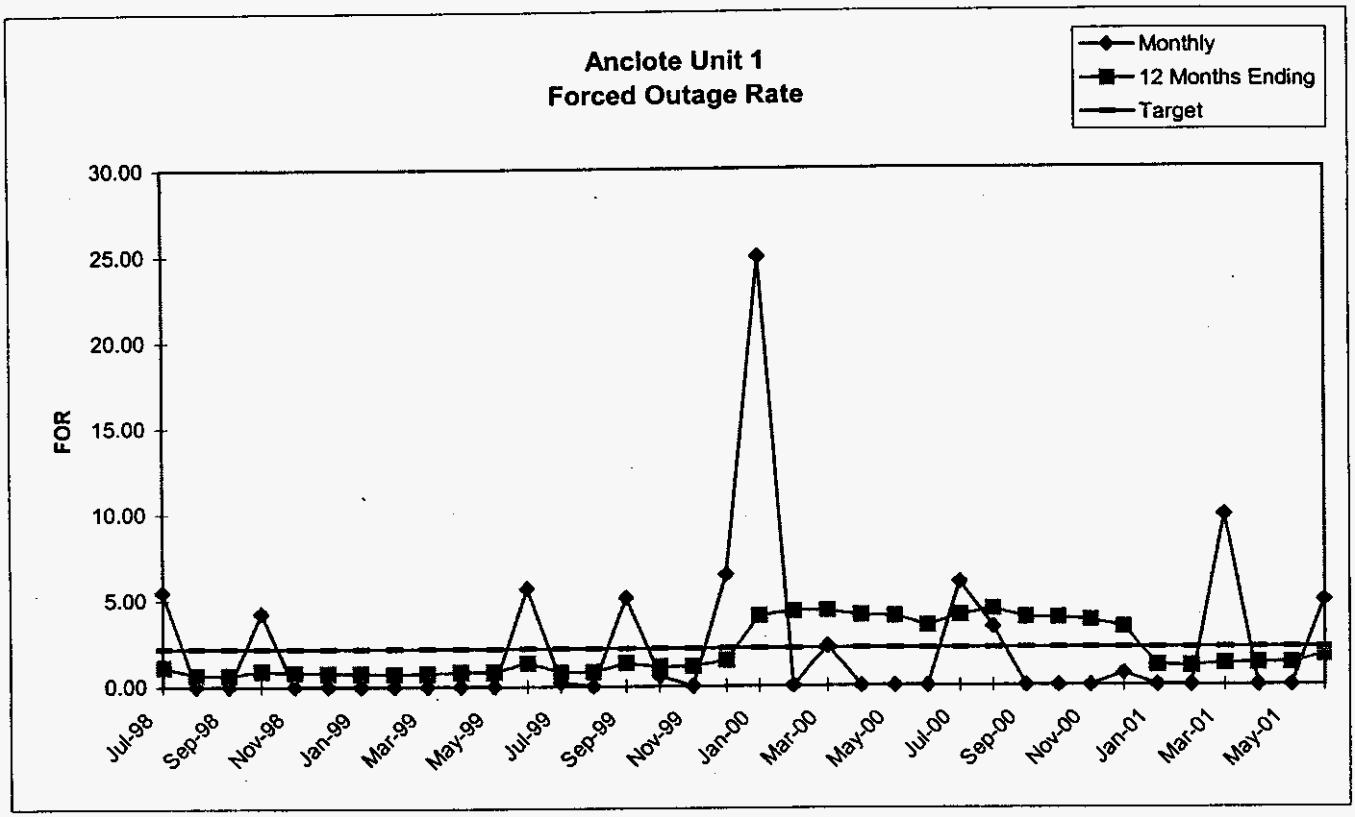
12 MONTHS	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
FOR	1.14	0.64	0.64	0.88	0.80	0.77	0.77	0.73	0.75	0.83	0.83	1.37	0.81	0.81	1.34	1.10	1.15	1.48
MOR	0.14	0.14	0.14	0.14	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.97	0.97	0.97	0.97	0.92	1.88	4.95
PFOR	1.19	0.94	0.70	0.45	0.52	0.58	0.60	0.57	0.58	0.58	0.67	0.60	0.50	0.65	0.74	0.83	0.75	0.67
PMOR	1.01	1.34	1.57	1.66	1.62	1.55	1.54	1.55	1.57	1.50	1.38	1.42	1.51	1.46	1.45	1.61	1.63	1.76
EUOR	3.45	3.04	3.03	3.11	3.04	2.89	2.89	2.83	2.88	2.89	2.86	4.28	3.73	3.83	4.43	4.40	5.29	8.56
EUOF	2.68	2.36	2.36	2.36	2.54	2.50	2.52	2.59	2.57	2.34	2.28	3.42	2.98	3.06	3.54	3.68	4.29	6.66
POF	9.63	9.63	9.63	13.07	6.50	6.36	6.36	6.36	9.07	17.27	18.31	18.31	18.31	18.31	18.31	14.40	14.40	14.40
EAF	87.69	88.01	88.01	84.57	90.96	91.14	91.12	91.05	88.36	80.39	79.40	78.27	78.71	78.63	78.15	81.91	81.30	78.94

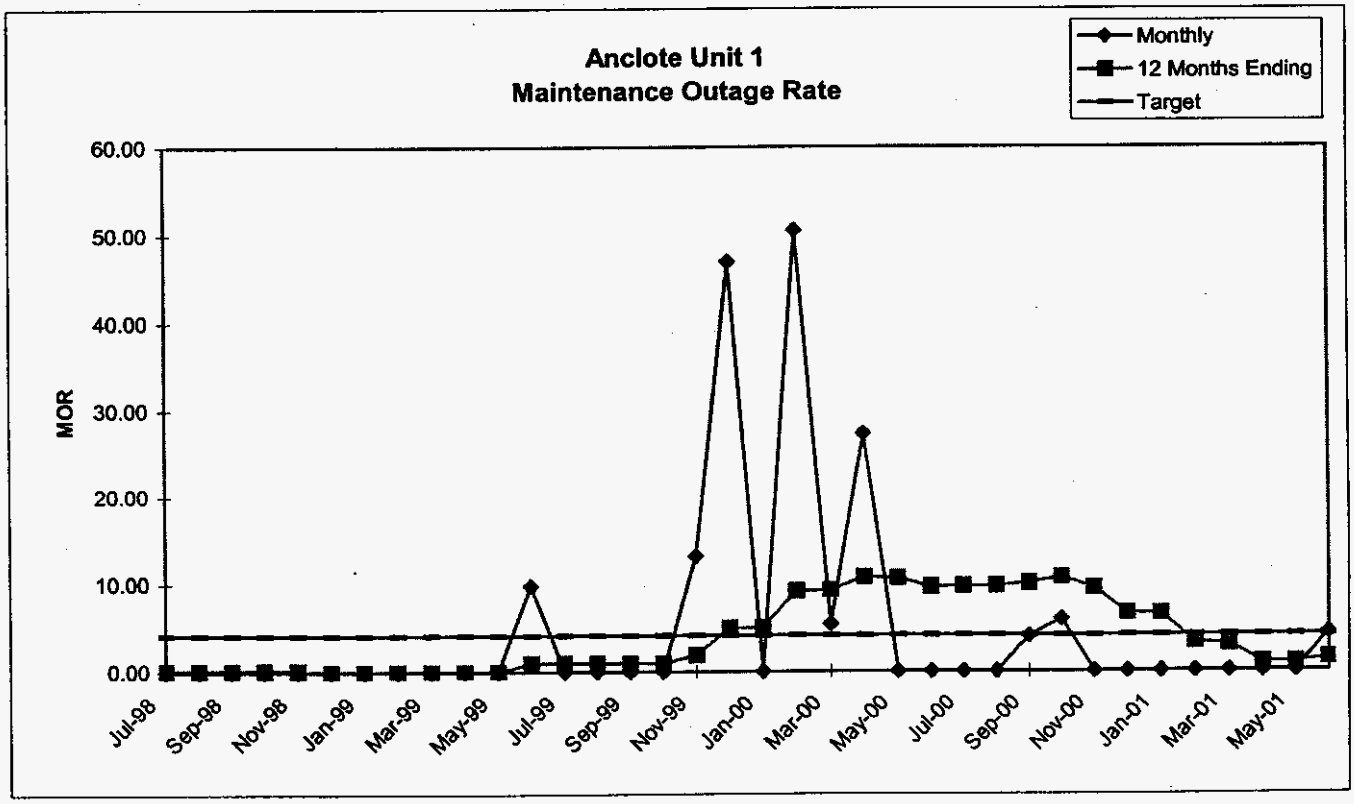
Anclote
Unit 1

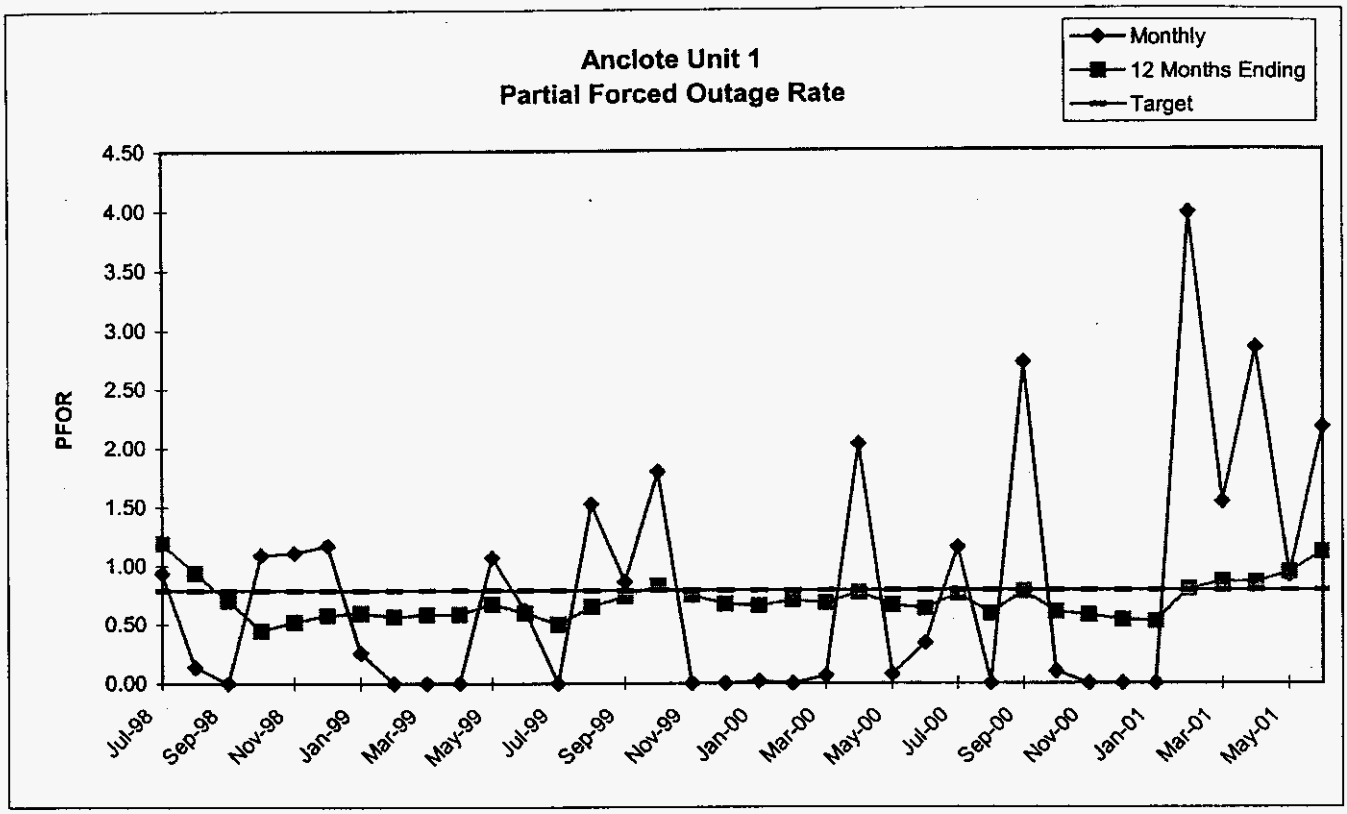
	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
PER HOURS	744.00	696.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	513.40	258.10	532.10	432.20	739.30	720.00	699.47	718.80	690.90	641.72	720.00	739.00	636.35	580.65	172.60	217.23	744.00	656.50
RSH	59.90	173.90	169.20	124.00	4.70	0.00	0.00	0.00	0.00	62.68	0.00	0.00	107.65	91.35	0.00	0.00	0.00	0.00
UH	170.70	264.00	42.80	162.80	0.00	0.00	44.53	25.20	29.10	40.60	0.00	5.00	0.00	0.00	571.40	501.77	0.00	63.50
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	552.50	501.77	0.00	0.00
FOH	170.70	0.00	12.50	0.00	0.00	0.00	44.53	25.20	0.00	0.00	0.00	5.00	0.00	0.00	18.90	0.00	0.00	33.85
MOH	0.00	264.00	30.30	162.80	0.00	0.00	0.00	0.00	29.10	40.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.65
PFOH	0.10	0.00	4.20	30.20	5.70	38.80	42.28	0.00	167.68	1.88	0.00	0.00	0.00	47.45	7.87	11.67	62.63	95.38
LRPF	496.70	0.00	40.40	146.20	50.00	31.80	96.17	156.56	56.40	170.66	0.00	0.00	0.00	242.19	168.46	263.68	54.54	74.53
EFOH	0.10	0.00	0.34	8.78	0.57	2.45	8.08	0.00	18.80	0.64	0.00	0.00	0.00	23.08	2.66	6.18	6.86	14.28
PMOH	0.00	18.00	48.00	23.80	80.60	66.20	54.62	279.42	49.67	59.18	47.28	18.35	0.00	38.32	0.00	0.00	60.37	54.15
LRPM	0.00	170.20	170.20	170.20	167.60	160.30	158.22	156.56	161.75	170.23	170.25	181.83	0.00	174.55	0.00	0.00	174.80	168.52
EMOH	0.00	6.09	16.24	8.05	26.86	21.10	17.18	86.97	15.97	20.03	16.00	6.63	0.00	13.43	0.00	0.00	21.19	18.32
NPC	503.00	503.00	503.00	503.00	503.00	503.00	503.00	503.00	503.00	503.00	503.00	503.00	498.00	498.00	498.00	498.00	498.00	498.00

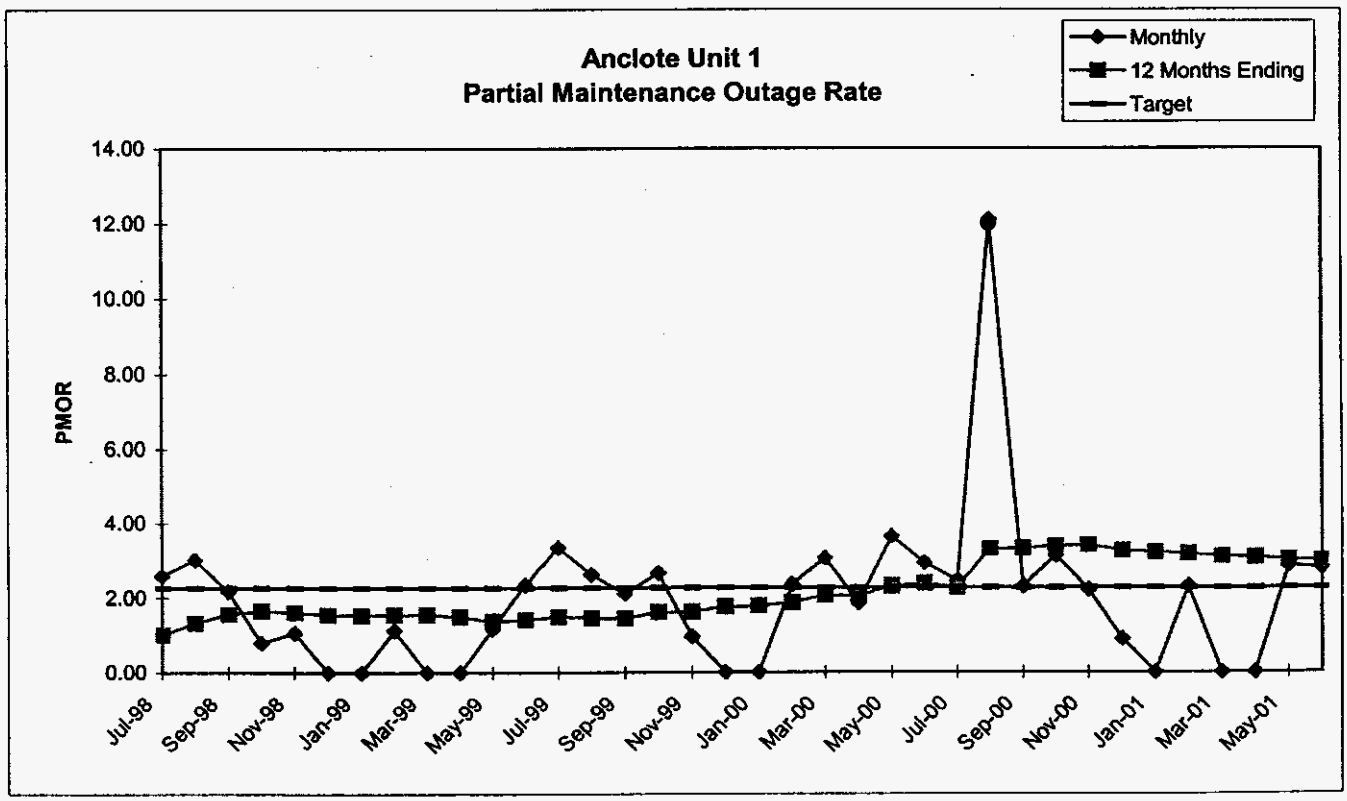
MONTHLY	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FOR	24.95	0.00	2.30	0.00	0.00	0.00	5.99	3.39	0.00	0.00	0.00	0.67	0.00	0.00	9.87	0.00	0.00	4.90
MOR	0.00	50.57	5.39	27.36	0.00	0.00	0.00	0.00	4.04	5.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.32
PFOR	0.02	0.00	0.06	2.03	0.08	0.34	1.16	0.00	2.72	0.10	0.00	0.00	0.00	3.97	1.54	2.84	0.92	2.17
PMOR	0.00	2.36	3.05	1.86	3.63	2.93	2.46	12.10	2.31	3.12	2.22	0.90	0.00	2.31	0.00	0.00	2.85	2.79
EUOR	24.97	51.73	10.33	30.19	3.71	3.27	9.38	15.08	8.87	8.98	2.22	1.56	0.00	6.29	11.26	2.84	3.77	13.35
EUOF	22.96	38.81	7.98	24.98	3.69	3.27	9.38	15.08	8.87	8.22	2.22	1.56	0.00	5.43	2.90	0.86	3.77	13.35
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	74.26	69.79	0.00	0.00
EAF	77.04	61.19	92.02	75.02	96.31	96.73	90.62	84.92	91.13	91.78	97.78	98.44	100.00	94.57	22.84	29.35	96.23	86.65

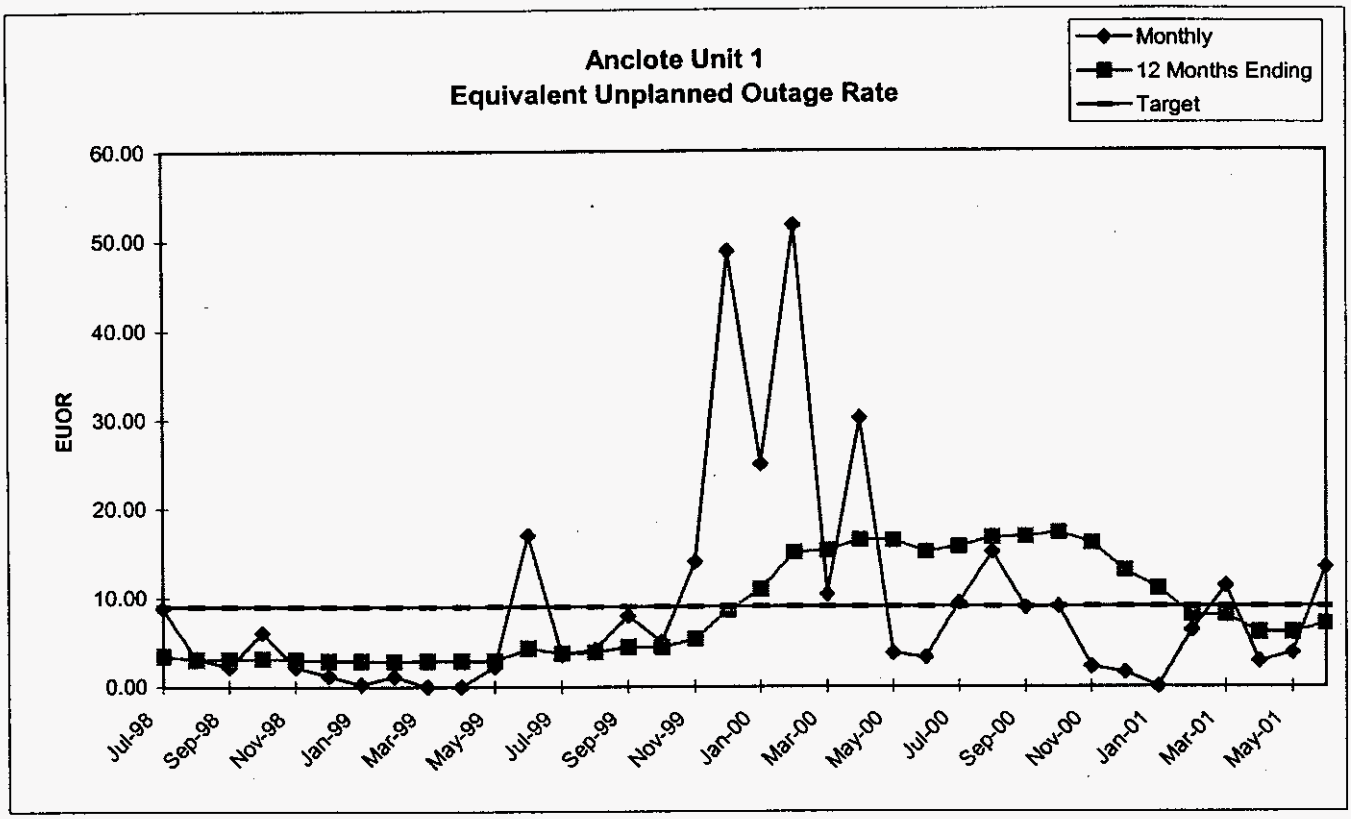
12 MONTHS	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FOR	4.05	4.32	4.35	4.07	4.02	3.45	4.06	4.42	3.91	3.91	3.75	3.37	1.15	1.10	1.23	1.27	1.27	1.74
MOR	5.00	9.18	9.26	10.73	10.60	9.65	9.71	9.74	10.08	10.71	9.54	6.64	6.54	3.24	3.01	0.95	0.95	1.36
PFOR	0.66	0.70	0.68	0.77	0.66	0.63	0.76	0.59	0.78	0.60	0.58	0.54	0.53	0.80	0.87	0.86	0.94	1.12
PMOR	1.78	1.88	2.07	2.06	2.32	2.38	2.28	3.30	3.32	3.37	3.40	3.26	3.20	3.16	3.10	3.08	3.00	2.99
EUOR	10.89	15.01	15.25	16.42	16.40	15.12	15.68	16.73	16.82	17.27	16.10	13.01	10.99	8.06	7.97	6.05	6.05	7.03
EUOF	8.59	11.55	12.23	14.27	14.42	13.29	13.78	14.71	14.79	15.06	14.45	12.13	10.19	7.55	7.12	5.14	5.14	5.97
POF	14.40	14.37	9.22	1.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.31	12.04	12.04	12.04
EAF	77.01	74.08	78.55	84.69	85.58	86.71	86.22	85.29	85.21	84.94	85.55	87.87	89.81	92.45	86.58	82.83	82.82	81.99

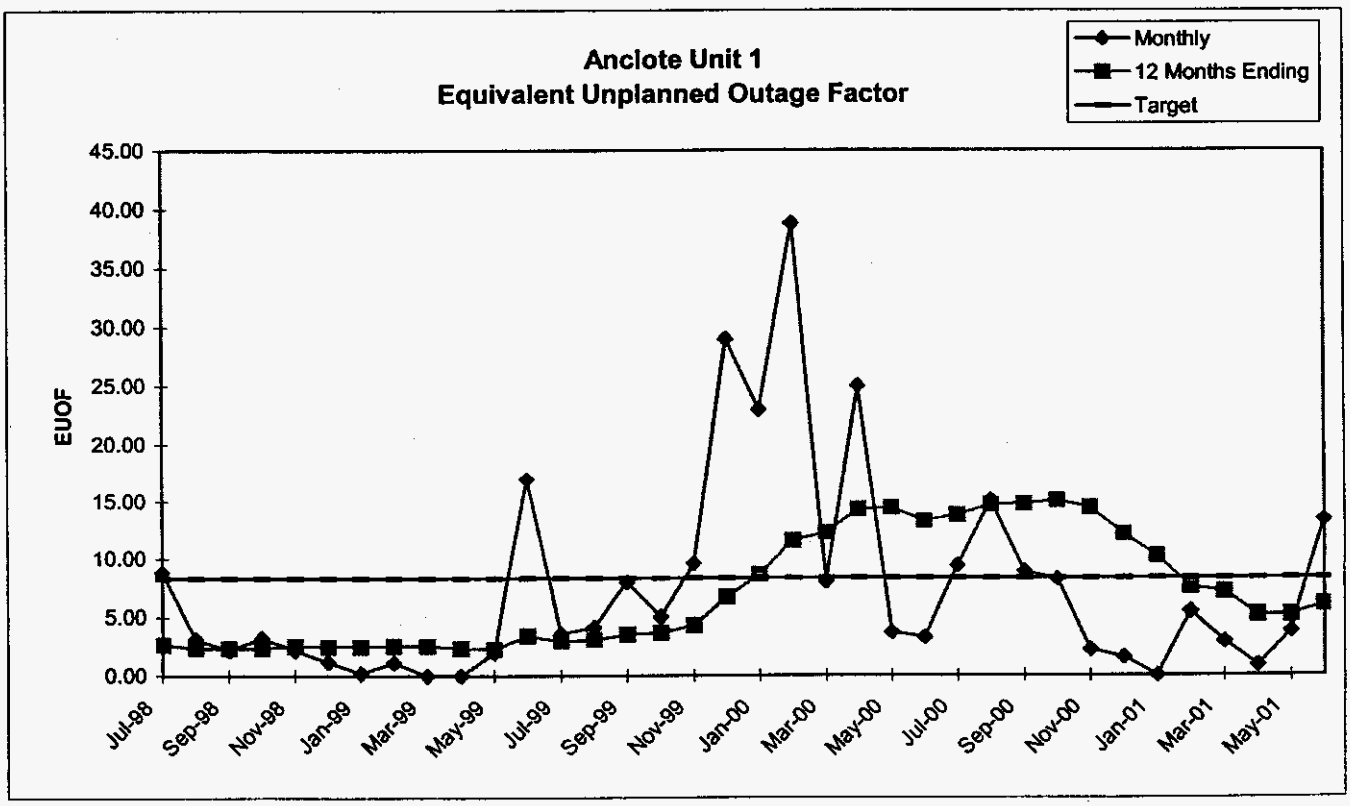

Anclote Unit 1
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Anclote Unit 1
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Anclote Unit 1
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Anclote Unit 1
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Anclote Unit 1
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Anclote Unit 1
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01

Anclote
Unit 2

	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	689.30	720.00	528.55	0.00	458.82	744.00	624.32	550.60	719.00	690.15	612.93	744.00	744.00	720.00	493.30	545.60	744.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	219.00	174.40	0.00
UH	0.00	54.70	0.00	216.45	720.00	285.18	0.00	0.00	193.40	0.00	53.85	107.07	0.00	0.00	0.00	32.70	0.00	0.00
POH	0.00	0.00	0.00	216.45	720.00	285.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	48.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOH	0.00	6.50	0.00	0.00	0.00	0.00	0.00	47.68	193.40	0.00	53.85	107.07	0.00	0.00	0.00	32.70	0.00	0.00
PFOH	24.10	24.40	0.00	0.00	0.00	2.35	13.75	279.32	4.50	36.51	2.97	9.82	0.00	167.40	161.30	44.90	0.50	418.60
LRPF	51.10	44.60	0.00	0.00	0.00	427.72	174.00	40.70	432.80	109.20	19.40	193.90	0.00	57.50	73.00	346.20	489.80	20.50
EFOH	2.41	2.13	0.00	0.00	0.00	1.97	4.68	22.25	3.81	7.80	0.11	3.73	0.00	18.84	23.04	30.42	0.48	16.79
PMOH	70.30	80.10	43.00	44.83	0.00	0.00	25.17	34.88	0.00	21.40	45.10	46.30	43.00	35.70	42.50	24.00	23.20	22.00
LRPM	164.90	164.80	165.80	170.35	0.00	0.00	170.30	249.30	0.00	186.20	170.30	160.50	171.30	170.30	154.00	137.70	170.30	170.30
EMOH	22.69	25.83	13.95	14.95	0.00	0.00	8.39	17.02	0.00	7.80	15.03	14.54	14.41	11.90	12.81	6.47	7.73	7.33
NPC	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00	511.00

MONTHLY	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
FOR	0.00	6.55	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.93	0.00	0.00	0.00	0.00	0.00	7.10	25.99	0.00	7.24	14.87	0.00	0.00	0.00	6.22	0.00	0.00
PFOR	0.32	0.31	0.00	0.00	0.00	0.43	0.63	3.56	0.69	1.09	0.02	0.61	0.00	2.53	3.20	6.17	0.09	2.26
PMOR	3.05	3.75	1.94	2.83	0.00	0.00	1.13	2.73	0.00	1.08	2.18	2.37	1.94	1.60	1.78	1.31	1.42	0.99
EUOR	3.37	11.12	1.94	2.83	0.00	0.43	1.76	12.94	26.51	2.17	9.27	17.41	1.94	4.13	4.98	13.23	1.50	3.24
EUOF	3.37	11.12	1.94	2.01	0.00	0.26	1.76	12.94	26.51	2.17	9.27	17.41	1.94	4.13	4.98	9.34	1.14	3.24
POF	0.00	0.00	0.00	29.05	100.00	38.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	96.63	88.88	98.06	68.94	0.00	61.40	98.24	87.06	73.49	97.83	90.73	82.59	98.06	95.87	95.02	90.66	98.86	96.76

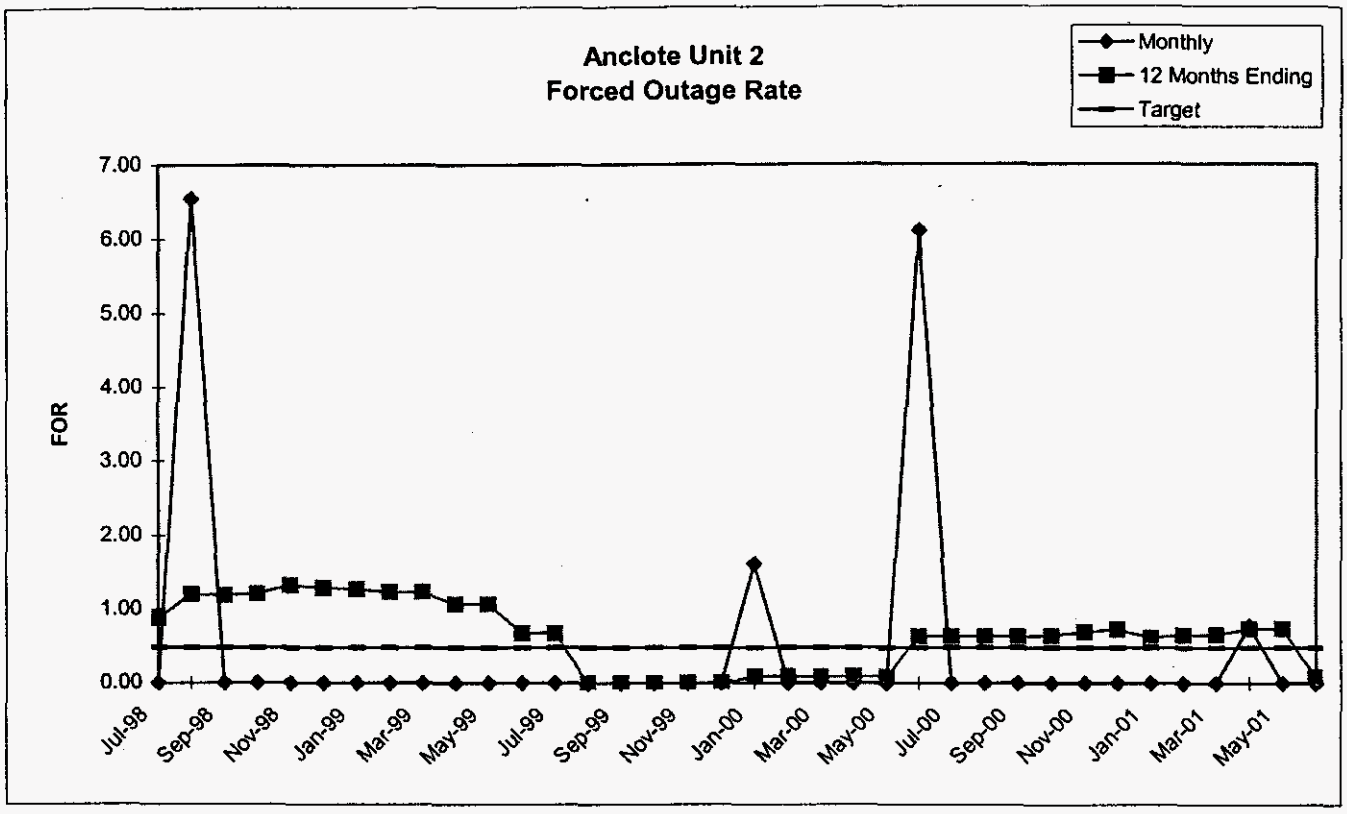
12 MONTHS	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
FOR	0.88	1.21	1.19	1.22	1.33	1.30	1.28	1.24	1.24	1.07	1.08	0.68	0.68	0.00	0.00	0.00	0.00	0.00
MOR	5.82	5.93	5.92	6.03	6.54	6.52	6.46	6.88	9.32	3.32	4.04	5.45	5.45	5.33	5.33	5.77	5.38	5.20
PFOR	3.38	3.01	2.52	2.16	1.56	1.58	1.64	1.91	1.33	1.09	1.08	0.69	0.66	0.89	1.21	1.64	1.53	1.66
PMOR	1.00	1.36	1.56	1.80	1.96	1.96	2.07	2.23	2.22	2.09	1.99	1.98	1.86	1.65	1.64	1.53	1.52	1.56
EUOR	10.69	11.06	10.77	10.78	10.95	10.92	11.00	11.77	13.52	7.36	7.95	8.57	8.43	7.74	8.03	8.75	8.26	8.25
EUOF	9.45	9.78	9.52	9.36	8.77	8.78	8.92	9.89	11.63	6.34	6.84	7.37	7.25	6.66	6.91	7.53	7.62	7.88
POF	5.95	5.95	5.95	8.43	16.18	15.88	15.88	15.88	13.95	13.95	13.95	13.95	13.95	13.95	13.95	11.47	3.26	0.00
EAF	84.60	84.27	84.53	82.21	75.05	75.35	75.21	74.23	74.42	79.72	79.21	78.68	78.80	79.40	79.15	80.99	89.12	92.12

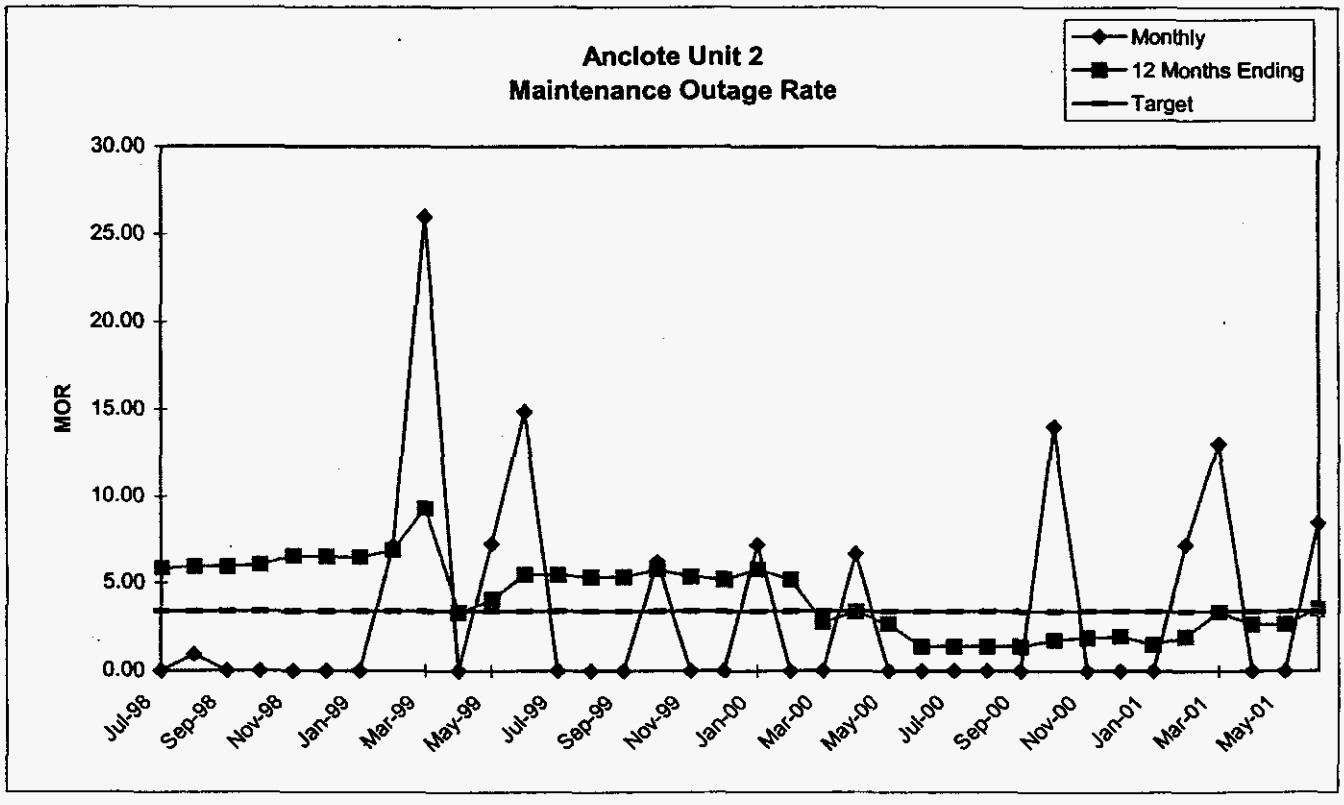
Anclote
Unit 2

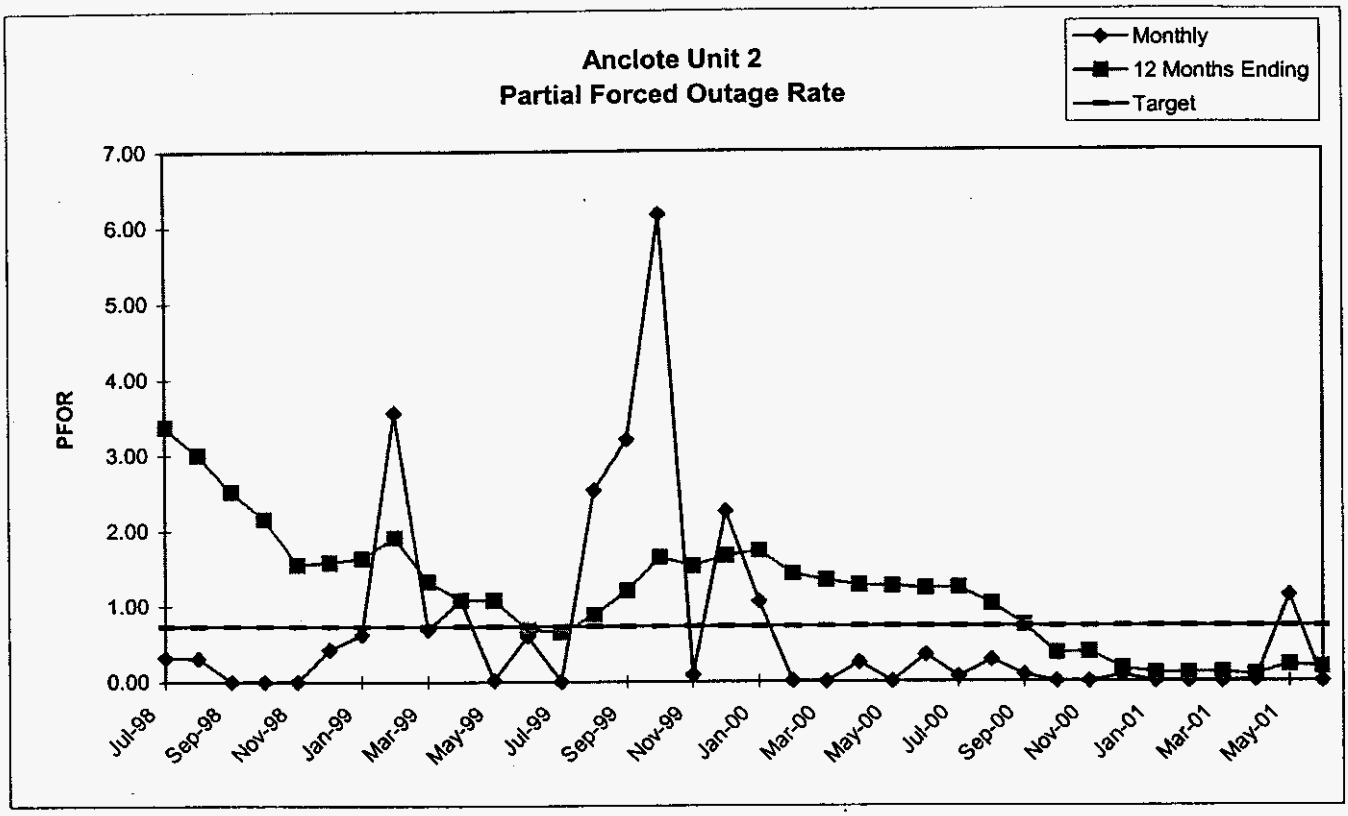
	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
PER HOURS	744.00	696.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	419.30	695.10	744.00	671.20	744.00	676.00	744.00	744.00	720.00	371.50	0.00	411.82	551.45	335.83	647.17	713.40	744.00	659.05
RSH	285.40	0.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	155.95	0.00	106.78	192.55	310.18	0.00	0.00	0.00	0.00
UH	39.40	0.00	0.00	47.90	0.00	44.00	0.00	0.00	0.00	217.55	720.00	225.40	0.00	25.98	96.83	5.60	0.00	60.95
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	157.00	720.00	225.40	0.00	0.00	0.00	0.00	0.00	0.00
FOH	6.90	0.00	0.00	0.00	0.00	44.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.60	0.00	0.00
MOH	32.50	0.00	0.00	47.90	0.00	0.00	0.00	0.00	0.00	60.55	0.00	0.00	0.00	25.98	96.83	0.00	0.00	60.95
PFOH	28.20	1.80	0.00	16.10	0.00	4.50	4.58	3.70	6.17	0.00	0.00	1.92	0.00	0.00	0.00	1.92	61.36	0.00
LRPF	79.30	14.30	0.00	52.90	0.00	264.60	52.92	287.81	52.87	0.00	0.00	84.42	0.00	0.00	0.00	36.75	68.19	0.00
EFOH	4.45	0.05	0.00	1.69	0.00	2.37	0.48	2.12	0.65	0.00	0.00	0.32	0.00	0.00	0.00	0.14	8.45	0.00
PMOH	10.80	11.20	25.80	39.60	58.40	30.70	66.87	38.53	41.68	15.35	0.00	0.00	0.00	0.00	17.32	28.72	44.54	35.65
LRPM	166.40	168.20	168.30	168.30	168.30	168.30	162.00	168.33	164.95	168.29	0.00	0.00	0.00	0.00	165.56	165.61	180.85	165.64
EMOH	3.57	3.75	8.63	13.25	19.54	10.27	21.54	12.89	13.67	5.14	0.00	0.00	0.00	0.00	5.79	9.61	16.27	11.93
NPC	503.00	503.00	503.00	503.00	503.00	503.00	503.00	503.00	503.00	503.00	503.00	503.00	495.00	495.00	495.00	495.00	495.00	495.00

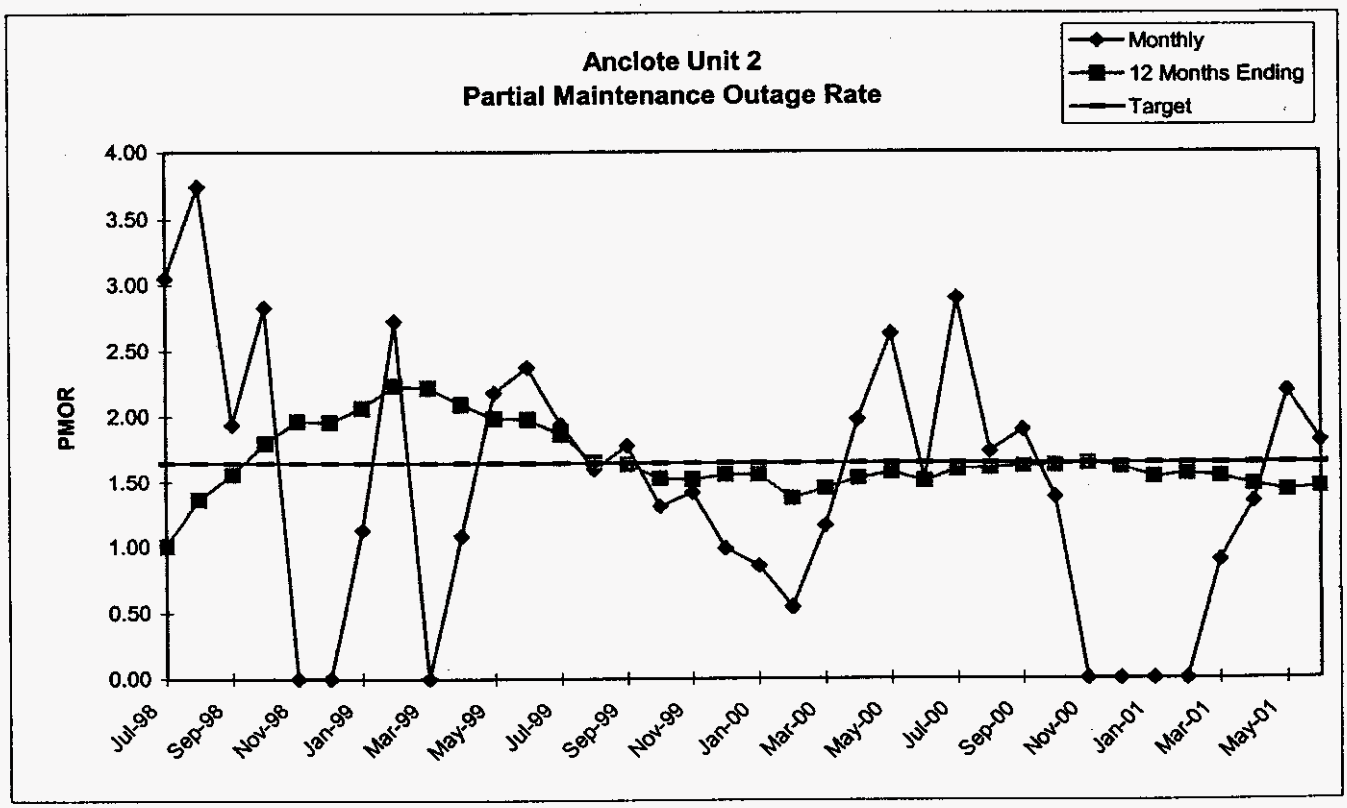
MONTHLY	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FOR	1.62	0.00	0.00	0.00	0.00	6.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.78	0.00	0.00
MOR	7.19	0.00	0.00	6.66	0.00	0.00	0.00	0.00	0.00	14.01	0.00	0.00	0.00	7.18	13.02	0.00	0.00	8.47
PFOR	1.06	0.01	0.00	0.25	0.00	0.35	0.06	0.28	0.09	0.00	0.00	0.08	0.00	0.00	0.00	0.02	1.14	0.00
PMOR	0.85	0.54	1.16	1.97	2.63	1.52	2.89	1.73	1.90	1.38	0.00	0.00	0.00	0.00	0.90	1.35	2.19	1.81
EUOR	10.34	0.55	1.16	8.74	2.63	7.87	2.96	2.02	1.99	15.20	0.00	0.08	0.00	7.18	13.79	2.14	3.32	10.12
EUOF	6.37	0.55	1.16	8.74	2.63	7.87	2.96	2.02	1.99	8.82	0.00	0.04	0.00	3.87	13.79	2.14	3.32	10.12
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.07	100.00	30.30	0.00	0.00	0.00	0.00	0.00	0.00
EAF	93.63	99.45	98.84	91.26	97.37	92.13	97.04	97.98	98.01	70.11	0.00	69.66	100.00	96.13	86.21	97.86	96.68	89.88

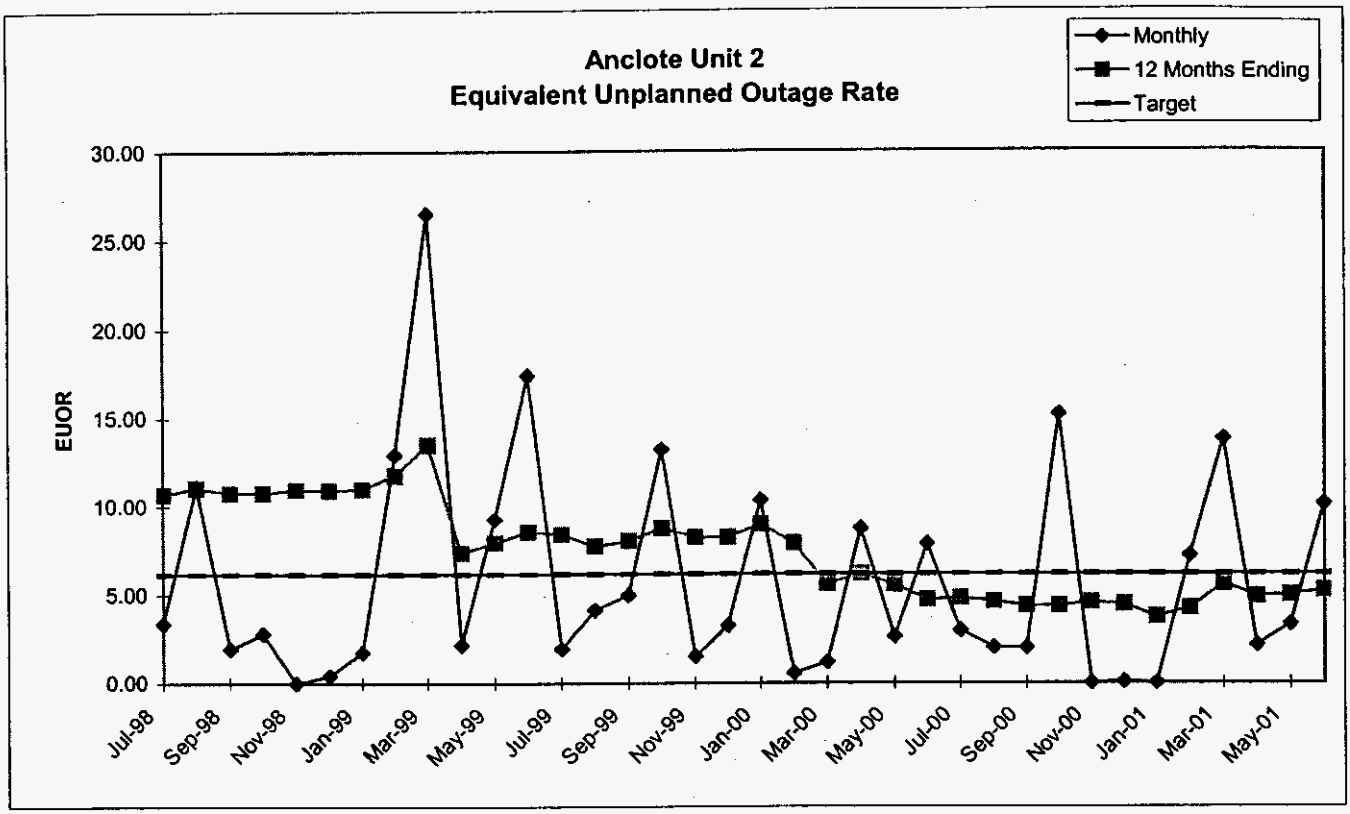
12 MONTHS	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FOR	0.09	0.09	0.09	0.09	0.09	0.64	0.64	0.64	0.64	0.65	0.69	0.73	0.62	0.65	0.66	0.74	0.74	0.08
MOR	5.79	5.18	2.79	3.38	2.72	1.40	1.40	1.40	1.40	1.77	1.90	1.99	1.51	1.96	3.38	2.68	2.68	3.55
PFOR	1.73	1.43	1.34	1.27	1.26	1.24	1.24	1.03	0.75	0.37	0.39	0.17	0.11	0.11	0.12	0.09	0.22	0.18
PMOR	1.56	1.37	1.45	1.53	1.57	1.51	1.60	1.61	1.62	1.63	1.64	1.62	1.54	1.56	1.54	1.48	1.43	1.46
EUOR	8.96	7.91	5.59	6.17	5.56	4.71	4.80	4.61	4.34	4.35	4.55	4.43	3.72	4.22	5.59	4.90	4.97	5.21
EUOF	8.27	7.30	5.15	5.69	5.13	4.35	4.43	4.25	4.01	3.96	3.87	3.60	3.06	3.32	4.39	3.85	3.91	4.10
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.79	9.98	12.55	12.55	12.58	12.58	12.58	12.58	12.58
EAF	91.73	92.70	94.85	94.31	94.87	95.65	95.57	95.75	95.99	94.25	86.14	83.85	84.39	84.09	83.02	83.56	83.50	83.32

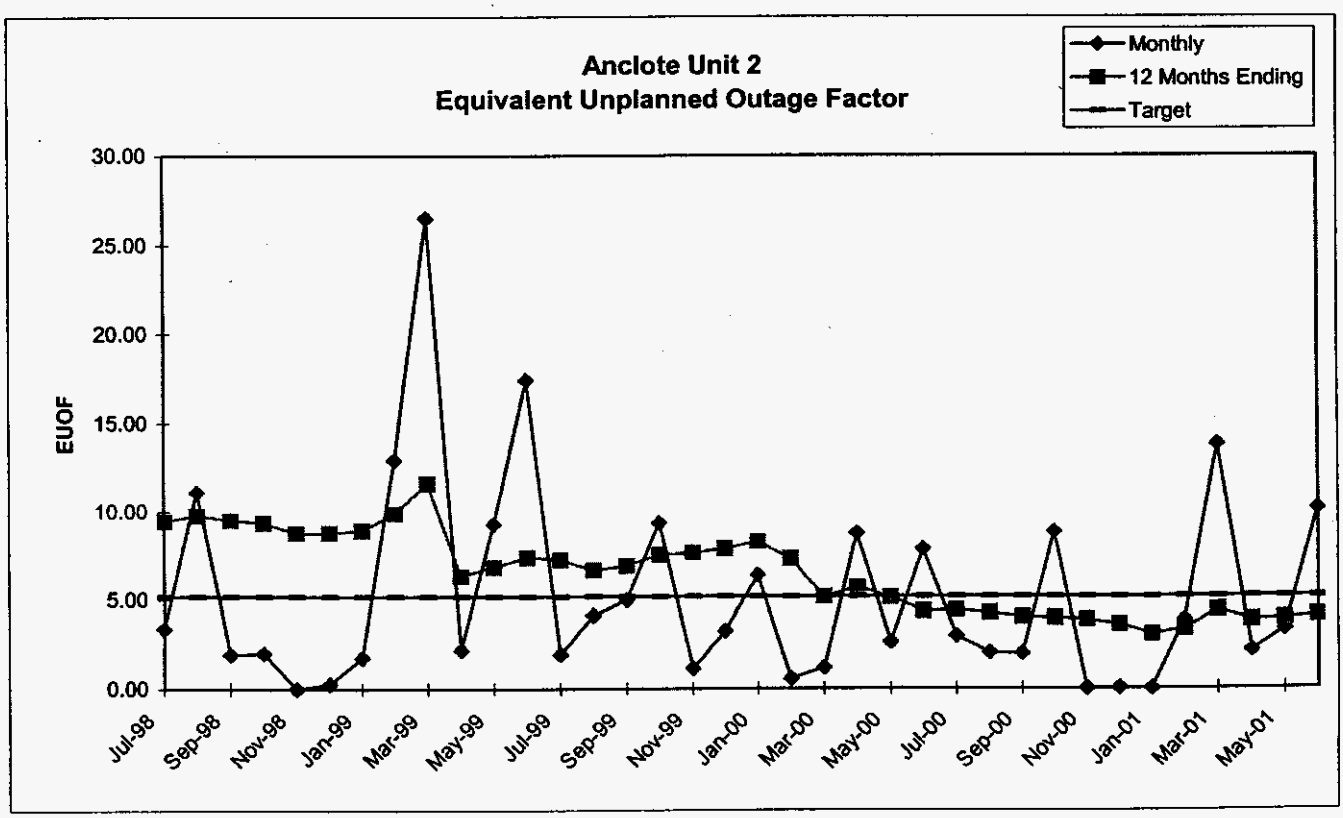

Anclote Unit 2
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Anclote Unit 2
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Anclote Unit 2
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Anclote Unit 2
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Anclote Unit 2
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Anclote Unit 2
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01

Bartow
Unit 3

	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	665.75	744.00	720.00	742.07	491.30	260.88	742.57	672.00	670.42	683.57	660.27	720.00	744.00	744.00	561.18	745.00	716.95	628.22
RSH	0.00	0.00	0.00	0.00	0.00	35.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	67.20
UH	78.25	0.00	0.00	2.93	228.70	448.02	1.43	0.00	73.58	35.43	83.73	0.00	0.00	0.00	158.82	0.00	3.05	48.58
POH	6.92	0.00	0.00	0.00	228.70	422.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	2.93	0.00	25.27	1.43	0.00	0.00	35.43	83.73	0.00	0.00	0.00	158.82	0.00	3.05	48.58
MOH	71.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	73.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EFOH	24.30	0.13	13.68	1.54	0.00	0.00	0.43	7.05	2.16	0.00	1.01	0.00	2.45	2.31	0.54	1.56	6.74	0.34
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	20.27	32.02	22.98	4.59	0.00	7.86	1.43	9.40	4.07	13.62	9.56	16.44	16.52	10.43	9.82	12.30	1.77
NPC	208.00	208.00	208.00	208.00	208.00	208.00	208.00	208.00	208.00	208.00	208.00	208.00	208.00	208.00	208.00	208.00	208.00	208.00

MONTHLY	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
FOR	0.00	0.00	0.00	0.39	0.00	8.83	0.19	0.00	0.00	4.93	11.25	0.00	0.00	0.00	22.06	0.00	0.42	7.18
MOR	9.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	3.65	0.02	1.90	0.21	0.00	0.00	0.06	1.05	0.32	0.00	0.15	0.00	0.33	0.31	0.10	0.21	0.94	0.05
PMOR	0.00	2.72	4.45	3.10	0.93	0.00	1.06	0.21	1.40	0.60	2.06	1.33	2.21	2.22	1.86	1.32	1.72	0.28
EUOR	12.97	2.74	6.35	3.68	0.93	8.83	1.31	1.26	11.44	5.49	13.22	1.33	2.54	2.53	23.58	1.53	3.07	7.49
EUOF	12.85	2.74	6.35	3.68	0.64	3.40	1.31	1.26	11.44	5.49	13.22	1.33	2.54	2.53	23.58	1.53	3.07	6.81
POF	0.93	0.00	0.00	0.00	31.76	56.82	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	86.22	97.26	93.65	96.32	67.60	39.78	98.69	98.74	88.56	94.51	86.78	98.67	97.46	97.47	76.42	98.47	96.93	93.19

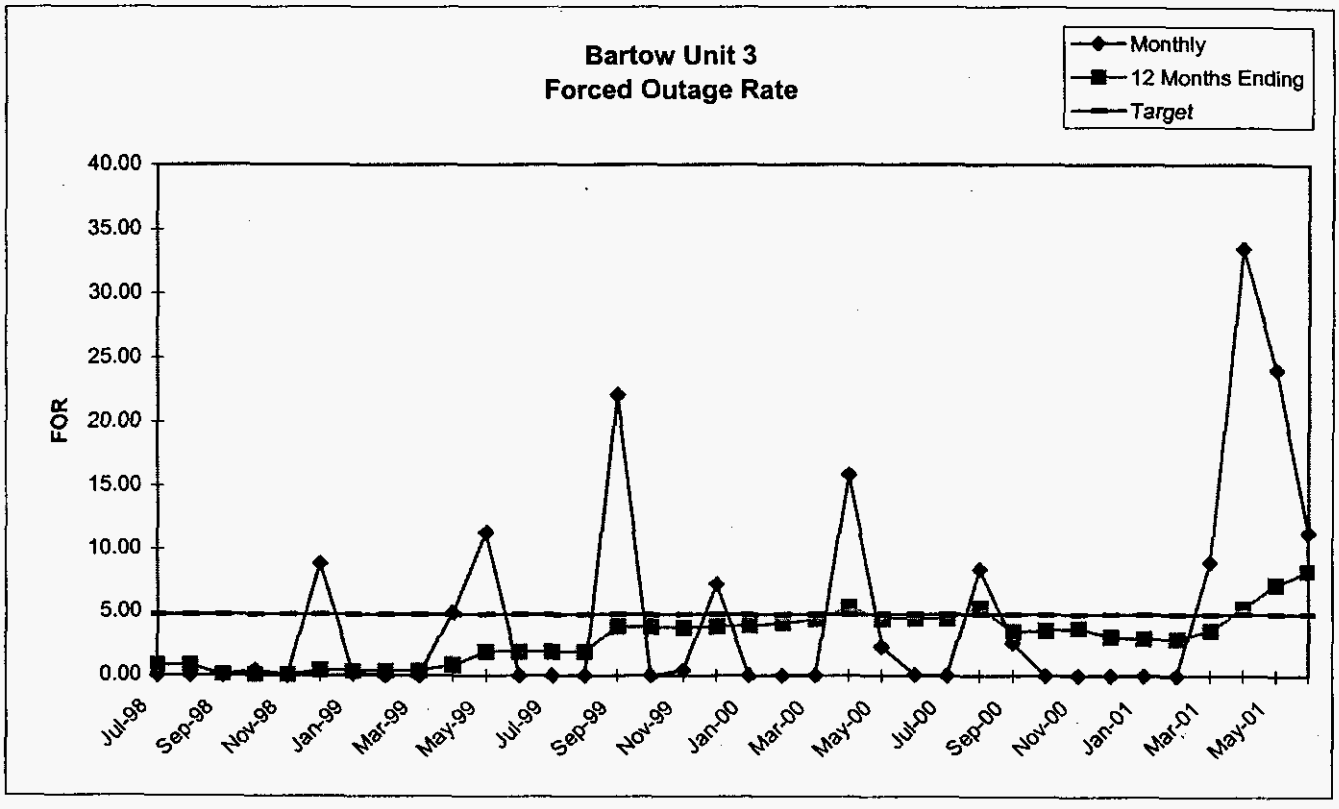
12 MONTHS	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
FOR	0.82	0.82	0.03	0.07	0.07	0.39	0.38	0.37	0.38	0.82	1.88	1.88	1.86	1.86	3.85	3.81	3.74	3.84
MOR	1.00	0.94	0.93	0.86	0.86	0.90	0.90	0.89	1.82	1.81	1.83	1.83	0.93	0.93	0.95	0.95	0.92	0.88
PFOR	2.91	2.22	2.23	1.71	1.61	1.70	0.59	0.60	0.63	0.63	0.65	0.65	0.36	0.39	0.23	0.23	0.31	0.30
PMOR	2.11	1.51	1.65	1.78	1.84	1.81	1.73	1.58	1.62	1.54	1.58	1.62	1.81	1.76	1.52	1.35	1.41	1.37
EUOR	6.73	5.40	4.81	4.38	4.33	4.75	3.56	3.40	4.38	4.71	5.79	5.82	4.87	4.85	6.39	6.19	6.23	6.24
EUOF	5.84	4.72	4.20	4.16	4.13	4.30	3.23	3.11	4.01	4.34	5.33	5.36	4.49	4.47	5.89	5.70	5.90	6.19
POF	11.69	11.17	11.17	3.50	3.30	8.12	8.12	8.12	8.12	7.52	7.52	7.52	7.44	7.44	7.44	7.44	4.83	0.00
EAF	82.47	84.12	84.64	92.34	92.58	87.57	88.65	88.76	87.87	88.14	87.15	87.12	88.08	88.09	86.68	86.86	89.27	93.81

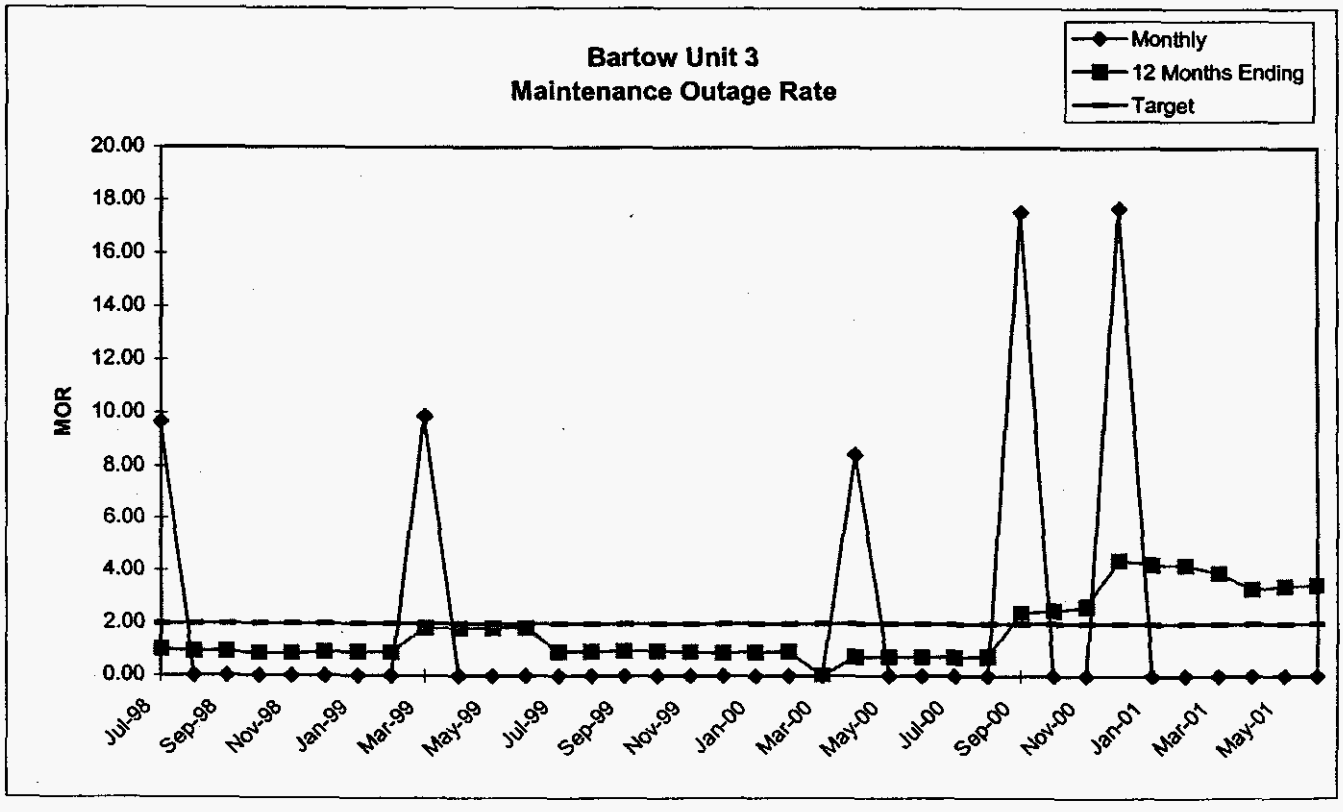
Bartow
Unit 3

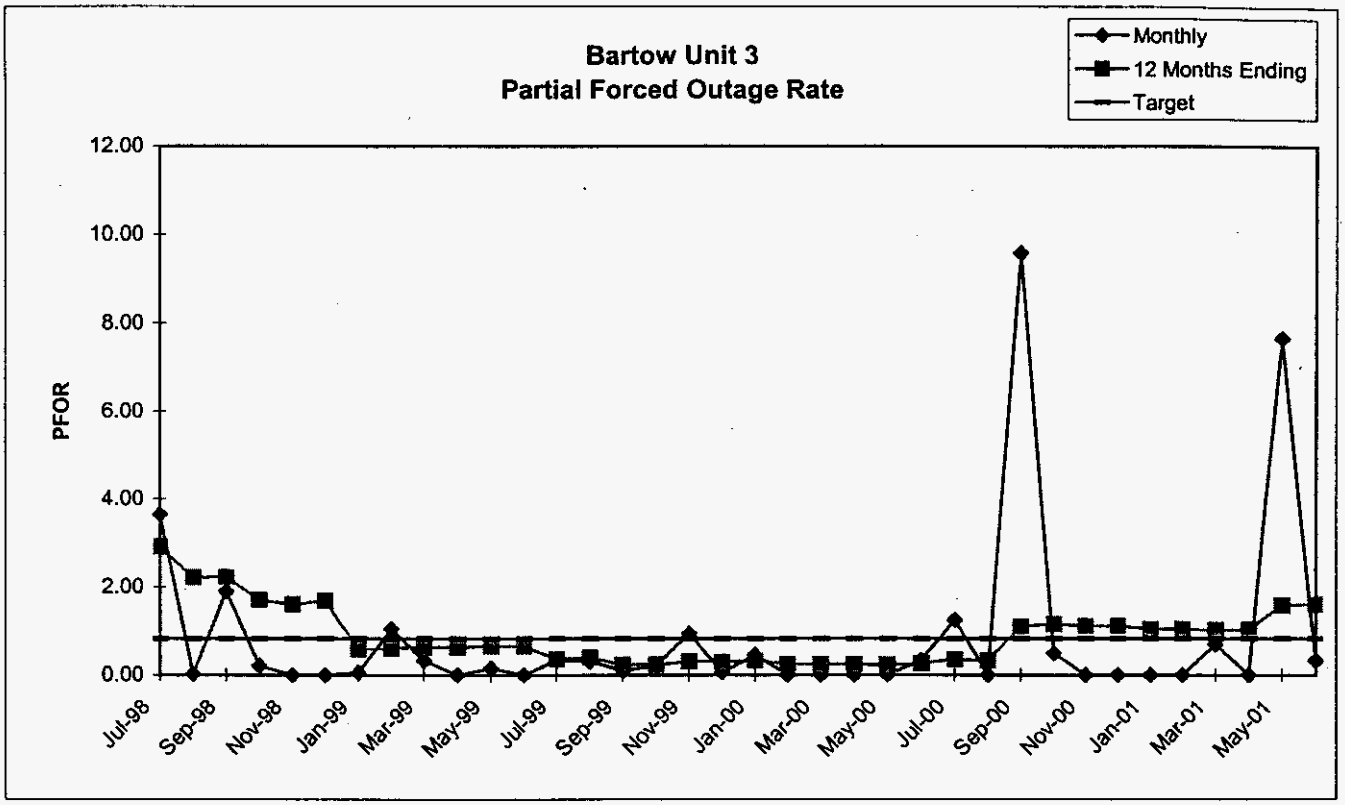
	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
PER HOURS	744.00	696.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	475.70	391.00	121.90	561.60	727.30	719.50	744.00	681.93	581.05	518.12	360.13	567.17	717.55	448.68	677.65	478.58	471.47	639.28
RSH	268.30	105.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	226.88	359.87	54.77	26.45	223.42	0.00	0.00	0.00	0.00
UH	0.00	199.40	622.10	157.40	16.70	0.50	0.00	62.07	138.95	0.00	0.00	122.07	0.00	0.00	66.35	240.42	272.53	80.72
POH	0.00	199.40	622.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	123.68	0.00
FOH	0.00	0.00	0.00	105.50	16.70	0.50	0.00	62.07	15.22	0.00	0.00	0.00	0.00	0.00	66.35	240.42	148.85	80.72
MOH	0.00	0.00	0.00	51.90	0.00	0.00	0.00	0.00	123.73	0.00	0.00	122.07	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	3.90	0.00	0.00	0.00	0.00	3.10	17.30	0.00	116.37	7.58	0.00	0.00	0.00	0.00	21.92	0.00	476.52	7.75
LRPF	113.00	0.00	0.00	0.00	0.00	159.80	111.89	0.00	99.64	69.35	0.00	0.00	0.00	0.00	43.60	0.00	15.44	55.02
EFOH	2.12	0.00	0.00	0.00	0.00	2.38	9.31	0.00	55.75	2.53	0.00	0.00	0.00	0.00	4.69	0.00	36.07	2.09
PMOH	5.00	11.20	0.00	7.50	12.80	23.50	82.73	35.40	29.36	367.48	2.00	0.00	36.40	0.00	7.30	6.95	19.97	45.25
LRPM	120.90	127.30	0.00	118.40	119.00	119.00	127.52	122.85	97.35	84.25	119.01	0.00	99.46	0.00	121.34	117.68	106.44	92.66
EMOH	2.91	6.85	0.00	4.27	7.32	13.44	50.72	20.91	13.74	148.84	1.14	0.00	17.75	0.00	4.34	4.01	10.42	20.55
NPC	208.00	208.00	208.00	208.00	208.00	208.00	208.00	208.00	208.00	208.00	208.00	208.00	204.00	204.00	204.00	204.00	204.00	204.00

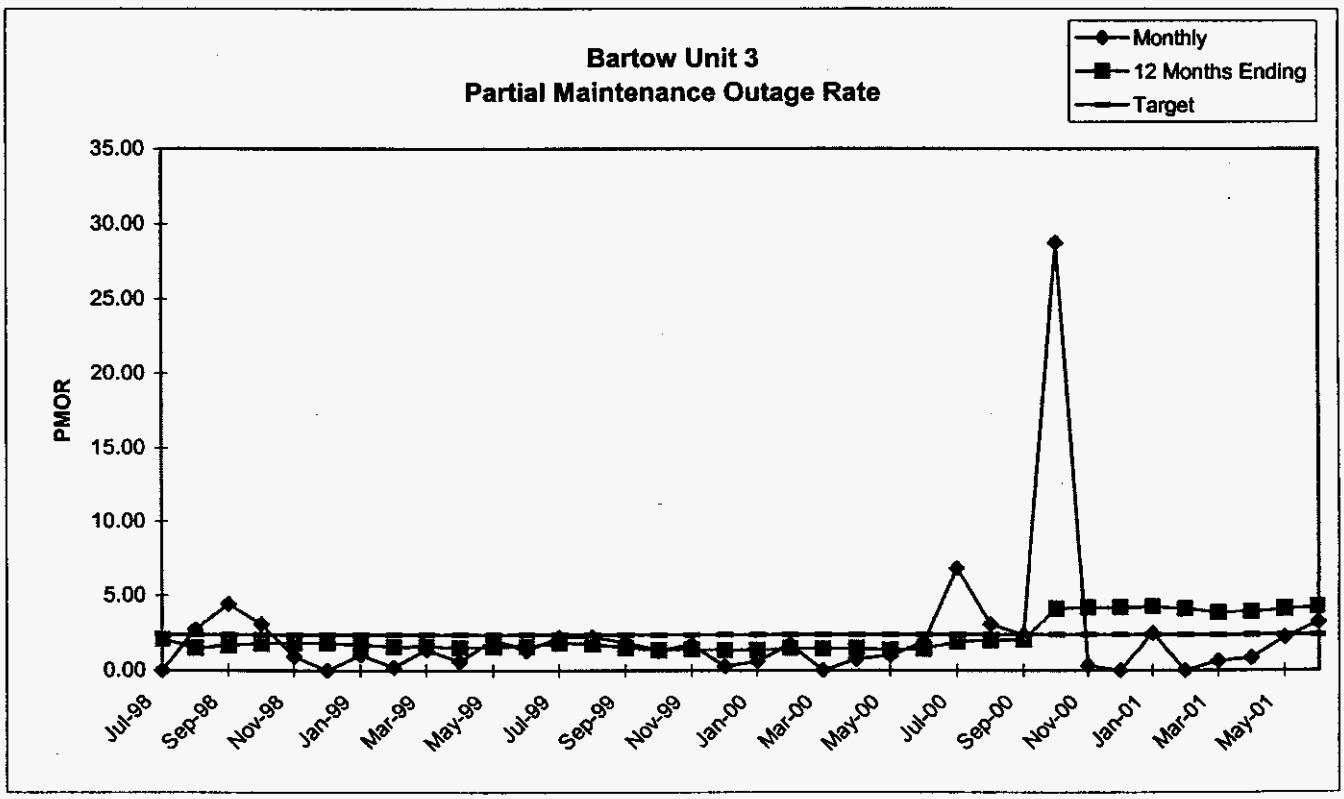
MONTHLY	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FOR	0.00	0.00	0.00	15.81	2.24	0.07	0.00	8.34	2.55	0.00	0.00	0.00	0.00	0.00	8.92	33.44	24.00	11.21
MOR	0.00	0.00	0.00	8.46	0.00	0.00	0.00	0.00	17.56	0.00	0.00	17.71	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.45	0.00	0.00	0.00	0.00	0.33	1.25	0.00	9.59	0.49	0.00	0.00	0.00	0.00	0.69	0.00	7.65	0.33
PMOR	0.61	1.75	0.00	0.76	1.01	1.87	6.82	3.07	2.37	28.73	0.32	0.00	2.47	0.00	0.64	0.84	2.21	3.22
EUOR	1.06	1.75	0.00	22.49	3.23	2.27	8.07	11.15	28.95	29.22	0.32	17.71	2.47	0.00	10.13	34.00	31.49	14.36
EUOF	0.68	0.98	0.00	22.49	3.23	2.27	8.07	11.15	28.95	20.32	0.16	16.41	2.39	0.00	10.13	34.00	26.26	14.36
POF	0.00	28.65	83.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.62	0.00
EAF	99.32	70.37	16.38	77.51	96.77	97.73	91.93	88.85	71.05	79.68	99.84	83.59	97.61	100.00	89.87	66.00	57.12	85.64

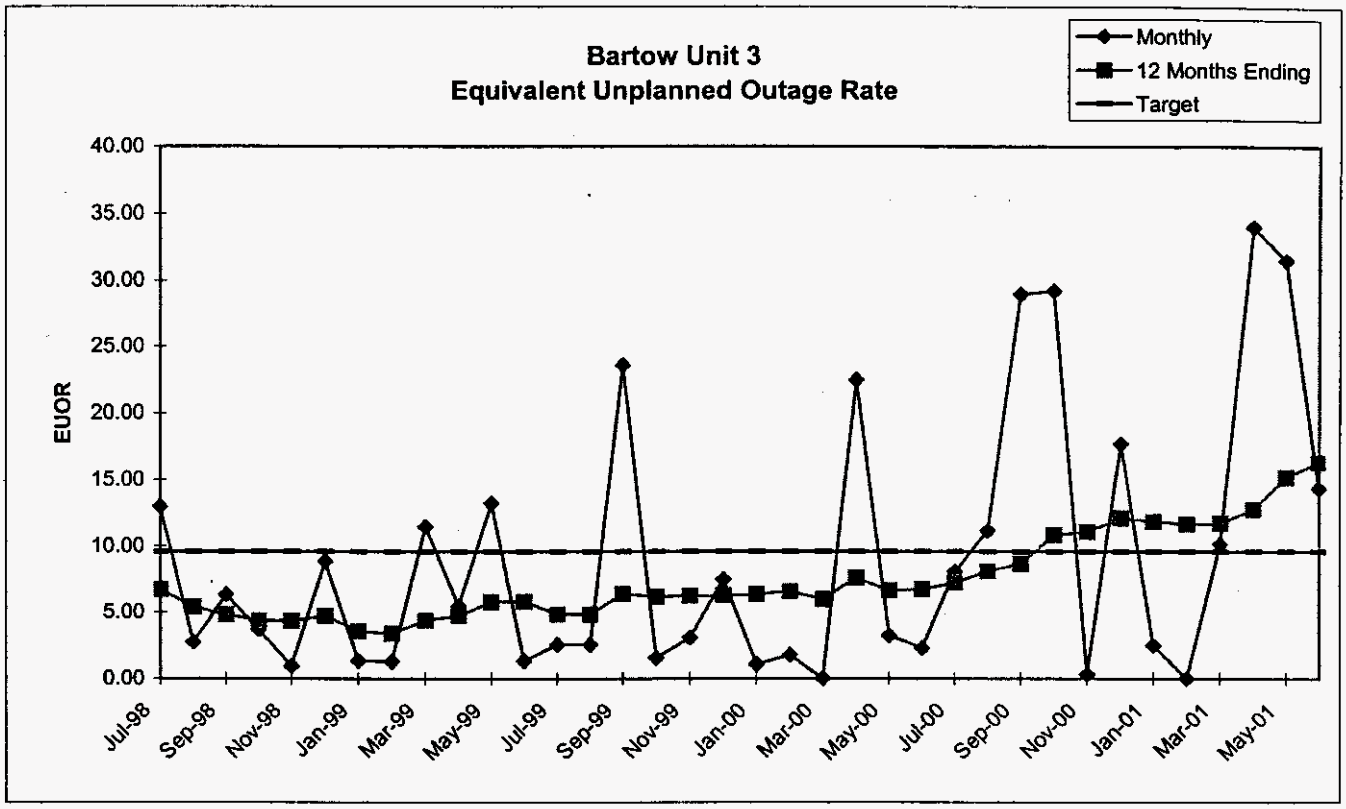
12 MONTHS	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FOR	3.95	4.08	4.38	5.35	4.45	4.46	4.46	5.29	3.43	3.53	3.68	3.01	2.90	2.88	3.52	5.26	7.11	8.18
MOR	0.91	0.94	0.00	0.73	0.72	0.72	0.72	0.73	2.42	2.49	2.63	4.41	4.26	4.22	3.92	3.29	3.41	3.45
PFOR	0.33	0.25	0.24	0.24	0.23	0.26	0.35	0.32	1.10	1.15	1.11	1.12	1.05	1.04	1.02	1.03	1.59	1.60
PMOR	1.35	1.47	1.45	1.48	1.38	1.43	1.91	1.99	2.03	4.12	4.18	4.19	4.26	4.12	3.87	3.91	4.10	4.25
EUOR	6.38	6.58	6.00	7.62	6.63	6.72	7.27	8.12	8.64	10.82	11.08	12.09	11.86	11.67	11.71	12.76	15.17	16.30
EUOF	6.14	6.10	5.13	6.52	5.68	5.76	6.22	6.95	7.39	8.99	8.75	9.56	9.71	9.66	10.52	11.46	13.42	14.41
POF	0.00	2.27	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35	7.10	0.00	0.00	1.41	1.41
EAF	93.86	91.63	85.51	84.12	84.97	84.89	84.42	83.69	83.25	81.66	81.90	81.09	80.94	83.24	89.48	88.54	85.17	84.18

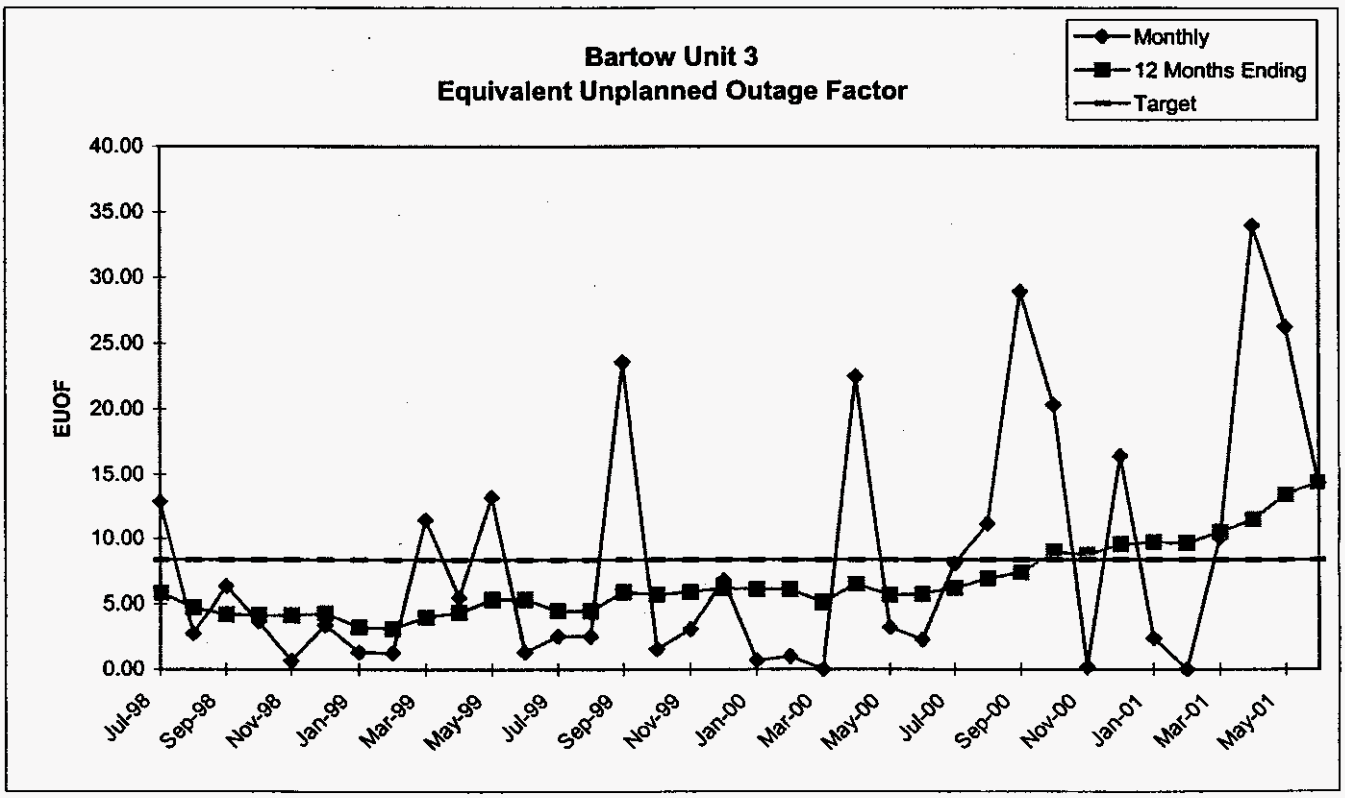

Bartow Unit 3
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Bartow Unit 3
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Bartow Unit 3
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Bartow Unit 3
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Bartow Unit 3
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Bartow Unit 3
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01

Crystal River
Unit 1

	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	386.90	712.50	720.00	745.00	613.82	353.15	594.07	404.32	674.18	385.20	510.23	709.38	723.30	744.00	720.00	476.00	0.00	388.70
RSH	0.00	0.00	0.00	0.00	106.18	224.65	149.93	264.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	357.10	31.50	0.00	0.00	0.00	166.20	0.00	3.33	69.82	333.80	233.77	10.62	20.70	0.00	0.00	269.10	720.00	355.30
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	215.70	720.00	303.60
FOH	162.30	31.50	0.00	0.00	0.00	72.85	0.00	3.33	25.23	0.00	32.18	1.23	0.00	0.00	0.00	0.00	0.00	51.70
MOH	194.80	0.00	0.00	0.00	0.00	93.35	0.00	0.00	44.58	333.80	201.58	9.38	20.70	0.00	0.00	53.40	0.00	0.00
PFOH	138.60	46.60	49.50	33.91	8.72	85.30	101.64	375.77	148.50	115.35	22.83	263.91	17.50	59.70	36.20	1.10	0.00	109.40
LRPF	37.40	115.40	121.20	37.30	57.60	76.31	28.20	18.60	38.10	109.19	53.66	106.62	99.50	106.10	75.20	93.30	0.00	204.60
EFOH	13.93	14.46	16.13	3.40	1.35	17.50	7.70	18.79	15.21	33.86	3.29	75.64	4.68	17.03	7.32	0.28	0.00	60.17
PMOH	0.00	8.60	46.20	15.29	79.05	0.00	2.33	0.00	5.53	0.00	7.23	24.85	45.60	28.30	45.50	15.40	0.00	9.20
LRPM	0.00	155.70	156.90	162.30	83.50	0.00	74.60	0.00	74.47	0.00	14.00	167.41	114.30	140.10	125.70	159.40	0.00	186.00
EMOH	0.00	3.60	19.49	6.67	17.74	0.00	0.47	0.00	1.11	0.00	0.27	11.18	14.01	10.66	15.37	6.60	0.00	4.60
NPC	372.00	372.00	372.00	372.00	372.00	372.00	372.00	372.00	372.00	372.00	372.00	372.00	372.00	372.00	372.00	372.00	372.00	372.00

MONTHLY	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
FOR	29.55	4.23	0.00	0.00	0.00	17.10	0.00	0.82	3.61	0.00	5.93	0.17	0.00	0.00	0.00	0.00	0.00	11.74
MOR	33.49	0.00	0.00	0.00	0.00	20.91	0.00	0.00	6.20	46.43	28.32	1.31	2.78	0.00	0.00	10.09	0.00	0.00
PFOR	3.60	2.03	2.24	0.46	0.22	4.95	1.30	4.65	2.26	8.79	0.65	10.66	0.65	2.29	1.02	0.06	0.00	15.48
PMOR	0.00	0.51	2.71	0.90	2.89	0.00	0.08	0.00	0.16	0.00	0.05	1.58	1.94	1.43	2.14	1.39	0.00	1.18
EUOR	49.87	6.66	4.95	1.35	3.11	35.37	1.38	5.43	11.58	51.13	31.90	13.53	5.29	3.72	3.15	11.39	0.00	26.45
EUOF	49.87	6.66	4.95	1.35	2.65	24.69	1.10	3.29	11.58	51.13	31.90	13.53	5.29	3.72	3.15	8.09	0.00	15.65
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.95	100.00	40.81
EAF	50.13	93.34	95.05	98.65	97.35	75.31	98.90	96.71	88.42	48.87	68.10	86.47	94.71	96.28	96.85	62.96	0.00	43.54

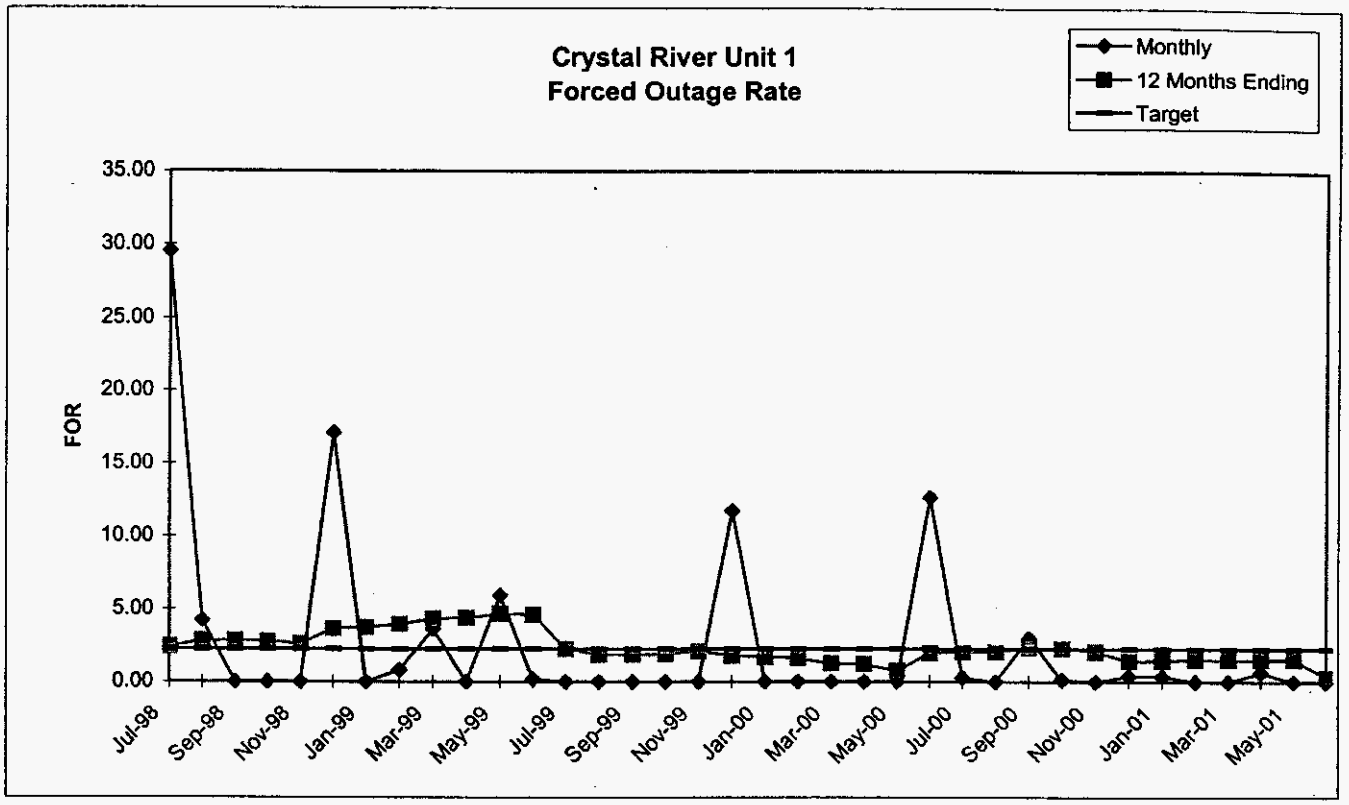
12 MONTHS	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
FOR	2.40	2.82	2.82	2.79	2.59	3.67	3.74	3.93	4.33	4.37	4.67	4.60	2.27	1.84	1.84	1.91	2.10	1.76
MOR	5.43	5.45	5.45	4.70	4.38	5.80	5.82	6.04	6.69	11.03	13.09	11.42	8.96	8.93	8.93	9.87	10.73	9.49
PFOR	2.51	2.39	2.29	2.15	1.94	1.97	2.12	2.24	2.41	2.95	2.89	3.25	2.97	2.99	2.87	2.93	3.20	3.85
PMOR	0.60	0.65	0.91	0.99	1.24	1.31	1.31	1.18	0.82	0.79	0.77	0.89	1.04	1.14	1.08	1.12	0.95	1.02
EUOR	10.45	10.77	10.92	10.16	9.72	12.05	12.26	12.61	13.36	17.70	19.69	18.56	14.43	14.15	13.99	15.02	16.04	15.27
EUOF	9.63	9.93	10.07	9.37	8.84	10.66	10.63	10.55	11.18	15.34	18.02	16.99	13.20	12.95	12.80	13.38	13.16	12.39
POF	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	4.82	0.00	0.00	0.00	0.00	0.00	2.46	10.68	14.15
EAF	82.56	82.26	82.13	82.82	83.35	81.54	81.56	81.64	81.01	79.84	81.98	83.01	86.80	87.05	87.20	84.16	76.16	73.46

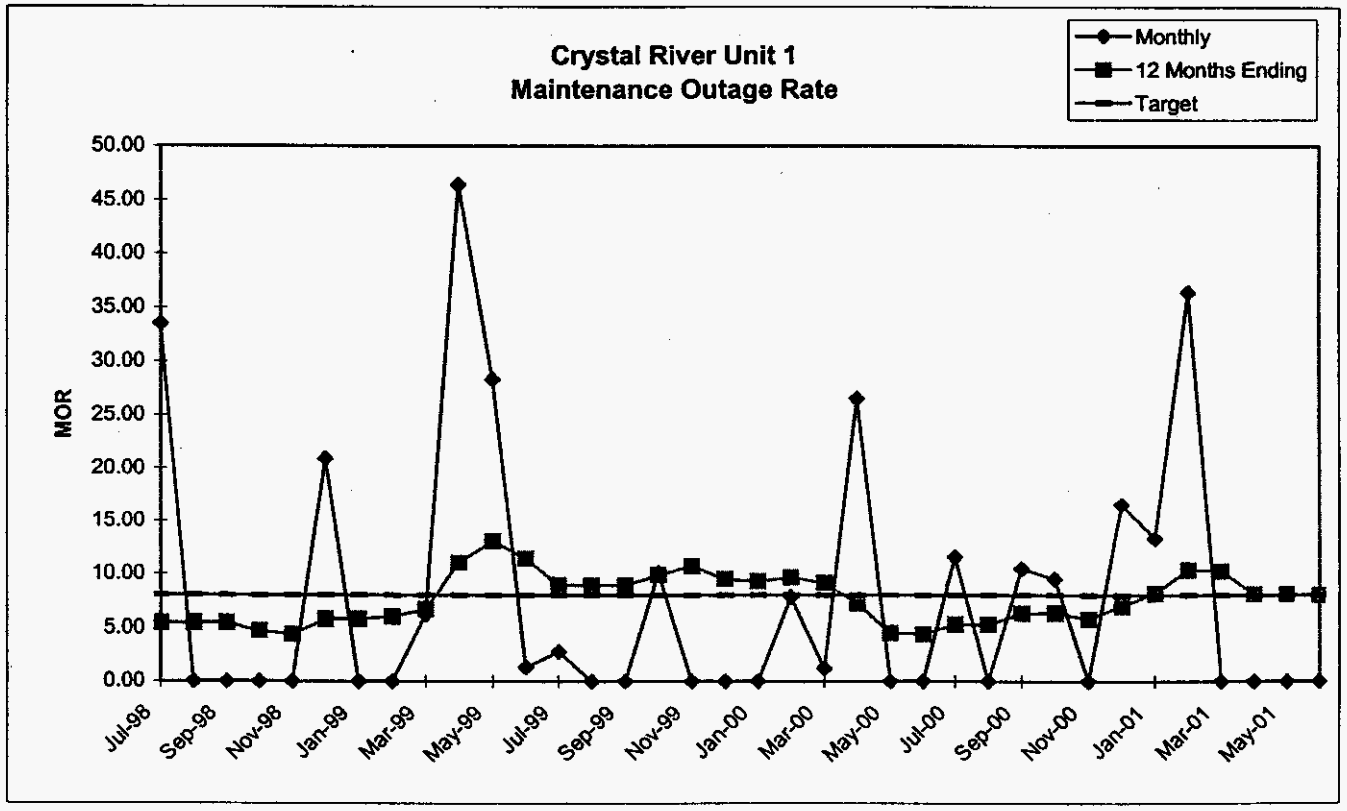
Crystal River
Unit 1

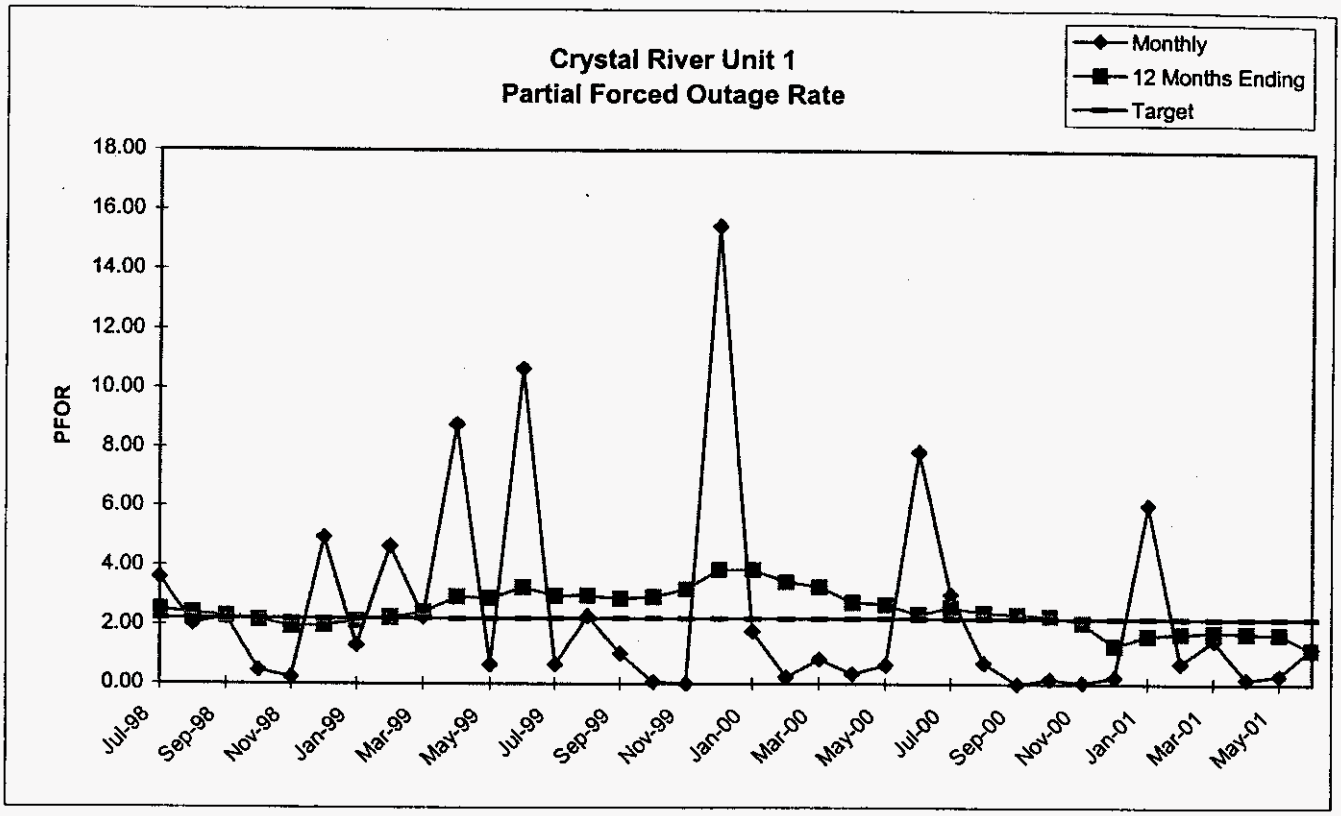
	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
PER HOURS	744.00	696.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	744.00	641.50	735.10	528.20	744.00	628.90	656.02	744.00	627.20	673.23	720.00	618.95	642.83	427.37	744.00	675.33	744.00	720.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	54.50	8.90	190.80	0.00	91.10	87.98	0.00	92.80	71.77	0.00	125.05	101.17	244.63	0.00	43.67	0.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	91.10	1.93	0.00	19.27	0.83	0.00	2.40	2.35	0.00	0.00	4.37	0.00	0.00
MOH	0.00	54.50	8.90	190.80	0.00	0.00	86.05	0.00	73.53	70.93	0.00	122.65	98.82	244.63	0.00	0.00	0.00	0.00
PFOH	41.10	6.30	24.40	4.10	12.10	119.00	73.80	22.63	0.00	2.10	12.58	3.00	150.54	7.48	25.95	4.78	4.05	34.16
LRPF	119.00	83.10	92.30	158.60	143.80	153.60	99.25	86.01	0.00	193.80	9.23	175.24	98.19	151.65	160.79	85.33	198.94	99.04
EFOH	13.25	1.42	6.10	1.76	4.72	49.53	19.85	5.27	0.00	1.10	0.31	1.42	39.00	2.99	11.01	1.08	2.13	8.93
PMOH	14.60	20.90	31.70	9.20	8.20	31.80	20.58	36.01	42.00	61.62	30.96	17.68	13.75	7.53	34.63	58.95	42.39	60.87
LRPM	184.60	83.00	193.70	101.50	101.40	193.70	180.42	199.85	193.71	108.85	119.87	78.15	89.76	104.26	232.51	104.63	177.03	150.32
EMOH	7.30	4.70	16.64	2.53	2.25	16.69	10.06	19.50	22.05	18.18	10.06	3.74	3.26	2.07	21.25	16.27	19.80	24.14
NPC	369.00	369.00	369.00	369.00	369.00	369.00	369.00	369.00	369.00	369.00	369.00	369.00	379.00	379.00	379.00	379.00	379.00	379.00

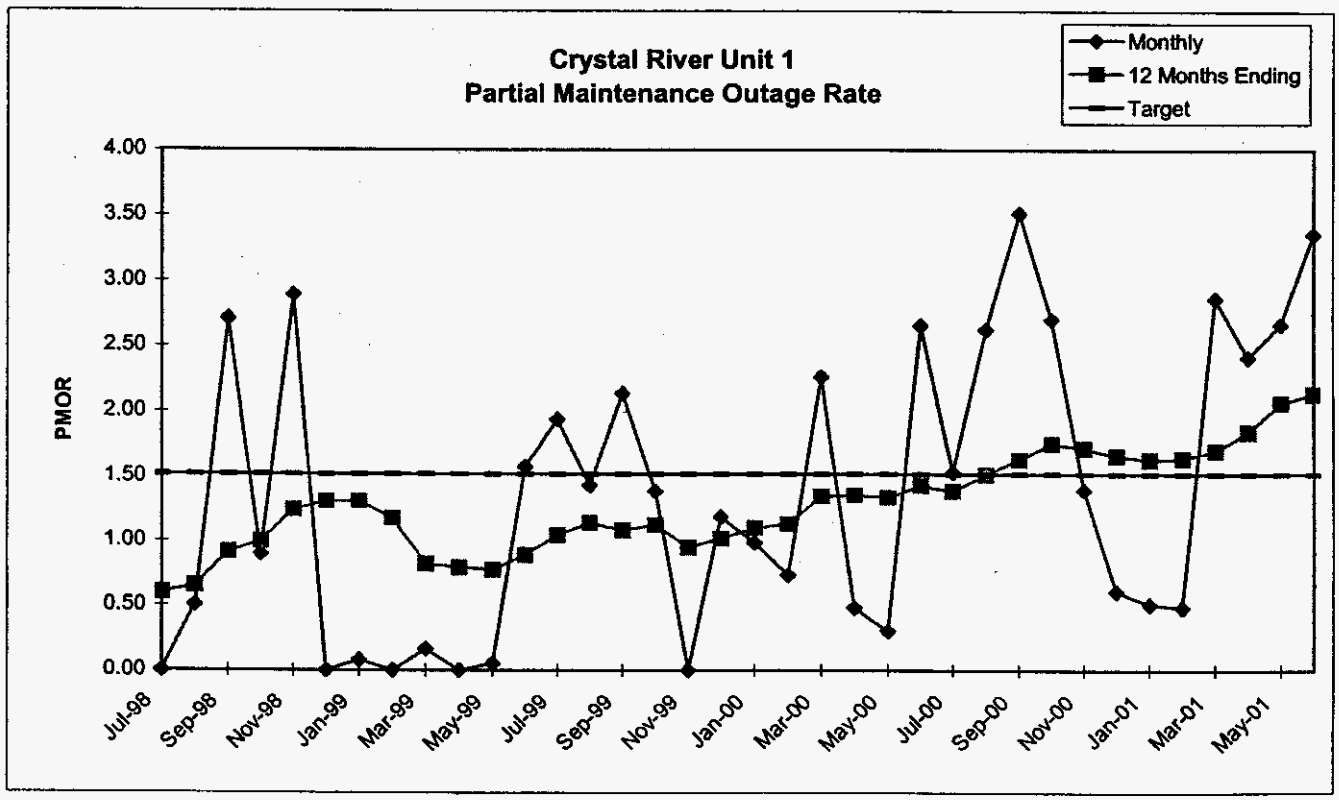
MONTHLY	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FOR	0.00	0.00	0.00	0.00	0.00	12.65	0.29	0.00	2.98	0.12	0.00	0.39	0.36	0.00	0.00	0.64	0.00	0.00
MOR	0.00	7.83	1.20	26.54	0.00	0.00	11.60	0.00	10.49	9.53	0.00	16.54	13.32	36.40	0.00	0.00	0.00	0.00
PFOR	1.78	0.22	0.83	0.33	0.63	7.88	3.03	0.71	0.00	0.16	0.04	0.23	6.07	0.70	1.48	0.16	0.29	1.24
PMOR	0.98	0.73	2.26	0.48	0.30	2.65	1.53	2.62	3.52	2.70	1.40	0.60	0.51	0.48	2.86	2.41	2.66	3.35
EUOR	2.76	8.71	4.25	27.13	0.94	21.85	15.85	3.33	15.95	12.22	1.44	17.50	19.28	37.16	4.34	3.20	2.95	4.59
EUOF	2.76	8.71	4.25	27.13	0.94	21.85	15.85	3.33	15.95	12.22	1.44	17.50	19.28	37.16	4.34	3.02	2.95	4.59
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	97.24	91.29	95.75	72.87	99.06	78.15	84.15	96.67	84.05	87.78	98.56	82.50	80.72	62.84	95.66	96.98	97.05	95.41

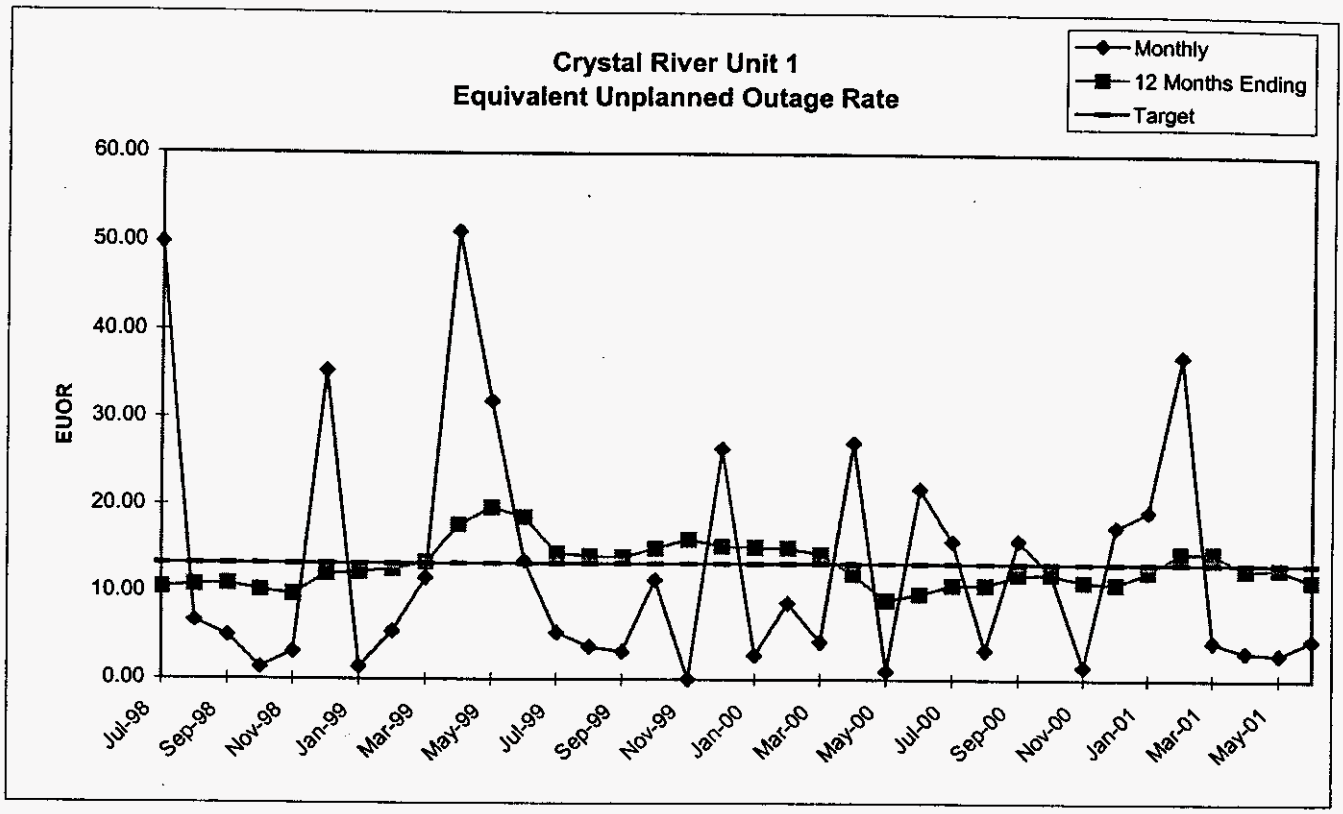
12 MONTHS	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FOR	1.72	1.62	1.24	1.21	0.73	1.98	2.02	2.02	2.32	2.27	2.06	1.41	1.46	1.50	1.50	1.52	1.52	0.39
MOR	9.29	9.66	9.15	7.23	4.51	4.44	5.32	5.32	6.33	6.38	5.83	7.01	8.15	10.37	10.27	8.10	8.10	8.02
PFOR	3.85	3.46	3.29	2.76	2.69	2.35	2.59	2.42	2.35	2.29	2.09	1.30	1.64	1.71	1.77	1.72	1.69	1.16
PMOR	1.10	1.13	1.35	1.36	1.34	1.43	1.39	1.52	1.63	1.75	1.72	1.66	1.63	1.64	1.70	1.84	2.06	2.13
EUOR	15.13	15.06	14.34	12.05	9.00	9.79	10.83	10.79	12.01	12.08	11.17	10.94	12.34	14.54	14.54	12.62	12.79	11.37
EUOF	12.53	12.94	12.32	10.35	7.73	8.41	9.30	9.27	10.32	10.67	10.79	10.94	12.34	14.54	14.54	12.56	12.73	11.32
POF	14.15	14.11	14.11	14.11	14.11	14.11	14.11	14.11	14.11	11.65	3.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	73.32	72.96	73.58	75.54	78.16	77.48	76.59	76.62	75.57	77.68	85.76	89.06	87.66	85.46	85.46	87.44	87.27	88.68

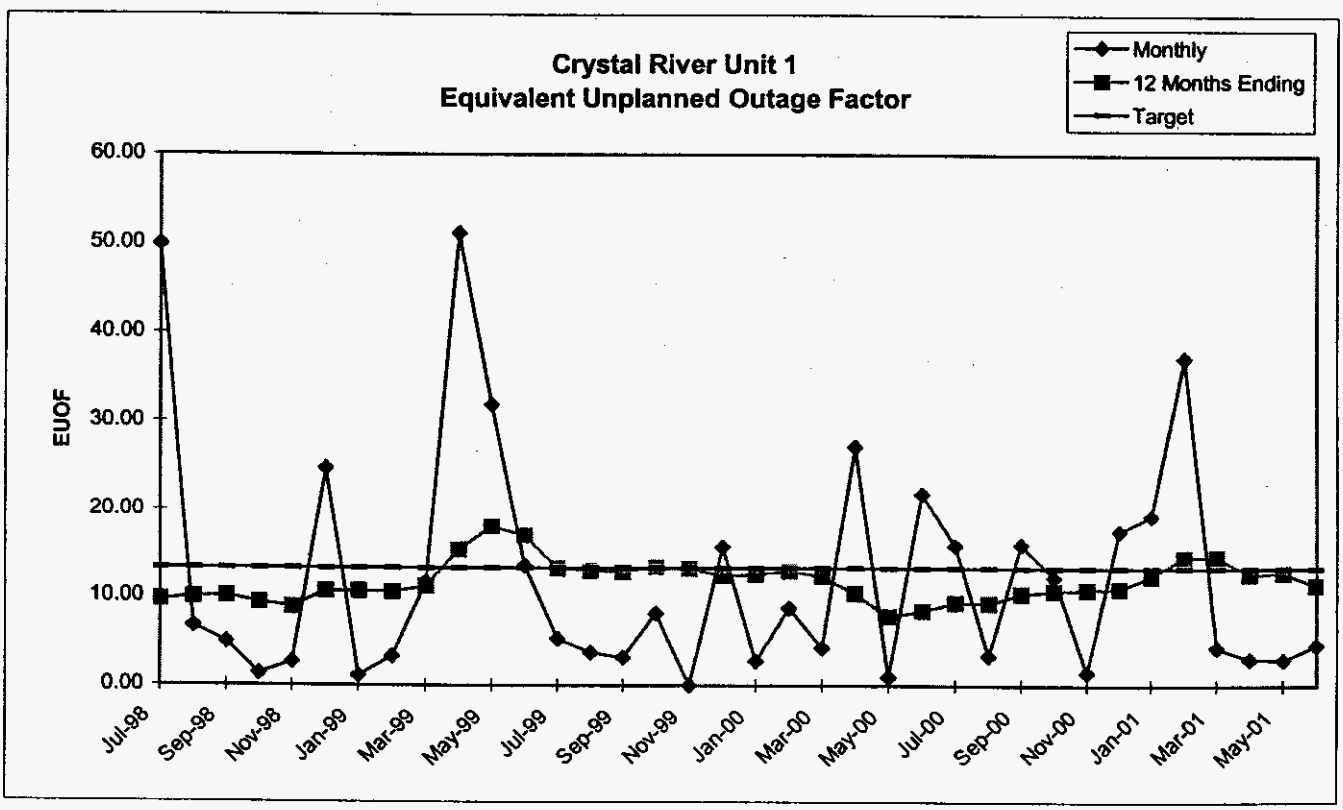

Crystal River Unit 1
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 1
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 1
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 1
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 1
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 1
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01

Crystal River
Unit 2

	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	744.00	718.80	745.00	720.00	695.22	660.33	550.53	666.70	713.75	744.00	698.27	744.00	744.00	635.50	745.00	720.00	744.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	83.67	121.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	1.20	0.00	0.00	48.78	0.00	0.00	77.30	5.25	0.00	21.73	0.00	0.00	84.50	0.00	0.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	1.20	0.00	0.00	48.78	0.00	0.00	0.00	5.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	77.30	0.00	0.00	21.73	0.00	0.00	84.50	0.00	0.00	0.00
PFOH	16.60	107.30	56.90	0.00	81.28	7.48	0.00	50.65	20.20	39.65	6.35	25.43	77.40	299.40	757.10	15.40	17.60	0.00
LRPF	29.50	20.00	120.50	0.00	446.43	117.13	0.00	29.34	131.50	176.47	93.60	129.32	39.10	100.60	38.00	116.40	260.20	0.00
EFOH	1.05	4.59	14.65	0.00	77.53	1.87	0.00	3.18	5.68	14.95	1.27	7.03	6.47	64.36	61.47	3.83	9.79	0.00
PMOH	37.40	0.00	49.30	0.00	3.00	52.83	0.00	0.00	0.00	0.00	44.75	22.90	39.60	21.10	20.40	32.90	692.60	575.80
LRPM	93.60	0.00	219.00	0.00	468.00	79.51	0.00	0.00	0.00	0.00	108.92	152.99	216.20	166.10	145.20	1210.50	48.30	57.10
EMOH	7.48	0.00	23.07	0.00	3.00	8.98	0.00	0.00	0.00	0.00	10.42	7.49	18.29	7.49	6.33	85.10	71.48	70.25
NPC	468.00	468.00	468.00	468.00	468.00	468.00	468.00	468.00	468.00	468.00	468.00	468.00	468.00	468.00	468.00	468.00	468.00	468.00

MONTHLY	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
FOR	0.00	0.00	0.17	0.00	0.00	6.56	0.00	0.00	0.00	0.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.39	0.00	0.00	3.02	0.00	0.00	11.74	0.00	0.00	0.00
PFOR	0.14	0.62	2.04	0.00	10.77	0.27	0.00	0.58	0.85	2.09	0.17	1.01	0.87	8.65	9.67	0.51	1.36	0.00
PMOR	1.01	0.00	3.21	0.00	0.42	1.29	0.00	0.00	0.00	0.00	1.40	1.07	2.46	1.01	1.00	11.42	9.93	9.44
EUOR	1.15	0.62	5.41	0.00	11.19	8.01	0.00	0.58	11.15	2.81	1.57	5.03	3.33	9.66	21.15	11.94	11.29	9.44
EUOF	1.15	0.62	5.41	0.00	11.19	8.01	0.00	0.47	11.15	2.81	1.57	5.03	3.33	9.66	21.15	11.94	11.29	9.44
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	98.85	99.38	94.59	100.00	88.81	91.99	100.00	99.53	88.85	97.19	98.43	94.97	96.67	90.34	78.85	88.06	88.71	90.56

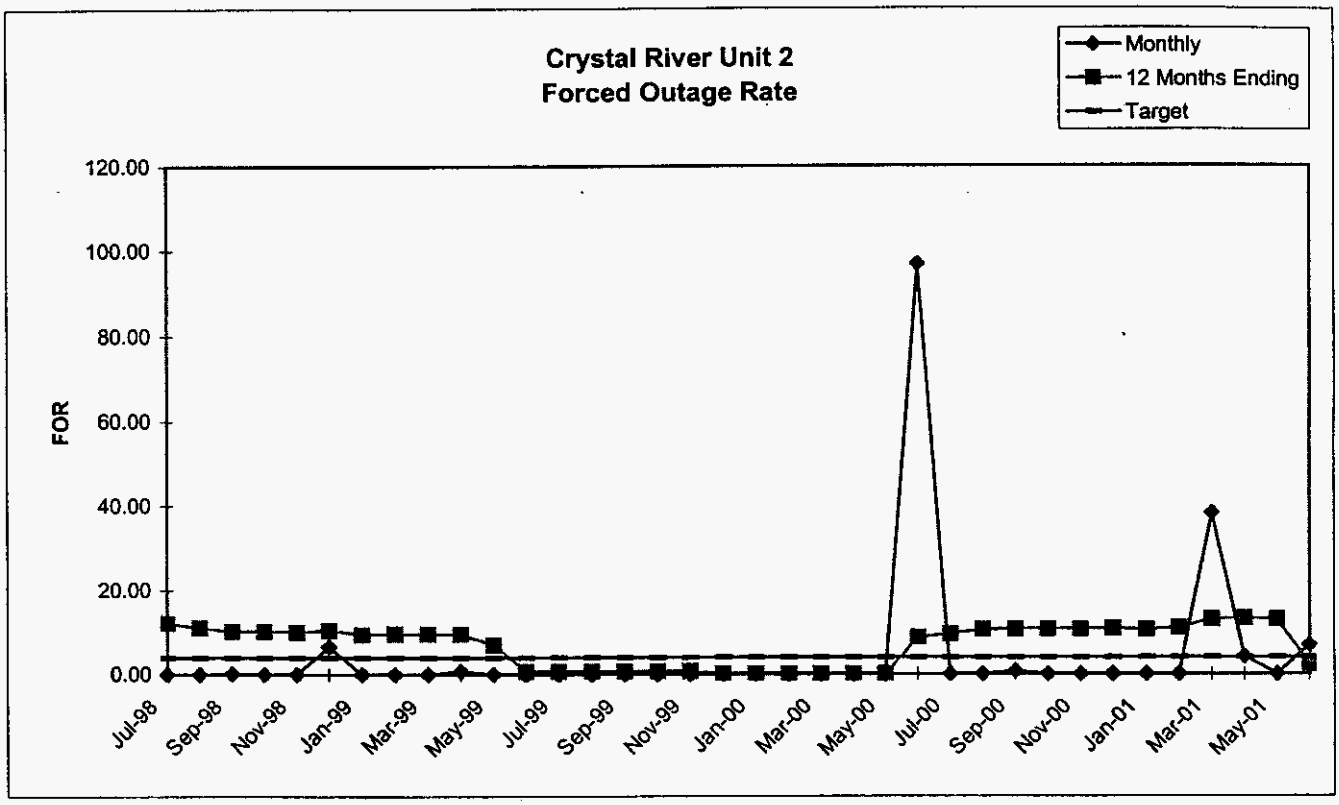
12 MONTHS	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
FOR	12.17	10.99	10.16	10.16	10.00	10.36	9.45	9.59	9.49	9.51	6.98	0.65	0.65	0.65	0.65	0.65	0.65	0.06
MOR	6.51	6.42	6.21	6.21	4.55	2.76	2.69	2.74	1.68	1.36	1.33	1.17	1.17	1.17	2.16	2.16	2.16	2.15
PFOR	3.70	3.25	3.01	2.58	2.68	2.05	1.57	1.64	1.66	1.80	1.59	1.57	1.63	2.34	2.93	2.98	2.16	2.13
PMOR	0.80	0.79	1.09	1.09	1.12	1.22	1.13	0.84	0.83	0.66	0.67	0.72	0.85	0.94	0.75	1.77	2.59	3.31
EUOR	20.96	19.50	18.68	18.32	16.98	15.45	14.05	14.01	13.09	12.84	10.21	4.05	4.24	5.03	6.35	7.39	7.40	7.52
EUOF	20.93	19.50	18.68	18.32	16.98	15.45	13.91	13.68	12.78	12.53	9.97	3.96	4.14	4.91	6.20	7.22	7.23	7.35
POF	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	78.93	80.50	81.32	81.68	83.02	84.55	86.09	86.32	87.22	87.47	90.03	96.04	95.86	95.09	93.80	92.78	92.77	92.65

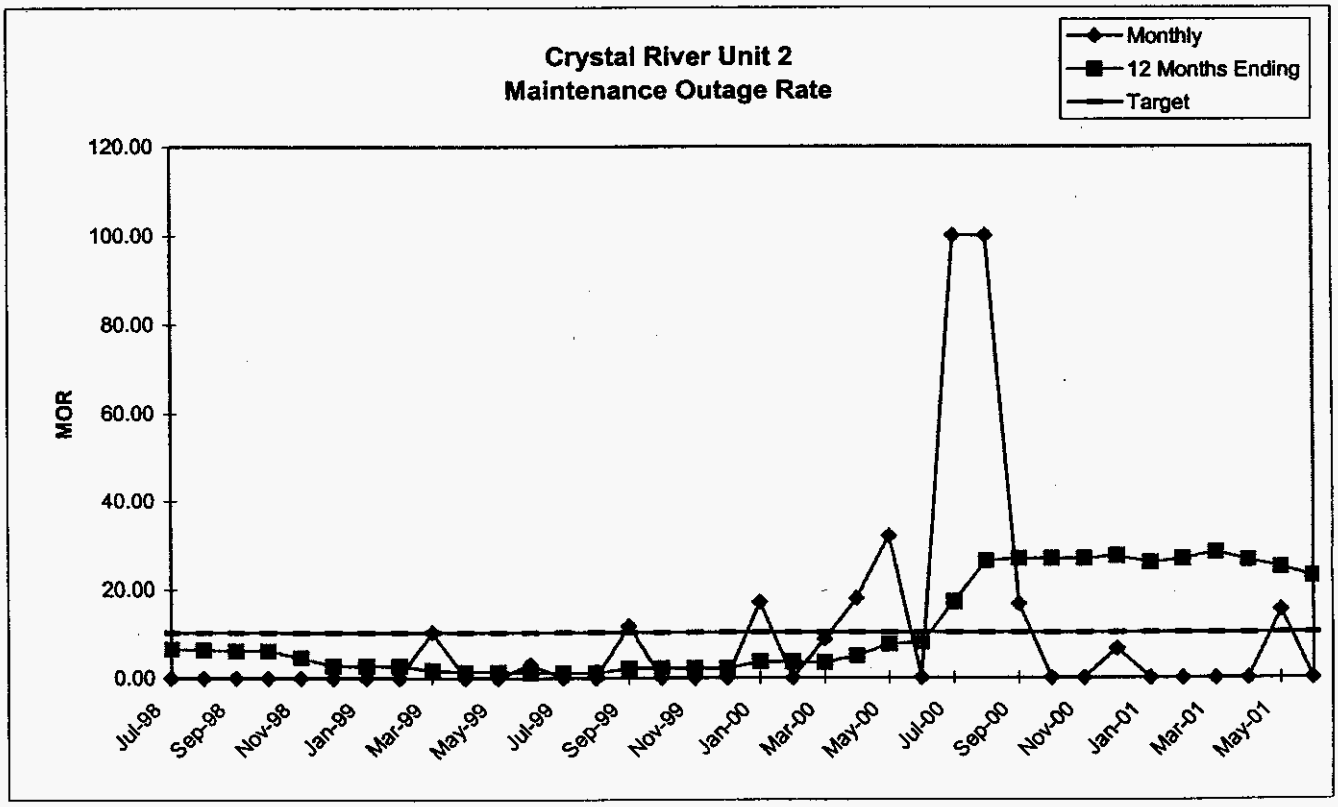
Crystal River
Unit 2

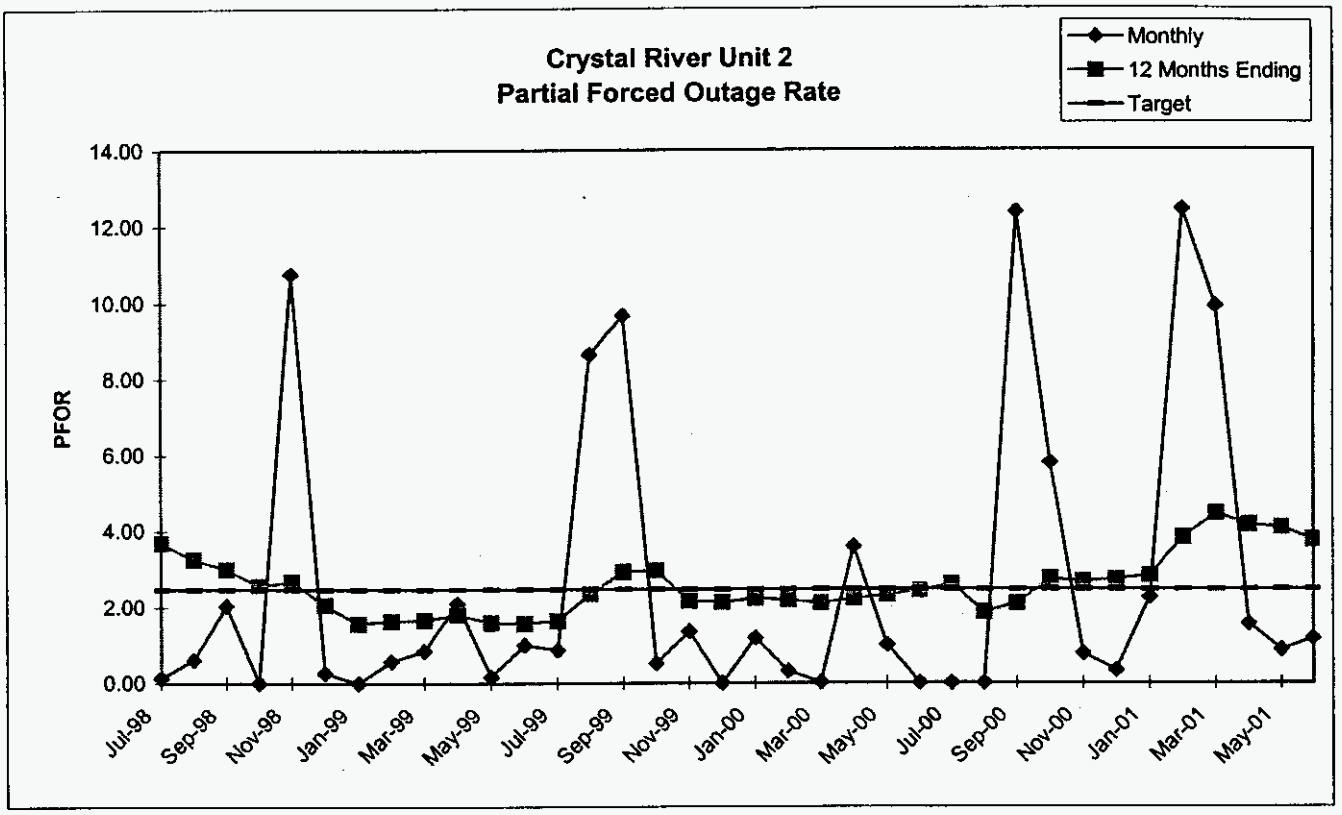
	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
PER HOURS	744.00	696.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	616.50	696.00	678.50	589.90	505.90	22.30	0.03	0.02	596.55	745.00	720.00	695.05	744.00	405.32	99.72	689.73	629.48	670.47
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	127.50	0.00	65.50	129.10	238.10	697.70	743.97	743.98	123.45	0.00	0.00	48.95	0.00	266.68	644.28	29.27	114.52	49.53
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	266.68	582.43	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	697.70	0.00	0.00	3.88	0.00	0.00	0.00	0.00	0.00	61.85	29.27	0.00	49.53
MOH	127.50	0.00	65.50	129.10	238.10	0.00	743.97	743.98	119.57	0.00	0.00	48.95	0.00	0.00	0.00	0.00	114.52	0.00
PFOH	17.60	3.70	5.50	150.00	15.50	0.00	0.00	0.00	411.97	120.15	11.75	5.77	202.47	309.17	23.33	151.73	33.31	28.25
LRPF	192.20	269.30	9.30	65.50	152.40	0.00	0.00	0.00	87.12	174.88	232.57	193.33	40.29	79.28	205.89	34.32	79.50	134.96
EFOH	7.29	2.15	0.11	21.17	5.09	0.00	0.00	0.00	73.85	43.23	5.62	2.30	16.79	50.44	9.88	10.72	5.45	7.84
PMOH	516.70	149.40	75.30	43.60	41.10	0.00	0.00	0.00	0.00	49.62	39.17	28.99	31.78	0.00	0.00	46.25	72.14	64.15
LRPM	55.50	102.60	173.00	170.30	128.60	0.00	0.00	0.00	0.00	188.90	190.09	139.42	198.93	0.00	0.00	231.45	152.47	236.65
EMOH	61.80	33.04	28.08	16.00	11.39	0.00	0.00	0.00	0.00	19.29	15.32	8.32	13.01	0.00	0.00	22.03	22.63	31.24
NPC	464.00	464.00	464.00	464.00	464.00	464.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00

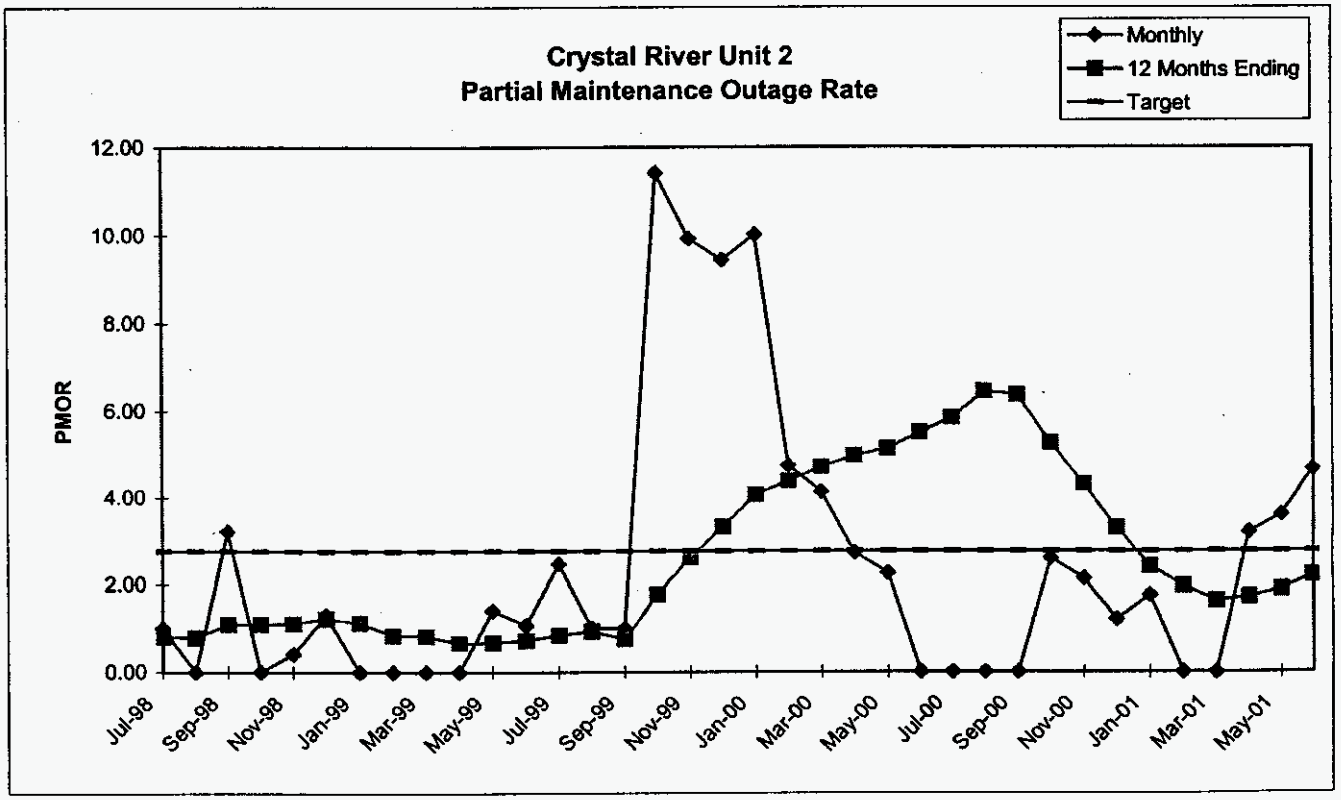
MONTHLY	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FOR	0.00	0.00	0.00	0.00	0.00	96.90	0.00	0.00	0.65	0.00	0.00	0.00	0.00	0.00	38.28	4.07	0.00	6.88
MOR	17.14	0.00	8.80	17.96	32.00	0.00	100.00	100.00	16.70	0.00	0.00	6.58	0.00	0.00	0.00	0.00	15.39	0.00
PFOR	1.18	0.31	0.02	3.59	1.01	0.00	0.00	0.00	12.38	5.80	0.78	0.33	2.26	12.44	9.91	1.55	0.87	1.17
PMOR	10.02	4.75	4.14	2.71	2.25	0.00	0.00	0.00	0.00	2.59	2.13	1.20	1.75	0.00	0.00	3.19	3.60	4.66
EUOR	26.42	5.06	12.59	23.13	34.22	96.90	100.00	100.00	27.40	8.39	2.91	8.01	4.00	12.44	44.40	8.62	19.17	12.31
EUOF	26.42	5.06	12.59	23.13	34.22	96.90	100.00	100.00	27.40	8.39	2.91	8.01	4.00	7.51	9.64	8.62	19.17	12.31
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.68	78.28	0.00	0.00	0.00
EAF	73.58	94.94	87.41	76.87	65.78	3.10	0.00	0.00	72.60	91.61	97.09	91.99	96.00	52.81	12.07	91.38	80.83	87.69

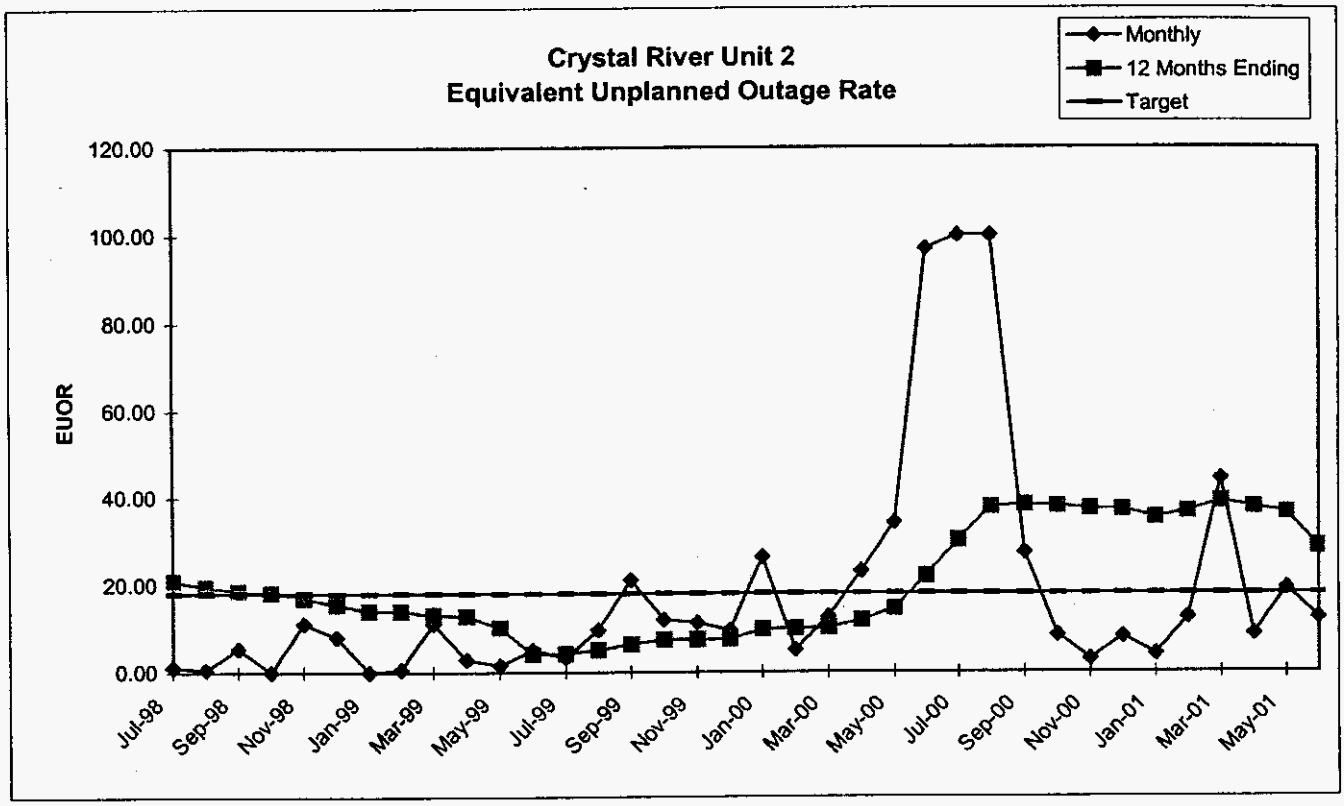
12 MONTHS	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FOR	0.06	0.06	0.06	0.00	0.00	8.57	9.43	10.49	10.60	10.60	10.60	10.68	10.48	10.96	12.97	13.18	12.91	2.35
MOR	3.60	3.54	3.41	4.88	7.59	7.97	17.17	26.37	26.82	26.82	26.82	27.43	25.85	26.81	28.31	26.62	24.88	22.80
PFOR	2.23	2.18	2.11	2.21	2.33	2.44	2.62	1.86	2.08	2.75	2.68	2.74	2.84	3.83	4.46	4.17	4.08	3.77
PMOR	4.07	4.39	4.71	4.98	5.13	5.50	5.84	6.44	6.38	5.26	4.31	3.29	2.41	1.95	1.63	1.71	1.88	2.20
EUOR	9.73	9.93	10.05	11.71	14.48	22.01	30.20	37.85	38.36	38.06	37.37	37.25	35.35	36.74	39.17	37.85	36.44	28.74
EUOF	9.59	9.93	10.05	11.71	14.48	22.01	30.20	37.85	38.36	38.06	37.37	37.25	35.35	35.62	35.37	34.18	32.91	25.95
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.04	9.69	9.69	9.69	9.69
EAF	90.41	90.07	89.95	88.29	85.52	77.99	69.80	62.15	61.64	61.94	62.63	62.75	64.65	61.33	54.93	56.12	57.40	64.35

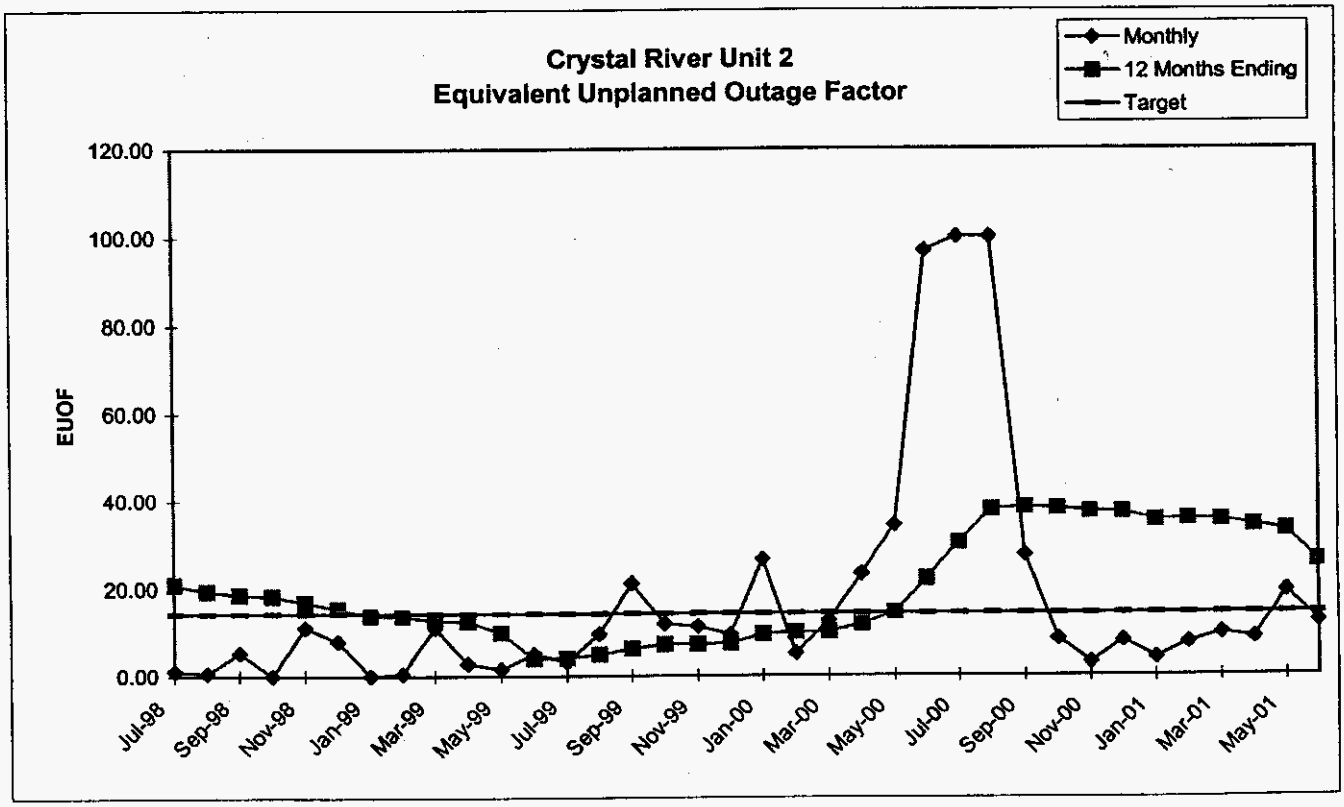

Crystal River Unit 2
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 2
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 2
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 2
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 2
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 2
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01

Crystal River
Unit 3

	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	704.50	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	0.00	380.00	744.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	39.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	340.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	745.00	267.00	0.00
FOH	0.00	39.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	73.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	79.60	0.00	0.00	0.00	29.33	0.00	3.13	467.32	0.00	51.50	0.00	38.00	47.70	25.50	0.00	0.00	61.00	0.00
LRPF	19.50	0.00	0.00	0.00	101.90	0.00	17.67	19.77	0.00	366.43	0.00	157.93	15.80	111.50	0.00	0.00	425.80	0.00
EFOH	2.09	0.00	0.00	0.00	4.02	0.00	0.07	12.48	0.00	25.50	0.00	8.11	1.02	3.84	0.00	0.00	35.10	0.00
PMOH	71.20	20.90	0.00	3.33	0.00	10.93	2.75	21.17	0.00	30.00	48.75	38.00	0.00	0.00	52.80	0.00	122.50	3.90
LRPM	113.40	227.90	0.00	48.63	0.00	47.49	18.65	421.89	0.00	10.87	111.54	41.46	0.00	0.00	75.40	0.00	380.80	176.10
EMOH	10.87	6.41	0.00	0.22	0.00	0.70	0.07	12.07	0.00	0.44	7.35	2.13	0.00	0.00	5.38	0.00	63.04	0.93
NPC	743.00	743.00	743.00	743.00	743.00	743.00	740.00	740.00	740.00	740.00	740.00	740.00	740.00	740.00	740.00	740.00	740.00	740.00

MONTHLY	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
FOR	0.00	5.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.11	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.28	0.00	0.00	0.00	0.56	0.00	0.01	1.86	0.00	3.55	0.00	1.13	0.14	0.52	0.00	0.00	9.24	0.00
PMOR	1.46	0.91	0.00	0.03	0.00	0.09	0.01	1.80	0.00	0.06	0.99	0.30	0.00	0.00	0.75	0.00	16.59	0.12
EUOR	1.74	6.17	0.00	0.03	0.56	0.09	0.02	3.65	0.00	3.61	0.99	1.42	0.14	0.52	0.75	0.00	37.78	0.12
EUOF	1.74	6.17	0.00	0.03	0.56	0.09	0.02	3.65	0.00	3.61	0.99	1.42	0.14	0.52	0.75	0.00	23.77	0.12
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00	37.08	0.00
EAF	98.26	93.83	100.00	99.97	99.44	99.91	99.98	96.35	100.00	96.39	99.01	98.58	99.86	99.48	99.25	0.00	39.15	99.88

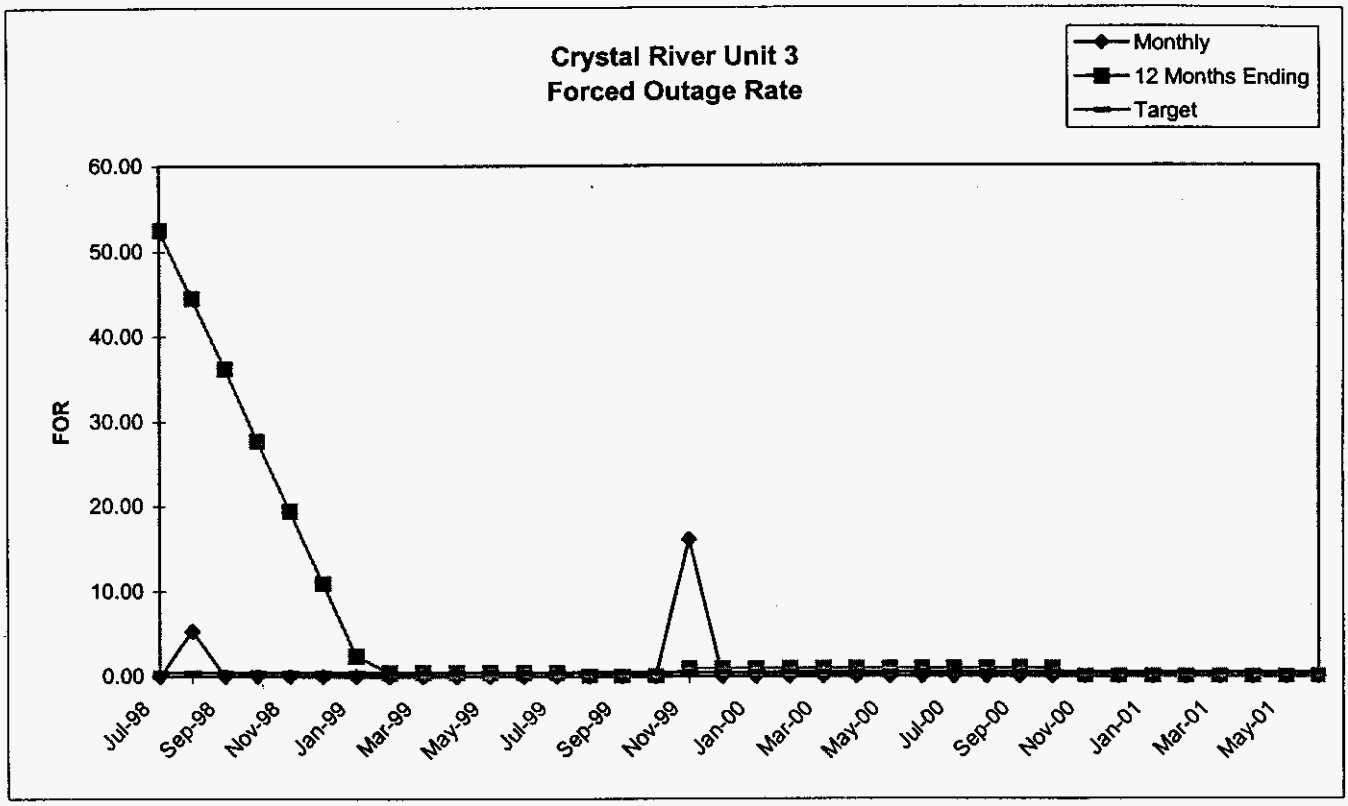
12 MONTHS	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
FOR	52.54	44.47	36.23	27.70	19.45	10.94	2.42	0.45	0.45	0.45	0.45	0.45	0.45	0.00	0.00	0.00	0.94	0.94
MOR	0.64	0.55	0.48	0.42	0.38	0.34	0.31	0.15	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.58	0.50	0.43	0.38	0.40	0.36	0.33	0.26	0.26	0.55	0.51	0.60	0.59	0.63	0.63	0.69	1.12	1.12
PMOR	1.87	1.73	1.51	1.33	1.20	1.09	1.00	0.57	0.57	0.35	0.44	0.46	0.34	0.26	0.32	0.35	1.19	1.19
EUOR	53.85	45.88	37.66	29.16	20.98	12.50	4.01	1.42	1.42	1.35	1.39	1.51	1.37	0.89	0.95	1.04	3.23	3.23
EUOF	53.85	45.88	37.66	29.16	20.98	12.50	4.01	1.42	1.42	1.35	1.39	1.51	1.37	0.89	0.95	0.95	2.86	2.86
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.50	11.55	11.55
EAF	46.15	54.12	62.34	70.84	79.02	87.50	95.99	98.58	98.58	98.65	98.61	98.49	98.63	99.11	99.05	90.55	85.59	85.59

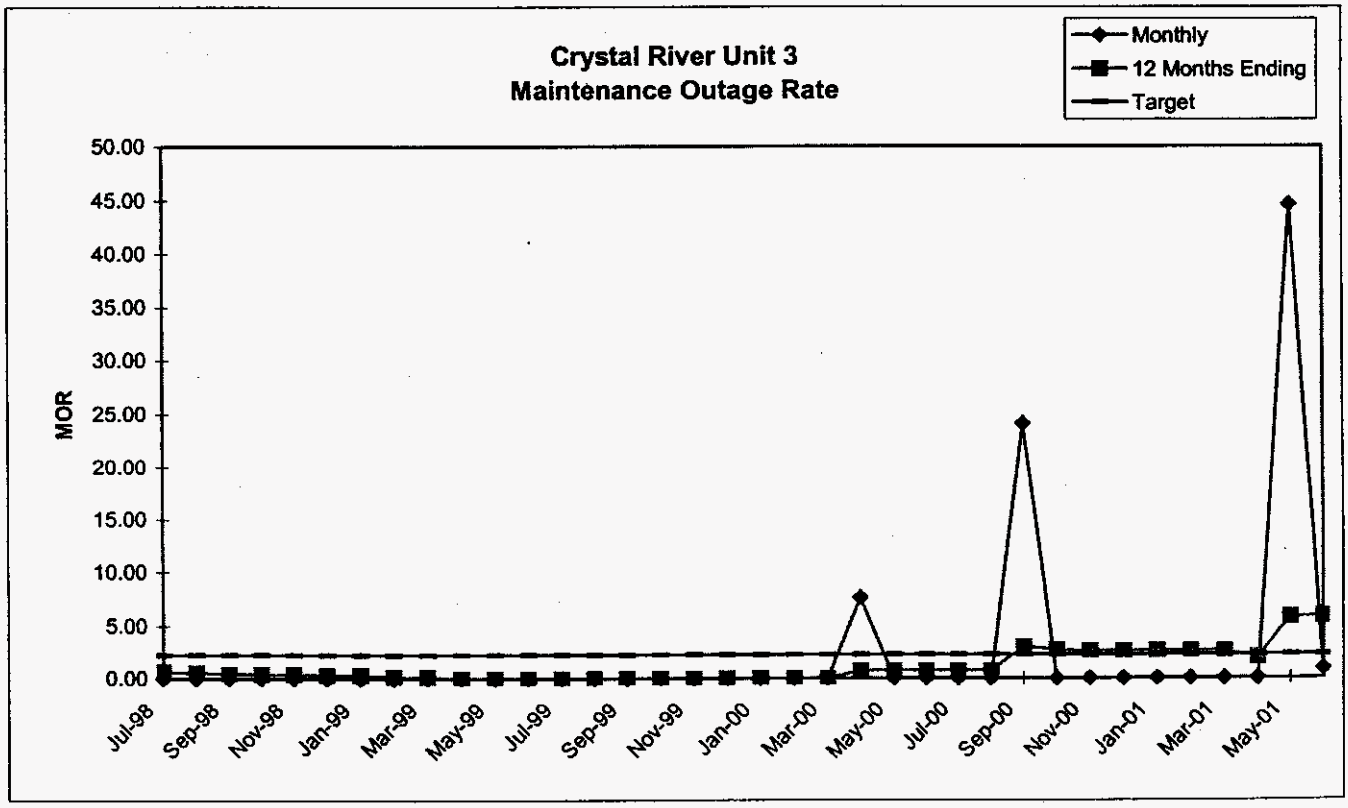
Crystal River
Unit 3

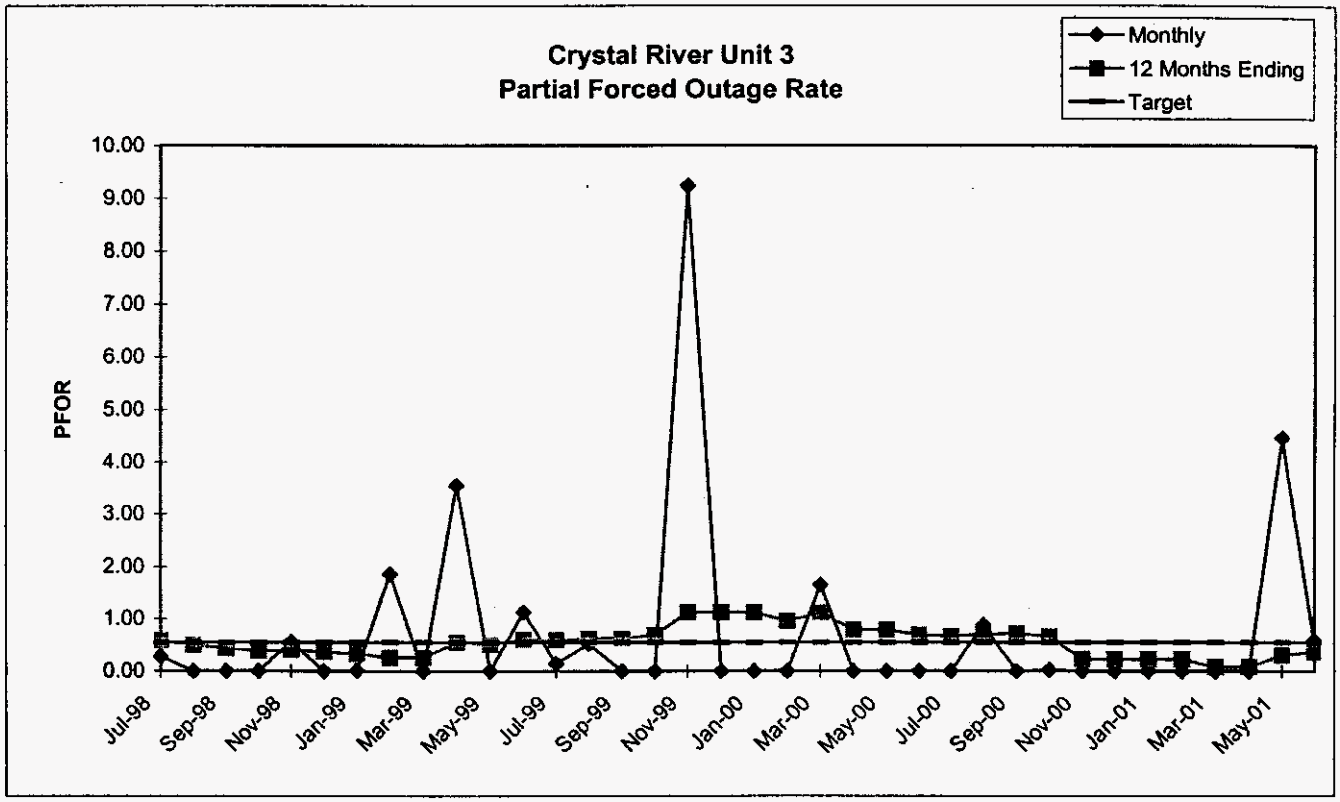
	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
PER HOURS	744.00	696.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	744.00	696.00	744.00	664.10	744.00	720.00	744.00	744.00	546.58	745.00	720.00	744.00	744.00	672.00	744.00	719.00	412.27	713.63
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	54.90	0.00	0.00	0.00	0.00	173.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	331.73	6.37
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0.00	54.90	0.00	0.00	0.00	0.00	173.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	331.73	6.37
PFOH	0.00	0.00	33.30	0.00	0.00	0.00	0.00	34.17	0.00	30.25	0.00	0.00	0.00	0.00	0.00	0.00	132.93	9.65
LRPF	0.00	0.00	278.30	0.00	0.00	0.00	0.00	144.52	0.00	4.70	0.00	0.00	0.00	0.00	0.00	0.00	105.89	334.84
EFOH	0.00	0.00	12.29	0.00	0.00	0.00	0.00	6.55	0.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	18.40	4.22
PMOH	3.00	29.50	0.00	26.30	0.00	0.00	0.00	0.00	23.48	56.25	0.00	0.00	0.00	3.57	0.00	4.50	0.00	18.05
LRPM	31.00	113.80	0.00	340.40	0.00	0.00	0.00	0.00	295.52	146.66	0.00	0.00	0.00	35.34	0.00	27.67	0.00	1.90
EMOH	0.12	4.45	0.00	11.87	0.00	0.00	0.00	0.00	9.20	10.94	0.00	0.00	0.00	0.16	0.00	0.16	0.00	0.04
NPC	754.00	754.00	754.00	754.00	754.00	754.00	754.00	754.00	754.00	754.00	754.00	754.00	765.00	765.00	765.00	765.00	765.00	765.00

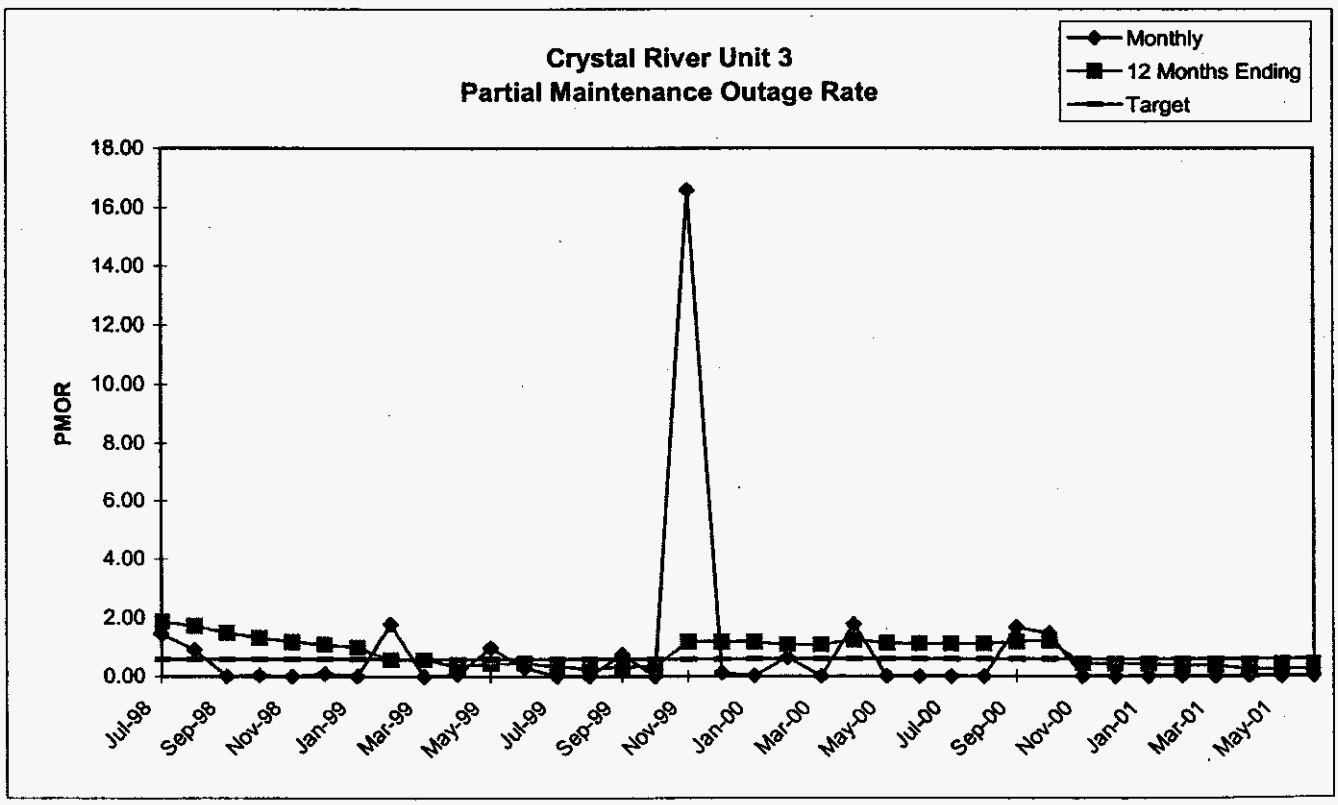
MONTHLY	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	7.64	0.00	0.00	0.00	0.00	24.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.59	0.88
PFOR	0.00	0.00	1.65	0.00	0.00	0.00	0.00	0.88	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	4.46	0.59
PMOR	0.02	0.64	0.00	1.79	0.00	0.00	0.00	0.00	1.68	1.47	0.00	0.00	0.00	0.02	0.00	0.02	0.00	0.01
EUOR	0.02	0.64	1.65	9.29	0.00	0.00	0.00	0.88	25.36	1.49	0.00	0.00	0.00	0.02	0.00	0.02	47.06	1.48
EUOF	0.02	0.64	1.65	9.29	0.00	0.00	0.00	0.88	25.36	1.49	0.00	0.00	0.00	0.02	0.00	0.02	47.06	1.48
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.98	99.36	98.35	90.71	100.00	100.00	100.00	99.12	74.64	98.51	100.00	100.00	100.00	99.98	100.00	99.98	52.94	98.52

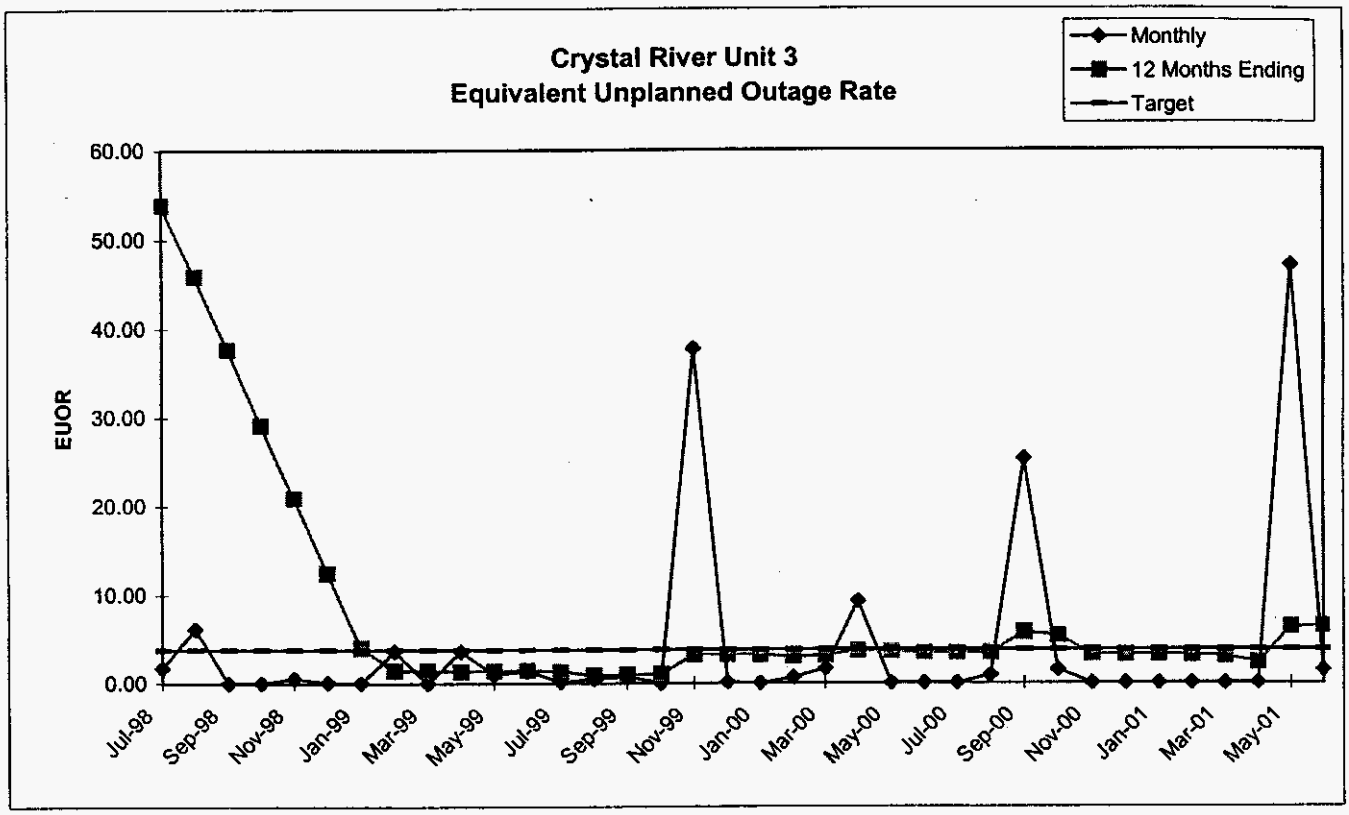
12 MONTHS	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FOR	0.94	0.94	0.94	0.95	0.95	0.95	0.95	0.95	0.97	0.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.71	0.71	0.71	0.71	0.71	2.97	2.70	2.60	2.60	2.60	2.61	2.61	1.98	5.77	5.84
PFOR	1.12	0.96	1.12	0.79	0.79	0.68	0.67	0.71	0.72	0.66	0.22	0.22	0.22	0.22	0.08	0.08	0.30	0.36
PMOR	1.19	1.09	1.09	1.25	1.15	1.12	1.12	1.12	1.20	1.22	0.44	0.43	0.43	0.38	0.38	0.24	0.25	0.25
EUOR	3.23	2.96	3.12	3.65	3.55	3.42	3.41	3.44	5.72	5.35	3.24	3.23	3.23	3.19	3.05	2.29	6.29	6.41
EUOF	2.86	2.62	2.76	3.23	3.14	3.03	3.02	3.05	5.06	5.19	3.24	3.23	3.23	3.19	3.05	2.29	6.29	6.41
POF	11.55	11.52	11.52	11.52	11.52	11.52	11.52	11.52	11.52	3.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	85.59	85.86	85.72	85.25	85.33	85.45	85.46	85.43	83.41	91.77	96.76	96.77	96.77	96.81	96.95	97.71	93.71	93.59

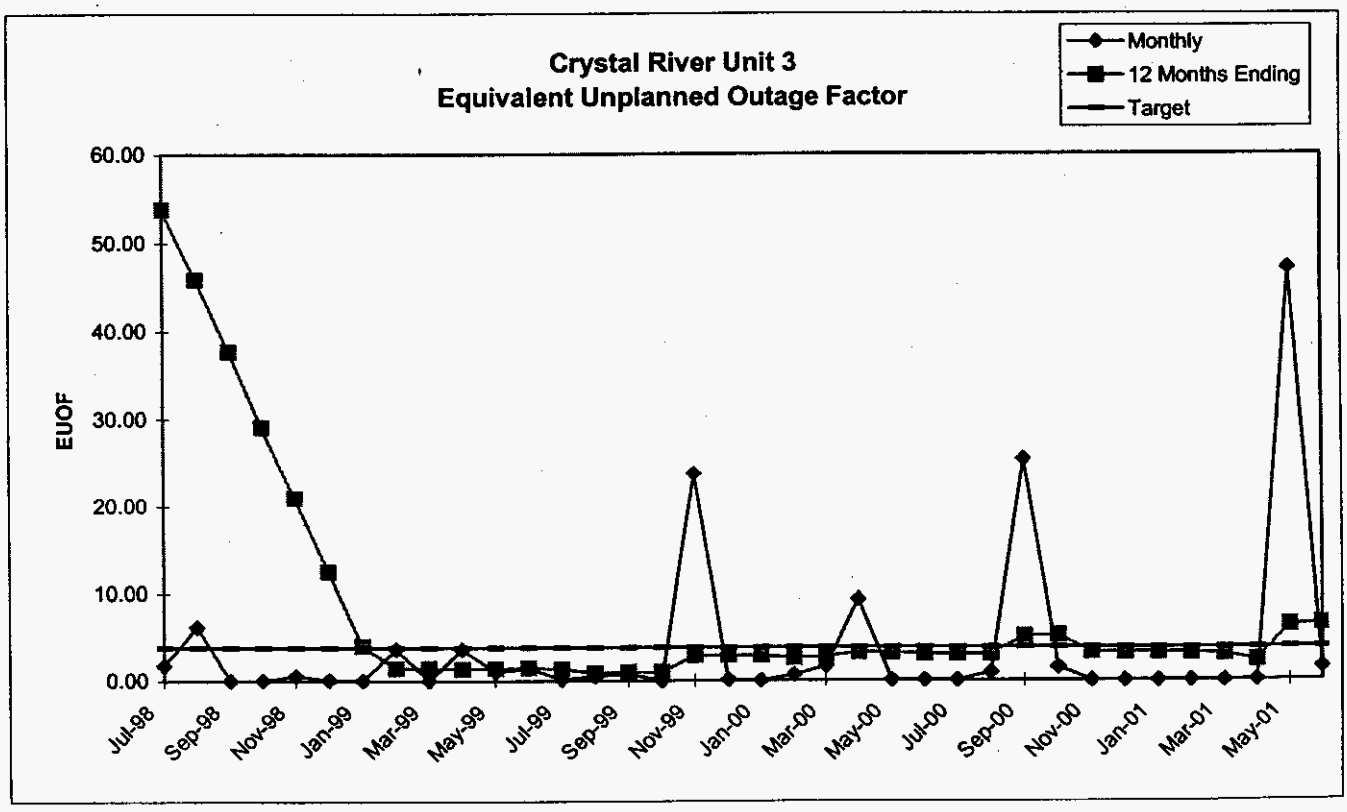

Crystal River Unit 3
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 3
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 3
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 3
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 3
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 3
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01

Crystal River
Unit 4

	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	737.70	720.00	745.00	656.10	719.30	462.85	668.33	744.00	715.28	733.58	720.00	744.00	716.60	664.80	708.30	709.90	744.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	281.15	3.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	6.30	0.00	0.00	63.90	24.80	0.00	0.00	0.00	3.72	10.42	0.00	0.00	27.40	55.30	36.70	10.10	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	6.30	0.00	0.00	63.90	24.80	0.00	0.00	0.00	3.72	10.42	0.00	0.00	27.40	0.00	36.70	1.10	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	55.30	0.00	9.00	0.00
PFOH	26.80	16.70	21.60	7.60	0.00	0.00	24.92	20.52	66.17	18.03	12.30	5.92	10.00	732.00	23.00	30.90	15.90	0.00
LRPF	238.70	100.10	34.80	111.20	0.00	0.00	474.50	553.69	367.09	47.74	355.87	515.33	305.10	58.50	202.70	223.00	205.10	0.00
EFOH	9.18	2.40	1.08	1.21	0.00	0.00	16.96	16.30	34.85	1.24	6.28	4.38	4.38	61.44	6.69	9.89	4.68	0.00
PMOH	0.00	0.00	0.00	160.20	241.60	0.00	0.00	0.00	0.00	0.00	85.98	0.00	0.00	51.40	530.70	0.00	0.00	5.80
LRPM	0.00	0.00	0.00	47.70	47.70	0.00	0.00	0.00	0.00	0.00	47.75	0.00	0.00	38.20	46.70	0.00	0.00	353.20
EMOH	0.00	0.00	0.00	10.96	16.53	0.00	0.00	0.00	0.00	0.00	5.89	0.00	0.00	2.82	35.56	0.00	0.00	2.94
NPC	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00

MONTHLY	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
FOR	0.00	0.85	0.00	0.00	8.88	3.33	0.00	0.00	0.00	0.52	1.40	0.00	0.00	3.68	0.00	4.93	0.15	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.68	0.00	1.25	0.00
PFOR	1.23	0.33	0.15	0.16	0.00	0.00	3.67	2.44	4.68	0.17	0.86	0.61	0.59	8.57	1.01	1.40	0.66	0.00
PMOR	0.00	0.00	0.00	1.47	2.52	0.00	0.00	0.00	0.00	0.00	0.80	0.00	0.00	0.39	5.35	0.00	0.00	0.40
EUOR	1.23	1.17	0.15	1.63	11.17	3.33	3.67	2.44	4.68	0.69	3.04	0.61	0.59	12.32	13.55	6.25	2.05	0.40
EUOF	1.23	1.17	0.15	1.63	11.17	3.33	2.28	2.43	4.68	0.69	3.04	0.61	0.59	12.32	13.55	6.25	2.05	0.40
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	98.77	98.83	99.85	98.37	88.83	96.67	97.72	97.57	95.32	99.31	96.96	99.39	99.41	87.68	86.45	93.75	97.95	99.60

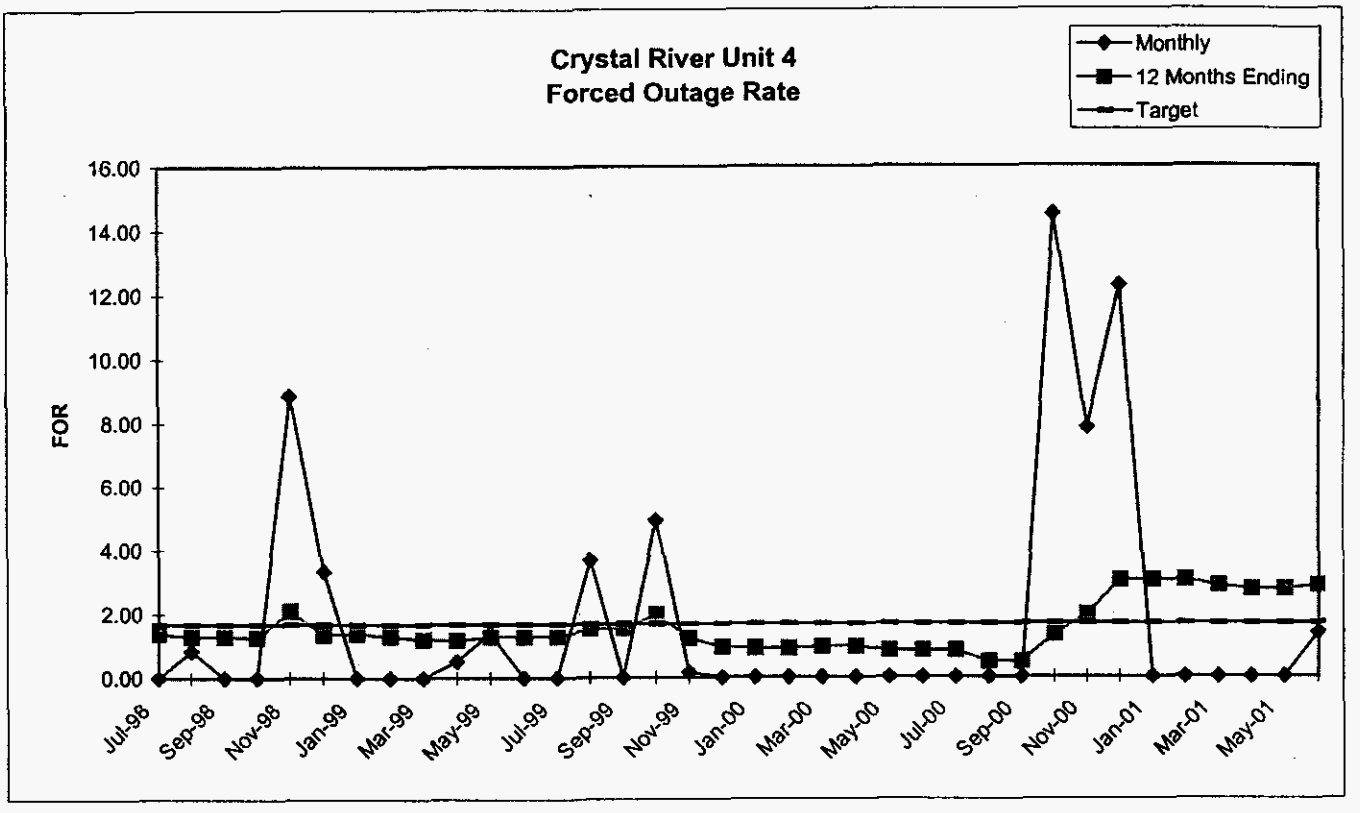
12 MONTHS	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
FOR	1.38	1.29	1.29	1.27	2.10	1.35	1.40	1.30	1.21	1.18	1.29	1.29	1.29	1.54	1.55	1.98	1.24	0.94
MOR	3.84	3.83	3.83	3.01	1.59	1.58	1.24	1.24	1.15	0.89	0.00	0.00	0.00	0.00	0.66	0.67	0.77	0.77
PFOR	2.23	2.11	2.03	1.95	1.66	0.88	0.70	0.83	1.22	1.15	1.22	1.12	1.06	1.77	1.85	1.97	2.01	2.01
PMOR	0.00	0.00	0.00	0.15	0.37	0.37	0.38	0.38	0.35	0.33	0.40	0.40	0.40	0.43	0.87	0.74	0.53	0.57
EUOR	7.24	7.04	6.95	6.22	5.58	4.10	3.66	3.70	3.86	3.50	2.88	2.79	2.73	3.71	4.85	5.26	4.48	4.22
EUOF	6.32	6.15	6.08	5.44	4.87	3.58	3.08	3.11	3.51	3.38	2.79	2.70	2.64	3.59	4.69	5.08	4.34	4.09
POF	12.59	12.59	12.59	12.59	12.59	12.59	12.59	12.59	5.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	81.08	81.26	81.33	81.97	82.53	83.82	84.33	84.30	90.71	96.62	97.21	97.30	97.36	96.41	95.31	94.92	95.66	95.91

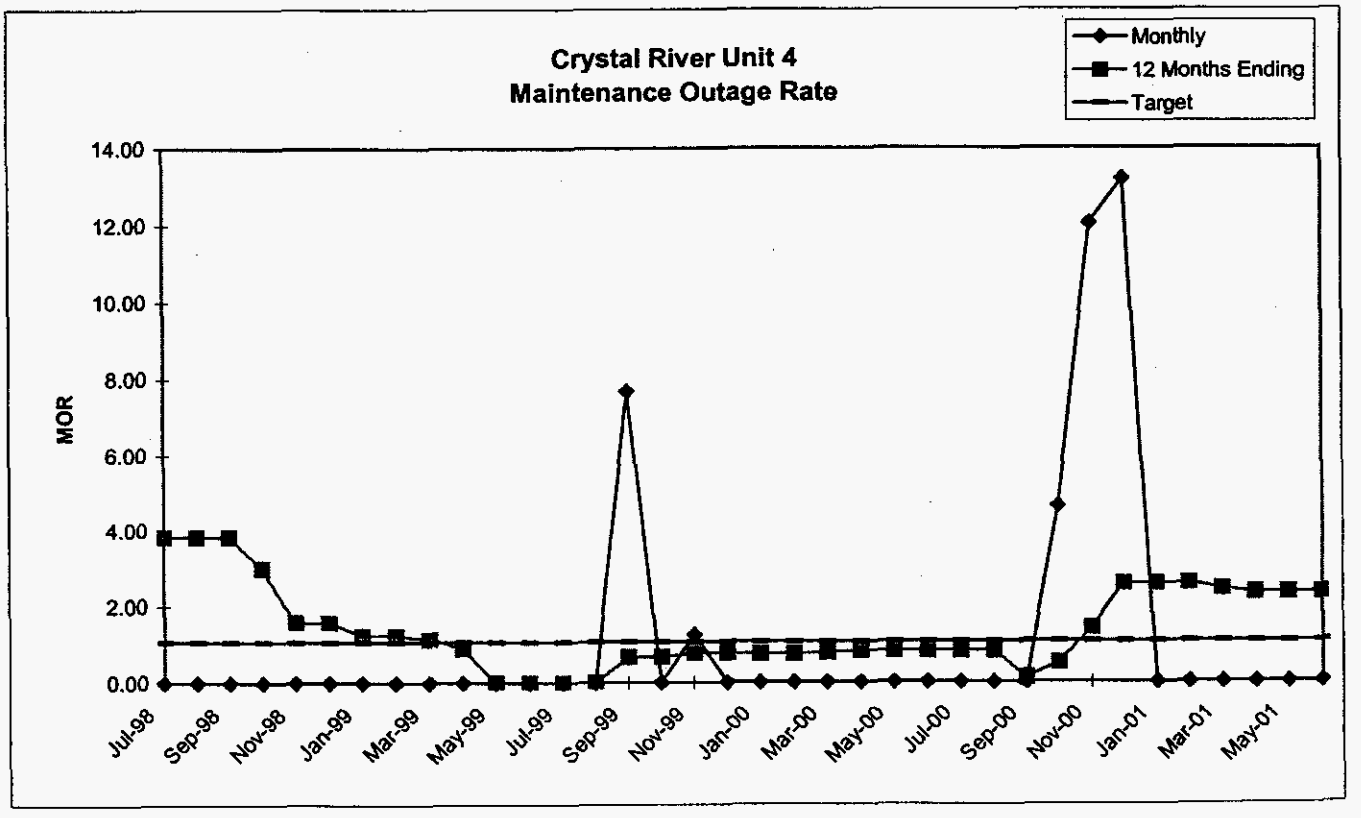
Crystal River
Unit 4

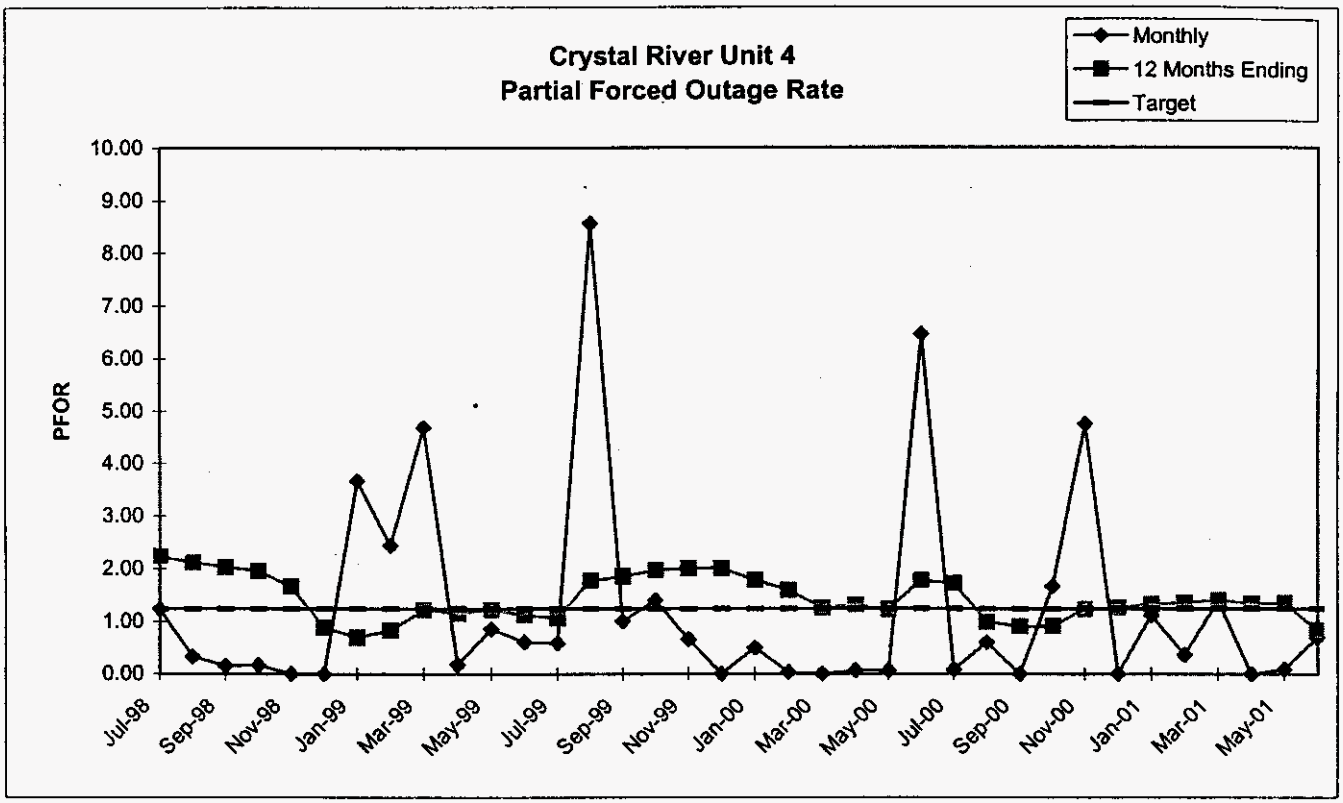
	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
PER HOURS	744.00	696.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	744.00	696.00	265.20	342.80	744.00	720.00	744.00	744.00	720.00	611.67	589.30	575.90	744.00	672.00	744.00	719.00	744.00	710.10
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	478.80	376.20	0.00	0.00	0.00	0.00	0.00	133.33	130.70	168.10	0.00	0.00	0.00	0.00	0.00	9.90
POH	0.00	0.00	478.80	376.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	103.67	50.00	80.60	0.00	0.00	0.00	0.00	0.00	9.90
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.67	80.70	87.50	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	21.50	2.20	0.00	1.70	5.20	83.40	4.83	36.67	0.00	21.07	86.05	0.00	46.85	7.10	69.47	0.00	0.80	9.98
LRPF	119.60	66.80	0.00	95.50	66.80	389.10	92.96	84.73	0.00	337.38	227.13	0.00	128.21	246.61	107.34	0.00	591.78	356.74
EFOH	3.69	0.21	0.00	0.23	0.50	46.56	0.64	4.46	0.00	10.20	28.04	0.00	8.34	2.43	10.36	0.00	0.66	4.94
PMOH	0.00	0.30	0.00	0.00	46.60	3.40	0.00	11.45	0.00	0.00	68.00	5.00	6.85	0.00	0.00	121.80	18.16	47.87
LRPM	0.00	255.10	0.00	0.00	85.90	85.80	0.00	85.93	0.00	0.00	85.93	525.18	591.78	0.00	0.00	88.77	114.10	78.07
EMOH	0.00	0.11	0.00	0.00	5.74	0.42	0.00	1.41	0.00	0.00	8.38	3.77	5.63	0.00	0.00	15.02	2.88	5.19
NPC	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	720.00	720.00	720.00	720.00	720.00	720.00

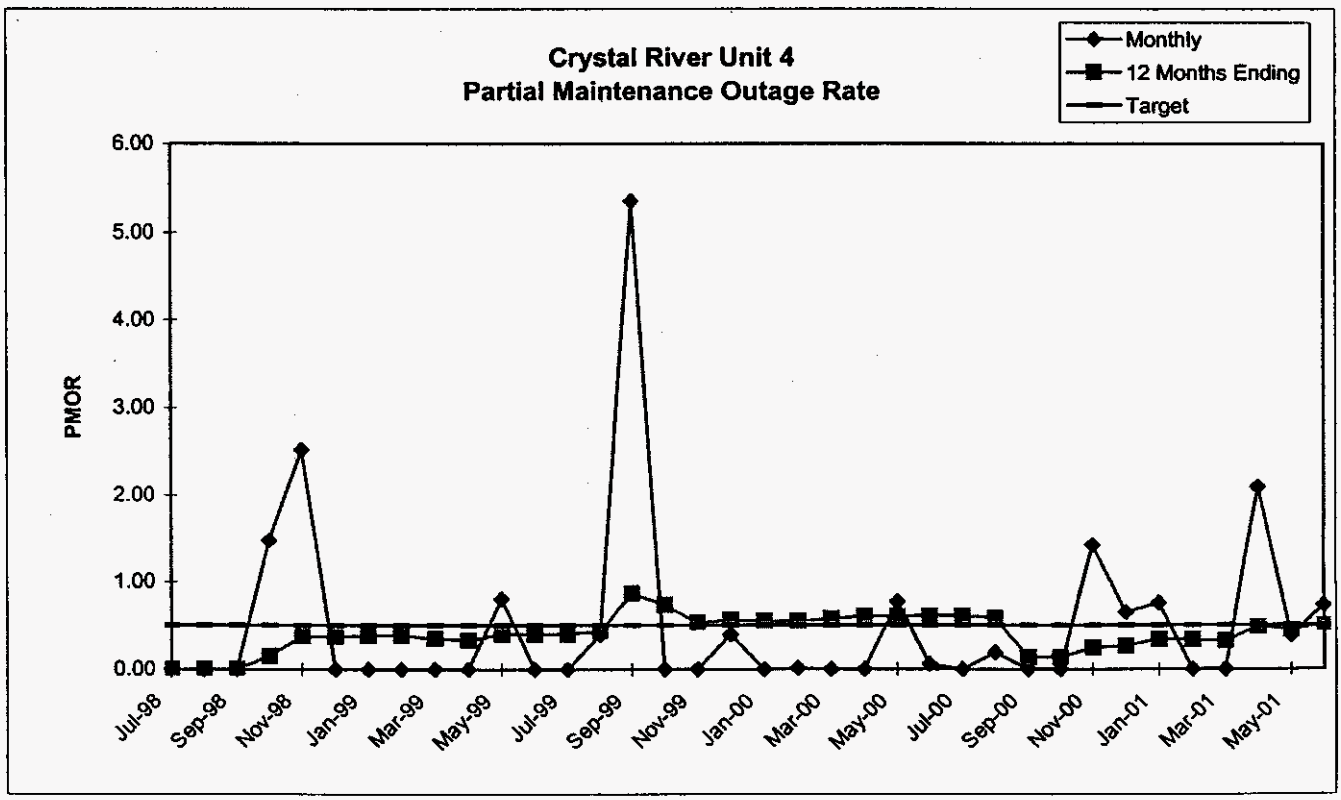
MONTHLY	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.49	7.82	12.28	0.00	0.00	0.00	0.00	0.00	1.38
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.63	12.04	13.19	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.50	0.03	0.00	0.07	0.07	6.47	0.09	0.60	0.00	1.67	4.76	0.00	1.12	0.36	1.39	0.00	0.09	0.70
PMOR	0.00	0.02	0.00	0.00	0.77	0.06	0.00	0.19	0.00	0.00	1.42	0.65	0.76	0.00	0.00	2.09	0.39	0.73
EUOR	0.50	0.05	0.00	0.07	0.84	6.52	0.09	0.79	0.00	19.27	23.21	23.10	1.88	0.36	1.39	2.09	0.48	2.78
EUOF	0.50	0.05	0.00	0.03	0.84	6.52	0.09	0.79	0.00	19.27	23.21	23.10	1.88	0.36	1.39	2.09	0.48	2.78
POF	0.00	0.00	64.35	52.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.50	99.95	35.65	47.64	99.16	93.48	99.91	99.21	100.00	80.73	76.79	76.90	98.12	99.64	98.61	97.91	99.52	97.22

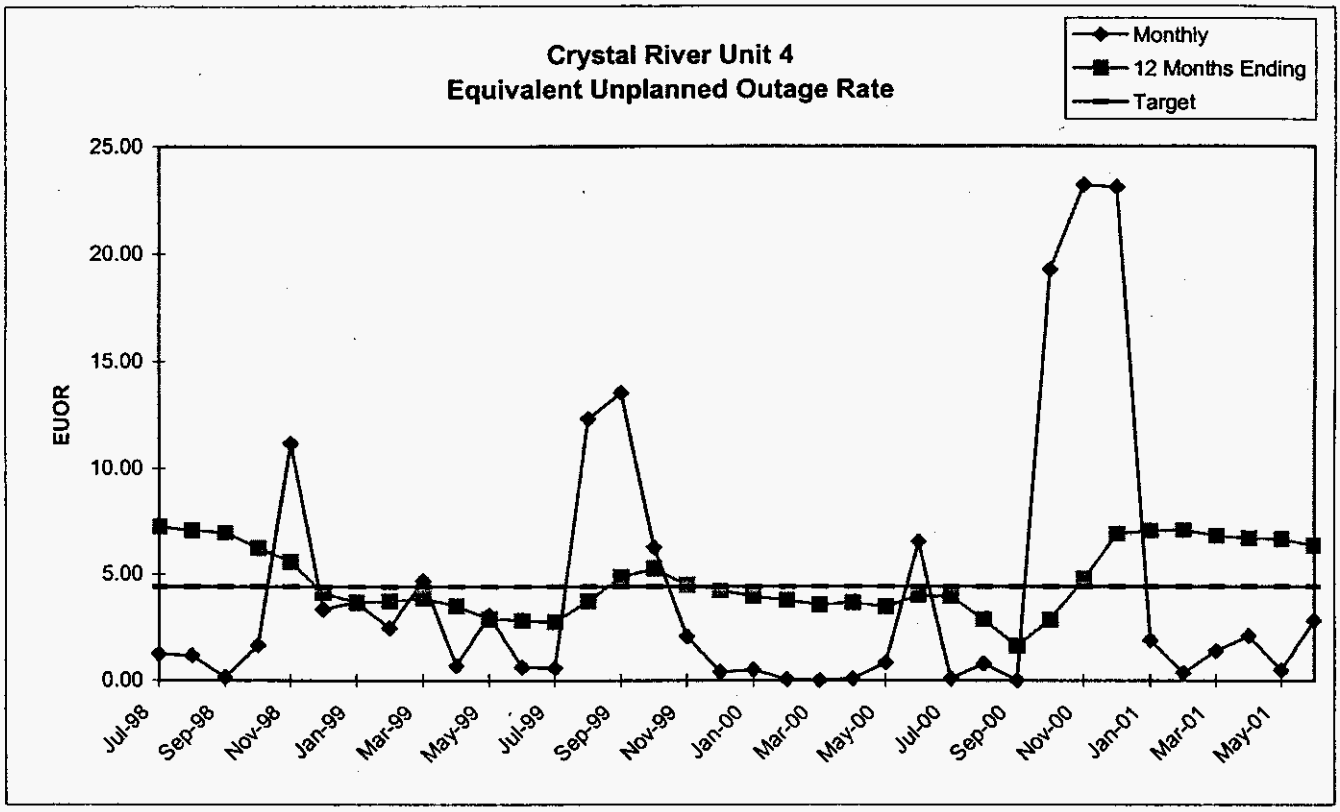
12 MONTHS	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FOR	0.91	0.91	0.96	0.96	0.83	0.83	0.83	0.48	0.48	1.33	1.97	3.03	3.03	3.04	2.86	2.74	2.74	2.85
MOR	0.74	0.74	0.78	0.82	0.82	0.82	0.82	0.81	0.11	0.49	1.42	2.57	2.57	2.58	2.43	2.32	2.32	2.32
PFOR	1.79	1.59	1.26	1.31	1.23	1.77	1.72	0.99	0.90	0.91	1.23	1.26	1.32	1.36	1.41	1.34	1.34	0.84
PMOR	0.55	0.55	0.58	0.61	0.60	0.61	0.61	0.59	0.13	0.14	0.25	0.26	0.34	0.34	0.32	0.48	0.45	0.51
EUOR	3.94	3.74	3.54	3.65	3.44	3.98	3.93	2.85	1.62	2.84	4.76	6.89	7.02	7.07	6.79	6.67	6.64	6.33
EUOF	3.93	3.74	3.34	3.29	3.11	3.59	3.55	2.57	1.46	2.56	4.30	6.22	6.34	6.38	6.50	6.67	6.64	6.33
POF	0.00	0.00	5.45	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.76	4.29	0.00	0.00	0.00
EAF	96.07	96.26	91.20	86.98	87.16	86.68	86.72	87.70	88.81	87.70	85.97	84.04	83.93	83.86	89.21	93.33	93.36	93.67

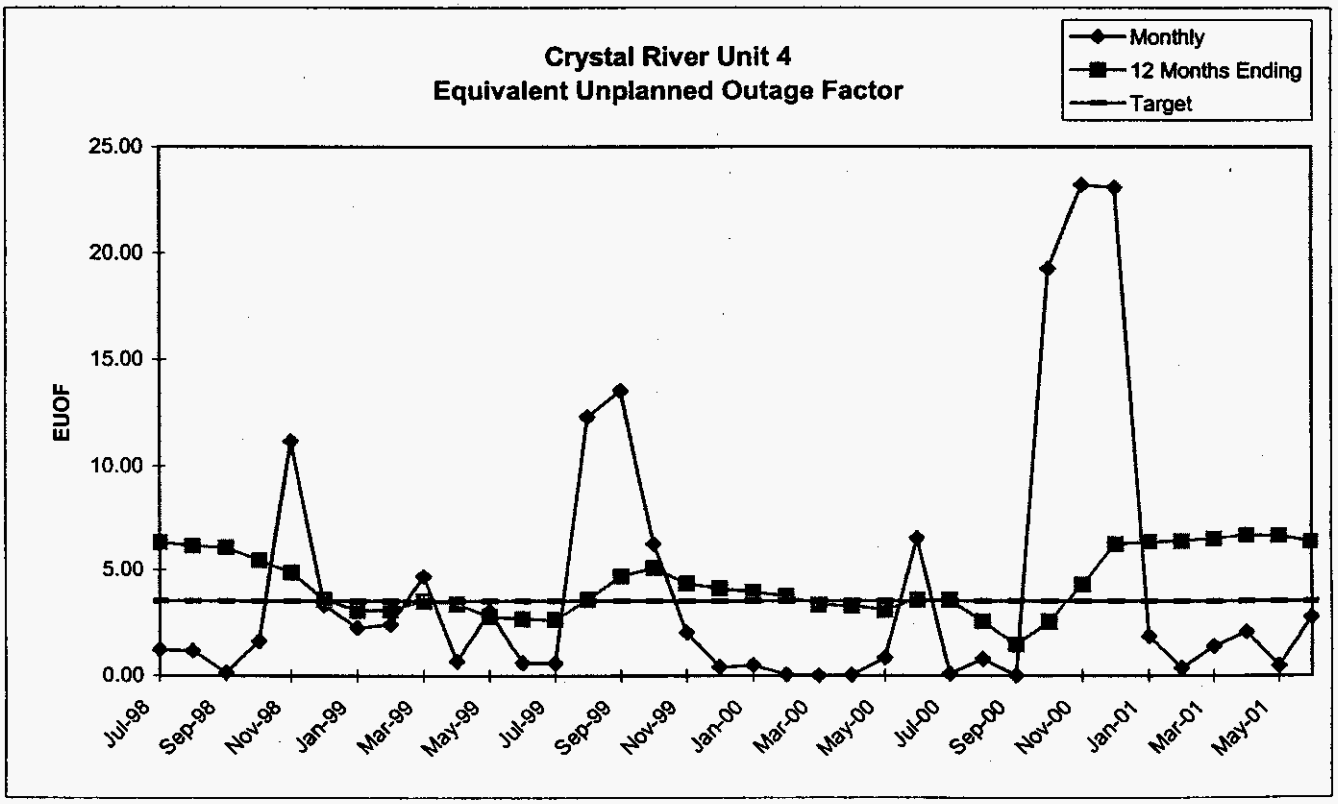

Crystal River Unit 4
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 4
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 4
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 4
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 4
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
25.00
20.00
15.00
10.00
5.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 4
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
25.00
20.00
15.00
10.00
5.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01

Crystal River
Unit 5

	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	737.70	744.00	688.80	745.00	710.30	676.10	744.00	672.00	277.38	0.02	356.83	711.68	714.80	744.00	720.00	724.40	720.00	642.80
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	6.30	0.00	31.20	0.00	9.70	67.90	0.00	0.00	456.98	718.98	387.17	8.32	29.20	0.00	0.00	20.60	0.00	101.20
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	456.98	718.98	209.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	6.30	0.00	31.20	0.00	9.70	0.00	0.00	0.00	0.00	0.00	177.33	0.00	0.00	0.00	0.00	20.60	0.00	6.10
MOH	0.00	0.00	0.00	0.00	0.00	67.90	0.00	0.00	0.00	0.00	0.00	8.32	29.20	0.00	0.00	0.00	0.00	95.10
PFOH	32.50	12.60	17.20	10.30	89.90	0.00	72.25	8.60	38.50	0.00	4.65	0.00	3.80	9.70	0.00	0.00	0.00	17.40
LRPF	284.20	467.50	100.00	365.90	50.60	0.00	60.30	481.34	85.94	0.00	47.67	0.00	76.30	65.70	0.00	0.00	0.00	94.30
EFOH	13.25	8.45	2.47	5.41	6.53	0.00	6.25	5.94	4.75	0.00	0.32	0.00	0.42	0.91	0.00	0.00	0.00	2.35
PMOH	0.00	0.00	0.00	0.00	168.20	113.20	69.03	0.00	0.00	0.00	0.00	0.00	6.50	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	47.70	47.70	47.70	0.00	0.00	0.00	0.00	0.00	76.40	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	11.51	7.75	4.72	0.00	0.00	0.00	0.00	0.00	0.71	0.00	0.00	0.00	0.00	0.00
NPC	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00	697.00

MONTHLY	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
FOR	0.85	0.00	4.33	0.00	1.35	0.00	0.00	0.00	0.00	0.00	33.20	0.00	0.00	0.00	0.00	2.77	0.00	0.94
MOR	0.00	0.00	0.00	0.00	0.00	9.13	0.00	0.00	0.00	0.00	0.00	1.16	3.92	0.00	0.00	0.00	0.00	12.89
PFOR	1.80	1.14	0.36	0.73	0.92	0.00	0.84	0.88	1.71	0.00	0.09	0.00	0.06	0.12	0.00	0.00	0.00	0.37
PMOR	0.00	0.00	0.00	0.00	1.62	1.15	0.63	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00
EUOR	2.63	1.14	4.68	0.73	3.85	10.17	1.48	0.88	1.71	0.00	33.26	1.16	4.08	0.12	0.00	2.77	0.00	13.92
EUOF	2.63	1.14	4.68	0.73	3.85	10.17	1.48	0.88	0.64	0.00	23.88	1.16	4.08	0.12	0.00	2.77	0.00	13.92
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	61.42	100.00	28.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	97.37	98.86	95.32	99.27	96.15	89.83	98.52	99.12	37.94	0.00	47.92	98.84	95.92	99.88	100.00	97.23	100.00	86.08

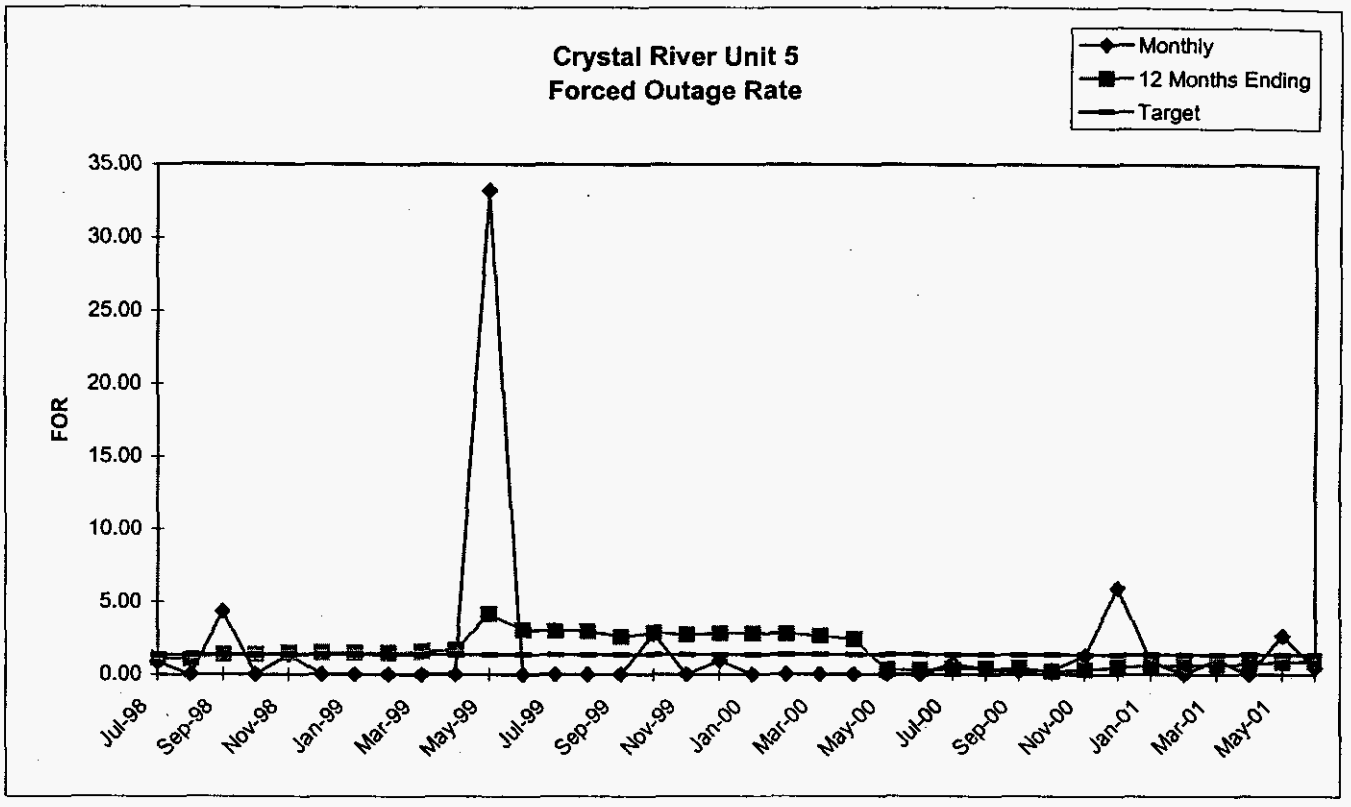
12 MONTHS	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
FOR	1.09	1.09	1.36	1.36	1.47	1.48	1.48	1.47	1.56	1.68	4.16	3.08	3.01	3.01	2.58	2.86	2.73	2.82
MOR	0.00	0.00	0.00	0.00	0.00	0.79	0.79	0.79	0.83	0.91	0.96	1.07	1.48	1.48	1.47	1.47	1.47	1.85
PFOR	1.20	1.26	1.25	1.21	1.22	1.12	0.98	0.96	1.08	0.78	0.83	0.76	0.58	0.47	0.43	0.36	0.26	0.30
PMOR	0.20	0.20	0.20	0.20	0.33	0.33	0.38	0.38	0.40	0.44	0.34	0.34	0.35	0.35	0.35	0.35	0.19	0.08
EUOR	2.48	2.54	2.80	2.76	3.00	3.67	3.59	3.55	3.80	3.75	6.15	5.13	5.28	5.18	4.72	4.93	4.55	4.93
EUOF	2.46	2.52	2.77	2.74	2.98	3.64	3.55	3.54	3.60	3.24	5.17	4.32	4.44	4.35	3.97	4.14	3.83	4.14
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.22	13.42	15.82	15.82	15.82	15.82	15.82	15.82	15.82	15.82
EAF	97.54	97.48	97.23	97.26	97.02	96.36	96.45	96.46	91.19	83.33	79.01	79.86	79.74	79.83	80.21	80.04	80.35	80.04

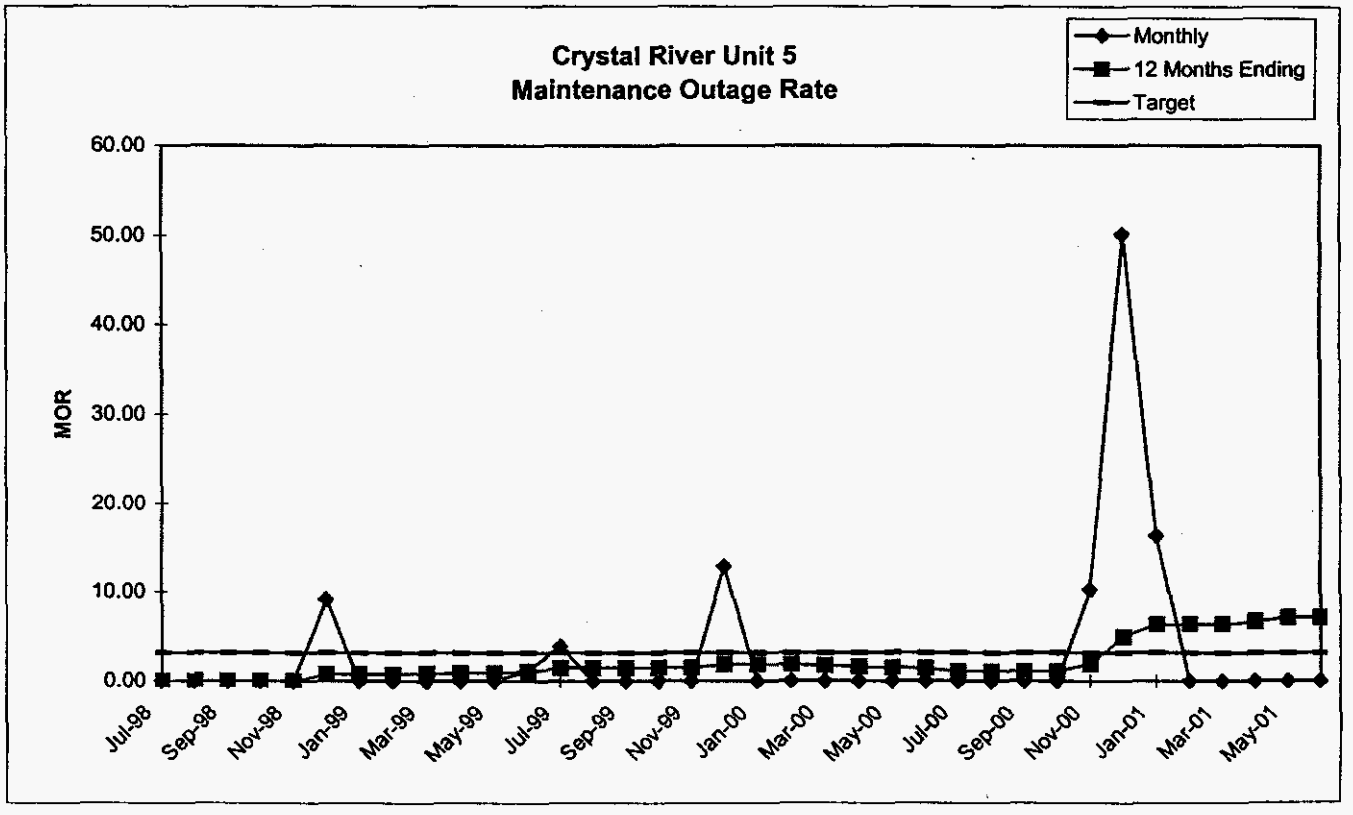
Crystal River
Unit 5

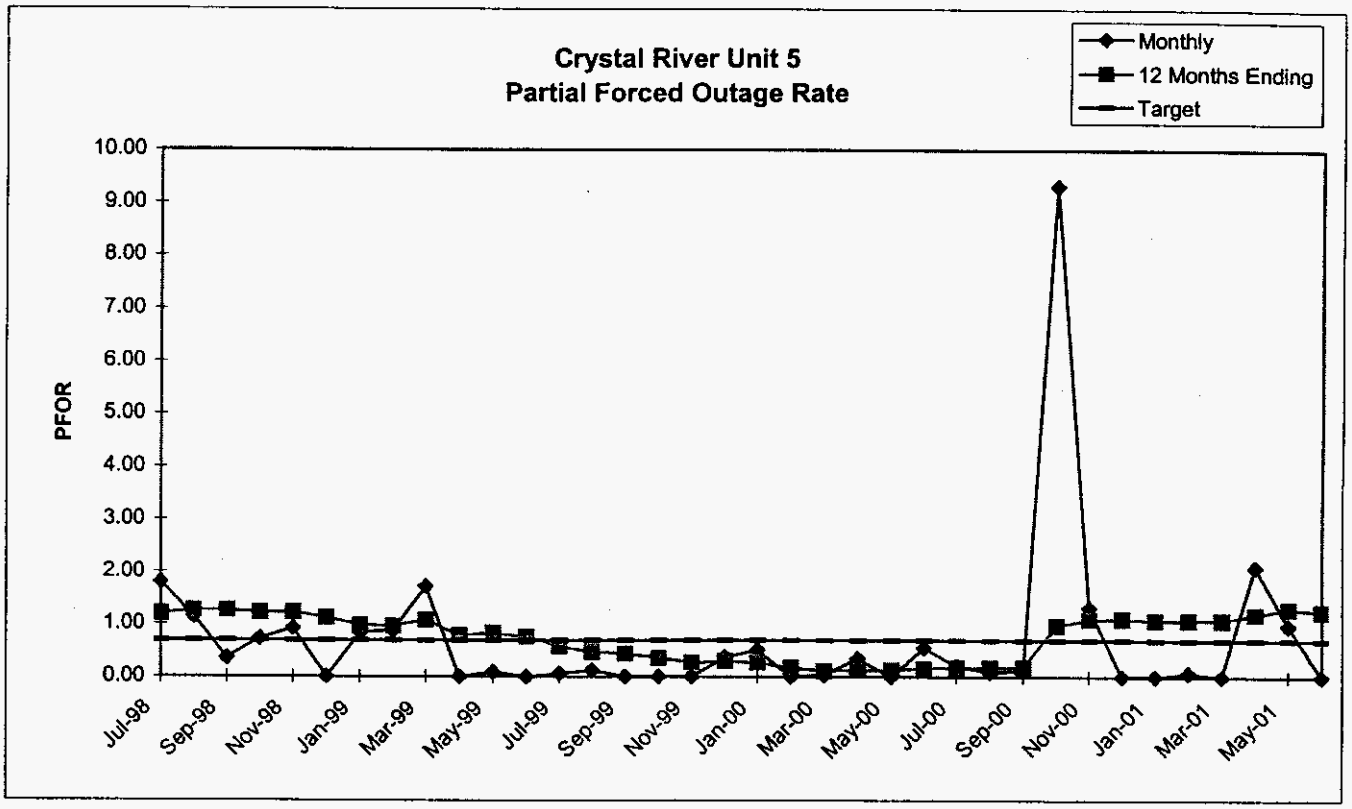
	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
PER HOURS	744.00	696.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	744.00	696.00	744.00	719.00	744.00	720.00	738.67	741.55	718.50	743.00	638.78	359.70	618.20	672.00	736.40	312.60	245.70	716.60
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	0.00	0.00	0.00	5.33	2.45	1.50	2.00	81.22	384.30	125.80	0.00	7.60	406.40	498.30	3.40
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	406.40	491.60	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	5.33	2.45	1.50	2.00	8.32	22.80	5.40	0.00	7.60	0.00	6.70	3.40
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	72.90	361.50	120.40	0.00	0.00	0.00	0.00	0.00
PFOH	6.30	0.00	2.80	3.00	0.00	10.10	22.85	3.50	2.05	507.73	63.80	0.00	0.00	3.25	0.00	84.25	18.07	0.00
LRPF	427.30	0.00	65.10	590.70	0.00	280.40	46.74	141.38	282.38	97.30	93.68	0.00	0.00	103.65	0.00	55.67	94.98	0.00
EFOH	3.77	0.00	0.26	2.48	0.00	3.97	1.50	0.69	0.81	69.19	8.37	0.00	0.00	0.47	0.00	6.54	2.39	0.00
PMOH	34.70	153.90	8.20	0.00	0.00	0.00	8.00	0.00	0.00	0.00	238.38	0.00	0.00	16.00	0.00	0.00	0.00	9.75
LRPM	74.60	74.60	581.40	0.00	0.00	0.00	103.24	0.00	0.00	0.00	72.65	0.00	0.00	103.68	0.00	0.00	0.00	535.56
EMOH	3.63	16.08	6.68	0.00	0.00	0.00	1.16	0.00	0.00	0.00	24.25	0.00	0.00	2.31	0.00	0.00	0.00	7.28
NPC	714.00	714.00	714.00	714.00	714.00	714.00	714.00	714.00	714.00	714.00	714.00	714.00	717.00	717.00	717.00	717.00	717.00	717.00

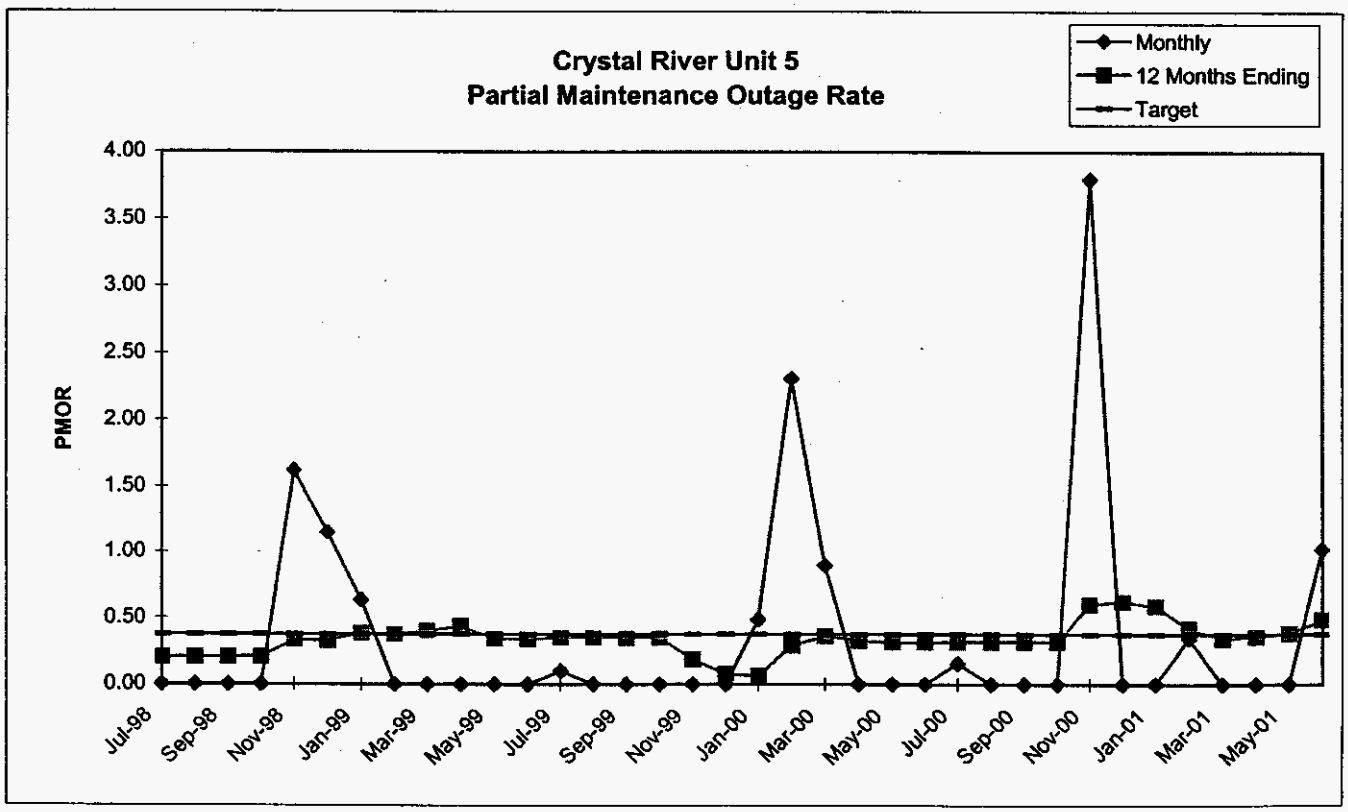
MONTHLY	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.72	0.33	0.21	0.27	1.29	5.96	0.87	0.00	1.02	0.00	2.65	0.47
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.24	50.12	16.30	0.00	0.00	0.00	0.00	0.00
PFOR	0.51	0.00	0.03	0.35	0.00	0.55	0.20	0.09	0.11	9.31	1.31	0.00	0.00	0.07	0.00	2.09	0.97	0.00
PMOR	0.49	2.31	0.90	0.00	0.00	0.00	0.16	0.00	0.00	0.00	3.80	0.00	0.00	0.34	0.00	0.00	0.00	1.02
EUOR	0.99	2.31	0.93	0.35	0.00	0.55	1.07	0.42	0.32	9.56	15.81	51.65	16.91	0.41	1.02	2.09	3.60	1.48
EUOF	0.99	2.31	0.93	0.35	0.00	0.55	1.07	0.42	0.32	9.56	15.81	51.65	16.91	0.41	1.02	0.91	1.22	1.48
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.52	66.08	0.00
EAF	99.01	97.69	99.07	99.65	100.00	99.45	98.93	99.58	99.68	90.44	84.19	48.35	83.09	99.59	98.98	42.57	32.70	98.52

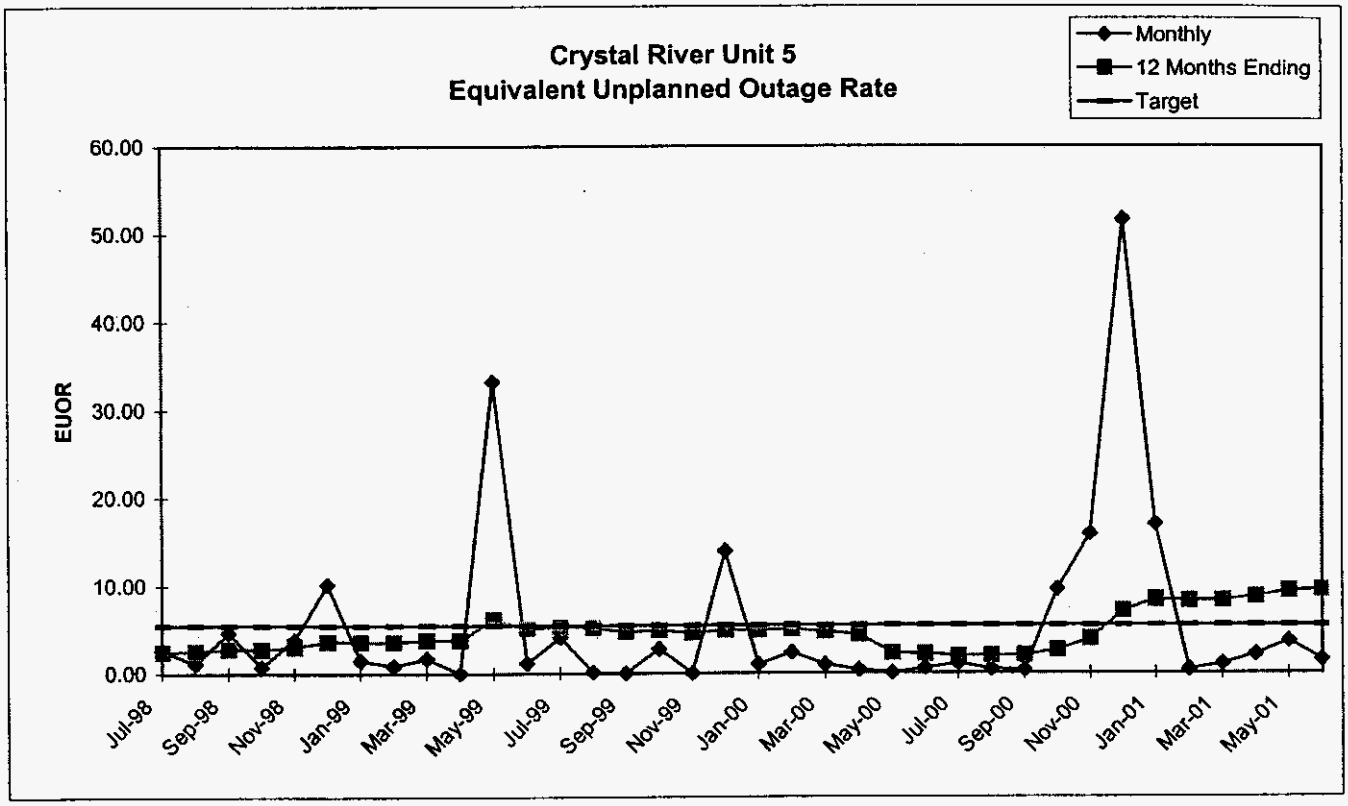
12 MONTHS	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FOR	2.82	2.81	2.64	2.42	0.31	0.31	0.37	0.40	0.41	0.20	0.30	0.51	0.58	0.58	0.68	0.71	0.85	0.90
MOR	1.85	1.85	1.73	1.58	1.51	1.42	1.09	1.09	1.09	1.08	1.92	4.97	6.35	6.37	6.37	6.69	7.11	7.12
PFOR	0.26	0.18	0.11	0.13	0.12	0.16	0.18	0.17	0.18	0.98	1.09	1.10	1.07	1.08	1.07	1.18	1.30	1.24
PMOR	0.06	0.29	0.36	0.33	0.31	0.31	0.32	0.32	0.32	0.32	0.60	0.62	0.59	0.42	0.34	0.36	0.38	0.48
EUOR	4.88	5.00	4.73	4.36	2.24	2.19	1.93	1.96	1.99	2.56	3.86	7.05	8.40	8.27	8.28	8.73	9.39	9.48
EUOF	4.10	4.21	4.23	4.26	2.24	2.19	1.93	1.96	1.99	2.56	3.86	7.05	8.40	8.27	8.28	8.33	8.43	8.51
POF	15.82	15.78	10.57	2.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.64	10.25	10.25
EAF	80.08	80.02	85.19	93.35	97.76	97.81	98.07	98.04	98.01	97.44	96.14	92.95	91.60	91.73	91.72	87.03	81.32	81.24

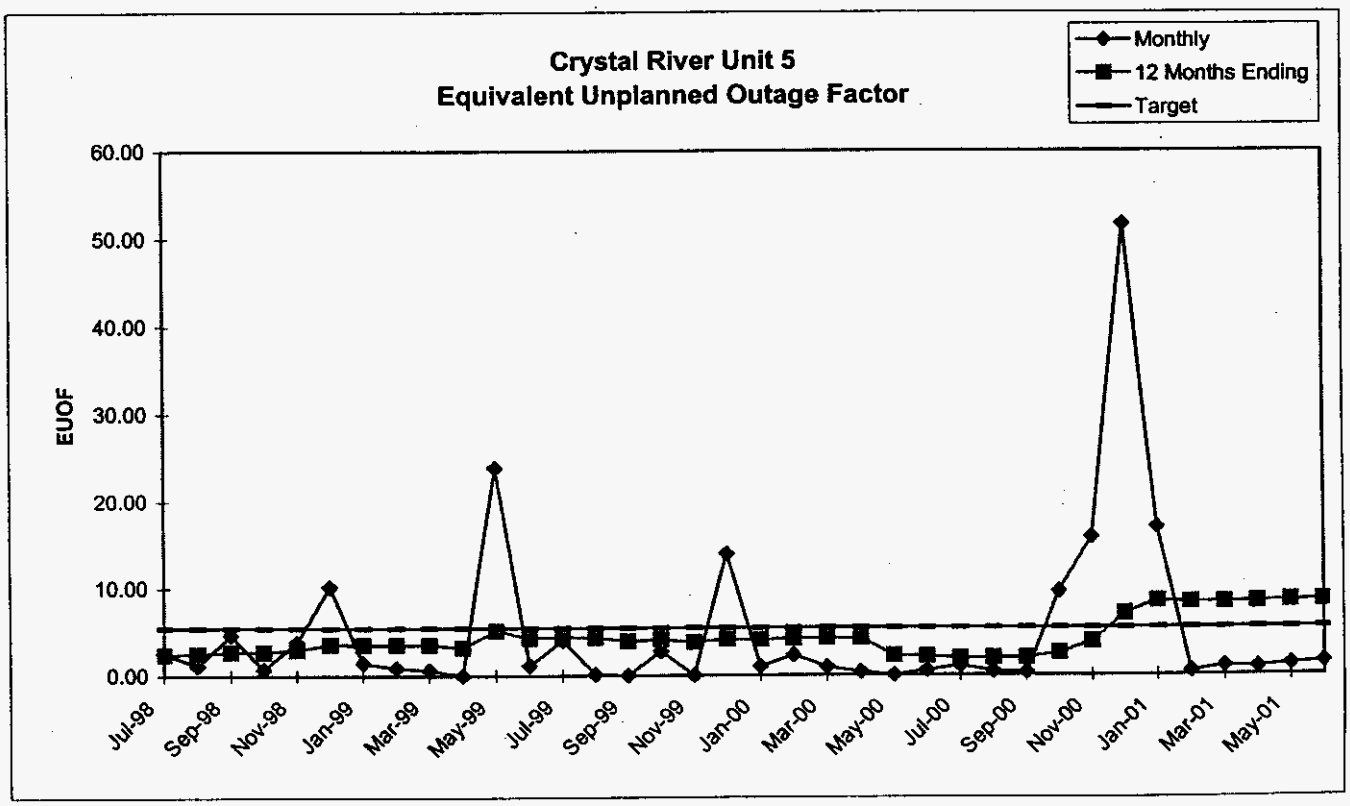

Crystal River Unit 5
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 5
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 5
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 5
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 5
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Crystal River Unit 5
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01

Tiger Bay

	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	701.12	616.33	686.00	724.62	205.27	151.63	132.13	368.77	385.82	123.77	544.48	720.00	738.78	684.33	688.97	720.07	720.00	666.15
RSH	0.00	0.00	0.00	0.00	243.18	229.48	573.50	298.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	42.88	127.67	34.00	20.38	271.55	362.88	38.37	4.53	358.18	595.23	199.52	0.00	5.22	59.67	31.03	24.93	0.00	77.85
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	358.18	526.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	42.88	72.53	34.00	20.38	271.55	0.00	38.37	4.53	0.00	0.00	199.52	0.00	5.22	59.67	31.03	24.93	0.00	69.68
MOH	0.00	55.13	0.00	0.00	0.00	362.88	0.00	0.00	0.00	69.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.17
PFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.02	1.99	0.11	0.00	2.07	0.00	0.00	0.40
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.04	2.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	206.00	206.00	206.00	206.00	206.00	206.00	206.00	206.00	206.00	206.00	206.00	206.00	206.00	206.00	206.00	206.00	206.00	206.00

MONTHLY	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
FOR	5.76	10.53	4.72	2.74	56.95	0.00	22.50	1.21	0.00	0.00	26.82	0.00	0.70	8.02	4.31	3.35	0.00	9.47
MOR	0.00	8.21	0.00	0.00	0.00	70.53	0.00	0.00	0.00	35.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.21
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.19	0.28	0.01	0.00	0.30	0.00	0.00	0.06
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.69	0.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	5.76	17.16	4.72	2.74	56.95	70.53	22.50	1.21	0.00	39.51	27.29	0.28	0.72	8.02	4.60	3.35	0.00	10.52
EUOF	5.76	17.16	4.72	2.74	37.72	48.77	5.16	0.67	0.00	10.60	27.29	0.28	0.72	8.02	4.60	3.35	0.00	10.52
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.14	73.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	94.24	82.84	95.28	97.26	62.28	51.23	94.84	99.33	51.86	16.24	72.71	99.72	99.28	91.98	95.40	96.65	100.00	89.48

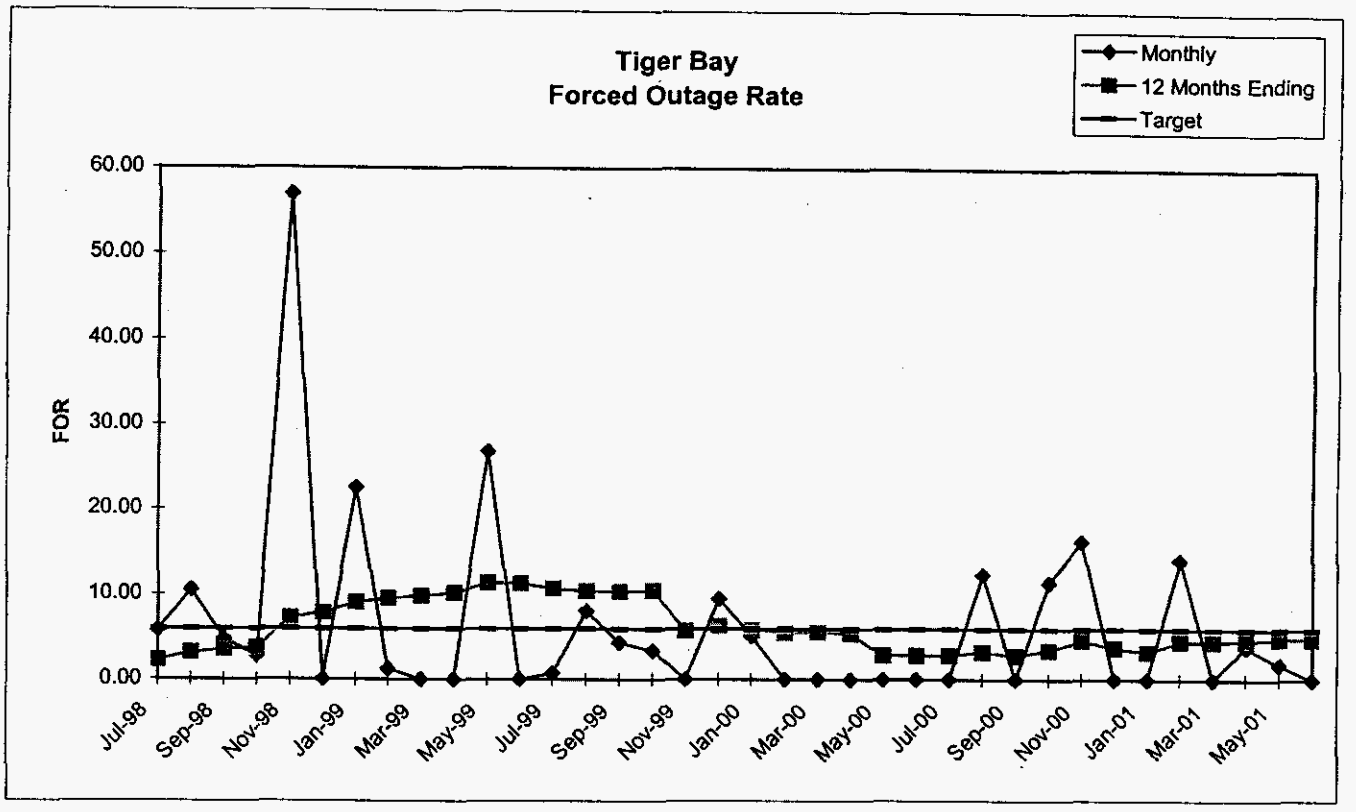
12 MONTHS	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
FOR	2.29	3.10	3.51	3.66	7.21	7.79	9.03	9.52	9.82	10.16	11.31	11.31	10.69	10.38	10.33	10.41	5.73	6.25
MOR	0.00	0.69	0.70	0.70	0.75	5.84	6.38	6.69	6.91	8.25	8.33	8.33	8.28	7.33	7.32	7.33	6.74	1.18
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.06	0.06	0.06	0.09	0.09	0.09	0.09
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.18	0.18	0.18	0.18	0.18	0.18	0.16	0.15
EUOR	2.29	3.75	4.16	4.31	7.85	12.78	14.34	15.03	15.48	16.99	18.09	18.12	17.55	16.51	16.49	16.56	11.96	7.50
EUOF	2.14	3.51	3.90	4.04	7.14	11.28	11.72	11.77	11.77	12.64	13.49	13.51	13.08	12.31	12.30	12.35	9.25	6.00
POF	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55	8.64	10.26	10.09	10.09	10.09	10.09	10.09	10.09	10.09	10.09
EAF	93.31	91.94	91.55	91.41	88.31	84.17	83.73	83.68	79.59	77.10	76.42	76.40	76.82	77.60	77.61	77.56	80.66	83.91

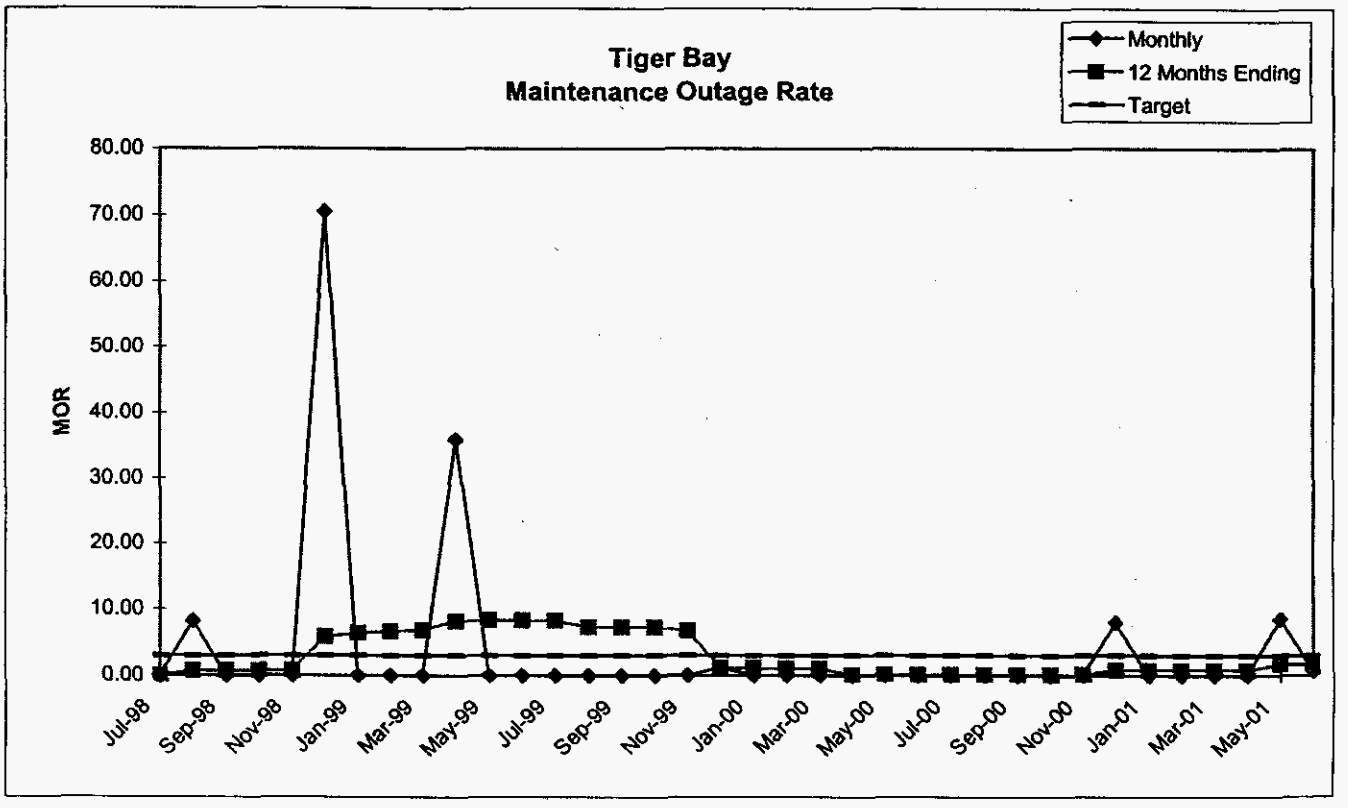
Tiger Bay

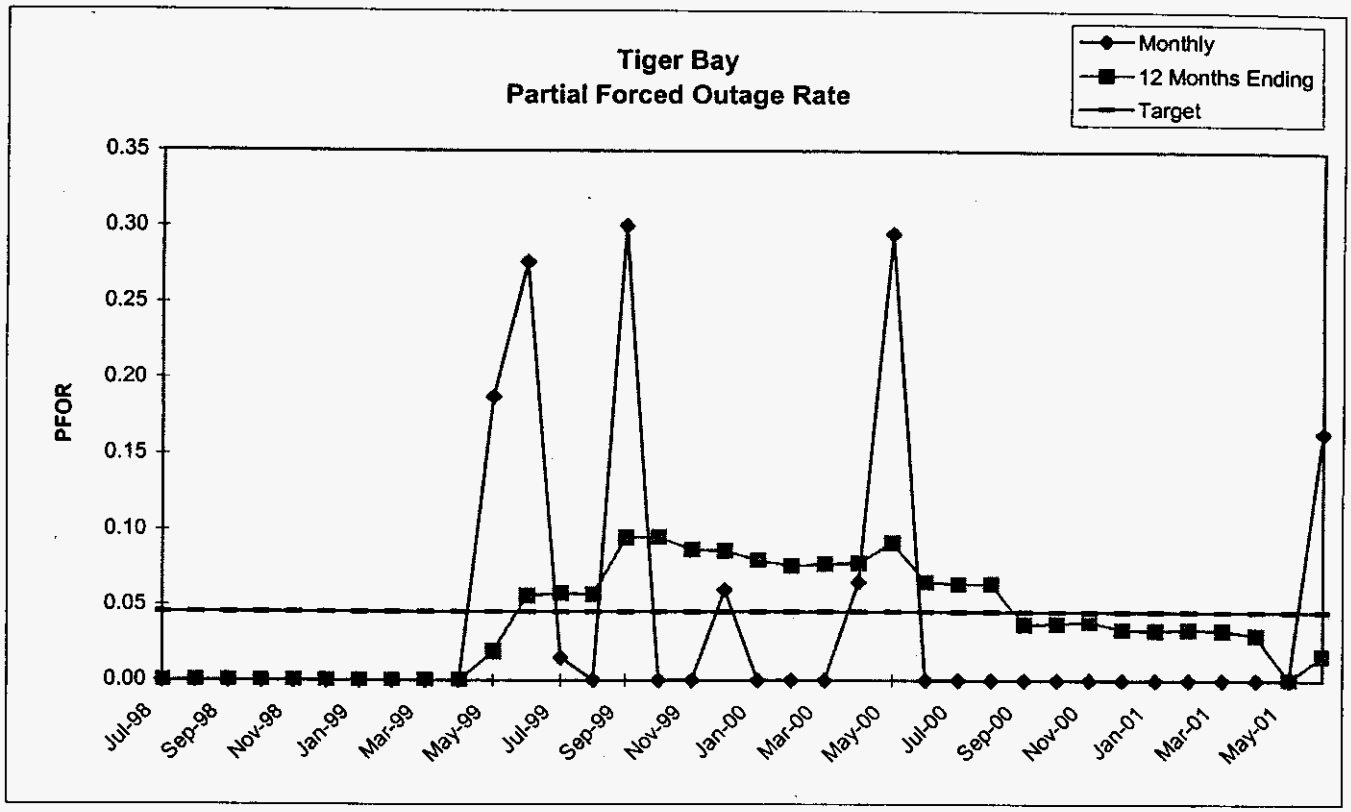
	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
PER HOURS	744.00	696.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	636.90	696.00	282.70	357.90	744.00	720.00	744.00	651.97	720.00	574.13	396.38	684.60	744.00	577.15	385.93	375.67	669.57	715.37
RSH	72.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	96.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	34.20	0.00	461.30	361.10	0.00	0.00	0.00	92.03	0.00	73.95	323.62	59.40	0.00	94.85	358.07	343.33	74.43	4.63
POH	0.00	0.00	461.30	361.10	0.00	0.00	0.00	0.00	0.00	0.00	246.50	0.00	0.00	0.00	358.07	328.23	0.00	0.00
FOH	34.20	0.00	0.00	0.00	0.00	0.00	0.00	92.03	0.00	73.95	77.12	0.00	0.00	94.85	0.00	15.10	12.25	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	59.40	0.00	0.00	0.00	0.00	62.18	4.63
PFOH	0.00	0.00	0.00	0.80	3.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.62
LRPF	0.00	0.00	0.00	60.00	145.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	150.21
EFOH	0.00	0.00	0.00	0.23	2.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.18
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	206.00	206.00	206.00	206.00	206.00	206.00	206.00	206.00	206.00	206.00	206.00	206.00	207.00	207.00	207.00	207.00	207.00	207.00

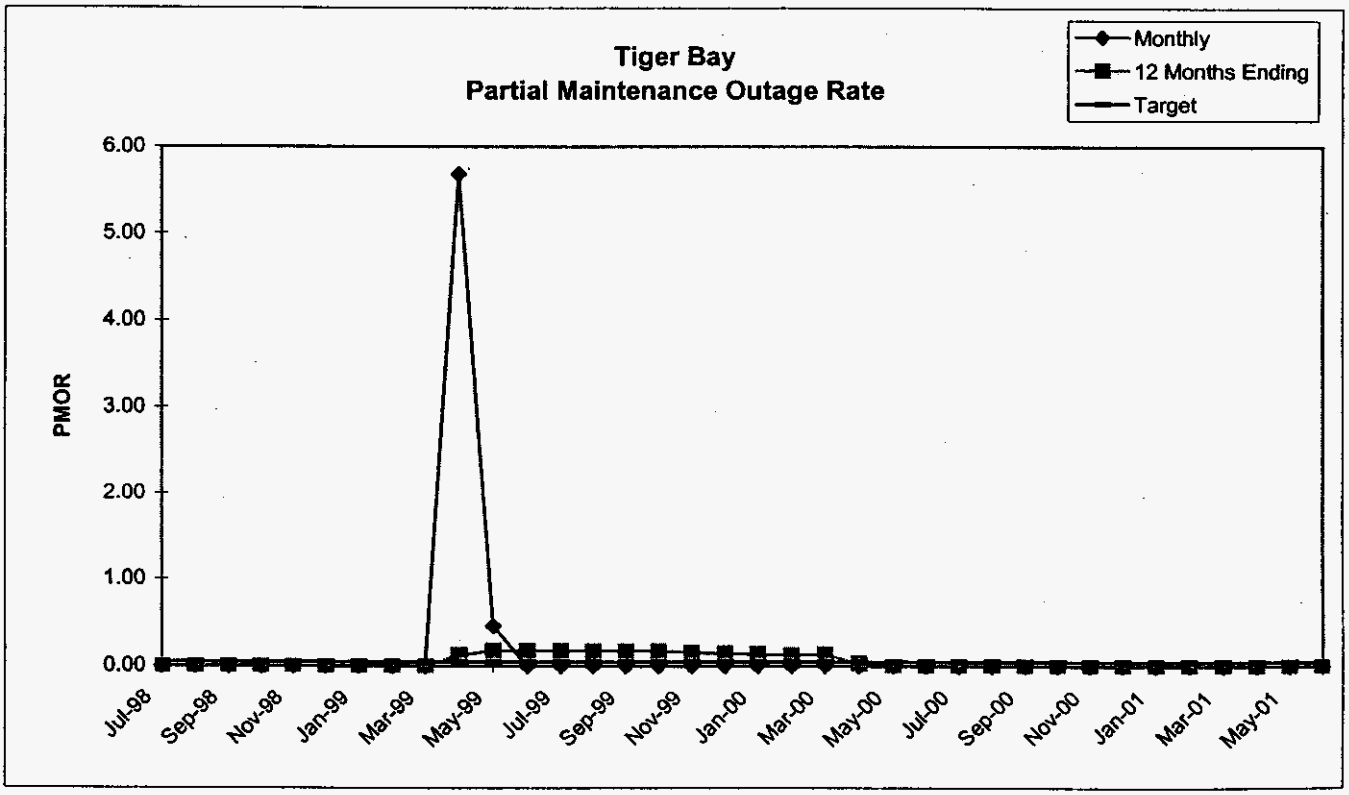
MONTHLY	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FOR	5.10	0.00	0.00	0.00	0.00	0.00	0.00	12.37	0.00	11.41	16.29	0.00	0.00	14.11	0.00	3.86	1.80	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.98	0.00	0.00	0.00	0.00	8.50	0.64
PFOR	0.00	0.00	0.00	0.07	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.16
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	5.10	0.00	0.00	0.07	0.30	0.00	0.00	12.37	0.00	11.41	16.29	7.98	0.00	14.11	0.00	3.86	10.00	0.81
EUOF	4.60	0.00	0.00	0.03	0.30	0.00	0.00	12.37	0.00	9.93	10.71	7.98	0.00	14.11	0.00	2.10	10.00	0.81
POF	0.00	0.00	62.00	50.22	0.00	0.00	0.00	0.00	0.00	0.00	34.24	0.00	0.00	0.00	48.13	45.65	0.00	0.00
EAF	95.40	100.00	38.00	49.75	99.70	100.00	100.00	87.63	100.00	90.07	55.05	92.02	100.00	85.89	51.87	52.25	90.00	99.19

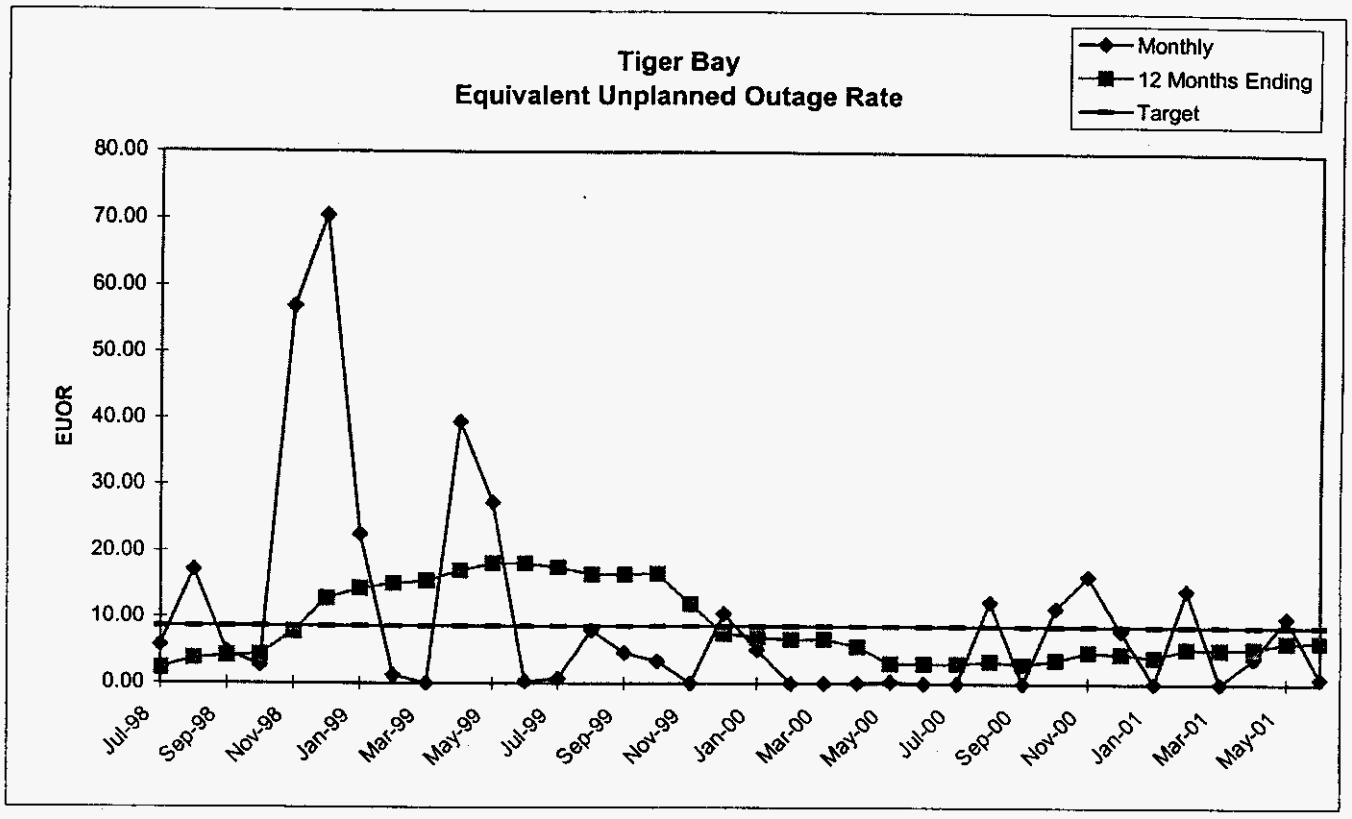
12 MONTHS	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
FOR	5.77	5.47	5.55	5.38	2.85	2.85	2.79	3.20	2.80	3.47	4.60	3.70	3.22	4.49	4.42	4.60	4.80	4.80
MOR	1.09	1.05	1.06	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.82	0.81	0.82	0.81	0.81	1.65	1.71
PFOR	0.08	0.08	0.08	0.08	0.09	0.07	0.06	0.06	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.00	0.02
PMOR	0.14	0.13	0.13	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	6.95	6.60	6.69	5.59	3.04	3.02	2.95	3.36	2.94	3.60	4.74	4.49	4.00	5.26	5.19	5.36	6.30	6.37
EUOF	5.95	5.88	5.88	5.02	2.73	2.71	2.65	3.02	2.64	3.20	4.08	3.86	3.47	4.56	4.56	4.73	5.56	5.62
POF	10.09	10.07	11.24	9.36	9.36	9.36	9.36	9.36	9.36	9.36	12.17	12.17	12.17	12.20	11.02	10.65	10.65	10.65
EAF	83.96	84.05	82.88	85.62	87.91	87.93	87.99	87.62	88.00	87.44	83.76	83.97	84.36	83.23	84.41	84.62	83.79	83.73


Tiger Bay
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Tiger Bay
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Tiger Bay
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Tiger Bay
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01


Tiger Bay
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01

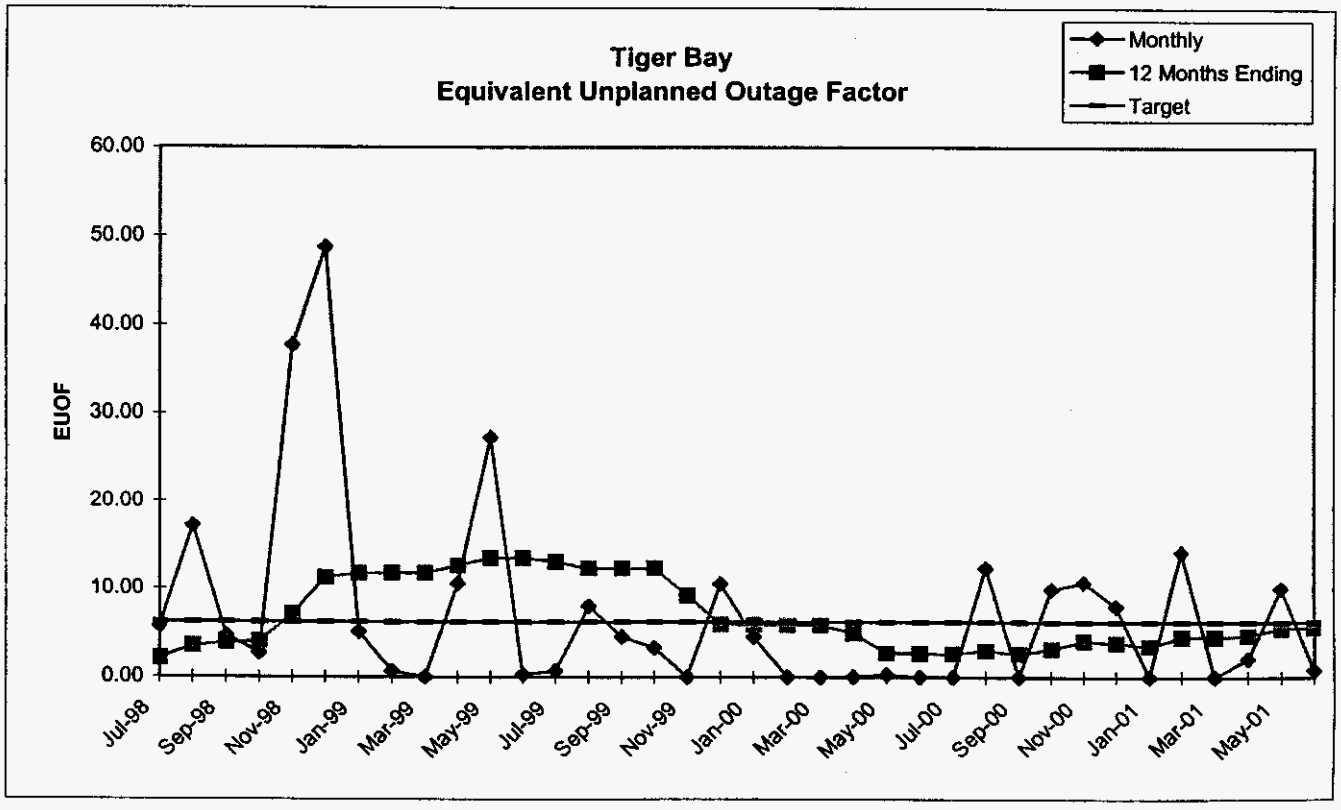

Tiger Bay
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01

EXHIBIT NO. _____
DOCKET NO. 010001-EI
TAMPA ELECTRIC COMPANY
(BSB-1)

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2000 - DECEMBER 2000

TRUE-UP

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010001-EI EXHIBIT NO. 19
COMPANY/
WITNESS. Buchler
DATE: 10-20-21-01

EXHIBIT NO. _____
DOCKET NO. 010001-EI
TAMPA ELECTRIC COMPANY
(BSB-1)

GENERATING PERFORMANCE INCENTIVE FACTOR

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EXHIBITS TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCKET NO. 010001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2000 - DECEMBER 2000

TRUE-UP

DOCUMENT NO. 1

GPIF SCHEDULES

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2000 - DECEMBER 2000
TRUE-UP
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ACTUAL
JANUARY 2000 - DECEMBER 2000

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	15,613.6	4,943.1
+9	14,052.2	4,448.8
+8	12,490.9	3,954.5
+7	10,929.5	3,460.2
+6	9,368.2	2,965.9
+5	7,806.8	2,471.6
+4	6,245.4	1,977.3
+3	4,684.1	1,482.9
+2	3,122.7	988.6
+1	1,561.4	494.3
0	0.0	0.0
-1	(2,381.0)	(494.3)
-2	(4,762.1)	(988.6)
-3	(7,143.1)	(1,482.9)
-4	(9,524.1)	(1,977.3)
-5	(11,905.2)	(2,471.6)
-6	(14,286.2)	(2,965.9)
-7	(16,667.2)	(3,460.2)
-8	(19,048.2)	(3,954.5)
-9	(21,429.3)	(4,448.8)
-10	(23,810.3)	(4,943.1)



TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS - ACTUAL
JANUARY 2000 - DECEMBER 2000

Line 1	Beginning of period balance of common equity: End of month common equity:		$	1,202,600,000
Line 2	Month of January	2000	$	1,201,801,000
Line 3	Month of February	2000	$	1,213,569,000
Line 4	Month of March	2000	$	1,225,452,000
Line 5	Month of April	2000	$	1,214,599,000
Line 6	Month of May	2000	$	1,226,492,000
Line 7	Month of June	2000	$	1,238,501,000
Line 8	Month of July	2000	$	1,237,579,000
Line 9	Month of August	2000	$	1,249,697,000
Line 10	Month of September	2000	$	1,261,933,000
Line 11	Month of October	2000	$	1,250,858,000
Line 12	Month of November	2000	$	1,263,106,000
Line 13	Month of December	2000	$	1,275,474,000
Line 14	(Summation of line 1 through line 13 divided by 13)		$	1,235,512,385
Line 15	25 Basis points			0.0025
Line 16	Revenue Expansion Factor			61.37%
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	5,032,735
Line 18	Jurisdictional Sales			16,644,004 MWH
Line 19	Total Sales			16,945,711 MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			98.22%
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$**	**4,943,131**

TAMPA ELECTRIC COMPANY
CALCULATION OF SYSTEM GPIF POINTS - ACTUAL
JANUARY 2000 - DECEMBER 2000

PLANT / UNIT	12 MONTH ADJ. ACTUAL PERFORMANCE		WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
BIG BEND 1	74.3%	EAF	8.45%	-5.429	-0.459
BIG BEND 2	83.2%	EAF	6.47%	8.125	0.526
BIG BEND 3	79.6%	EAF	8.71%	10.000	0.871
BIG BEND 4	86.1%	EAF	7.71%	6.296	0.485
GANNON 5	57.2%	EAF	2.79%	-10.000	-0.279
GANNON 6	28.2%	EAF	8.49%	-10.000	-0.849
BIG BEND 1	10091	ANOHR	11.53%	0.000	0.000
BIG BEND 2	9811	ANOHR	11.54%	5.973	0.689
BIG BEND 3	9841	ANOHR	10.80%	9.183	0.992
BIG BEND 4	9799	ANOHR	10.66%	4.232	0.451
GANNON 5	10766	ANOHR	5.37%	-3.921	-0.211
GANNON 6	10529	ANOHR	7.47%	0.000	0.000
			100.00%		2.217

GPIF REWARD	$ 1,095,745

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)	EAF ADJUSTED ACTUAL (%)	ACTUAL FUEL SAVINGS/ LOSS ($000)
BIG BEND 1	8.45%	78.1	81.7	71.1	1,319.2	(2,856.0)	74.3%	(1,550.4)
BIG BEND 2	6.47%	80.6	83.8	74.4	1,010.3	(2,749.8)	83.2%	2,234.2
BIG BEND 3	8.71%	76.3	79.6	67.6	1,359.8	(2,945.8)	79.6%	2,945.8
BIG BEND 4	7.71%	84.4	87.1	78.6	1,203.7	(2,364.4)	86.1%	1,488.7
GANNON 5	2.79%	75.3	79.3	67.1	435.3	(1,098.3)	57.2%	(1,098.3)
GANNON 6	8.49%	72.2	76.9	62.9	1,326.3	(2,837.0)	28.2%	(2,837.0)
GPIF SYSTEM	**42.62%**				**6,654.6**	**(14,851.3)**		

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR (Btu/kwh)	TARGET NOF (%)	ANOHR TARGET RANGE MIN.	ANOHR TARGET RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)	ACTUAL ADJUSTED ANOHR	ACTUAL FUEL SAVINGS/ LOSS ($000)
BIG BEND 1	11.53%	10,127	87.1	9,740	10,514	1,801.0	(1,801.0)	10,091	0.0
BIG BEND 2	11.54%	10,061	91.0	9,693	10,429	1,802.0	(1,802.0)	9,811	1,076.3
BIG BEND 3	10.80%	10,197	80.6	9,816	10,578	1,686.0	(1,686.0)	9,841	1,548.3
BIG BEND 4	10.66%	9,976	88.7	9,660	10,292	1,665.0	(1,665.0)	9,799	704.7
GANNON 5	5.37%	10,562	66.7	10,158	10,966	839.0	(839.0)	10,766	(329.0)
GANNON 6	7.47%	10,507	68.1	10,141	10,873	1,166.0	(1,166.0)	10,529	0.0
GPIF SYSTEM	**57.38%**					**8,959.0**	**(8,959.0)**		

TAMPA ELECTRIC COMPANY
UNIT PERFORMANCE DATA - ACTUAL
JANUARY 2000 - DECEMBER 2000

PLANT / UNIT	ACTUAL EAF (%)	ADJUSTMENTS (1) TO EAF (%)	EAF ADJUSTED ACTUAL (%)
BIG BEND 1	75.8	-1.5	74.3
BIG BEND 2	85.6	-2.4	83.2
BIG BEND 3	75.0	4.6	79.6
BIG BEND 4	87.8	-1.7	86.1
GANNON 5	55.6	1.6	57.2
GANNON 6	33.2	-5.0	28.2

PLANT / UNIT	ACTUAL ANOHR (Btu/kwh)	ADJUSTMENTS (2) TO ANOHR (Btu/kwh)	ANOHR ADJUSTED ACTUAL (Btu/kwh)
BIG BEND 1	10231	-140	10091
BIG BEND 2	9925	-114	9811
BIG BEND 3	9866	-25	9841
BIG BEND 4	9896	-97	9799
GANNON 5	10748	18	10766
GANNON 6	10501	28	10529

(1) Documentation of adjustments to Actual EAF on pages 7 - 12

(2) Documentation of adjustments to Actual ANOHR on pages 13 - 18

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 1
JANUARY 2000 - DECEMBER 2000

WEIGHTING FACTOR = 8.45%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8784.0	8784.0	8784.0
EAF	78.1	75.8	74.3
POH	504.0	325.9	504.0
FOH + EFOH	813.0	977.6	957.0
MOH + EMOH	604.0	812.6	795.5
POF	5.7	3.7	5.7
EFOF	9.3	11.1	10.9
EMOF	6.9	9.3	9.1
	-5.429	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8784 - 504}{8784 - 325.9} \quad (977.6 + 812.6) \quad = \quad 1752.5$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 5.7 - \frac{1752.5}{8784.0} \times 100 \quad = \quad 74.3$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 2
JANUARY 2000 - DECEMBER 2000

WEIGHTING FACTOR = 6.47%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8784.0	8784.0	8784.0
EAF	80.6	85.6	83.2
POH	432.0	181.0	432.0
FOH + EFOH	810.0	640.8	622.1
MOH + EMOH	460.0	433.2	420.6
POF	4.9	2.1	4.9
EFOF	9.2	7.3	7.1
EMOF	5.2	4.9	4.8
	8.125	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8784 - 432}{8784 - 181} \times (640.8 + 433.2) = 1042.7$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 4.9 - \frac{1042.7}{8784.0} \times 100 = 83.2$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 3
JANUARY 2000 - DECEMBER 2000

WEIGHTING FACTOR = 8.71%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8784.0	8784.0	8784.0
EAF	76.3	75.0	79.6
POH	504.0	984.8	504.0
FOH + EFOH	1092.0	880.3	934.6
MOH + EMOH	488.0	332.8	353.3
POF	5.7	11.2	5.7
EFOF	12.4	10.0	10.6
EMOF	5.6	3.8	4.0
	10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8784 - 504}{8784 - 984.8} \times (880.3 + 332.8) = 1287.9$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 5.7 - \frac{1287.9}{8784.0} \times 100 = 79.6$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 4
JANUARY 2000 - DECEMBER 2000

WEIGHTING FACTOR = 7.71%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8784.0	8784.0	8784.0
EAF	84.4	87.8	86.1
POH	168.0	0.0	168.0
FOH + EFOH	593.0	638.4	626.2
MOH + EMOH	612.0	432.6	424.3
POF	1.9	0.0	1.9
EFOF	6.8	7.3	7.1
EMOF	7.0	4.9	4.8
	6.296	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8784 - 168}{8784 - 0} \times (638.4 + 432.6) = 1050.5$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 1.9 - \frac{1050.5}{8784.0} \times 100 = 86.1$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
GANNON UNIT NO. 5
JANUARY 2000 - DECEMBER 2000

WEIGHTING FACTOR = 2.79%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8784.0	8784.0	8784.0
EAF	75.3	55.6	57.2
POH	336.0	566.3	336.0
FOH + EFOH	1404.0	2466.0	2535.1
MOH + EMOH	265.0	868.7	893.0
POF	3.8	6.4	3.8
EFOF	16.0	28.1	28.9
EMOF	3.0	9.9	10.2
	-10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8784 - 336}{8784 - 566.3} \times (2466 + 868.7) = 3428.2$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 3.8 - \frac{3428.2}{8784.0} \times 100 = 57.2$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
GANNON UNIT NO. 6
JANUARY 2000 - DECEMBER 2000

WEIGHTING FACTOR = 8.49%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8784.0	8784.0	8784.0
EAF	72.2	33.2	28.2
POH	2015.0	784.0	2015.0
FOH + EFOH	1532.0	4783.0	4047.0
MOH + EMOH	406.0	297.4	251.6
POF	22.9	8.9	22.9
EFOF	17.4	54.5	46.1
EMOF	4.6	3.4	2.9
	-10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8784 - 2015}{8784 - 784} \times (4783 + 297.4) = 4298.7$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 22.9 - \frac{4298.7}{8784.0} \times 100 = 28.2$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 1
JANUARY 2000 - DECEMBER 2000

WEIGHTING FACTOR = 11.53%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10127	10231
NET GENERATION (GWH)	2778.6	2452.1
OPERATING BTU (10^9)	28137.576	25087.855
NET OUTPUT FACTOR	87.1	77.8

0.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-15.0564) + 11438 = ANOHR

77.8 * (-15.0564) + 11438 = 10267

10231 - 10267 = -36

10127 + -36 = 10091 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 2
JANUARY 2000 - DECEMBER 2000

WEIGHTING FACTOR = 11.54%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10061	9925
NET GENERATION (GWH)	2957.8	2754.2
OPERATING BTU (10^9)	29757.271	27336.719
NET OUTPUT FACTOR	91.0	79.5

5.973 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-9.9261) + 10964 = ANOHR

79.5 * (-9.9261) + 10964 = 10175

9925 - 10175 = -250

10061 + -250 = 9811 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 3
JANUARY 2000 - DECEMBER 2000

WEIGHTING FACTOR = 10.80%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10197	9866
NET GENERATION (GWH)	2643.6	2479.3
OPERATING BTU (10^9)	26957.712	24459.282
NET OUTPUT FACTOR	80.6	79.9

9.183 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-35.3936) + 13050 = ANOHR

79.9 * (-35.3936) + 13050 = 10222

9866 - 10222 = -356

10197 + -356 = 9841 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 4
JANUARY 2000 - DECEMBER 2000

WEIGHTING FACTOR = 10.66%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	9976	9896
NET GENERATION (GWH)	3164.0	3090.1
OPERATING BTU (10^9)	31565.419	30579.650
NET OUTPUT FACTOR	88.7	84.7

4.232 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-24.0193) + 12107 = ANOHR

84.7 * (-24.0193) + 12107 = 10073

9896 - 10073 = -177

9976 + -177 = 9799 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
GANNON UNIT NO. 5
JANUARY 2000 - DECEMBER 2000

WEIGHTING FACTOR = 5.37%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10562	10748
NET GENERATION (GWH)	1.8	931.1
OPERATING BTU (10^9)	12381.670	10007.269
NET OUTPUT FACTOR	66.7	68.2

-3.921 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-12.3085) + 11383 = ANOHR

68.2 * (-12.3085) + 11383 = 10544

10748 - 10544 = 204

10562 + 204 = 10766 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
GANNON UNIT NO. 6
JANUARY 2000 - DECEMBER 2000

WEIGHTING FACTOR = 7.47%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10507	10501
NET GENERATION (GWH)	6.5	899.6
OPERATING BTU (10^9)	18833.195	9446.813
NET OUTPUT FACTOR	68.1	74.8

0.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-4.153) + 10790 = ANOHR

74.8 * (-4.153) + 10790 = 10479

10501 - 10479 = 22

10507 + 22 = 10529 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

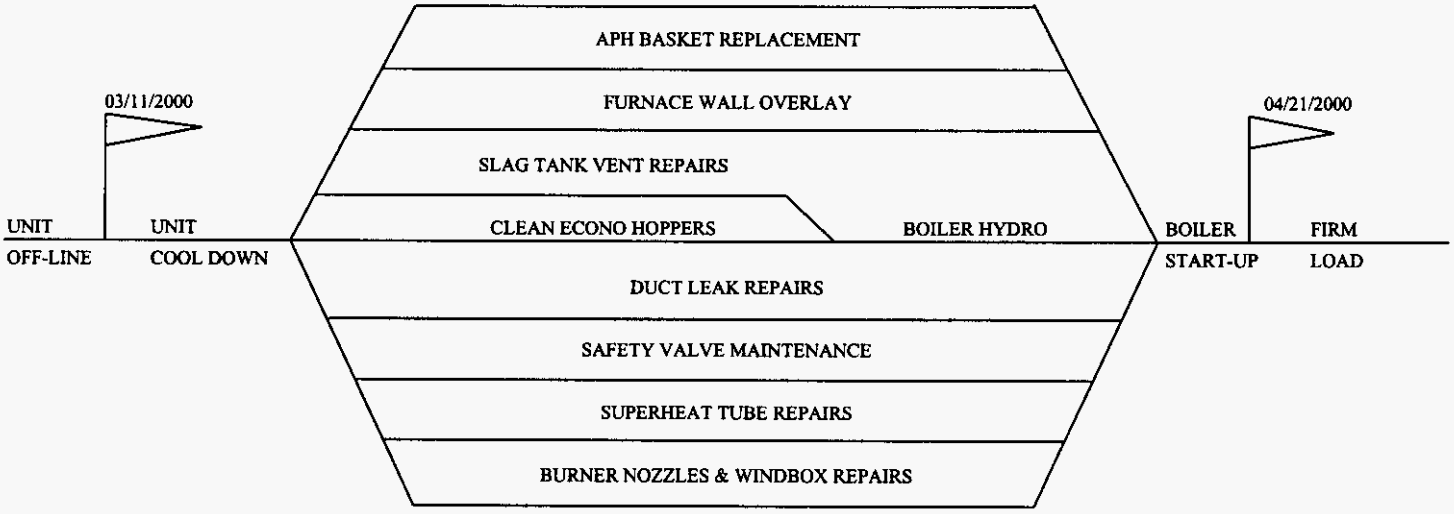
ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE - ACTUAL
GPIF UNITS ONLY
JANUARY 2000 - DECEMBER 2000

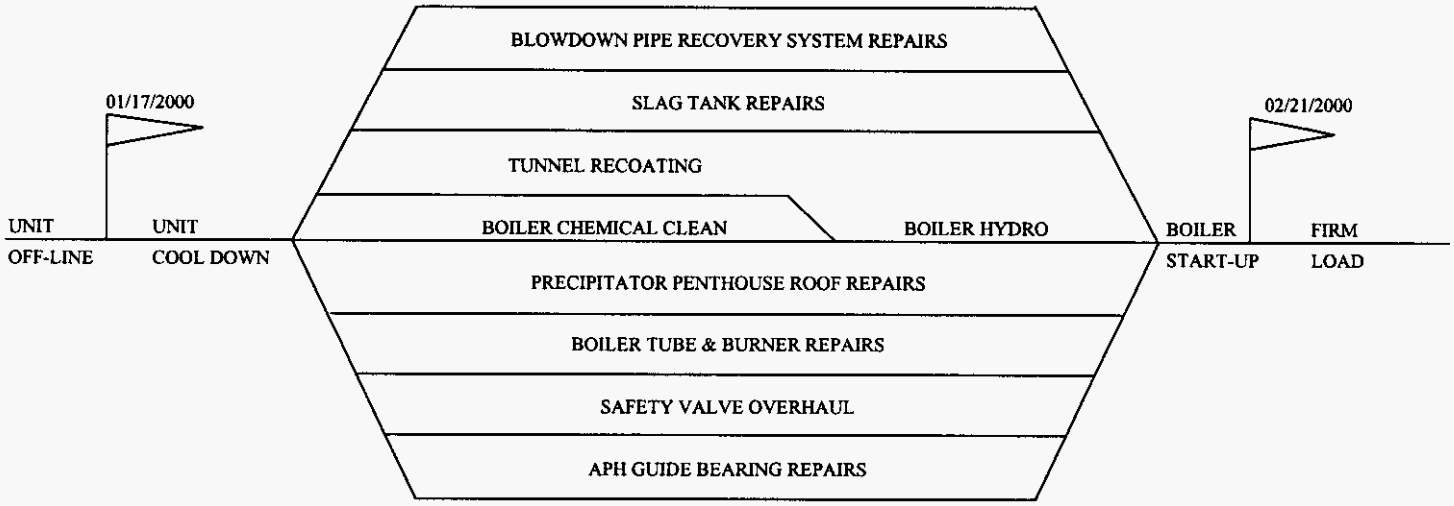
	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
+	BIG BEND 1	Apr 23	-	May 06	Fuel System Clean-up
+	BIG BEND 2	Feb 19	-	Feb 26	Fuel System Clean-up
	BIG BEND 3	Mar 11	-	Apr 21	APH basket replacement, furnace wall overlay, duct leak repairs, clean econo hoppers, safety valve maintenance, SH tube repairs, burner nozzles, windbox, and slag tank vent repairs
+	BIG BEND 4		-		No Outage
+	GANNON 5	Mar 07	-	Mar 31	Fuel System Clean-up
	GANNON 6	Jan 17	-	Feb 21	Chemical clean, tunnel recoating, slag tank repairs, blowdown pipe recovery system repairs, burner repairs, boiler tube repairs, APH guide bearing repairs, safety valve overhaul, and precipitator penthouse roof repairs

+ **CPM for units with less than or equal to 4 weeks are not included.**

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2000 - DECEMBER 2000



TAMPA ELECTRIC COMPANY
BIG BEND UNIT NUMBER 3
PLANNED OUTAGE 2000
ACTUAL CPM
12/31/2000



TAMPA ELECTRIC COMPANY
GANNON UNIT NUMBER 6
PLANNED OUTAGE 2000
ACTUAL CPM
12/31/2000

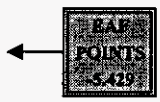
TAMPA ELECTRIC COMPANY

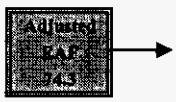
GENERATING PERFORMANCE INCENTIVE POINTS TABLE

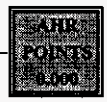
JANUARY 2000 - DECEMBER 2000

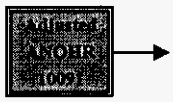
BIG BEND 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,319.2	81.7	+10	1,801.0	9,740
+9	1,187.3	81.3	+9	1,620.9	9,771
+8	1,055.4	81.0	+8	1,440.8	9,802
+7	923.4	80.6	+7	1,260.7	9,834
+6	791.5	80.3	+6	1,080.6	9,865
+5	659.6	79.9	+5	900.5	9,896
+4	527.7	79.5	+4	720.4	9,927
+3	395.8	79.2	+3	540.3	9,958
+2	263.8	78.8	+2	360.2	9,990
+1	131.9	78.5	+1	180.1	10,021
					10,052
0	0.0	78.1	0	0.0	10,127
					10,202
-1	(285.6)	77.4	-1	(180.1)	10,233
-2	(571.2)	76.7	-2	(360.2)	10,264
-3	(856.8)	76.0	-3	(540.3)	10,296
-4	(1,142.4)	75.3	-4	(720.4)	10,327
-5	(1,428.0)	74.6	-5	(900.5)	10,358
-6	(1,713.6)	73.9	-6	(1,080.6)	10,389
-7	(1,999.2)	73.2	-7	(1,260.7)	10,420
-8	(2,284.8)	72.5	-8	(1,440.8)	10,452
-9	(2,570.4)	71.8	-9	(1,620.9)	10,483
-10	(2,856.0)	71.1	-10	(1,801.0)	10,514









Weighting Factor = 8.45%

Weighting Factor = 11.53%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2000 - DECEMBER 2000

BIG BEND 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,010.3	83.8	+10	1,802.0	9,693
+9	909.3	83.5	+9	1,621.8	9,722
+8	808.2	83.2	+8	1,441.6	9,752
+7	707.2	82.8	+7	1,261.4	9,781
+6	606.2	82.5	+6	1,081.2	9,810
+5	505.2	82.2	+5	901.0	9,840
+4	404.1	81.9	+4	720.8	9,869
+3	303.1	81.6	+3	540.6	9,898
+2	202.1	81.2	+2	360.4	9,927
+1	101.0	80.9	+1	180.2	9,957
					9,986
0	0.0	80.6	0	0.0	10,061
					10,136
-1	(275.0)	80.0	-1	(180.2)	10,165
-2	(550.0)	79.4	-2	(360.4)	10,195
-3	(824.9)	78.7	-3	(540.6)	10,224
-4	(1,099.9)	78.1	-4	(720.8)	10,253
-5	(1,374.9)	77.5	-5	(901.0)	10,283
-6	(1,649.9)	76.9	-6	(1,081.2)	10,312
-7	(1,924.9)	76.3	-7	(1,261.4)	10,341
-8	(2,199.8)	75.6	-8	(1,441.6)	10,370
-9	(2,474.8)	75.0	-9	(1,621.8)	10,400
-10	(2,749.8)	74.4	-10	(1,802.0)	10,429

Weighting Factor = 6.47%

Weighting Factor = 11.54%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2000 - DECEMBER 2000

BIG BEND 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,359.8	79.6	+10	1,686.0	9,816
+9	1,223.8	79.3	+9	1,517.4	9,847
+8	1,087.8	78.9	+8	1,348.8	9,877
+7	951.9	78.6	+7	1,180.2	9,908
+6	815.9	78.3	+6	1,011.6	9,938
+5	679.9	78.0	+5	843.0	9,969
+4	543.9	77.6	+4	674.4	10,000
+3	407.9	77.3	+3	505.8	10,030
+2	272.0	77.0	+2	337.2	10,061
+1	136.0	76.6	+1	168.6	10,091
					10,122
0	0.0	76.3	0	0.0	10,197
					10,272
-1	(294.6)	75.4	-1	(168.6)	10,303
-2	(589.2)	74.6	-2	(337.2)	10,333
-3	(883.7)	73.7	-3	(505.8)	10,364
-4	(1,178.3)	72.8	-4	(674.4)	10,394
-5	(1,472.9)	72.0	-5	(843.0)	10,425
-6	(1,767.5)	71.1	-6	(1,011.6)	10,456
-7	(2,062.1)	70.2	-7	(1,180.2)	10,486
-8	(2,356.6)	69.3	-8	(1,348.8)	10,517
-9	(2,651.2)	68.5	-9	(1,517.4)	10,547
-10	(2,945.8)	67.6	-10	(1,686.0)	10,578

Weighting Factor = 8.71%

Weighting Factor = 10.80%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2000 - DECEMBER 2000

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,203.7	87.1	+10	1,665.0	9,660
+9	1,083.3	86.8	+9	1,498.5	9,684
+8	963.0	86.6	+8	1,332.0	9,708
+7	842.6	86.3	+7	1,165.5	9,732
+6	722.2	86.0	+6	999.0	9,756
+5	601.9	85.8	+5	832.5	9,781
+4	481.5	85.5	+4	666.0	9,805
+3	361.1	85.2	+3	499.5	9,829
+2	240.7	84.9	+2	333.0	9,853
+1	120.4	84.7	+1	166.5	9,877
					9,901
0	0.0	84.4	0	0.0	9,976
					10,051
-1	(236.4)	83.8	-1	(166.5)	10,075
-2	(472.9)	83.2	-2	(333.0)	10,099
-3	(709.3)	82.7	-3	(499.5)	10,123
-4	(945.8)	82.1	-4	(666.0)	10,147
-5	(1,182.2)	81.5	-5	(832.5)	10,172
-6	(1,418.6)	80.9	-6	(999.0)	10,196
-7	(1,655.1)	80.3	-7	(1,165.5)	10,220
-8	(1,891.5)	79.8	-8	(1,332.0)	10,244
-9	(2,128.0)	79.2	-9	(1,498.5)	10,268
-10	(2,364.4)	78.6	-10	(1,665.0)	10,292

Weighting Factor = 7.71%

Weighting Factor = 10.66%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2000 - DECEMBER 2000

GANNON 5

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	435.3	79.3	+10	839.0	10,158
+9	391.8	78.9	+9	755.1	10,191
+8	348.2	78.5	+8	671.2	10,224
+7	304.7	78.1	+7	587.3	10,257
+6	261.2	77.7	+6	503.4	10,290
+5	217.7	77.3	+5	419.5	10,323
+4	174.1	76.9	+4	335.6	10,355
+3	130.6	76.5	+3	251.7	10,388
+2	87.1	76.1	+2	167.8	10,421
+1	43.5	75.7	+1	83.9	10,454
					10,487
0	0.0	75.3	0	0.0	10,562
					10,637
-1	(109.8)	74.5	-1	(83.9)	10,670
-2	(219.7)	73.7	-2	(167.8)	10,703
-3	(329.5)	72.8	-3	(251.7)	10,736
-4	(439.3)	72.0	-4	(335.6)	10,769
-5	(549.2)	71.2	-5	(419.5)	10,802
-6	(659.0)	70.4	-6	(503.4)	10,834
-7	(768.8)	69.6	-7	(587.3)	10,867
-8	(878.6)	68.7	-8	(671.2)	10,900
-9	(988.5)	67.9	-9	(755.1)	10,933
-10	(1,098.3)	67.1	-10	(839.0)	10,966

Weighting Factor = 2.79%

Weighting Factor = 5.37%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2000 - DECEMBER 2000

GANNON 6

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,326.3	76.9	+10	1,166.0	10,141
+9	1,193.7	76.4	+9	1,049.4	10,170
+8	1,061.0	76.0	+8	932.8	10,199
+7	928.4	75.5	+7	816.2	10,228
+6	795.8	75.0	+6	699.6	10,257
+5	663.2	74.6	+5	583.0	10,287
+4	530.5	74.1	+4	466.4	10,316
+3	397.9	73.6	+3	349.8	10,345
+2	265.3	73.1	+2	233.2	10,374
+1	132.6	72.7	+1	116.6	10,403
					10,432
0	0.0	72.2	0	0.0	10,507
			← AHR POINTS 0.000		Adjusted GANNON 10,523 → 10,582
-1	(283.7)	71.3	-1	(116.6)	10,611
-2	(567.4)	70.3	-2	(233.2)	10,640
-3	(851.1)	69.4	-3	(349.8)	10,669
-4	(1,134.8)	68.5	-4	(466.4)	10,698
-5	(1,418.5)	67.6	-5	(583.0)	10,728
-6	(1,702.2)	66.6	-6	(699.6)	10,757
-7	(1,985.9)	65.7	-7	(816.2)	10,786
-8	(2,269.6)	64.8	-8	(932.8)	10,815
-9	(2,553.3)	63.8	-9	(1,049.4)	10,844
-10 ← EAF POINTS -10.000	(2,837.0)	Adjusted EAF 62.9 → 62.9	-10	(1,166.0)	10,873

Weighting Factor = 8.49%

Weighting Factor = 7.47%

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 00 - DEC 00 POF	EUOF	EUOR	ACTUAL PERFORMANC JAN 00 - DEC 00 POF	EUOF	EUOR
BIG BEND 1	8.45%	19.8%	5.7	16.1	17.1	3.7	20.4	21.2
BIG BEND 2	6.47%	15.2%	4.9	14.5	15.2	2.1	12.2	12.5
BIG BEND 3	8.71%	20.4%	5.7	18.0	19.1	11.2	13.8	15.6
BIG BEND 4	7.71%	18.1%	1.9	13.7	14.0	0.0	12.2	12.2
GANNON 5	2.79%	6.5%	5.7	19.0	20.2	6.4	38.0	40.6
GANNON 6	8.49%	19.9%	5.7	22.1	23.4	8.9	57.8	63.5
GPIF SYSTEM	**42.62%**	**100.0%**	**4.9**	**17.2**	**18.1**	**5.5**	**24.9**	**26.8**

GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%) **77.9** **69.5**

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
7.7	**17.3**	**19.0**	**75.0**

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 00 - DEC 00	ADJUSTED ACTUAL HEAT RATE JAN 00 - DEC 00
BIG BEND 1	11.53%	20.1%	10,127	10,091
BIG BEND 2	11.54%	20.1%	10,061	9,811
BIG BEND 3	10.80%	18.8%	10,197	9,841
BIG BEND 4	10.66%	18.6%	9,976	9,799
GANNON 5	5.37%	9.4%	10,562	10,766
GANNON 6	7.47%	13.0%	10,507	10,529
GPIF SYSTEM	**57.38%**	**100.0%**		

GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh) **10,189** **10,054**

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE POINTS CALCULATION
JANUARY 2000 - DECEMBER 2000

Points are calculated according to the formula:

$$GPIP = \sum_{i=1}^{n} \left[a_i(EAP_i) + e_i(AHRP_i) \right]$$

Where:

$GPIP$ = Generating performance incentive points

a_i = Percentage of total system fuel cost reduction attributed to maximum reasonably attainable equivalent availability of unit i during the period

e_i = Percentage of total system fuel cost reduction attributed to minimum reasonably attainable average heat rate of unit i during the period

EAP_i = Equivalent availability points awarded/deducted for unit i

$AHRP_i$ = Average heat rate points awarded/deducted for unit i

Weighting factors and point values are listed on page 4.

GPIP =	8.45%	*	(BB 1 EAP)	+	6.47%	*	(BB 2 EAP)	+	8.71%	*	(BB 3 EAP)
+	7.71%	*	(BB 4 EAP)	+	2.79%	*	(GN 5 EAP)	+	8.49%	*	(GN 6 EAP)
+	11.53%	*	(BB 1 AHRP)	+	11.54%	*	(BB 2 AHRP)	+	10.80%	*	(BB 3 AHRP)
+	10.66%	*	(BB 4 AHRP)	+	5.37%	*	(GN 5 AHRP)	+	7.47%	*	(GN 6 AHRP)

GPIP =	8.45%	*	-5.429	+	6.47%	*	8.125	+	8.71%	*	10.000
+	7.71%	*	6.296	+	2.79%	*	-10.000	+	8.49%	*	-10.000
+	11.53%	*	0.000	+	11.54%	*	5.973	+	10.80%	*	9.183
+	10.66%	*	4.232	+	5.37%	*	-3.921	+	7.47%	*	0.000

GPIP =	-0.459	+	0.526	+	0.871
+	0.485	+	-0.279	+	-0.849
+	0.000	+	0.689	+	0.992
+	0.451	+	-0.211	+	0.000

GPIP = 2.217 POINTS

REWARD/PENALTY dollar amounts of the Generating Performance Incentive Factor (GPIF) are determined directly from the table for the corresponding Generating Performance Points (GPIP) on page 2.

GPIF REWARD = $1,095,745

EXHIBITS TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCKET NO. 010001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2000 - DECEMBER 2000

TRUE-UP

DOCUMENT NO. 2

ACTUAL UNIT PERFORMANCE DATA

TAMPA ELECTRIC COMPANY
ACTUAL UNIT PERFORMANCE DATA
JANUARY 2000 - DECEMBER 2000
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ACTUAL UNIT PERFORMANCE DATA

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BIG BEND 1	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	88.9	76.3	92.2	62.2	66.5	86.0	70.4	89.9	60.9	64.3	89.3	65.2	75.8
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	689.6	585.5	744.0	531.2	535.2	691.1	555.1	744.0	498.9	565.7	720.0	542.8	7403.1
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	54.4	110.5	0.0	187.9	208.9	28.9	188.9	0.0	221.2	179.4	0.0	201.2	1381.3
6. POH	0.0	0.0	0.0	187.9	138.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	325.9
7. FOH	0.0	3.2	0.0	0.0	20.7	0.0	64.0	0.0	44.0	66.5	0.0	201.2	399.5
8. MOH	54.4	107.3	0.0	0.0	50.1	28.9	124.9	0.0	177.2	112.9	0.0	0.0	655.7
9. PFOH	104.3	384.0	282.5	521.6	399.1	476.8	325.8	433.9	378.3	470.5	574.2	364.4	4715.4
10. LR PF (MW)	64.6	42.5	48.4	52.7	30.7	50.3	36.3	40.4	49.5	78.2	51.2	86.5	52.2
11. PMOH	98.7	38.8	55.8	44.7	23.3	29.5	13.4	64.8	33.1	0.0	17.5	5.2	424.8
12. LR PM (MW)	54.4	178.3	196.0	163.1	194.4	204.1	86.9	211.6	191.9	0.0	194.2	224.3	157.4
13. NSC (MW)	426	426	426	416	416	416	416	416	416	426	426	426	421
14. OPR BTU(GBTU)	2180.0811	1916.3493	2439.7886	1724.4891	1860.8162	2446.0859	1957.0985	2619.8442	1636.6629	1823.0039	2535.7102	1947.9251	25087.8550
15. NET GEN (MWH)	224848	189859	248745	162278	175967	228545	186220	247258	155545	171208	241000	190621	2422094
16. ANOHR (BTU/KWH)	9696	10094	9808	10627	10575	10703	10510	10596	10522	10648	10522	10219	10358
17. NOF (%)	76.5	76.1	78.5	73.4	79.0	79.5	80.6	79.9	75.0	71.0	78.6	82.4	77.7
18. NPC (MW)	426	426	426	416	416	416	416	416	416	426	426	426	421

19. *ANOHR EQUATION* *ANOHR = NOF(-15.0564)+ 11438*

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ACTUAL UNIT PERFORMANCE DATA

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BIG BEND 1	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	88.9	76.3	92.2	62.2	66.5	86.0	70.4	89.9	60.9	64.3	89.3	65.2	75.8
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	689.6	585.5	744.0	531.2	535.2	691.1	555.1	744.0	498.9	565.7	720.0	542.8	7403.1
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	54.4	110.5	0.0	187.9	208.9	28.9	188.9	0.0	221.2	179.4	0.0	201.2	1381.3
6. POH	0.0	0.0	0.0	187.9	138.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	325.9
7. FOH	0.0	3.2	0.0	0.0	20.7	0.0	64.0	0.0	44.0	66.5	0.0	201.2	399.5
8. MOH	54.4	107.3	0.0	0.0	50.1	28.9	124.9	0.0	177.2	112.9	0.0	0.0	655.7
9. PFOH	104.3	384.0	282.5	521.6	399.1	476.8	325.8	433.9	378.3	470.5	574.2	364.4	4715.4
10. LR PF (MW)	64.6	42.5	48.4	52.7	30.7	50.3	36.3	40.4	49.5	78.2	51.2	86.5	52.2
11. PMOH	98.7	38.8	55.8	44.7	23.3	29.5	13.4	64.8	33.1	0.0	17.5	5.2	424.8
12. LR PM (MW)	54.4	178.3	196.0	163.1	194.4	204.1	86.9	211.6	191.9	0.0	194.2	224.3	157.4
13. NSC (MW)	426	426	426	416	416	416	416	416	416	426	426	426	421
14. OPR BTU(GBTU)	2180.0811	1916.3493	2439.7886	1724.4891	1860.8162	2446.0859	1957.0985	2619.8442	1636.6629	1823.0039	2535.7102	1947.9251	25087.8550
15. NET GEN (MWH)	224848	189859	248745	162278	175967	228545	186220	247258	155545	171208	241000	190621	2422094
16. ANOHR (BTU/KWH)	9696	10094	9808	10627	10575	10703	10510	10596	10522	10648	10522	10219	10358
17. NOF (%)	76.5	76.1	78.5	73.4	79.0	79.5	80.6	79.9	75.0	71.0	78.6	82.4	77.7
18. NPC (MW)	426	426	426	416	416	416	416	416	416	426	426	426	421

19. ANOHR EQUATION ANOHR = NOF(-15.0564)+ 11438

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ACTUAL UNIT PERFORMANCE DATA

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PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 2	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	89.6	69.9	90.0	97.7	89.7	86.7	72.2	87.2	89.8	76.8	82.5	94.9	85.6
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	704.6	515.0	737.8	719.0	744.0	675.2	575.2	717.8	720.0	641.1	642.8	744.0	8136.5
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	39.4	181.0	6.3	0.0	0.0	44.8	168.8	26.2	0.0	103.9	77.2	0.0	647.6
6. POH	0.0	181.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	181.0
7. FOH	39.4	0.0	6.3	0.0	0.0	44.8	168.8	26.2	0.0	1.5	0.0	0.0	287.0
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	102.4	77.2	0.0	179.6
9. PFOH	160.8	31.3	244.2	117.4	581.2	206.7	212.1	244.7	418.6	233.3	285.6	159.6	2895.5
10. LR PF (MW)	53.5	158.0	82.2	32.9	31.5	54.8	44.3	69.3	44.1	77.2	46.7	46.6	52.1
11. PMOH	48.4	41.1	49.9	19.0	88.9	57.1	37.1	58.0	66.1	63.7	37.3	42.1	608.7
12. LR PM (MW)	158.6	176.6	181.5	156.4	152.4	172.1	171.8	205.3	184.9	178.1	195.6	203.4	177.5
13. NSC (MW)	426	426	426	416	416	416	416	416	416	426	426	426	421
14. OPR BTU(GBTU)	2323.8097	1667.4602	2416.6609	2525.2027	2492.9829	2353.4439	2001.9073	2445.8014	2400.3673	2004.1493	2129.9752	2574.9581	27336.7189
15. NET GEN (MWH)	233094	172032	250853	255056	243138	228193	195086	239238	238322	197267	210104	259270	2721653
16. ANOHR (BTU/KWH)	9969	9693	9634	9901	10253	10313	10262	10223	10072	10160	10138	9932	10044
17. NOF (%)	77.7	78.4	79.8	85.3	78.6	81.2	81.5	80.1	79.6	72.2	76.7	81.8	79.5
18. NPC (MW)	426	426	426	416	416	416	416	416	416	426	426	426	421

19. ANOHR EQUATION ANOHR = NOF(-9.9261) + 10964

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ACTUAL UNIT PERFORMANCE DATA

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BIG BEND 3	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	61.8	87.0	31.2	16.5	80.6	95.0	93.1	89.0	88.0	86.4	81.7	89.5	75.0
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	487.1	644.9	241.2	139.2	615.6	720.0	716.3	726.0	697.7	745.0	631.6	723.3	7087.9
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	256.9	51.1	502.8	579.8	128.5	0.0	27.7	18.0	22.3	0.0	88.4	20.7	1696.2
6. POH	0.0	0.0	502.8	482.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	984.8
7. FOH	256.9	0.0	0.0	97.8	128.5	0.0	2.9	18.0	22.3	0.0	0.0	20.7	547.1
8. MOH	0.0	51.1	0.0	0.0	0.0	0.0	24.8	0.0	0.0	0.0	88.4	0.0	164.3
9. PFOH	48.9	222.4	4.4	52.3	76.3	234.5	73.6	621.2	375.1	712.9	614.9	497.8	3534.3
10. LR PF (MW)	27.8	57.2	224.2	158.5	24.8	33.9	42.5	25.1	42.8	55.5	25.8	45.3	41.3
11. PMOH	65.2	24.7	12.6	3.8	34.8	53.8	49.5	66.7	217.1	34.1	13.6	12.8	588.7
12. LR PM (MW)	166.1	191.0	231.4	138.9	142.1	140.3	143.1	180.9	53.7	154.6	237.1	236.4	125.4
13. NSC (MW)	443	443	443	433	433	433	433	433	433	443	443	443	438
14. OPR BTU(GBTU)	1640.3695	2275.2669	761.6870	457.6067	2232.0335	2521.3593	2563.8692	2520.9239	2344.0866	2468.0310	2183.0198	2491.0288	24459.2822
15. NET GEN (MWH)	165334	232298	86677	39525	230167	259978	258674	256864	241247	244124	214117	250252	2479257
16. ANOHR BTU/KWH	9922	9795	8788	11578	9697	9698	9912	9814	9717	10110	10195	9954	9866
17. NOF (%)	76.6	81.3	81.1	65.6	86.4	83.4	83.4	81.7	79.9	74.0	76.5	78.1	79.9
18. NPC (MW)	443	443	443	433	433	433	433	433	433	443	443	443	438
19. ANOHR EQUATION	ANOHR = NOF(-35.3936) + 13050												

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ACTUAL UNIT PERFORMANCE DATA

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BIG BEND 4	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	88.7	96.7	96.2	97.9	96.8	86.7	95.4	84.8	84.0	78.4	72.4	76.3	87.8
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	665.1	696.0	744.0	719.0	744.0	640.2	744.0	650.8	629.8	715.9	633.1	626.3	8208.2
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	78.9	0.0	0.0	0.0	0.0	78.8	0.0	93.3	90.2	29.2	86.9	117.7	575.0
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	78.9	0.0	0.0	0.0	0.0	0.0	0.0	93.3	90.2	6.7	0.0	0.0	269.1
8. MOH	0.0	0.0	0.0	0.0	0.0	78.8	0.0	0.0	0.0	22.5	86.9	117.7	305.9
9. PFOH	0.0	184.4	57.0	34.6	37.8	30.1	51.9	139.4	65.4	668.7	616.2	426.2	2311.7
10. LR PF (MW)	0.0	37.9	109.9	42.3	110.7	135.4	92.6	46.2	94.2	76.9	75.6	60.4	71.0
11. PMOH	24.3	22.4	46.3	38.2	40.7	21.9	44.3	10.3	20.1	30.7	15.3	2.1	316.6
12. LR PM (MW)	94.8	151.9	134.9	138.8	156.7	156.4	235.3	232.0	250.8	246.5	217.4	253.2	177.9
13. NSC (MW)	447	447	447	442	442	442	442	442	442	447	447	447	445
14. OPR BTU(GBTU)	2606.1744	2540.6213	2802.9004	2731.1818	2788.8426	2452.1074	2876.8898	2453.1823	2397.8371	2379.4629	2198.3137	2352.1362	30579.6499
15. NET GEN (MWH)	264969	263444	286271	281073	283614	247524	290666	247101	241405	235197	214494	234332	3090089
16. ANOHR BTU/KWH	9836	9644	9791	9717	9833	9907	9898	9928	9933	10117	10249	10038	9896
17. NOF (%)	89.1	84.7	86.1	88.4	86.2	87.5	88.4	85.9	86.7	73.5	75.8	83.7	84.7
18. NPC (MW)	447	447	447	442	442	442	442	442	442	447	447	447	445

19. ANOHR EQUATION ANOHR = NOF(-24.0193) + 12107

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ACTUAL UNIT PERFORMANCE DATA

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GANNON 5	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	68.5	67.2	14.3	30.5	80.4	89.2	82.9	65.5	49.5	62.5	39.0	18.1	55.6
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	558.6	561.8	147.1	230.7	639.9	650.7	700.6	565.4	481.8	607.4	406.9	212.9	5763.8
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	185.4	134.2	596.9	488.4	104.1	69.3	43.4	178.6	238.2	137.6	313.1	531.1	3020.3
6. POH	0.0	0.0	566.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	566.3
7. FOH	185.4	134.2	19.8	207.4	82.6	69.3	43.4	178.6	238.2	137.6	1.5	400.0	1698.1
8. MOH	0.0	0.0	10.8	281.0	21.5	0.0	0.0	0.0	0.0	0.0	311.6	131.1	755.9
9. PFOH	205.5	525.0	145.4	25.4	105.3	0.0	201.8	208.5	502.4	632.6	406.9	428.4	3387.2
10. LR PF (MW)	48.6	41.5	67.2	100.7	90.3	0.0	94.5	85.7	23.6	49.7	73.1	43.0	53.7
11. PMOH	14.5	6.3	0.0	0.0	1.0	14.7	2.3	1.8	171.7	30.4	9.2	7.9	259.8
12. LR PM (MW)	123.6	148.8	0.0	0.0	109.5	135.7	138.6	127.2	100.8	93.9	77.7	59.3	102.9
13. NSC (MW)	242	242	242	232	232	232	232	232	232	242	242	242	237
14. OPR BTU(GBTU)	970.9964	911.2384	239.2678	414.5504	1235.4227	1260.8907	1259.1249	1041.7464	777.1975	993.9464	614.4926	288.3951	10007.2693
15. NET GEN (MWH)	86882	82004	23534	40373	116478	120173	115719	97098	70563	93570	56895	27772	931061
16. ANOHR BTU/KWH	11176	11112	10167	10268	10606	10492	10881	10729	11014	10622	10800	10384	10748
17. NOF (%)	64.3	60.3	66.1	75.4	78.5	79.6	71.2	74.0	63.1	63.7	57.8	53.9	68.2
18. NPC (MW)	242	242	242	232	232	232	232	232	232	242	242	242	237

19. ANOHR EQUATION ANOHR = NOF(-12.3085) + 11383

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GANNON 6	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	19.4	27.3	62.1	63.1	60.7	74.8	54.8	0.0	0.0	0.0	0.0	36.6	33.2
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	154.9	206.7	512.0	551.7	470.0	554.0	430.8	0.0	0.0	0.0	0.0	268.4	3148.5
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	72.8	72.8
5. UH	589.1	489.3	232.0	167.3	274.0	167.1	313.2	744.0	720.0	745.0	720.0	402.9	5563.9
6. POH	294.7	489.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	784.0
7. FOH	287.2	0.0	232.0	111.8	247.6	14.4	313.2	744.0	720.0	745.0	720.0	373.8	4509.0
8. MOH	7.2	0.0	0.0	55.5	26.4	152.7	0.0	0.0	0.0	0.0	0.0	29.1	270.9
9. PFOH	75.5	124.5	118.8	435.6	69.7	12.1	139.8	0.0	0.0	0.0	0.0	275.5	1251.5
10. LR PF (MW)	54.9	50.4	150.7	77.2	98.1	111.5	57.9	0.0	0.0	0.0	0.0	95.9	83.6
11. PMOH	0.0	1.8	7.6	34.7	0.0	22.0	4.0	0.0	0.0	0.0	0.0	5.0	75.1
12. LR PM (MW)	0.0	212.6	208.6	85.4	0.0	183.8	147.8	0.0	0.0	0.0	0.0	113.4	134.9
13. NSC (MW)	392	392	392	372	372	372	372	372	372	392	392	392	382
14. OPR BTU(GBTU)	445.2855	622.9596	1639.7486	1630.0975	1400.6812	1747.4723	1345.4527	0.0000	0.0000	0.0000	0.0000	615.1153	9446.8126
15. NET GEN (MWH)	41389	58684	151683	152524	136059	171091	124711	0	0	0	0	63447	899588
16. ANOHR BTU/KWH	10759	10615	10810	10687	10295	10214	10789	#N/A	#N/A	#N/A	#N/A	9695	10501
17. NOF (%)	68.2	72.4	75.6	74.3	77.8	83.0	77.8	0.0	0.0	0.0	0.0	60.3	74.8
18. NPC (MW)	392	392	392	372	372	372	372	372	372	392	392	392	382

19. ANOHR EQUATION ANOHR = NOF(-4.1530) + 10790

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GANNON 1	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	23.2	87.2	98.4	89.6	90.3	82.6	83.4	71.9	88.1	81.8	56.9	94.2	78.9
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	172.8	614.9	739.7	647.8	711.1	622.3	663.3	593.0	683.0	646.7	427.5	744.0	7266.1
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	571.3	81.1	4.3	71.2	32.9	99.3	80.8	151.1	37.0	98.3	292.5	0.0	1519.8
6. POH	495.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	495.8
7. FOH	75.5	28.6	4.3	71.2	9.6	57.0	80.8	123.0	37.0	98.3	292.5	0.0	877.8
8. MOH	0.0	52.5	0.0	0.0	23.3	42.3	0.0	28.1	0.0	0.0	0.0	0.0	146.2
9. PFOH	0.0	11.0	21.6	1.4	93.0	0.0	51.9	67.5	38.4	38.1	1.7	125.7	450.3
10. LR PF (MW)	0.0	23.8	36.6	75.8	31.8	0.0	41.5	59.1	43.2	42.9	42.7	26.5	37.7
11. PMOH	0.0	8.1	1.5	3.6	20.2	39.4	39.0	35.5	53.3	33.8	25.6	22.0	282.0
12. LR PM (MW)	0.0	76.0	76.0	76.1	76.0	76.0	70.6	74.5	73.6	78.0	76.0	73.3	74.6
13. NSC (MW)	114	114	114	114	114	114	114	114	114	114	114	114	114
14. OPR BTU(GBTU)	146.3312	489.7719	638.2157	584.3060	598.8848	507.0077	561.6885	556.2906	668.6742	534.9153	363.2711	656.9571	6306.3140
15. NET GEN (MWH)	13010	41808	57342	50688	52081	45592	47787	45551	57176	47627	30571	55293	544526
16. ANOHR BTU/KWH	11248	11715	11130	11528	11499	11121	11754	12212	11695	11231	11883	11881	11581
17. NOF (%)	66.1	59.6	68.0	68.6	64.2	64.3	63.2	67.4	73.4	64.6	62.7	65.2	65.7
18. NPC (MW)	114	114	114	114	114	114	114	114	114	114	114	114	114

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GANNON 2	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	96.8	87.9	88.6	72.2	12.5	65.8	88.7	74.6	75.9	47.7	61.9	78.5	70.8
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	616.4	607.1	661.8	520.9	94.2	465.8	671.1	593.1	573.7	358.3	446.2	586.2	6194.8
4. RSH	105.8	5.7	0.0	0.0	0.0	7.7	0.0	0.0	0.0	0.0	0.0	0.0	119.2
5. UH	21.8	83.3	82.3	198.1	649.9	246.5	73.0	150.9	146.4	386.7	273.8	157.8	2470.5
6. POH	0.0	0.0	0.0	138.0	645.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	783.1
7. FOH	21.8	39.0	82.3	60.1	4.2	246.5	73.0	150.9	111.7	386.7	265.5	157.8	1599.5
8. MOH	0.0	44.3	0.0	0.0	0.6	0.0	0.0	0.0	34.7	0.0	8.3	0.0	87.9
9. PFOH	7.7	0.0	0.0	0.0	0.0	0.0	15.0	47.4	30.6	0.0	0.0	1.4	102.1
10. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	35.9	38.2	22.5	0.0	0.0	42.0	30.3
11. PMOH	4.6	6.7	5.1	2.8	1.8	0.0	9.3	35.2	35.1	6.8	0.6	3.8	111.8
12. LR PM (MW)	42.1	11.5	42.1	55.4	55.4	0.0	55.4	55.4	55.4	42.1	41.9	42.1	50.3
13. NSC (MW)	88	88	88	98	98	98	98	98	98	88	88	88	93
14. OPR BTU(GBTU)	567.4524	477.3150	584.2579	376.3913	107.6430	443.3933	590.7588	547.3109	548.7654	324.5084	375.5554	519.6307	5462.9825
15. NET GEN (MWH)	44531	38359	46423	34799	6464	35122	48190	43751	44720	27166	32418	44785	446728
16. ANOHR BTU/KWH	12743	12443	12586	10816	16653	12624	12259	12510	12271	11945	11585	11603	12229
17. NOF (%)	82.1	71.8	79.7	68.2	70.0	76.9	73.3	75.3	79.5	86.2	82.6	86.8	77.5
18. NPC (MW)	88	88	88	98	98	98	98	98	98	88	88	88	93

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GANNON 3	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	88.3	62.2	49.4	95.0	85.2	93.6	88.0	83.7	93.2	76.4	86.1	38.4	78.2
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	623.2	393.9	393.9	687.9	642.5	694.3	684.1	656.1	715.1	622.5	713.3	408.6	7235.4
4. RSH	79.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	129.0
5. UH	41.8	252.1	350.1	31.1	101.6	25.8	59.9	88.0	4.9	122.5	6.7	335.4	1419.9
6. POH	0.0	240.0	267.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	507.1
7. FOH	32.4	12.1	0.0	31.1	48.0	0.6	59.9	20.9	4.9	93.4	6.7	23.5	333.5
8. MOH	9.4	0.0	83.0	0.0	53.6	25.2	0.0	67.1	0.0	29.1	0.0	311.9	579.3
9. PFOH	122.5	0.0	110.8	2.8	3.0	13.5	31.5	38.0	71.6	136.9	111.9	408.6	1051.1
10. LR PF (MW)	51.7	0.0	28.1	21.9	83.5	36.6	58.6	39.3	30.0	23.2	52.2	42.3	40.0
11. PMOH	6.8	17.1	11.5	8.3	12.2	28.3	28.5	39.4	52.6	52.8	89.3	31.0	377.8
12. LR PM (MW)	98.6	98.6	84.5	83.5	83.5	84.6	84.2	83.5	81.3	96.5	96.1	56.4	86.9
13. NSC (MW)	155	155	155	145	145	145	145	145	145	155	155	155	150
14. OPR BTU(GBTU)	814.9696	454.8421	539.2023	901.8939	819.1803	844.7192	942.2734	930.0114	998.1790	773.7104	884.2346	453.3634	9356.5797
15. NET GEN (MWH)	65051	38219	43496	75902	69955	72222	75382	77360	82938	64197	71519	37262	773503
16. ANOHR BTU/KWH	12528	11901	12397	11882	11710	11696	12500	12022	12035	12052	12364	12167	12096
17. NOF (%)	67.3	62.6	71.2	76.1	75.1	71.7	76.0	81.3	80.0	66.5	64.7	58.8	71.3
18. NPC (MW)	155	155	155	145	145	145	145	145	145	155	155	155	150

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GANNON 4	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	77.9	72.8	95.1	2.0	95.8	92.7	94.6	88.8	73.6	80.3	9.6	66.2	71.0
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	685.9	527.6	720.5	19.2	731.4	691.5	715.2	687.7	559.3	710.9	71.3	478.8	6599.3
4. RSH	39.2	9.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	24.8	73.3
5. UH	19.0	159.1	23.5	699.8	12.7	32.8	28.8	56.3	160.7	34.1	648.7	240.5	2116.0
6. POH	0.0	0.0	0.0	696.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	696.9
7. FOH	19.0	134.6	23.5	2.9	9.8	0.0	28.8	28.1	36.5	34.1	0.0	89.5	406.8
8. MOH	0.0	24.5	0.0	0.0	2.9	32.8	0.0	28.2	124.2	0.0	648.7	151.0	1012.3
9. PFOH	609.0	503.0	32.0	18.7	220.2	50.9	9.8	38.6	62.3	285.7	16.8	9.3	1856.3
10. LR PF (MW)	39.8	5.2	7.9	39.4	8.5	47.7	12.8	6.0	55.3	57.0	25.4	79.1	28.8
11. PMOH	3.7	24.6	18.5	0.0	12.1	8.0	19.5	47.0	13.5	28.7	0.0	11.6	187.2
12. LR PM (MW)	101.3	101.4	101.4	0.0	87.0	87.5	88.8	87.5	87.5	94.7	0.0	101.4	93.0
13. NSC (MW)	169	169	169	159	159	159	159	159	159	169	169	169	164
14. OPR BTU(GBTU)	800.3277	647.4914	969.3210	52.5776	1048.1424	934.3066	1053.4690	1063.5566	827.7811	894.3015	96.3897	687.2810	9074.9457
15. NET GEN (MWH)	64562	54453	83994	1862	91819	78857	87113	86380	69608	73981	7638	59548	759815
16. ANOHR BTU/KWH	12396	11891	11540	28237	11415	11848	12093	12313	11892	12088	12620	11542	11944
17. NOF (%)	55.7	61.1	69.0	60.9	79.0	71.7	76.6	79.0	78.3	61.6	63.4	73.6	70.2
18. NPC (MW)	169	169	169	159	159	159	159	159	159	169	169	169	164

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HOOKERS PT 1	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	93.5	100.0	100.0	100.0	100.0	100.0	100.0	97.2	65.5	99.0	100.0	100.0	96.3
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	25.5	12.8	0.0	127.4	329.0	286.6	267.1	245.4	62.4	55.0	4.1	7.7	1423.0
4. RSH	670.5	683.2	744.0	591.6	414.7	432.5	476.9	483.4	409.5	682.8	715.9	736.3	7041.3
5. UH	48.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3	248.1	7.2	0.0	0.0	318.6
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	0.0	7.2	0.0	0.0	7.2
8. MOH	48.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3	248.1	0.0	0.0	0.0	311.4
9. PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.2	0.0	0.0	0.0	0.0	11.2
10. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.5	0.0	0.0	0.0	0.0	14.5
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13. NSC (MW)	32	32	32	30	30	30	30	30	30	32	32	32	31
14. OPR BTU(GBTU)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
15. NET GEN (MWH)	303	67	0	2515	6271	5205	4532	2729	829	622	-1	-23	23049
16. ANOHR BTU/KWH	0	0	0	0	0	0	0	0	0	0	0	0	0
17. NOF (%)	37.1	16.2	0.0	65.8	63.5	60.5	56.6	37.1	44.3	35.3	-0.4	-9.5	52.2
18. NPC (MW)	32	32	32	30	30	30	30	30	30	32	32	32	31

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PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
HOOKERS PT 2	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	91.3	0.0	1.3	100.0	91.9	92.1	100.0	96.1	96.2	94.8	100.0	100.0	80.6
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	28.1	0.0	0.0	138.8	292.7	255.2	301.3	256.9	281.9	60.1	4.0	1.9	1620.9
4. RSH	651.0	0.0	9.5	580.3	402.2	408.8	442.7	458.1	425.6	677.7	716.0	742.1	5514.0
5. UH	65.0	696.0	734.5	0.0	49.2	54.8	0.0	29.0	12.5	7.2	0.0	0.0	1648.2
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	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	29.8	0.0	0.0	12.5	7.2	0.0	0.0	49.5
8. MOH	65.0	696.0	734.5	0.0	49.2	25.0	0.0	29.0	0.0	0.0	0.0	0.0	1598.7
9. PFOH	0.0	0.0	0.0	0.0	21.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	25.0
10. LR PF (MW)	0.0	0.0	0.0	0.0	16.2	13.7	0.0	0.0	0.0	0.0	0.0	0.0	15.8
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.8	60.1	0.0	0.0	94.9
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.9	16.7	0.0	0.0	15.3
13. NSC (MW)	32	32	32	30	30	30	30	30	30	32	32	32	31
14. OPR BTU(GBTU)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
15. NET GEN (MWH)	330	0	0	2606	5512	4212	5386	3939	4675	726	-1	-5	27380
16. ANOHR BTU/KWH	0	0	0	0	0	0	0	0	0	0	0	0	0
17. NOF (%)	36.7	0.0	0.0	62.6	62.8	55.0	59.6	51.1	55.3	37.7	-0.5	-7.5	54.5
18. NPC (MW)	32	32	32	30	30	30	30	30	30	32	32	32	31

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ORIGINAL SHEET NO. 9.401.00A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

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HOOKERS PT 3	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	93.5	100.0	73.2	96.5	81.0	95.9	10.6	100.0	92.3	94.4	100.0	46.1	81.7
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	33.7	17.9	0.0	136.5	263.0	302.4	22.1	320.9	333.6	62.6	4.0	0.0	1496.7
4. RSH	662.2	678.1	544.5	557.2	342.4	386.9	56.4	423.1	373.9	675.1	716.0	343.0	5758.8
5. UH	48.0	0.0	199.5	25.4	138.7	29.8	665.5	0.0	12.5	7.3	0.0	401.0	1527.7
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	401.0	401.0
7. FOH	0.0	0.0	0.0	0.4	10.7	0.0	0.0	0.0	12.5	7.3	0.0	0.0	30.9
8. MOH	48.0	0.0	199.5	25.0	128.0	29.8	665.5	0.0	0.0	0.0	0.0	0.0	1095.8
9. PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11. PMOH	0.0	0.0	0.0	0.0	4.9	0.0	0.0	0.0	72.9	62.6	0.0	0.0	140.4
12. LR PM (MW)	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	17.8	17.5	0.0	0.0	17.7
13. NSC (MW)	32	32	32	30	30	30	30	30	30	32	32	32	31
14. OPR BTU(GBTU)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
15. NET GEN (MWH)	350	120	0	2608	5311	5788	374	5383	4339	692	0	0	24965
16. ANOHR BTU/KWH	0	0	0	0	0	0	0	0	0	0	0	0	0
17. NOF (%)	32.5	20.9	0.0	63.7	67.3	63.8	56.5	55.9	43.4	34.5	0.0	0.0	53.8
18. NPC (MW)	32	32	32	30	30	30	30	30	30	32	32	32	31

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HOOKERS PT 4	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	24.9	100.0	100.0	100.0	11.5	65.6	100.0	98.7	73.0	0.0	0.0	99.9	64.3
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	27.7	26.3	0.0	168.9	34.9	202.2	317.7	349.5	265.5	0.0	0.0	16.8	1411.5
4. RSH	157.3	669.7	744.0	549.9	51.1	272.3	426.3	384.6	364.4	0.0	0.0	724.7	4344.3
5. UH	559.0	0.0	0.0	0.3	658.1	247.5	0.0	9.9	90.2	745.0	720.0	0.5	3030.5
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	0.0	0.0	0.0	0.3	3.8	0.0	0.0	1.9	16.6	0.0	0.0	0.5	23.1
8. MOH	559.0	0.0	0.0	0.0	654.3	247.5	0.0	8.0	73.6	745.0	720.0	0.0	3007.4
9. PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	143.3	0.0	0.0	0.0	143.4
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	26.6	0.0	0.0	28.3	0.0	0.0	0.0	28.3
13. NSC (MW)	41	41	41	39	39	39	39	39	39	41	41	41	40
14. OPR BTU(GBTU)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
15. NET GEN (MWH)	387	212	0	3993	690	4246	6903	6980	4982	0	0	-108	28285
16. ANOHR BTU/KWH	0	0	0	0	0	0	0	0	0	0	0	0	0
17. NOF (%)	34.0	19.7	0.0	60.6	50.7	53.9	55.7	51.2	48.1	0.0	0.0	0.0	50.1
18. NPC (MW)	41	41	41	39	39	39	39	39	39	41	41	41	40

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HOOKERS PT 5	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	97.4	45.8	1.3	56.3	51.5	88.9	64.8	53.9	85.0	87.2	0.0	0.0	52.4
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	9.9	20.5	0.0	79.9	139.8	256.4	173.3	177.9	254.6	13.6	0.0	0.0	1125.9
4. RSH	714.5	298.5	9.5	340.5	273.6	362.1	319.6	269.8	414.7	640.0	0.0	0.0	3642.8
5. UH	19.6	377.0	734.5	298.7	330.7	24.7	251.1	296.4	50.7	91.4	720.0	744.0	3938.8
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	19.6	0.0	0.0	1.7	1.1	2.7	1.1	18.9	13.2	0.0	0.0	0.0	58.3
8. MOH	0.0	377.0	734.5	297.0	329.6	22.0	250.0	277.5	37.5	91.4	720.0	744.0	3880.5
9. PFOH	9.8	0.0	0.0	71.9	139.1	248.0	49.9	176.6	0.0	0.0	0.0	0.0	695.3
10. LR PF (MW)	0.0	0.0	0.0	14.4	14.4	14.4	14.4	17.6	0.0	0.0	0.0	0.0	15.0
11. PMOH	0.0	0.0	0.0	0.0	0.0	8.4	0.0	0.0	242.3	21.5	0.0	0.0	272.2
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	14.4	0.0	0.0	15.8	8.9	0.0	0.0	15.2
13. NSC (MW)	52	52	52	67	67	67	67	67	67	52	52	52	60
14. OPR BTU(GBTU)	33.4768	23.1501	0.0000	240.5451	372.9705	478.9363	400.4892	426.8140	408.6005	57.6484	10.3358	9.0335	2462.0002
15. NET GEN (MWH)	34	255	0	3112	5295	10392	6326	6306	10230	367	0	0	42317
16. ANOHR BTU/KWH	23844	35398	#N/A	16216	16161	16049	17027	16845	16308	23950	#N/A	#N/A	16863
17. NOF (%)	6.7	24.0	0.0	58.2	56.6	60.5	54.5	52.9	60.0	51.8	0.0	0.0	63.2
18. NPC (MW)	52	52	52	67	67	67	67	67	67	52	52	52	60

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PHILLIPS 1	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	0.0	0.0	0.0	0.0	99.8	99.6	90.9	99.7	99.9	99.8	100.0	99.4	66.0
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	0.0	0.0	0.0	0.0	389.5	348.8	317.0	423.4	389.7	292.9	279.0	289.9	2730.2
4. RSH	0.0	0.0	0.0	0.0	353.0	368.5	359.5	318.2	329.9	450.3	441.0	449.4	3069.8
5. UH	744.0	696.0	744.0	719.0	1.5	2.7	67.5	2.5	0.5	1.8	0.0	4.8	2984.3
6. POH	744.0	696.0	744.0	719.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2903.0
7. FOH	0.0	0.0	0.0	0.0	1.5	2.7	4.1	2.5	0.5	1.8	0.0	4.8	17.9
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	63.4	0.0	0.0	0.0	0.0	0.0	63.4
9. PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13. NSC (MW)	17	17	17	17	17	17	17	17	17	17	17	17	17
14. OPR BTU(GBTU)	0.0000	0.0000	0.0000	0.0000	39.2482	48.8730	42.9003	58.6643	55.3250	42.0744	39.9944	39.6542	366.7338
15. NET GEN (MWH)	-92	-85	-87	-21	4132	5027	4400	6082	5647	4182	4005	4014	37204
16. ANOHR BTU/KWH	#N/A	#N/A	#N/A	#N/A	9499	9722	9750	9646	9797	10061	9986	9879	9857
17. NOF (%)	0.0	0.0	0.0	0.0	62.4	84.8	81.6	84.5	85.2	84.0	84.4	81.5	80.2
18. NPC (MW)	17	17	17	17	17	17	17	17	17	17	17	17	17

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PHILLIPS 2	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	0.0	0.0	0.0	1.4	89.2	99.7	91.5	99.8	99.9	100.0	100.0	96.4	65.1
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	0.0	0.0	0.0	10.0	286.1	335.0	320.7	423.3	390.1	295.2	278.4	295.0	2633.8
4. RSH	0.0	0.0	0.0	0.0	377.7	382.9	360.1	318.9	329.4	449.7	441.7	422.5	3082.9
5. UH	744.0	696.0	744.0	709.0	80.2	2.2	63.2	1.8	0.5	0.1	0.0	26.5	3067.5
6. POH	744.0	696.0	744.0	709.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2893.0
7. FOH	0.0	0.0	0.0	0.0	1.4	2.2	0.2	1.8	0.5	0.1	0.0	26.5	32.7
8. MOH	0.0	0.0	0.0	0.0	78.8	0.0	63.0	0.0	0.0	0.0	0.0	0.0	141.8
9. PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13. NSC (MW)	17	17	17	17	17	17	17	17	17	17	17	17	17
14. OPR BTU(GBTU)	0.0000	0.0000	0.0000	0.0000	39.2495	48.8730	42.9003	58.6643	55.3250	42.0744	39.9944	39.6542	366.7351
15. NET GEN (MWH)	-91	-86	-86	-21	4336	5587	5070	6655	6375	4894	4623	4463	41720
16. ANOHR BTU/KWH	#N/A	#N/A	#N/A	0	9052	8748	8462	8815	8678	8597	8651	8885	8790
17. NOF (%)	0.0	0.0	0.0	-12.4	89.1	98.1	93.0	92.5	96.1	97.5	97.7	89.0	93.2
18. NPC (MW)	17	17	17	17	17	17	17	17	17	17	17	17	17

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BIG BEND CT1	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	98.4	98.8	99.8
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	14.0	0.0	10.0	0.0	43.0	44.9	84.0	89.3	103.5	16.3	1.7	51.4	458.1
4. RSH	730.0	696.0	734.0	719.0	701.0	676.0	660.0	655.0	616.5	729.0	707.0	684.0	8307.5
5. UH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.3	9.0	20.3
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	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	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	0.0	0.0	0.0	11.3	9.0	20.3
9. PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13. NSC (MW)	17	17	17	12	12	12	12	12	12	17	17	17	15
14. OPR BTU(GBTU)	2.9389	0.0000	2.1999	0.0000	7.6768	8.9111	15.9817	16.5081	20.7751	2.8198	3.1179	10.6485	91.5778
15. NET GEN (MWH)	146	0	125	0	390	505	857	861	1160	137	10	680	4871
16. ANOHR BTU/KWH	20129	#N/A	17599	#N/A	19684	17646	18648	19173	17910	20583	311792	15660	18801
17. NOF (%)	61.3	0.0	73.5	0.0	75.6	93.8	85.0	80.3	93.4	49.5	35.2	77.9	73.3
18. NPC (MW)	17	17	17	12	12	12	12	12	12	17	17	17	15

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BIG BEND CT2	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	100.0	100.0	0.0	0.0	10.2	87.6	100.0	100.0	89.9	100.0	98.5	94.9	73.3
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	49.0	4.0	0.0	0.0	76.0	99.7	145.0	181.8	154.8	39.7	67.6	141.5	959.1
4. RSH	695.0	692.0	0.0	0.0	0.0	0.0	599.0	562.0	492.0	705.0	641.0	564.0	4950.0
5. UH	0.0	0.0	744.0	719.0	667.8	89.2	0.0	0.0	72.4	0.0	11.0	38.3	2341.7
6. POH	0.0	0.0	744.0	719.0	661.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2124.1
7. FOH	0.0	0.0	0.0	0.0	6.7	16.0	0.0	0.0	6.7	0.0	0.0	3.8	33.2
8. MOH	0.0	0.0	0.0	0.0	0.0	73.2	0.0	0.0	65.7	0.0	11.0	34.5	184.4
9. PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13. NSC (MW)	80	80	80	66	66	66	66	66	66	80	80	80	73
14. OPR BTU(GBTU)	34.5976	2.7252	0.0000	0.0000	2.2481	72.2984	111.5062	135.8403	122.4216	28.5895	27.3062	105.6229	643.1558
15. NET GEN (MWH)	2046	151	0	0	88	4551	7212	8718	7845	1774	1693	6986	41064
16. ANOHR BTU/KWH	16910	18047	#N/A	#N/A	25546	15886	15461	15582	15605	16116	16129	15119	15662
17. NOF (%)	52.2	47.2	0.0	0.0	1.8	69.2	75.4	72.7	76.8	55.8	31.3	61.7	58.7
18. NPC (MW)	80	80	80	66	66	66	66	66	66	80	80	80	73

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BIG BEND CT3	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	100.0	100.0	1.1	0.0	6.4	27.0	100.0	99.3	100.0	99.7	97.8	90.4	68.4
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	58.0	8.0	0.0	0.0	47.0	28.1	160.0	197.9	187.5	41.5	41.2	133.4	900.6
4. RSH	686.0	690.0	8.5	0.0	0.0	0.0	584.0	540.0	531.6	702.0	663.0	539.0	4944.1
5. UH	0.0	0.0	735.5	719.0	696.7	525.6	0.0	5.5	0.0	2.0	15.7	71.6	2771.6
6. POH	0.0	0.0	735.5	719.0	188.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1643.4
7. FOH	0.0	0.0	0.0	0.0	507.8	500.2	0.0	0.0	0.0	0.0	13.2	0.0	1021.2
8. MOH	0.0	0.0	0.0	0.0	0.0	25.4	0.0	5.5	0.0	2.0	2.5	71.6	107.0
9. PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13. NSC (MW)	80	80	80	66	66	66	66	66	66	80	80	80	73
14. OPR BTU(GBTU)	40.8689	3.4395	0.0000	0.0000	3.2834	19.7819	123.2786	146.9227	145.1259	29.2644	29.6273	100.3137	641.9064
15. NET GEN (MWH)	2724	180	0	0	184	1228	8362	9864	10067	1867	1919	6920	43315
16. ANOHR BTU/KWH	15003	19108	#N/A	#N/A	17845	16109	14743	14895	14416	15675	15439	14496	14819
17. NOF (%)	58.7	37.5	0.0	0.0	5.9	66.1	79.2	75.5	81.4	56.3	58.2	64.9	65.9
18. NPC (MW)	80	80	80	66	66	66	66	66	66	80	80	80	73

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GANNON CT1	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	100.0	100.0	100.0	100.0	99.6	99.5	100.0	93.2	62.6	0.0	0.0	0.0	71.1
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	17.0	0.0	15.0	0.0	56.0	52.8	109.0	95.1	56.3	0.0	0.0	0.0	401.2
4. RSH	727.0	696.0	729.0	719.0	685.0	685.0	635.0	599.0	395.0	0.0	0.0	0.0	5870.0
5. UH	0.0	0.0	0.0	0.0	2.9	3.6	0.0	50.4	269.1	745.0	720.0	744.0	2535.0
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	269.1	745.0	720.0	744.0	2478.1
8. MOH	0.0	0.0	0.0	0.0	2.9	3.6	0.0	50.4	0.0	0.0	0.0	0.0	56.9
9. PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13. NSC (MW)	17	17	17	12	12	12	12	12	12	17	17	17	15
14. OPR BTU(GBTU)	2.9918	0.0000	3.0192	0.0000	10.0861	0.9872	1.5747	1.6915	10.0646	0.0000	0.0000	0.0000	30.4152
15. NET GEN (MWH)	147	0	166	0	507	516	812	860	499	0	0	0	3507
16. ANOHR BTU/KWH	20353	#N/A	18188	#N/A	19894	1913	1939	1967	20170	#N/A	#N/A	#N/A	8673
17. NOF (%)	50.9	0.0	65.1	0.0	75.4	81.4	62.1	75.4	73.9	0.0	0.0	0.0	60.3
18. NPC (MW)	17	17	17	12	12	12	12	12	12	17	17	17	15

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POLK 1 GASIFIER	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	86.7	62.3	3.1	59.6	97.6	73.9	96.4	87.7	83.3	92.4	87.1	80.7	76.0
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	650.1	436.2	25.1	432.7	744.0	578.2	718.3	653.7	600.6	688.1	663.1	612.5	6802.6
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	93.9	259.8	719.0	286.4	0.0	141.9	25.7	90.3	119.4	56.9	56.9	131.6	1981.8
6. POH	0.0	96.6	368.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	464.7
7. FOH	88.4	136.2	350.9	286.4	0.0	141.9	25.7	90.3	119.4	56.9	56.9	17.5	1370.5
8. MOH	5.5	27.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	114.1	146.6
9. PFOH	88.5	26.6	8.2	81.8	745.0	715.7	19.5	48.4	7.2	1.2	466.4	120.9	2329.4
10. LR PF (MW)	3.8	23.1	53.8	11.6	5.4	15.9	15.4	4.3	41.3	5.3	19.4	25.4	13.2
11. PMOH	26.1	0.0	0.0	3.3	17.7	6.3	0.0	10.2	0.0	0.0	0.0	0.0	63.6
12. LR PM (MW)	34.3	0.0	0.0	7.7	22.3	22.3	0.0	12.0	0.0	0.0	0.0	0.0	24.8
13. NSC (MW)	250	250	250	250	250	250	250	250	250	250	250	250	250
14. OPR BTU(GBTU)	1691.7185	1042.9134	64.8754	1191.6836	1789.9413	1447.3077	1805.1655	1636.6323	1520.1863	1675.2129	1581.1111	1436.3630	16883.1110
15. NET GEN (MWH)	153594	98193	-2716	96860	179617	132300	176019	159204	140092	169966	164565	143327	1611021
16. ANOHR BTU/KWH	11014	10621	0	12303	9965	10940	10256	10280	10851	9856	9608	10022	10480
17. NOF (%)	94.5	90.0	0.0	89.5	96.6	91.5	98.0	97.4	93.3	98.8	99.3	93.6	94.7
18. NPC (MW)	250	250	250	250	250	250	250	250	250	250	250	250	250

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POLK CT 1 (Oil)	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	95.5	76.2	50.4	67.0	100.0	86.9	100.0	89.0	99.0	99.1	100.0	99.4	88.6
2. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
3. SH	33.4	87.9	27.9	23.0	0.0	10.4	19.1	8.3	111.4	51.6	8.9	126.6	508.5
4. RSH	677.4	444.6	349.8	458.5	744.0	615.4	724.9	653.7	601.7	687.9	711.1	613.1	7282.1
5. UH	33.2	163.5	366.3	237.5	0.0	94.2	0.0	82.0	7.0	5.5	0.0	4.3	993.5
6. POH	0.0	95.6	321.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	417.1
7. FOH	33.2	53.1	40.9	227.5	0.0	94.2	0.0	82.0	7.0	5.5	0.0	4.3	547.7
8. MOH	0.0	14.8	3.9	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	28.7
9. PFOH	0.0	6.6	3.4	0.0	0.0	0.0	0.0	0.0	0.0	4.5	0.0	0.0	14.5
10. LR PF (MW)	0.0	91.2	96.0	0.0	0.0	0.0	0.0	0.0	0.0	67.2	0.0	0.0	84.9
11. PMOH	0.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0
12. LR PM (MW)	0.0	0.0	187.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	187.3
13. NSC (MW)	245	245	245	225	225	225	225	225	225	245	245	245	235
14. OPR BTU(GBTU)	36.6070	84.8253	35.4510	24.6663	0.0000	11.2239	19.2639	16.2665	168.1753	76.2743	23.9193	182.1693	678.8421
15. NET GEN (MWH)	4087	9286	3561	4445	0	1479	2199	1760	19334	9758	1602	22504	80015
16. ANOHR BTU/KWH	8957	9135	9955	5549	#N/A	7589	8760	9242	8698	7817	14931	8095	8484
17. NOF (%)	50.0	43.1	52.1	86.0	0.0	63.2	51.2	94.2	77.2	77.1	73.6	72.6	67.0
18. NPC (MW)	245	245	245	225	225	225	225	225	225	245	245	245	235

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POLK CT 2 (Gas)	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)							71.9	93.2	99.4	61.2	66.9	13.8	67.4
2. PH							744	744	720	745	720	744	4417
3. SH							162.7	92.0	402.8	180.3	148.4	38.8	1025.0
4. RSH							372.6	601.7	312.9	277.9	333.2	64.3	1962.6
5. UH							208.7	50.4	4.4	286.8	238.4	641.0	1429.7
6. POH							0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH							71.5	23.1	4.4	286.8	205.1	61.0	651.9
8. MOH							137.2	27.3	0.0	0.0	33.3	580.0	777.8
9. PFOH							0.0	55.4	9.6	0.0	0.0	0.0	65.0
10. LR PF (MW)							0.0	20.9	38.5	0.0	0.0	0.0	23.5
11. PMOH							2.2	0.0	1.5	0.0	0.0	0.0	3.7
12. LR PM (MW)							83.3	0.0	4.4	0.0	0.0	0.0	51.3
13. NSC (MW)							150	150	155	160	150	150	153
14. OPR BTU(GBTU)							90.9020	276.0531	635.4582	283.3999	218.0219	48.3680	1552.2031
15. NET GEN (MWH)							7400	24530	53663	26420	18637	4805	135455
16. ANOHR BTU/KWH							12284	11254	11842	10727	11698	10066	11459
17. NOF (%)							30.3	177.7	86.0	91.6	83.7	82.7	86.7
18. NPC (MW)							150	150	155	160	150	150	153

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POLK CT 2 (Oil)	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)							87.4	92.7	99.1	61.2	88.5	70.5	82.9
2. PH							744	744	720	745	720	744	4417
3. SH							101.8	191.8	56.0	9.4	29.1	155.1	543.2
4. RSH							548.6	498.1	657.9	448.8	608.2	369.2	3130.8
5. UH							93.7	54.2	6.2	286.8	82.7	219.7	743.3
6. POH							0.0	0.0	0.0	0.0	0.0	134.1	134.1
7. FOH							22.6	26.9	5.6	286.8	1.7	6.3	349.9
8. MOH							71.1	27.3	0.6	0.0	81.0	79.3	259.3
9. PFOH							0.0	2.1	3.2	0.0	1.8	0.0	7.1
10. LR PF (MW)							0.0	56.2	81.8	0.0	20.0	0.0	58.6
11. PMOH							0.0	0.0	33.5	0.0	0.0	0.0	33.5
12. LR PM (MW)							0.0	0.0	35.1	0.0	0.0	0.0	35.1
13. NSC (MW)							150	150	155	160	170	170	159
14. OPR BTU(GBTU)							137.6527	325.5965	73.3135	13.3307	39.9499	236.0167	825.8600
15. NET GEN (MWH)							10632	27949	8556	978	3083	19421	70619
16. ANOHR BTU/KWH							12947	11650	8569	13631	12958	12153	11695
17. NOF (%)							69.6	97.2	98.7	65.0	62.3	73.6	81.7
18. NPC (MW)							150	150	155	160	170	170	159

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JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 1 w/o FGD	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. OPR BTU (GBTU)	2180.1	1916.3	2439.8	1724.5	1860.8	2446.1	1957.1	2619.8	1636.7	1823.0	2535.7	1947.9	25087.9
2. NET GEN w/FGD (MWH)	224848	189859	248745	162278	175967	228545	186220	247258	155545	171208	241000	190621	2422094
3. FGD CONSUMED (MWH)	3260.0	2693.7	2309.0	2292.5	1780.0	2966.9	1865.3	2487.1	1968.2	2963.6	3417.7	2028.3	30032.2
4. NET GEN w/o FGD (MWH)	228108.0	192552.7	251054.0	164570.5	177747.0	231511.9	188085.3	249745.1	157513.2	174171.6	244417.7	192649.3	2452126.2
5. ANOHR w/FGD (BTU/KWH)	9695.8	10093.5	9808.4	10626.8	10574.8	10702.9	10509.6	10595.6	10522.1	10647.9	10521.6	10218.8	10358.0
6. ANOHR w/o FGD (BTU/KWH)	9557.2	9952.3	9718.2	10478.7	10468.9	10565.7	10405.4	10490.1	10390.6	10466.7	10374.5	10111.3	10231.1
7. NOF w/FGD (%)	76.5	76.1	78.5	73.4	79.0	79.5	80.6	79.9	75.0	71.0	78.6	82.4	77.7
8. NOF w/o FGD (%)	76.7	76.3	78.3	73.6	78.9	79.6	80.5	79.7	75.0	71.4	78.8	82.3	77.8
9. NPC (MW) w/FGD	426	426	426	416	416	416	416	416	416	426	426	426	421
10. NPC (MW) w/o FGD	431	431	431	421	421	421	421	421	421	431	431	431	426

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TAMPA ELECTRIC COMPANY
PAGE 28 OF 29

ORIGINAL SHEET NO. 9.401.00A
TAMPA ELECTRIC COMPANY

UNIT PERFORMANCE DATA w/o FGD

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 2 w/o FGD	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. OPR BTU (GBTU)	2323.8	1667.5	2416.7	2525.2	2493.0	2353.4	2001.9	2445.8	2400.4	2004.1	2130.0	2575.0	27336.7
2. NET GEN w/FGD (MWH)	233094	172032	250853	255056	243138	228193	195086	239238	238322	197267	210104	259270	2721653
3. FGD CONSUMED (MWH)	3103.2	2059.4	2188.0	3219.3	2680.0	2899.7	2020.8	2297.6	2774.1	3388.5	2869.3	3092.3	32592.2
4. NET GEN w/o FGD (MWH)	236197.2	174091.4	253041.0	258275.3	245818.0	231092.7	197106.8	241535.6	241096.1	200655.5	212973.3	262362.3	2754245.2
5. ANOHR w/FGD (BTU/KWH)	9969.4	9692.7	9633.8	9900.6	10253.4	10313.4	10261.7	10223.3	10072.0	10159.6	10137.7	9931.6	10044.0
6. ANOHR w/o FGD (BTU/KWH)	9838.4	9578.1	9550.5	9777.2	10141.6	10184.0	10156.5	10126.0	9956.1	9988.0	10001.1	9814.5	9925.3
7. NOF w/FGD (%)	77.7	78.4	79.8	85.3	78.6	81.2	81.5	80.1	79.6	72.2	76.7	81.8	79.5
8. NOF w/o FGD (%)	77.8	78.4	79.6	85.3	78.5	81.3	81.4	79.9	79.5	72.6	76.9	81.8	79.5
9. NPC (MW) w/FGD	426	426	426	416	416	416	416	416	416	426	426	426	421
10. NPC (MW) w/o FGD	431	431	431	421	421	421	421	421	421	431	431	431	426

EXHIBIT NO._____
DOCKET NO. 010001-EI
TAMPA ELECTRIC COMPANY
(GAK-1)
FILED: SEPTEMBER 20, 2001

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GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2002 - DECEMBER 2002

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 20
COMPANY/ WITNESS: Roselowsky
DATE: 10-20 & 20-01

EXHIBITS TO THE TESTIMONY OF

GEORGE A. KESELOWSKY

DOCKET NO. 010001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2002 - DECEMBER 2002

DOCUMENT NO. 1

PART A - GPIF SCHEDULES

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2002 - DECEMBER 2002
TARGETS
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ESTIMATED
JANUARY 2002 - DECEMBER 2002

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	27,494.5	5,691.7
+9	24,745.1	5,122.6
+8	21,995.6	4,553.4
+7	19,246.2	3,984.2
+6	16,496.7	3,415.0
+5	13,747.3	2,845.9
+4	10,997.8	2,276.7
+3	8,248.4	1,707.5
+2	5,498.9	1,138.3
+1	2,749.5	569.2
0	0.0	0.0
-1	(3,951.9)	(569.2)
-2	(7,903.7)	(1,138.3)
-3	(11,855.6)	(1,707.5)
-4	(15,807.4)	(2,276.7)
-5	(19,759.3)	(2,845.9)
-6	(23,711.1)	(3,415.0)
-7	(27,663.0)	(3,984.2)
-8	(31,614.8)	(4,553.4)
-9	(35,566.7)	(5,122.6)
-10	(39,518.5)	(5,691.7)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
(ESTIMATED)
JANUARY 2002 - DECEMBER 2002

Line 1	Beginning of period balance of common equity: End of month common equity:		$ 1,417,501,000
Line 2	Month of January	2002	$ 1,407,610,000
Line 3	Month of February	2002	$ 1,421,392,000
Line 4	Month of March	2002	$ 1,435,310,000
Line 5	Month of April	2002	$ 1,431,555,000
Line 6	Month of May	2002	$ 1,445,572,000
Line 7	Month of June	2002	$ 1,459,727,000
Line 8	Month of July	2002	$ 1,449,603,000
Line 9	Month of August	2002	$ 1,463,797,000
Line 10	Month of September	2002	$ 1,478,130,000
Line 11	Month of October	2002	$ 1,474,200,000
Line 12	Month of November	2002	$ 1,488,635,000
Line 13	Month of December	2002	$ 1,503,211,000
Line 14	(Summation of line 1 through line 13 divided by 13)		$ 1,452,018,692
Line 15	25 Basis points		0.0025
Line 16	Revenue Expansion Factor		61.38%
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$ 5,913,978
Line 18	Jurisdictional Sales		17,751,526 MWH
Line 19	Total Sales		18,444,683 MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)		96.24%
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$ 5,691,728**

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2002 - DECEMBER 2002

EQUIVALENT AVAILABILITY

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	5.32%	77.3	81.2	69.3	1,461.7	(3,173.6)
BIG BEND 2	6.17%	66.7	70.4	59.1	1,697.2	(3,261.5)
BIG BEND 3	5.82%	67.5	71.7	59.1	1,600.4	(3,650.6)
BIG BEND 4	3.03%	82.6	85.2	77.4	833.3	(1,684.1)
GANNON 5	6.19%	56.7	63.1	44.0	1,702.3	(3,830.7)
GANNON 6	10.46%	63.9	68.4	54.9	2,875.0	(6,015.5)
POLK 1	4.98%	78.0	81.3	71.5	1,370.4	(1,948.3)
GPIF SYSTEM	**41.97%**					

AVERAGE NET OPERATING HEAT RATE

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR Btu/kwh	TARGET NOF	ANOHR RANGE MIN.	ANOHR RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	11.35%	10231	82.2	9597	10865	3,120.1	(3,120.1)
BIG BEND 2	6.97%	9928	86.3	9513	10343	1,916.1	(1,916.1)
BIG BEND 3	9.96%	10036	78.3	9408	10664	2,737.5	(2,737.5)
BIG BEND 4	7.48%	10089	82.7	9710	10468	2,055.3	(2,055.3)
GANNON 5	4.28%	10716	71.5	10024	11408	1,177.3	(1,177.3)
GANNON 6	6.87%	10704	78.4	10099	11309	1,889.6	(1,889.6)
POLK 1	11.12%	10087	98.2	9247	10927	3,058.3	(3,058.3)
GPIF SYSTEM	**58.03%**					**15,954.2**	**(15,954.2)**

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS PRIOR PERIOD ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 02 - DEC 02 POF	EUOF	EUOR	TARGET PERIOD JUL 00 - JUN 01 POF	EUOF	EUOR	TARGET PERIOD JUL 99 - JUN 00 POF	EUOF	EUOR	TARGET PERIOD JUL 98 - JUN 99 POF	EUOF	EUOR
BIG BEND 1	5.32%	12.7%	3.8	18.9	19.7	6.8	19.6	21.0	5.7	16.0	17.0	14.3	23.7	27.7
BIG BEND 2	6.17%	14.7%	19.2	14.1	17.5	0.0	17.7	17.7	5.6	10.4	11.0	6.1	18.5	19.7
BIG BEND 3	5.82%	13.9%	15.3	17.2	20.3	16.1	20.8	24.8	11.2	18.0	20.3	0.0	16.7	16.7
BIG BEND 4	3.03%	7.2%	5.8	11.6	12.3	6.4	14.2	15.2	10.9	9.5	10.7	8.5	12.6	13.8
GANNON 5	6.19%	14.8%	15.3	27.9	33.0	6.6	25.0	26.8	6.3	26.5	28.3	12.2	39.1	44.5
GANNON 6	10.46%	24.9%	18.1	18.0	22.0	23.2	24.7	32.2	9.1	30.0	33.0	8.3	23.3	25.4
POLK 1	4.98%	11.9%	7.7	14.3	15.5	5.7	37.5	39.8	4.9	13.3	14.0	4.3	8.7	9.1
GPIF SYSTEM	41.97%	100.0%	13.5	18.0	21.0	11.0	23.3	26.5	7.7	19.7	21.4	7.7	21.6	23.7
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%				68.5			65.7			72.6			70.7	

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
8.8	21.5	23.9	69.7

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 02 - DEC 02	ADJUSTED PRIOR HEAT RATE JUL 00 - JUN 01	ADJUSTED PRIOR HEAT RATE JUL 99 - JUN 00	ADJUSTED PRIOR HEAT RATE JUL 98 - JUN 99
BIG BEND 1	11.35%	19.6%	10,231	10,215	10,027	10,332
BIG BEND 2	6.97%	12.0%	9,928	10,003	9,791	9,964
BIG BEND 3	9.96%	17.2%	10,036	10,192	9,848	9,980
BIG BEND 4	7.48%	12.9%	10,089	10,100	9,972	10,133
GANNON 5	4.28%	7.4%	10,716	10,362	11,205	10,699
GANNON 6	6.87%	11.8%	10,704	10,693	10,999	10,434
POLK 1	11.12%	19.2%	10,087	9,673	10,222	10,144
GPIF SYSTEM	58.03%	100.0%				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh)			10,207	10,134	10,200	10,205

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2002 - DECEMBER 2002
PRODUCTION COSTING SIMULATION
FUEL COST ($000)

UNIT PERFORMANCE INDICATOR	AT TARGET (1)	AT MAXIMUM IMPROVEMENT (2)	SAVINGS (3)	WEIGHTING FACTOR (% OF SAVINGS
EQUIVALENT AVAILABILIT				
EA_1 BIG BEND 1	543574.8	542113.1	1461.7	5.32%
EA_2 BIG BEND 2	543574.8	541877.6	1697.2	6.17%
EA_3 BIG BEND 3	543574.8	541974.4	1600.4	5.82%
EA_4 BIG BEND 4	543574.8	542741.5	833.3	3.03%
EA_5 GANNON 5	543574.8	541872.5	1702.3	6.19%
EA_6 GANNON 6	543574.8	540699.8	2875	10.46%
EA_7 POLK 1	543574.8	542204.4	1370.4	4.98%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	543574.8	540454.7	3120.1	11.35%
AHR_2 BIG BEND 2	543574.8	541658.7	1916.1	6.97%
AHR_3 BIG BEND 3	543574.8	540837.3	2737.5	9.96%
AHR_4 BIG BEND 4	543574.8	541519.5	2055.3	7.48%
AHR_5 GANNON 5	543574.8	542397.5	1177.3	4.28%
AHR_6 GANNON 6	543574.8	541685.2	1889.6	6.87%
AHR_7 POLK 1	543574.8	540516.5	3058.3	11.12%
TOTAL SAVINGS			**27,494.5**	**100.00%**

(1) Fuel Adjustment Base Case - All unit performance indicators at target.
(2) All other units performance indicators at target.
(3) Expressed in replacement energy cost.

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2002 - DECEMBER 2002

BIG BEND 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,461.7	81.2	+10	3,120.1	9,597
+9	1,315.5	80.8	+9	2,808.1	9,653
+8	1,169.4	80.4	+8	2,496.1	9,709
+7	1,023.2	80.0	+7	2,184.1	9,765
+6	877.0	79.6	+6	1,872.1	9,821
+5	730.9	79.3	+5	1,560.1	9,877
+4	584.7	78.9	+4	1,248.0	9,932
+3	438.5	78.5	+3	936.0	9,988
+2	292.3	78.1	+2	624.0	10,044
+1	146.2	77.7	+1	312.0	10,100
					10,156
0	0.0	77.3	0	0.0	10,231
					10,306
-1	(317.4)	76.5	-1	(312.0)	10,362
-2	(634.7)	75.7	-2	(624.0)	10,418
-3	(952.1)	74.9	-3	(936.0)	10,474
-4	(1,269.4)	74.1	-4	(1,248.0)	10,530
-5	(1,586.8)	73.3	-5	(1,560.1)	10,586
-6	(1,904.2)	72.5	-6	(1,872.1)	10,641
-7	(2,221.5)	71.7	-7	(2,184.1)	10,697
-8	(2,538.9)	70.9	-8	(2,496.1)	10,753
-9	(2,856.2)	70.1	-9	(2,808.1)	10,809
-10	(3,173.6)	69.3	-10	(3,120.1)	10,865
	Weighting Factor =	5.32%		Weighting Factor =	11.35%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2002 - DECEMBER 2002

BIG BEND 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,697.2	70.4	+10	1,916.1	9,513
+9	1,527.5	70.0	+9	1,724.5	9,547
+8	1,357.8	69.7	+8	1,532.9	9,581
+7	1,188.0	69.3	+7	1,341.3	9,615
+6	1,018.3	68.9	+6	1,149.7	9,649
+5	848.6	68.6	+5	958.1	9,683
+4	678.9	68.2	+4	766.4	9,717
+3	509.2	67.8	+3	574.8	9,751
+2	339.4	67.4	+2	383.2	9,785
+1	169.7	67.1	+1	191.6	9,819
					9,853
0	0.0	66.7	0	0.0	9,928
					10,003
-1	(326.2)	65.9	-1	(191.6)	10,037
-2	(652.3)	65.2	-2	(383.2)	10,071
-3	(978.5)	64.4	-3	(574.8)	10,105
-4	(1,304.6)	63.7	-4	(766.4)	10,139
-5	(1,630.8)	62.9	-5	(958.1)	10,173
-6	(1,956.9)	62.1	-6	(1,149.7)	10,207
-7	(2,283.1)	61.4	-7	(1,341.3)	10,241
-8	(2,609.2)	60.6	-8	(1,532.9)	10,275
-9	(2,935.4)	59.9	-9	(1,724.5)	10,309
-10	(3,261.5)	59.1	-10	(1,916.1)	10,343
	Weighting Factor =	6.17%		Weighting Factor =	6.97%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2002 - DECEMBER 2002

BIG BEND 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,600.4	71.7	+10	2,737.5	9,408
+9	1,440.4	71.3	+9	2,463.8	9,463
+8	1,280.3	70.9	+8	2,190.0	9,519
+7	1,120.3	70.4	+7	1,916.3	9,574
+6	960.2	70.0	+6	1,642.5	9,629
+5	800.2	69.6	+5	1,368.8	9,685
+4	640.2	69.2	+4	1,095.0	9,740
+3	480.1	68.8	+3	821.3	9,795
+2	320.1	68.3	+2	547.5	9,850
+1	160.0	67.9	+1	273.8	9,906
					9,961
0	0.0	67.5	0	0.0	10,036
					10,111
-1	(365.1)	66.7	-1	(273.8)	10,166
-2	(730.1)	65.8	-2	(547.5)	10,222
-3	(1,095.2)	65.0	-3	(821.3)	10,277
-4	(1,460.2)	64.1	-4	(1,095.0)	10,332
-5	(1,825.3)	63.3	-5	(1,368.8)	10,388
-6	(2,190.4)	62.5	-6	(1,642.5)	10,443
-7	(2,555.4)	61.6	-7	(1,916.3)	10,498
-8	(2,920.5)	60.8	-8	(2,190.0)	10,553
-9	(3,285.5)	59.9	-9	(2,463.8)	10,609
-10	(3,650.6)	59.1	-10	(2,737.5)	10,664
	Weighting Factor =	5.82%		Weighting Factor =	9.96%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2002 - DECEMBER 2002

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	833.3	85.2	+10	2,055.3	9,710
+9	750.0	84.9	+9	1,849.8	9,740
+8	666.6	84.7	+8	1,644.2	9,771
+7	583.3	84.4	+7	1,438.7	9,801
+6	500.0	84.2	+6	1,233.2	9,832
+5	416.7	83.9	+5	1,027.7	9,862
+4	333.3	83.6	+4	822.1	9,892
+3	250.0	83.4	+3	616.6	9,923
+2	166.7	83.1	+2	411.1	9,953
+1	83.3	82.9	+1	205.5	9,984
					10,014
0	0.0	82.6	0	0.0	10,089
					10,164
-1	(168.4)	82.1	-1	(205.5)	10,194
-2	(336.8)	81.6	-2	(411.1)	10,225
-3	(505.2)	81.0	-3	(616.6)	10,255
-4	(673.6)	80.5	-4	(822.1)	10,286
-5	(842.1)	80.0	-5	(1,027.7)	10,316
-6	(1,010.5)	79.5	-6	(1,233.2)	10,346
-7	(1,178.9)	79.0	-7	(1,438.7)	10,377
-8	(1,347.3)	78.4	-8	(1,644.2)	10,407
-9	(1,515.7)	77.9	-9	(1,849.8)	10,438
-10	(1,684.1)	77.4	-10	(2,055.3)	10,468
	Weighting Factor =	3.03%		Weighting Factor =	7.48%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2002 - DECEMBER 2002

GANNON 5

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,702.3	63.1	+10	1,177.3	10,024
+9	1,532.1	62.5	+9	1,059.6	10,086
+8	1,361.8	61.8	+8	941.8	10,147
+7	1,191.6	61.2	+7	824.1	10,209
+6	1,021.4	60.5	+6	706.4	10,271
+5	851.2	59.9	+5	588.7	10,333
+4	680.9	59.3	+4	470.9	10,394
+3	510.7	58.6	+3	353.2	10,456
+2	340.5	58.0	+2	235.5	10,518
+1	170.2	57.3	+1	117.7	10,579
					10,641
0	0.0	56.7	0	0.0	10,716
					10,791
-1	(383.1)	55.4	-1	(117.7)	10,853
-2	(766.1)	54.2	-2	(235.5)	10,914
-3	(1,149.2)	52.9	-3	(353.2)	10,976
-4	(1,532.3)	51.6	-4	(470.9)	11,038
-5	(1,915.4)	50.4	-5	(588.7)	11,100
-6	(2,298.4)	49.1	-6	(706.4)	11,161
-7	(2,681.5)	47.8	-7	(824.1)	11,223
-8	(3,064.6)	46.5	-8	(941.8)	11,285
-9	(3,447.6)	45.3	-9	(1,059.6)	11,346
-10	(3,830.7)	44.0	-10	(1,177.3)	11,408
	Weighting Factor =	6.19%		Weighting Factor =	4.28%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2002 - DECEMBER 2002

GANNON 6

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	2,875.0	68.4	+10	1,889.6	10,099
+9	2,587.5	68.0	+9	1,700.6	10,152
+8	2,300.0	67.5	+8	1,511.7	10,205
+7	2,012.5	67.1	+7	1,322.7	10,258
+6	1,725.0	66.6	+6	1,133.8	10,311
+5	1,437.5	66.2	+5	944.8	10,364
+4	1,150.0	65.7	+4	755.8	10,417
+3	862.5	65.3	+3	566.9	10,470
+2	575.0	64.8	+2	377.9	10,523
+1	287.5	64.4	+1	189.0	10,576
					10,629
0	0.0	63.9	0	0.0	10,704
					10,779
-1	(601.6)	63.0	-1	(189.0)	10,832
-2	(1,203.1)	62.1	-2	(377.9)	10,885
-3	(1,804.7)	61.2	-3	(566.9)	10,938
-4	(2,406.2)	60.3	-4	(755.8)	10,991
-5	(3,007.8)	59.4	-5	(944.8)	11,044
-6	(3,609.3)	58.5	-6	(1,133.8)	11,097
-7	(4,210.9)	57.6	-7	(1,322.7)	11,150
-8	(4,812.4)	56.7	-8	(1,511.7)	11,203
-9	(5,414.0)	55.8	-9	(1,700.6)	11,256
-10	(6,015.5)	54.9	-10	(1,889.6)	11,309
	Weighting Factor =	10.46%		Weighting Factor =	6.87%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2002 - DECEMBER 2002

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,370.4	81.3	+10	3,058.3	9,247
+9	1,233.4	81.0	+9	2,752.5	9,324
+8	1,096.3	80.6	+8	2,446.6	9,400
+7	959.3	80.3	+7	2,140.8	9,477
+6	822.2	80.0	+6	1,835.0	9,553
+5	685.2	79.7	+5	1,529.2	9,630
+4	548.2	79.3	+4	1,223.3	9,706
+3	411.1	79.0	+3	917.5	9,783
+2	274.1	78.7	+2	611.7	9,859
+1	137.0	78.3	+1	305.8	9,936
					10,012
0	0.0	78.0	0	0.0	10,087
					10,162
-1	(194.8)	77.4	-1	(305.8)	10,239
-2	(389.7)	76.7	-2	(611.7)	10,315
-3	(584.5)	76.1	-3	(917.5)	10,392
-4	(779.3)	75.4	-4	(1,223.3)	10,468
-5	(974.2)	74.8	-5	(1,529.2)	10,545
-6	(1,169.0)	74.1	-6	(1,835.0)	10,621
-7	(1,363.8)	73.5	-7	(2,140.8)	10,698
-8	(1,558.6)	72.8	-8	(2,446.6)	10,774
-9	(1,753.5)	72.2	-9	(2,752.5)	10,851
-10	(1,948.3)	71.5	-10	(3,058.3)	10,927
	Weighting Factor =	4.98%		Weighting Factor =	11.12%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2002 - DECEMBER 2002

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 1 GPIF (w/o FGD)	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	80.2	43.0	77.7	80.3	80.2	80.3	80.2	80.2	80.3	80.3	80.3	80.2	77.2
2. POF	0.0	46.4	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8
3. EUOF	19.8	10.6	19.1	19.7	19.8	19.7	19.8	19.8	19.7	19.7	19.7	19.8	18.9
4. EUOR	19.8	19.7	19.7	19.7	19.8	19.7	19.8	19.8	19.7	19.7	19.7	19.8	19.7
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	653	315	614	623	653	626	645	644	632	653	632	644	7334
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	91	357	130	96	91	94	99	100	88	92	88	100	1426
9. POH	0	312	24	0	0	0	0	0	0	0	0	0	336
10. FOH & EFOH	65	31	63	63	65	63	65	65	63	65	63	65	733
11. MOH & EMOH	82	40	79	79	82	79	82	82	79	82	79	82	927
12. OPER BTU (GBTU)	2247.219	1130.360	2178.964	2194.265	2314.086	2279.461	2374.314	2377.161	2319.196	2326.067	2248.507	2280.235	26269.834
13. NET GEN (MWH)	221,662	112,706	213,598	215,347	225,383	221,687	228,992	229,262	225,551	228,179	220,551	224,843	2,567,761
14. ANOHR (Btu/kwh)	10,138	10,029	10,201	10,189	10,267	10,282	10,369	10,369	10,282	10,194	10,195	10,141	10,231
15. NOF (%)	78.8	82.9	80.7	82.1	82.0	84.1	84.4	84.5	84.8	81.1	81.0	80.9	82.2
16. NPC (MW)	431	431	431	421	421	421	421	421	421	431	431	431	426
17. ANOHR EQUATION	ANOHR = NOF(-12.328) + 11244												

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DOCKET NO: 010001-EI

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2002 - DECEMBER 2002

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 2 GPIF (w/o FGD)	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	82.5	82.6	82.5	82.5	82.5	82.5	82.5	82.5	55.0	0.0	2.8	82.5	66.7
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.3	100.0	96.7	0.0	19.2
3. EUOF	17.5	17.4	17.5	17.5	17.5	17.5	17.5	17.5	11.7	0.0	0.6	17.5	14.1
4. EUOR	17.5	17.4	17.5	17.5	17.5	17.5	17.5	17.5	17.5	0.0	16.7	17.5	17.5
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	682	616	682	660	682	660	682	682	440	0	22	682	6487
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	62	56	62	59	62	60	62	62	280	745	698	62	2273
9. POH	0	0	0	0	0	0	0	0	240	745	696	0	1681
10. FOH & EFOH	65	59	65	63	65	63	65	65	42	0	2	65	623
11. MOH & EMOH	65	58	65	63	65	63	65	65	42	0	2	65	616
12. OPER BTU (GBTU)	2479.092	2303.430	2428.639	2338.565	2484.258	2427.190	2520.372	2520.602	1630.721	0.000	81.454	2465.992	23680.315
13. NET GEN (MWH)	249,309	231,892	244,833	236,160	250,131	243,584	251,693	251,705	164,560	0	10,606	248,139	2,385,112
14. ANOHR (Btu/kwh)	9,944	9,933	9,920	9,902	9,932	9,964	10,014	10,014	9,910	0	7,680	9,938	9,928
15. NOF (%)	84.9	87.4	83.3	85.0	87.2	87.7	87.7	87.7	88.8	0.0	112.7	84.5	86.3
16. NPC (MW)	431	431	431	421	421	421	421	421	421	431	431	431	426
17. ANOHR EQUATION	ANOHR = NOF(-12.51) + 11008												

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EFFECTIVE: 09/20/01
DOCKET NO: 010001-EI

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2002 - DECEMBER 2002

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 3	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	79.7	79.8	2.6	10.4	79.7	79.7	79.7	79.7	79.7	79.7	79.7	79.7	67.5
2. POF	0.0	0.0	96.8	86.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3
3. EUOF	20.3	20.2	0.7	2.8	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	17.2
4. EUOR	20.3	20.2	20.8	21.1	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	562	592	22	79	658	628	649	649	636	644	622	643	6383
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	182	80	722	640	86	92	95	95	84	101	98	101	2377
9. POH	0	0	720	624	0	0	0	0	0	0	0	0	1344
10. FOH & EFOH	60	54	2	8	60	58	60	60	58	60	58	60	601
11. MOH & EMOH	91	82	3	12	91	88	91	91	88	91	88	91	905
12. OPER BTU (GBTU)	1752.441	2010.356	79.059	218.753	2090.826	2213.359	2283.025	2305.535	2322.122	2170.584	2194.868	2085.003	21725.933
13. NET GEN (MWH)	175,015	201,224	7,910	21,612	208,430	220,566	225,390	227,683	231,809	216,688	220,175	208,378	2,164,880
14. ANOHR (Btu/kwh)	10,013	9,991	9,995	10,122	10,031	10,035	10,129	10,126	10,017	10,017	9,969	10,006	10,036
15. NOF (%)	72.0	78.5	84.3	62.8	73.2	81.1	80.2	81.0	84.2	77.8	81.8	74.9	78.3
16. NPC (MW)	433	433	433	433	433	433	433	433	433	433	433	433	433
17. ANOHR EQUATION	ANOHR = NOF(-57.476) + 14536												

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SUSPENDED:
EFFECTIVE: 09/20/01
DOCKET NO: 010001-EI

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2002 - DECEMBER 2002

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 4	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	87.8	87.6	87.8	87.6	87.8	87.6	87.8	87.8	87.6	87.8	84.9	31.2	82.6
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	64.5	5.8
3. EUOF	12.2	12.4	12.2	12.4	12.2	12.4	12.2	12.2	12.4	12.2	11.8	4.3	11.6
4. EUOR	12.2	12.4	12.2	12.4	12.2	12.4	12.2	12.2	12.4	12.2	12.2	12.1	12.3
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	691	570	646	645	603	625	672	671	665	687	616	197	7287
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	53	102	98	74	141	95	72	73	55	58	104	547	1473
9. POH	0	0	0	0	0	0	0	0	0	0	24	480	504
10. FOH & EFOH	45	41	45	44	45	44	45	45	44	45	42	16	504
11. MOH & EMOH	46	42	46	45	46	45	46	46	45	46	43	16	512
12. OPER BTU (GBTU)	2481.054	2034.728	2329.232	2343.517	2148.367	2351.869	2557.026	2568.677	2523.161	2692.294	2287.650	703.338	27020.914
13. NET GEN (MWH)	247,723	202,839	231,577	233,507	212,788	231,752	250,787	251,891	248,921	268,698	227,633	70,136	2,678,252
14. ANOHR (Btu/kwh)	10,015	10,031	10,058	10,036	10,096	10,148	10,196	10,198	10,136	10,020	10,050	10,028	10,089
15. NOF (%)	80.2	79.7	80.2	82.0	79.8	83.8	84.5	85.0	84.7	87.4	82.7	79.8	82.7
16. NPC (MW)	447	447	447	442	442	442	442	442	442	447	447	447	445
17. ANOHR EQUATION	ANOHR = NOF(-33.833) + 12887												

FILED:
SUSPENDED:
EFFECTIVE: 09/20/01
DOCKET NO: 010001-EI

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2002 - DECEMBER 2002

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
GANNON 5	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	66.9	35.9	0.0	40.2	66.9	66.9	66.9	66.9	66.9	67.0	66.9	66.9	56.7
2. POF	0.0	46.4	100.0	40.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3
3. EUOF	33.1	17.7	0.0	19.7	33.1	33.1	33.1	33.1	33.1	33.0	33.1	33.1	27.9
4. EUOR	33.1	33.1	0.0	32.9	33.1	33.1	33.1	33.1	33.1	33.0	33.1	33.1	33.0
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	538	261	0	311	538	521	538	538	521	538	521	538	5361
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	206	411	744	408	206	199	206	206	199	207	199	206	3399
9. POH	0	312	744	288	0	0	0	0	0	0	0	0	1344
10. FOH & EFOH	186	90	0	108	186	180	186	186	180	186	180	186	1854
11. MOH & EMOH	60	29	0	34	60	58	60	60	58	60	58	60	593
12. OPER BTU (GBTU)	859.534	433.307	0.000	506.387	847.046	891.330	899.839	905.256	923.239	944.017	863.521	863.669	8937.146
13. NET GEN (MWH)	82,068	41,414	0	47,252	77,777	81,330	81,938	82,477	85,615	89,514	82,208	82,439	834,032
14. ANOHR (Btu/kwh)	10,473	10,463	0	10,717	10,891	10,959	10,982	10,976	10,784	10,546	10,504	10,476	10,716
15. NOF (%)	67.2	70.0	0.0	73.0	69.5	75.1	73.2	73.7	79.1	73.3	69.6	67.5	71.5
16. NPC (MW)	227	227	227	208	208	208	208	208	208	227	227	227	218
17. ANOHR EQUATION	ANOHR = NOF(-4.3274) + 11025												

FILED:
SUSPENDED:
EFFECTIVE: 09/20/01
DOCKET NO: 010001-EI

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2002 - DECEMBER 2002

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
GANNON 6	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	78.0	78.0	78.0	67.6	62.9	78.1	78.0	78.0	78.1	45.4	0.0	45.3	63.9
2. POF	0.0	0.0	0.0	13.4	19.4	0.0	0.0	0.0	0.0	41.9	100.0	41.9	18.1
3. EUOF	22.0	22.0	22.0	19.1	17.7	21.9	22.0	22.0	21.9	12.8	0.0	12.8	18.0
4. EUOR	22.0	22.0	22.0	22.0	22.0	21.9	22.0	22.0	21.9	21.9	0.0	22.0	22.0
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	565	511	565	475	456	547	565	565	547	329	0	328	5454
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	179	161	179	244	288	173	179	179	173	416	720	416	3307
9. POH	0	0	0	96	144	0	0	0	0	312	720	312	1584
10. FOH & EFOH	112	101	112	93	90	108	112	112	108	65	0	65	1076
11. MOH & EMOH	52	47	52	44	42	50	52	52	50	30	0	30	502
12. OPER BTU (GBTU)	1771.122	1642.639	1816.412	1492.794	1372.987	1761.459	1819.788	1832.828	1830.106	1090.587	0.000	1053.391	17484.111
13. NET GEN (MWH)	167,645	155,198	170,436	139,572	127,028	162,603	168,152	169,458	170,362	103,191	0	99,746	1,633,391
14. ANOHR (Btu/kwh)	10,565	10,584	10,657	10,696	10,809	10,833	10,822	10,816	10,742	10,569	0	10,561	10,704
15. NOF (%)	75.6	77.5	76.9	79.0	74.9	79.9	80.0	80.6	83.7	80.1	0.0	77.7	78.4
16. NPC (MW)	392	392	392	372	372	372	372	372	372	392	392	392	382
17. ANOHR EQUATION	ANOHR = NOF(25.825) + 8679.5												

FILED:
SUSPENDED:
EFFECTIVE: 09/20/01
DOCKET NO: 010001-EI

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2002 - DECEMBER 2002

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
POLK 1	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	84.5	84.4	84.5	53.4	38.2	84.6	84.5	84.5	84.6	84.6	84.6	84.5	78.0
2. POF	0.0	0.0	0.0	36.7	54.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.7
3. EUOF	15.5	15.6	15.5	9.9	7.0	15.4	15.5	15.5	15.4	15.4	15.4	15.5	14.3
4. EUOR	15.5	15.6	15.5	15.6	15.5	15.4	15.5	15.5	15.4	15.4	15.4	15.5	15.5
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	576	520	576	427	576	557	576	576	557	576	557	576	6652
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	168	152	168	292	168	163	168	168	163	169	163	168	2108
9. POH	0	0	0	264	408	0	0	0	0	0	0	0	672
10. FOH & EFOH	89	81	89	55	40	86	89	89	86	89	86	89	971
11. MOH & EMOH	26	24	26	16	12	25	26	26	25	26	25	26	283
12. OPER BTU (GBTU)	1420.694	1289.281	1427.784	1052.620	1388.930	1385.545	1430.622	1431.565	1390.353	1436.760	1389.052	1427.708	16470.914
13. NET GEN (MWH)	140,791	127,795	141,528	104,354	137,635	137,375	141,850	141,949	137,880	142,483	137,743	141,533	1,632,916
14. ANOHR (Btu/kwh)	10,091	10,089	10,088	10,087	10,091	10,086	10,085	10,085	10,084	10,084	10,084	10,087	10,087
15. NOF (%)	97.8	98.2	98.3	97.7	95.6	98.6	98.5	98.6	98.9	98.9	98.8	98.3	98.2
16. NPC (MW)	250	250	250	250	250	250	250	250	250	250	250	250	250
17. ANOHR EQUATION	ANOHR = NOF(-14.839) + 11544												

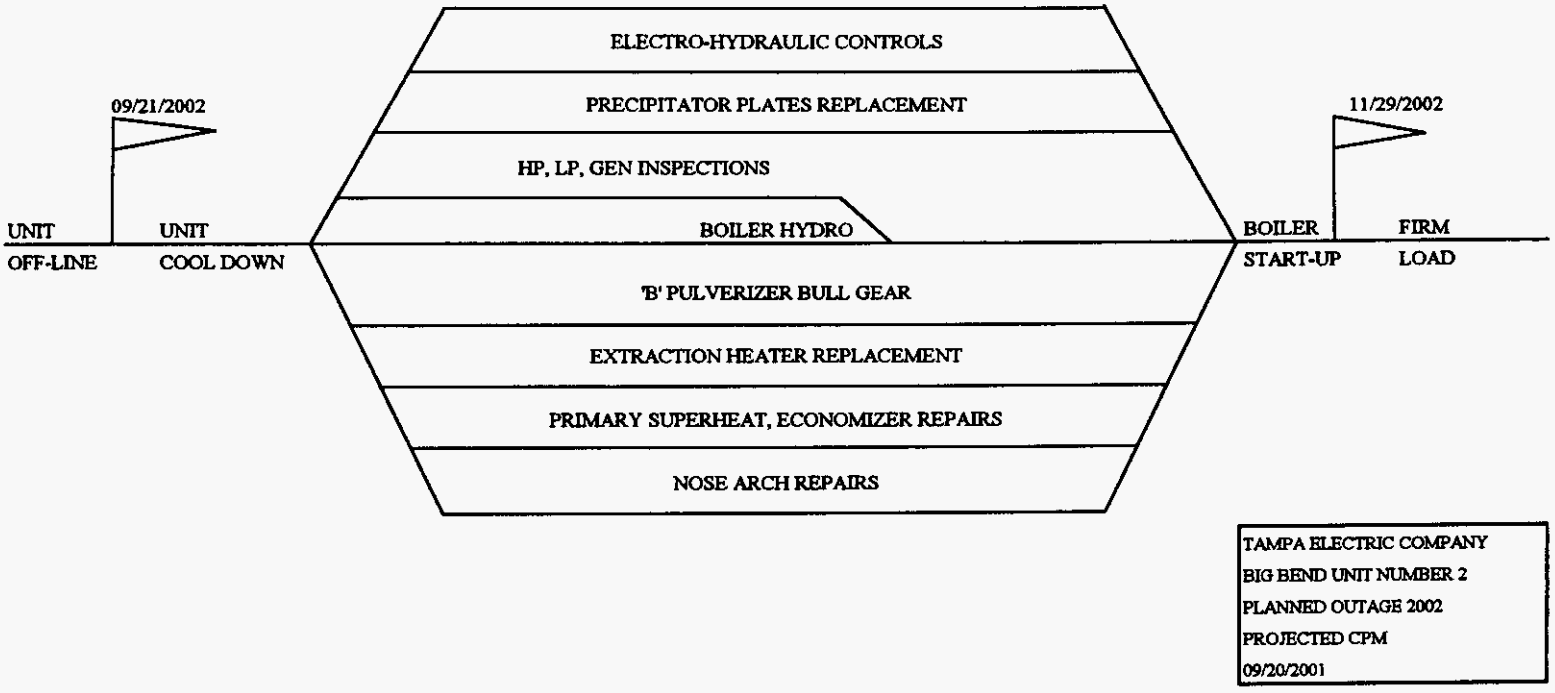
FILED:
SUSPENDED:
EFFECTIVE: 09/20/01
DOCKET NO: 010001-EI

TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ESTIMATED)
GPIF UNITS
JANUARY 2002 - DECEMBER 2002

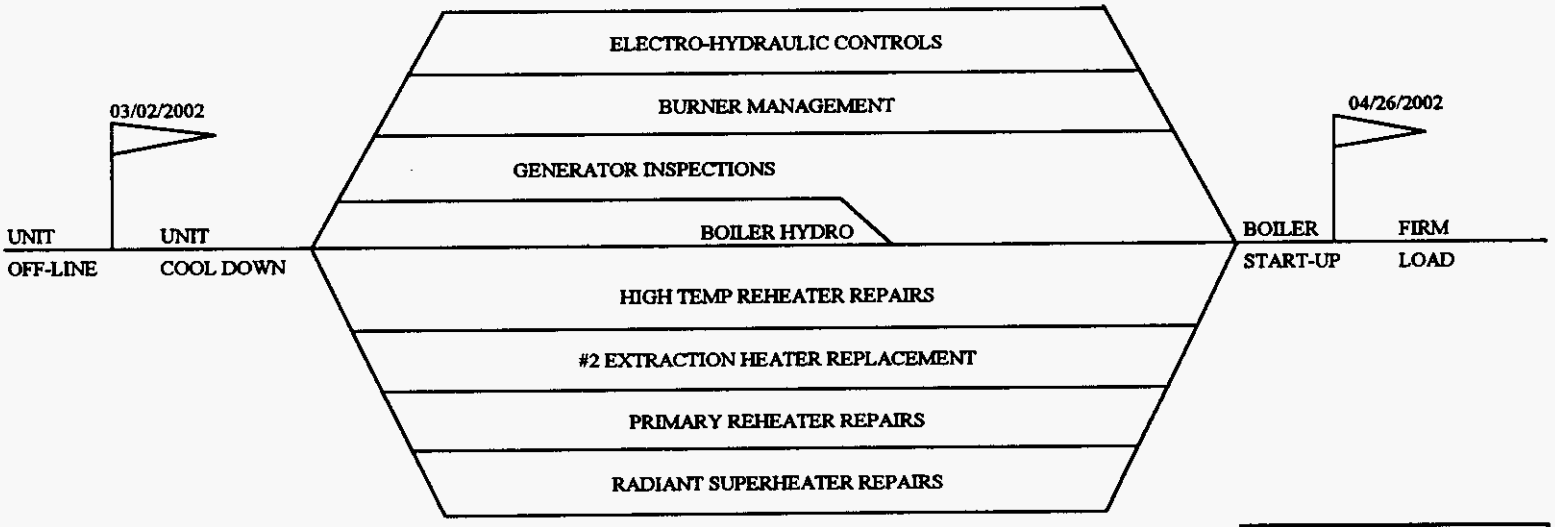
	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
	BIG BEND 1	Feb 16	-	Mar 01	Fuel System Clean-up
+	BIG BEND 2	Sep 21	-	Nov 29	LP inspection, HP inspection, nose arch repairs, precipator, B pulverizer bull gear, extraction heater replacement, generator inspection, primary superheater, economizer, electric-hydro controls
+	BIG BEND 3	Mar 02	-	Apr 26	Primary reheater, high temp reheater, radiant superheater, electric-hydro controls, generator inspection, #2 extraction heater, burner management
	BIG BEND 4	Nov 30	-	Dec 20	Fuel System Clean-up
+	GANNON 5	Feb 16	-	Apr 12	HP, IP, LP controls, generator rewind with rings, condenser repairs
+	GANNON 6	Apr 27	-	May 06	Fuel System Clean-up
		Oct 19	-	Dec 13	Boiler tube repairs, HP, IP, LP controls
	POLK 1	Apr 20	-	May 17	Fuel System Clean-up

+ **CPM for units with less than or equal to 4 weeks are not included.**

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2002 - DECEMBER 2002

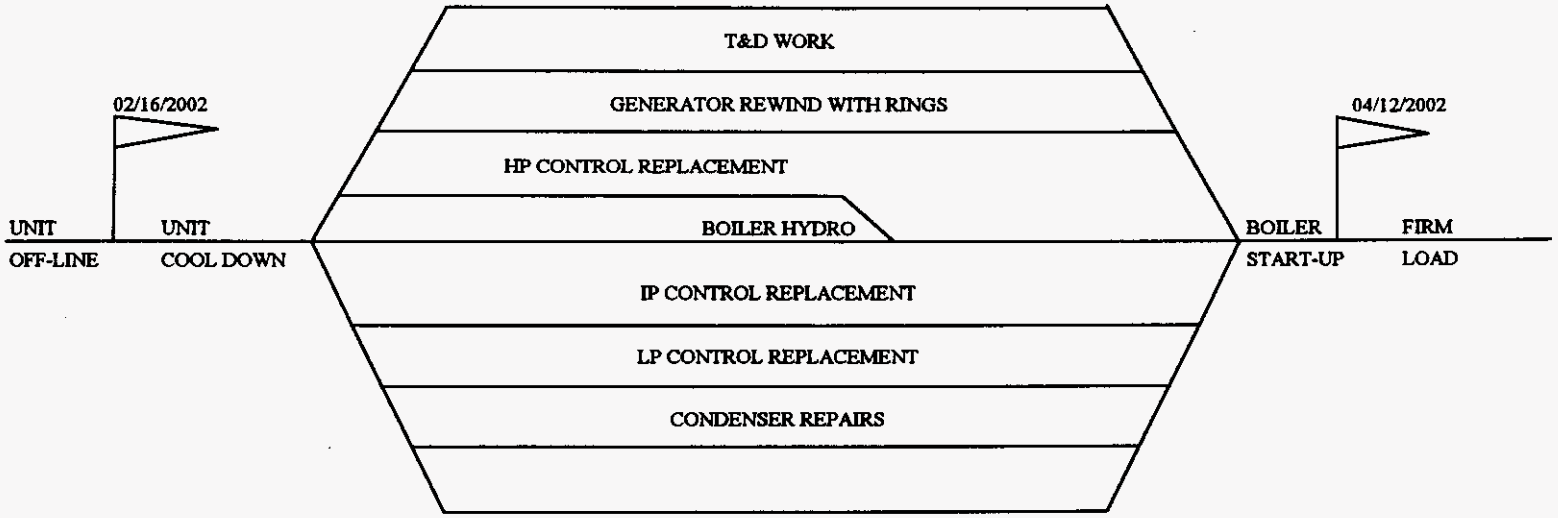


TAMPA ELECTRIC COMPANY
BIG BEND UNIT NUMBER 2
PLANNED OUTAGE 2002
PROJECTED CPM
09/20/2001

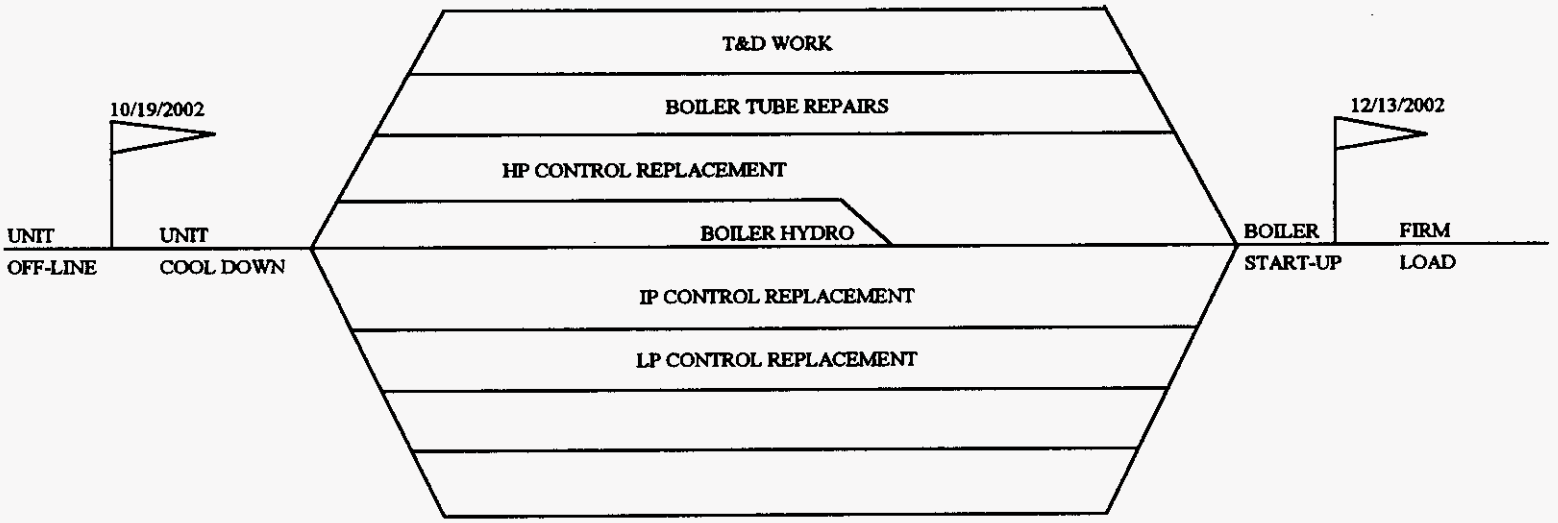


TAMPA ELECTRIC COMPANY
BIG BEND UNIT NUMBER 3
PLANNED OUTAGE 2002
PROJECTED CPM
09/20/2001

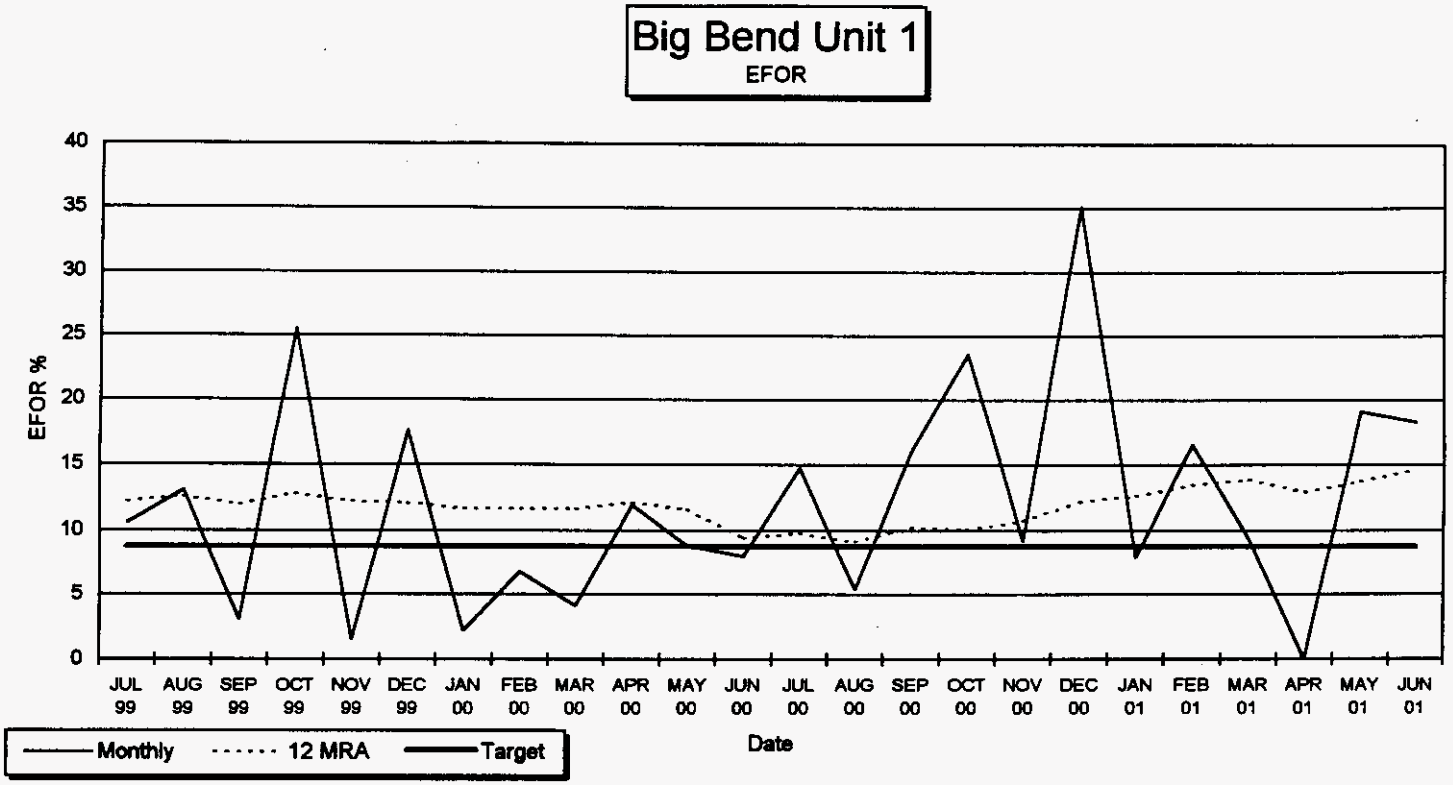
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2002 - DECEMBER 2002

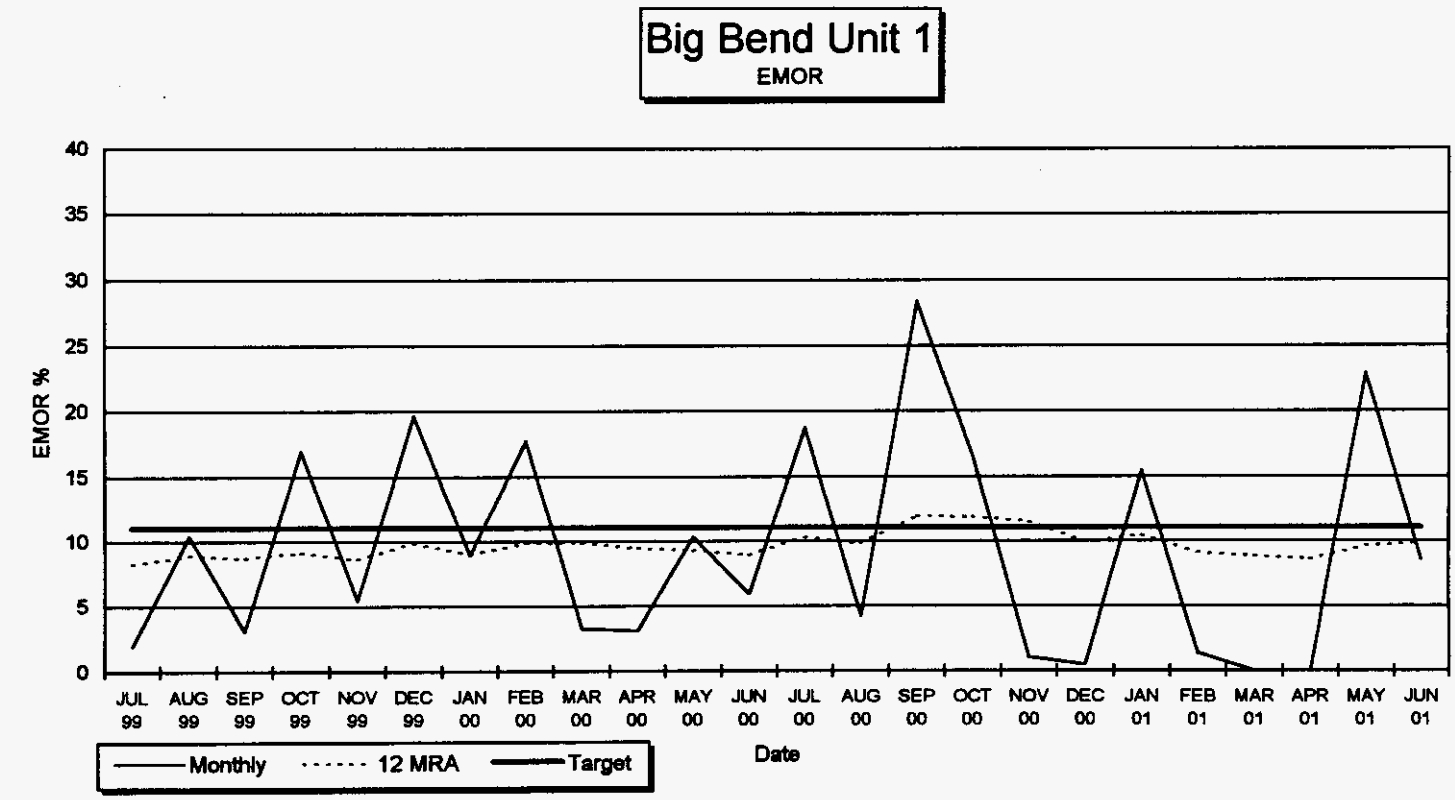


TAMPA ELECTRIC COMPANY
GANNON UNIT NUMBER 5
PLANNED OUTAGE 2002
PROJECTED CPM
09/20/2001

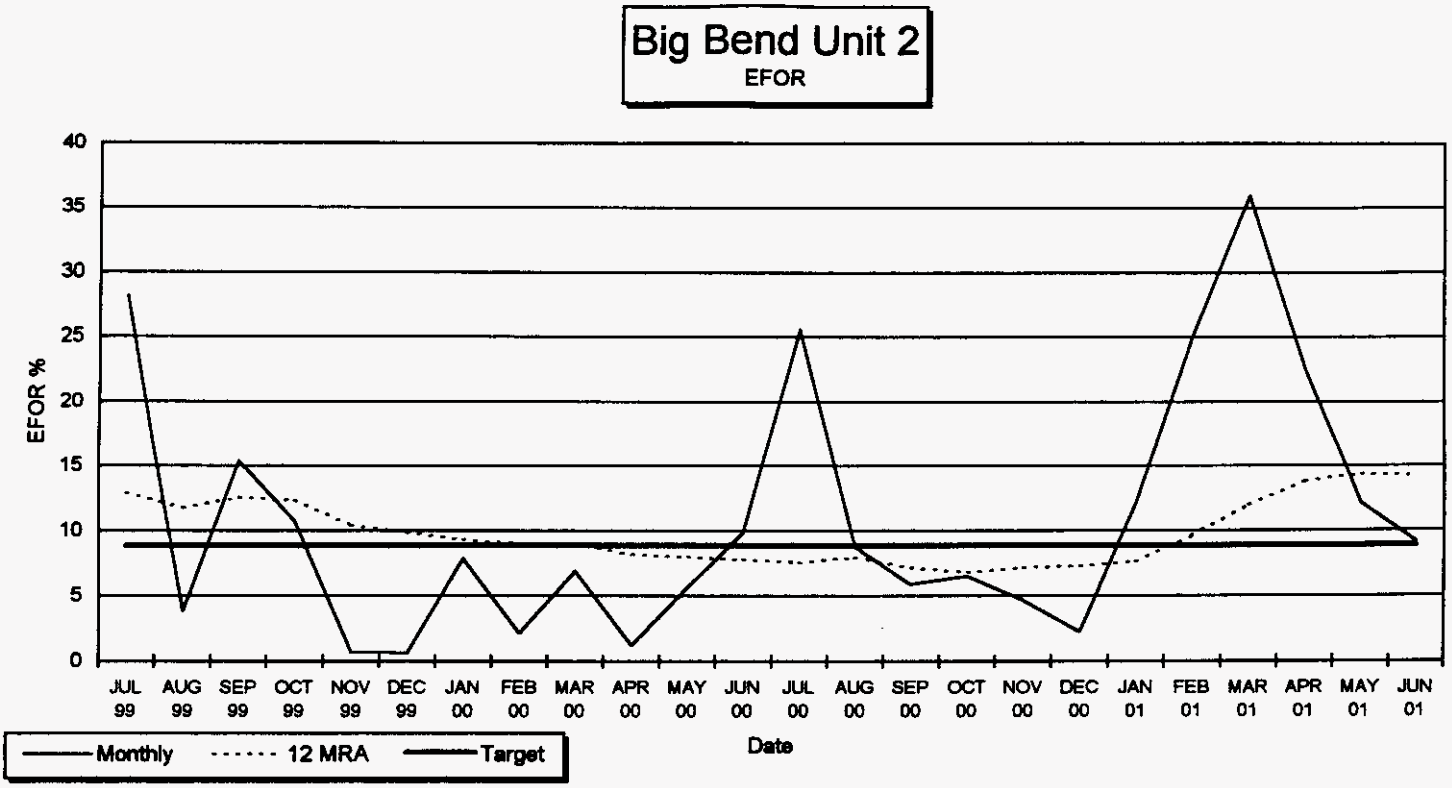


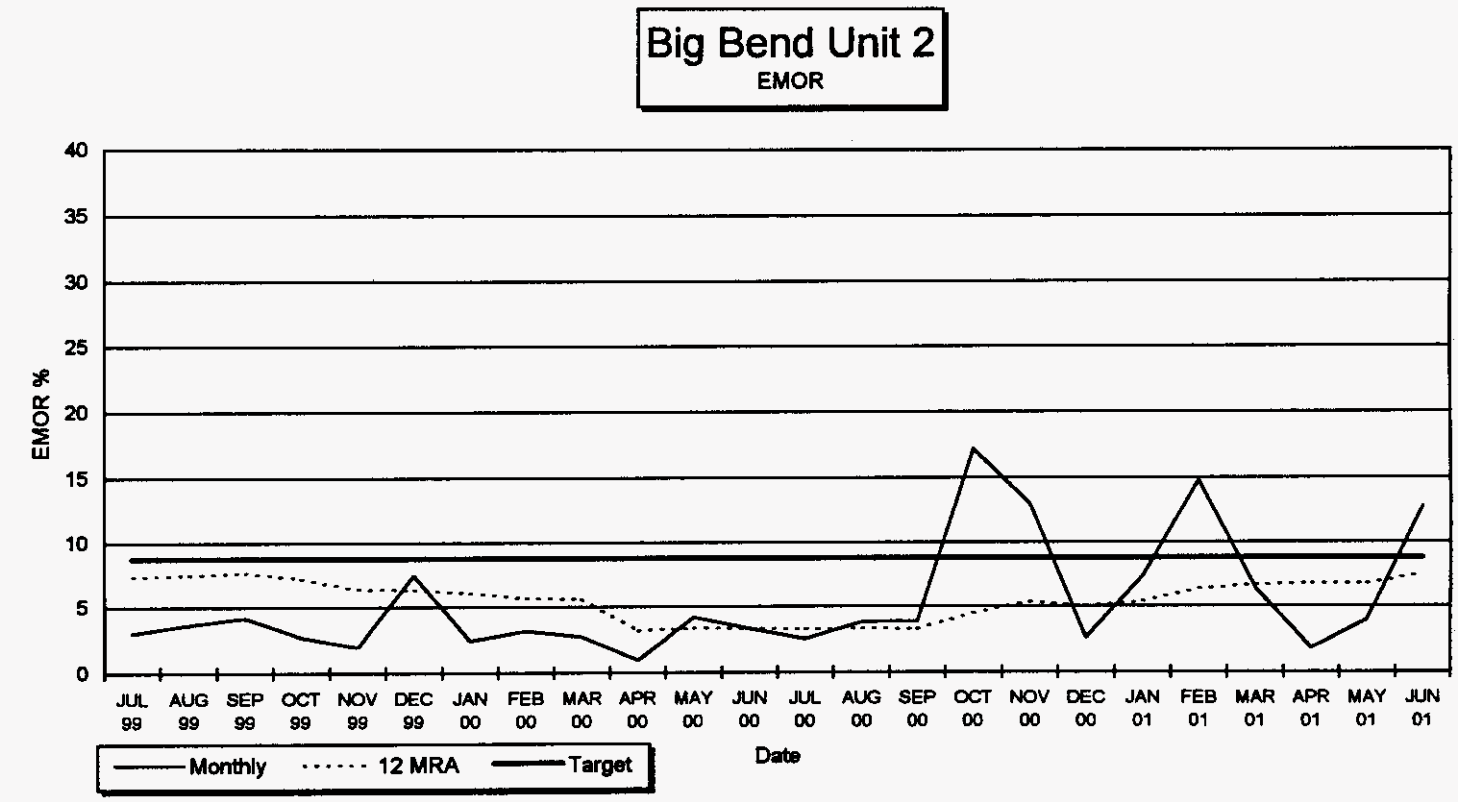
TAMPA ELECTRIC COMPANY
GANNON UNIT NUMBER 6
PLANNED OUTAGE 2002
PROJECTED CPM
09/20/2001



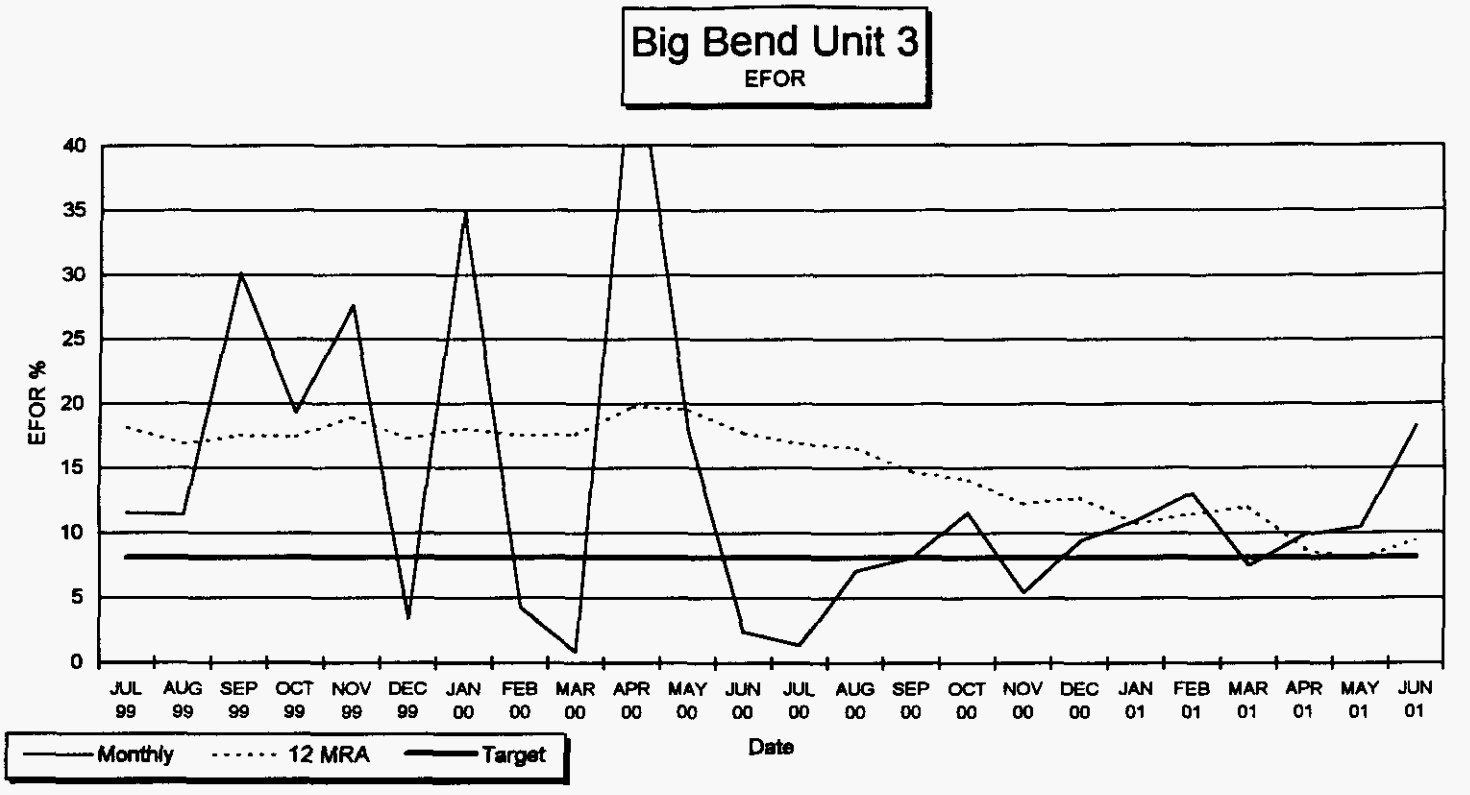


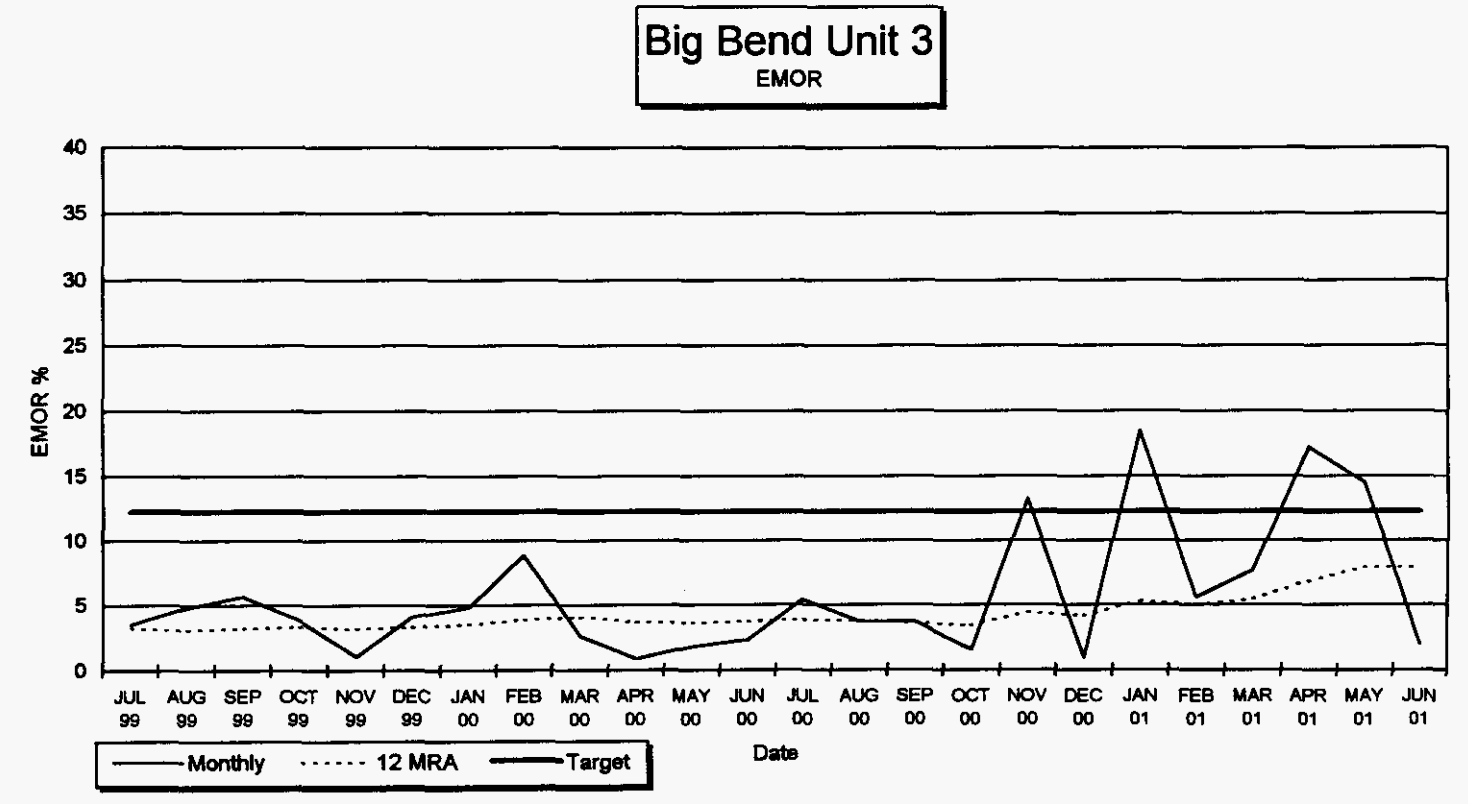
12 MRA = 12 Month Rolling Average



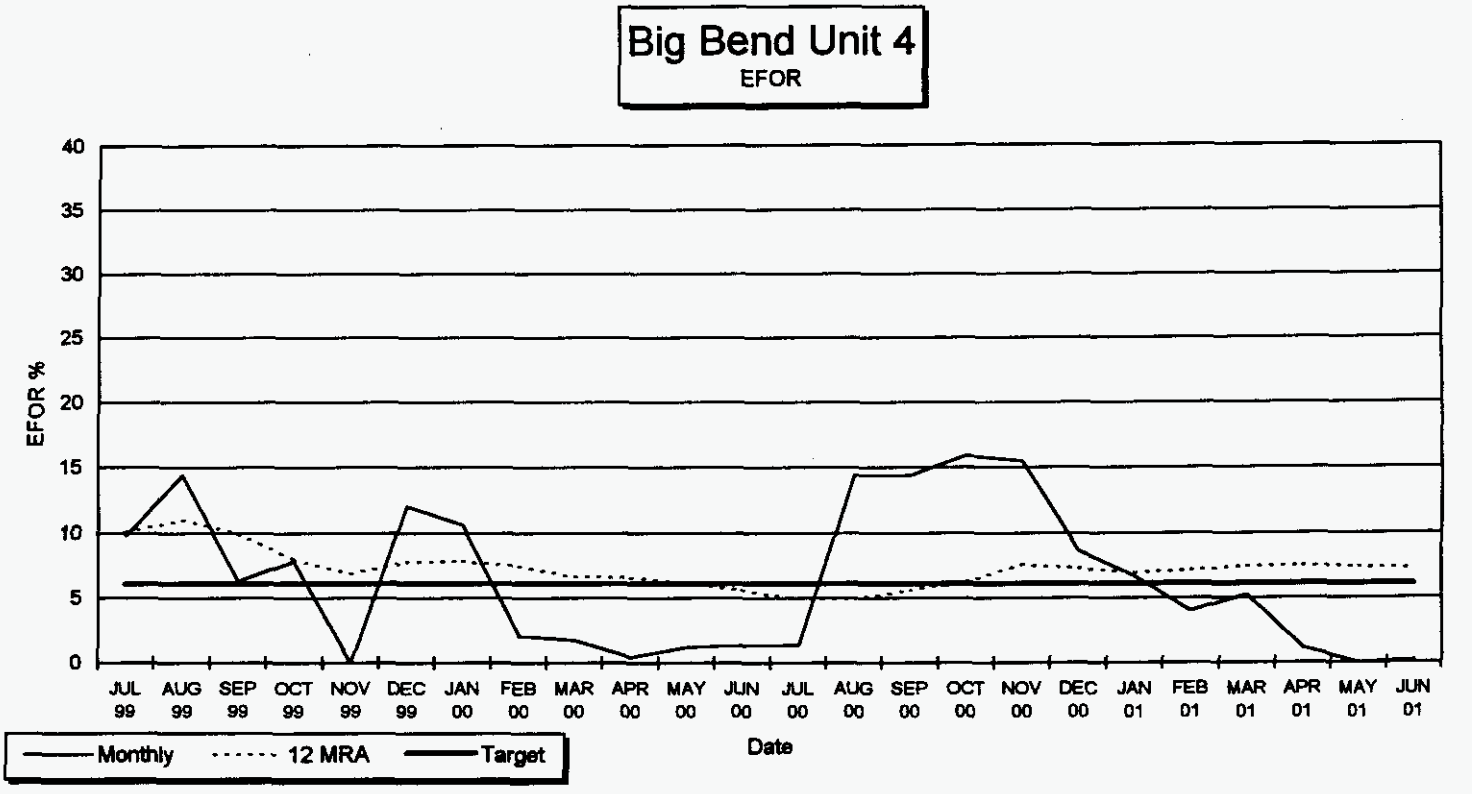


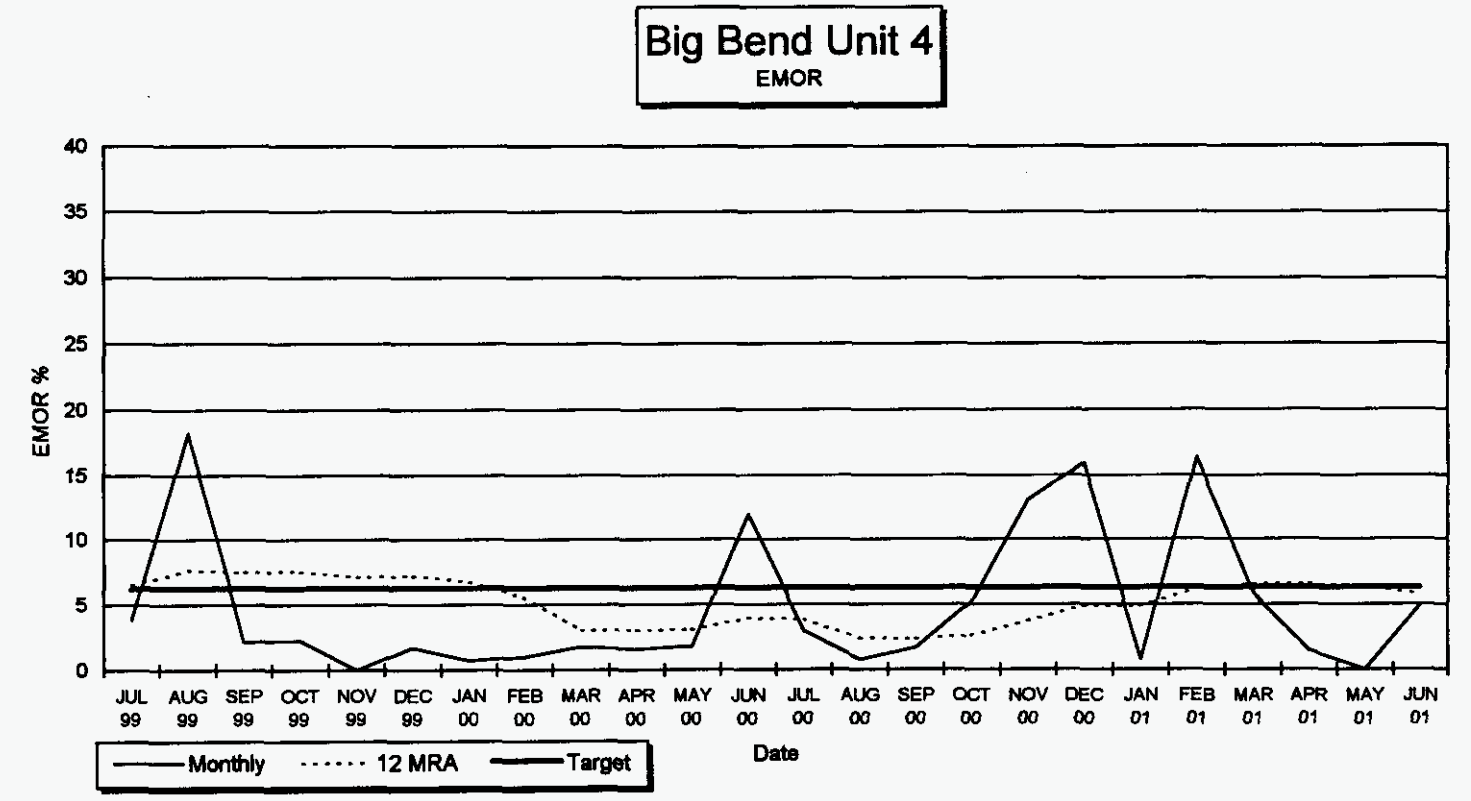
12 MRA = 12 Month Rolling Average



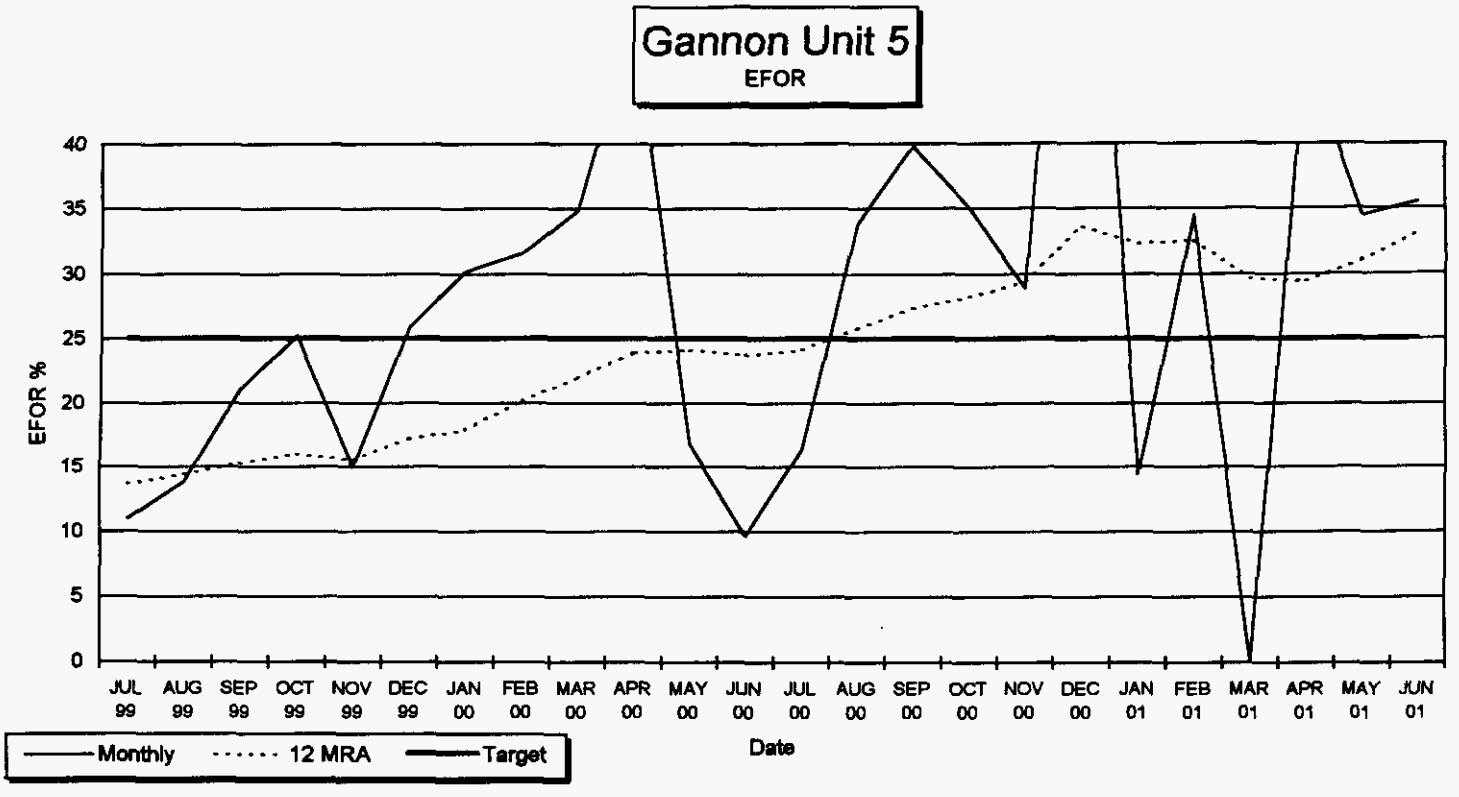


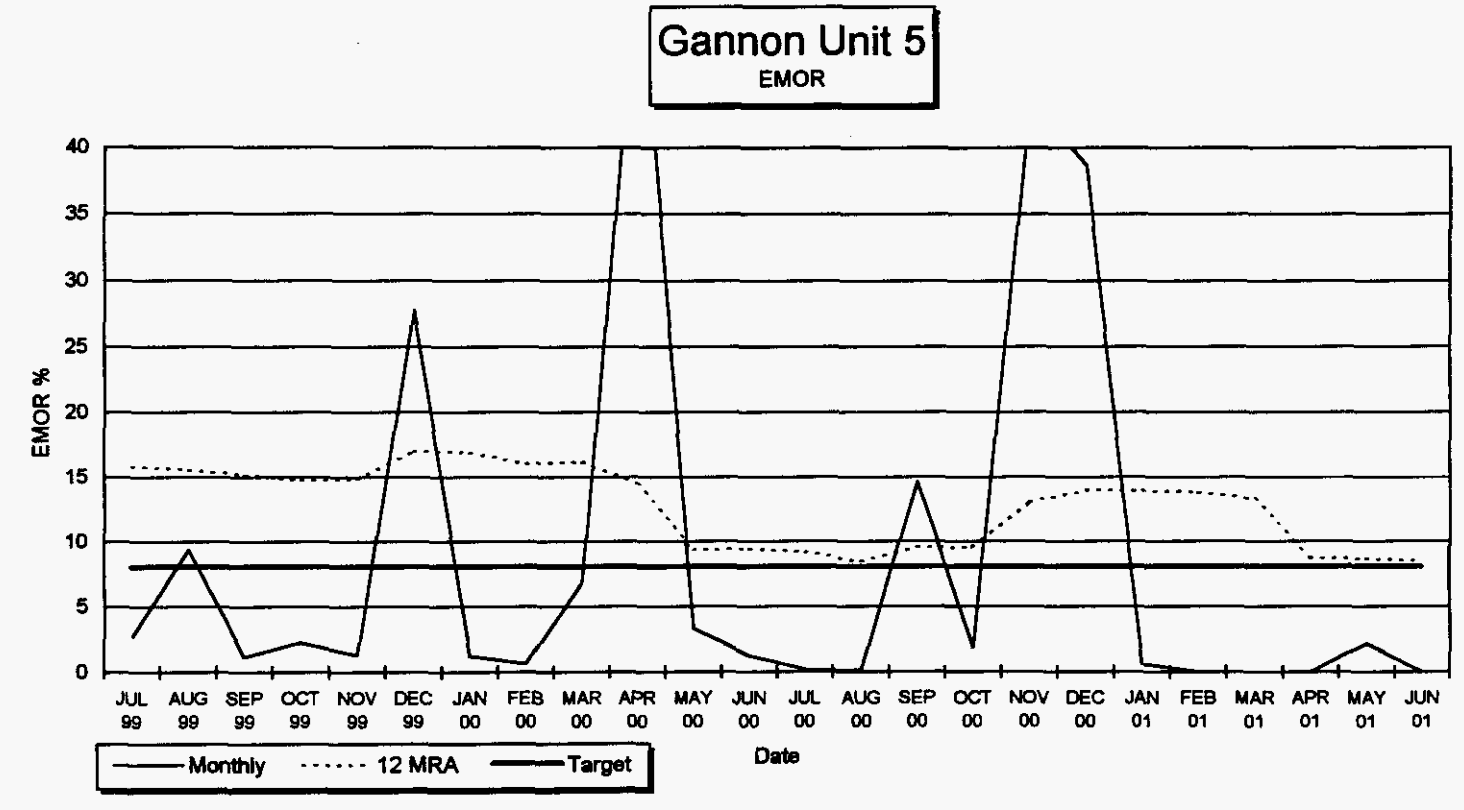
12 MRA = 12 Month Rolling Average



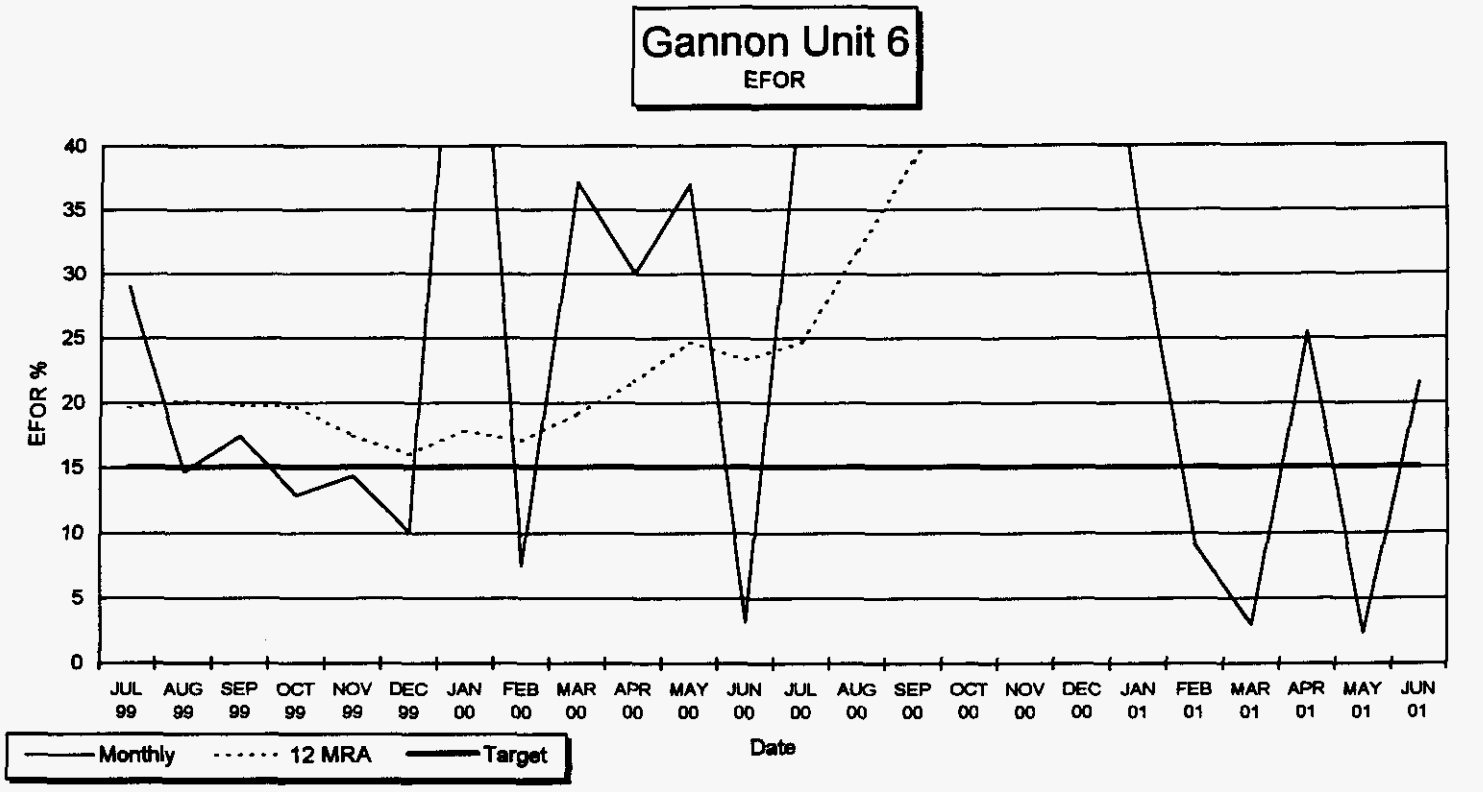


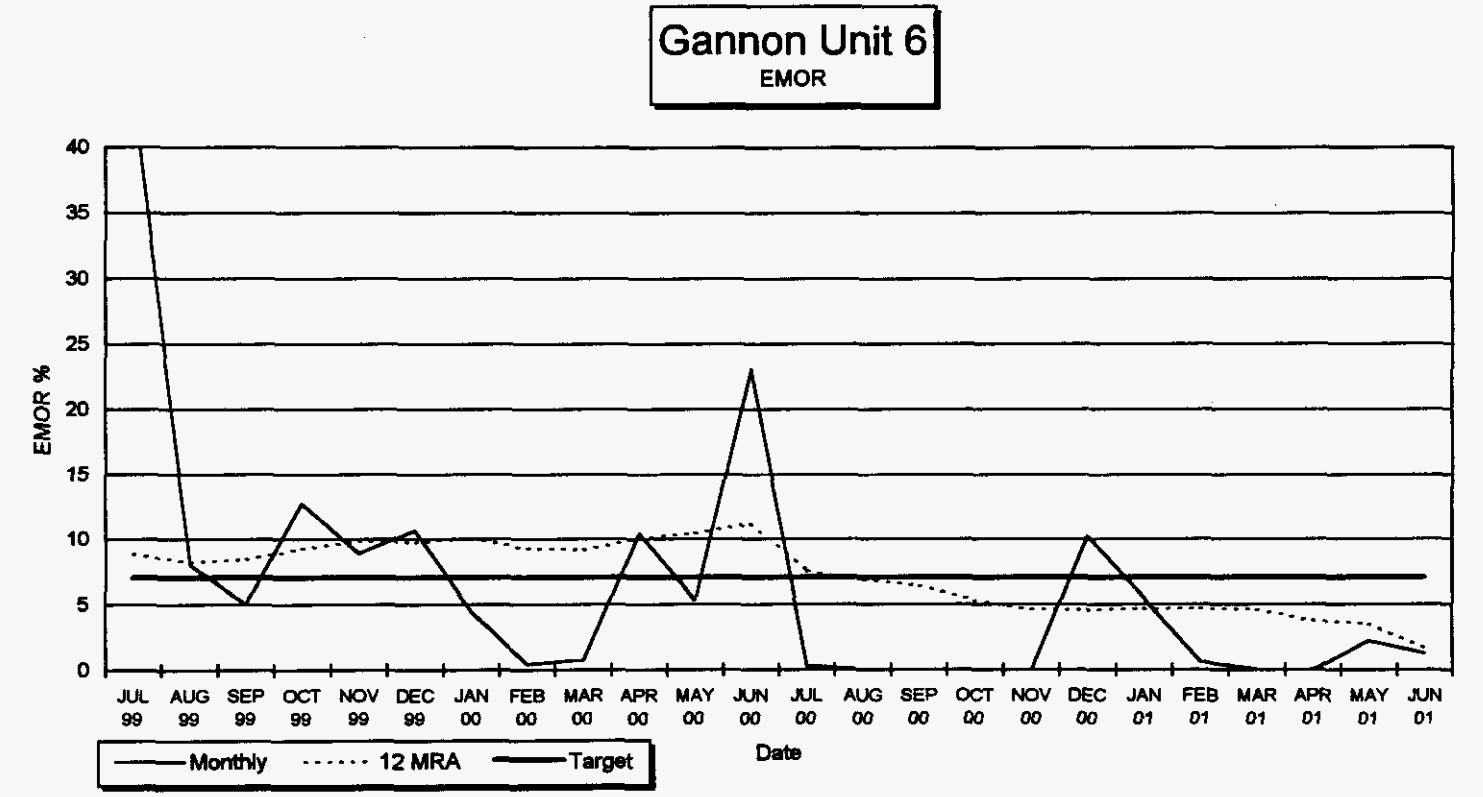
12 MRA = 12 Month Rolling Average



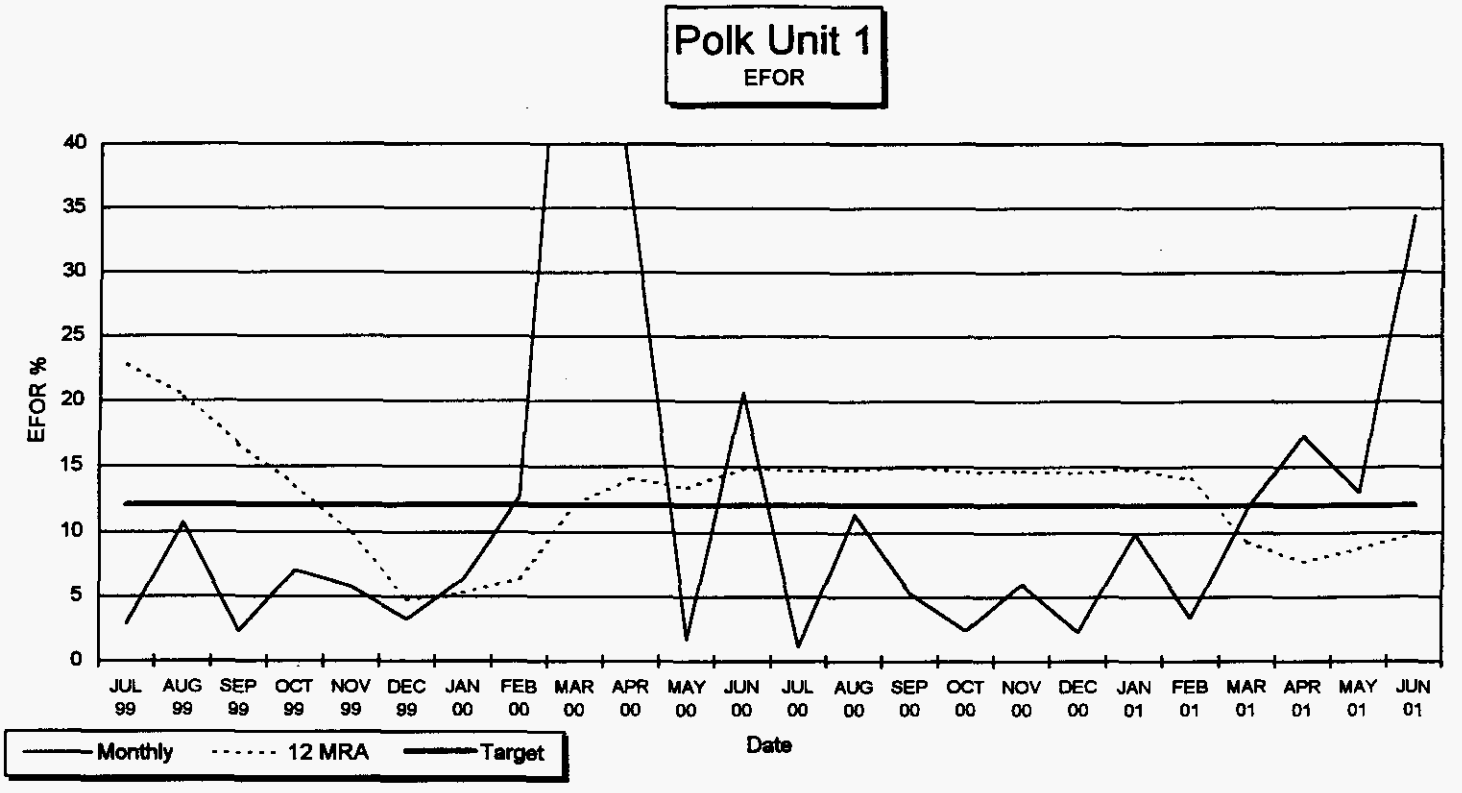


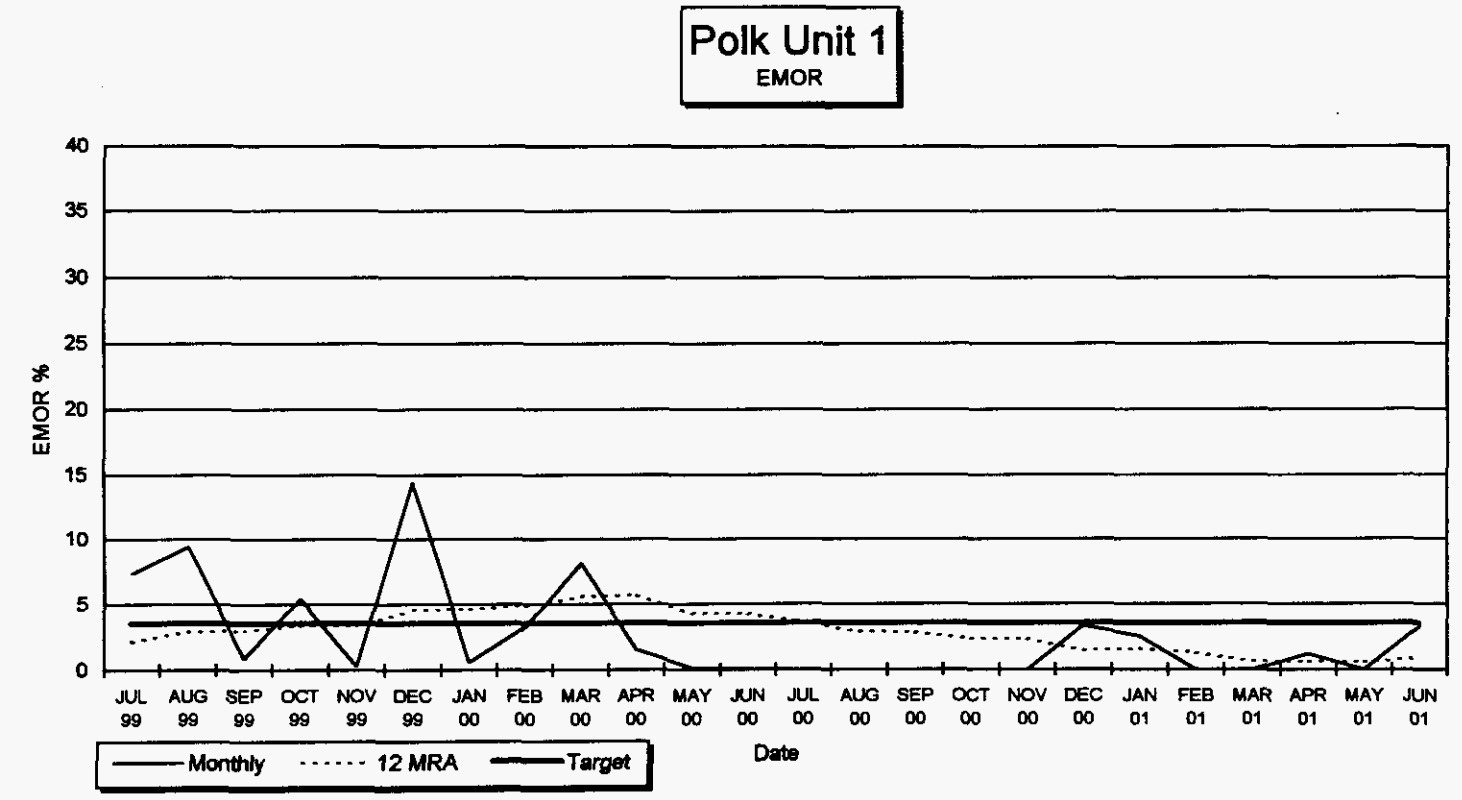
12 MRA = 12 Month Rolling Average





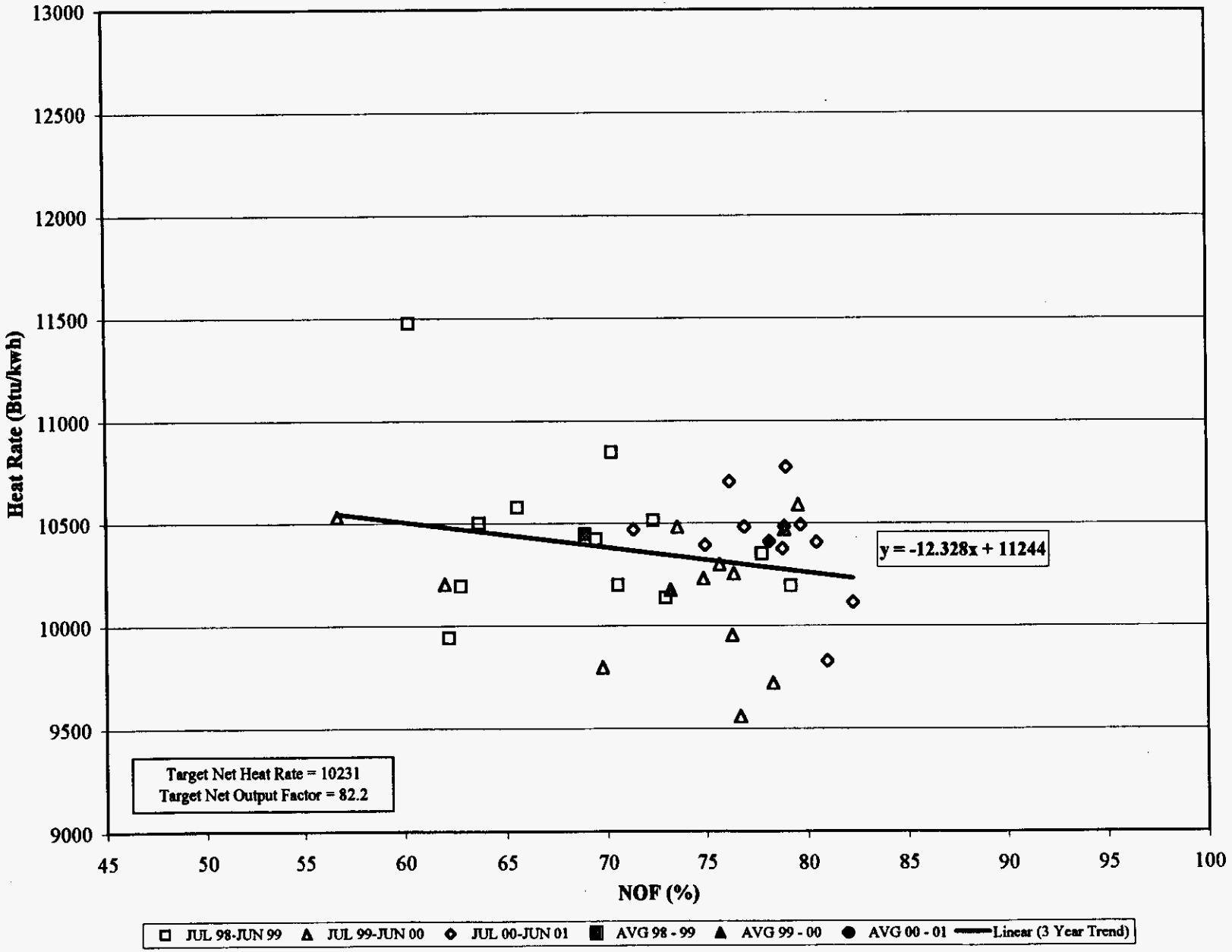
12 MRA = 12 Month Rolling Average



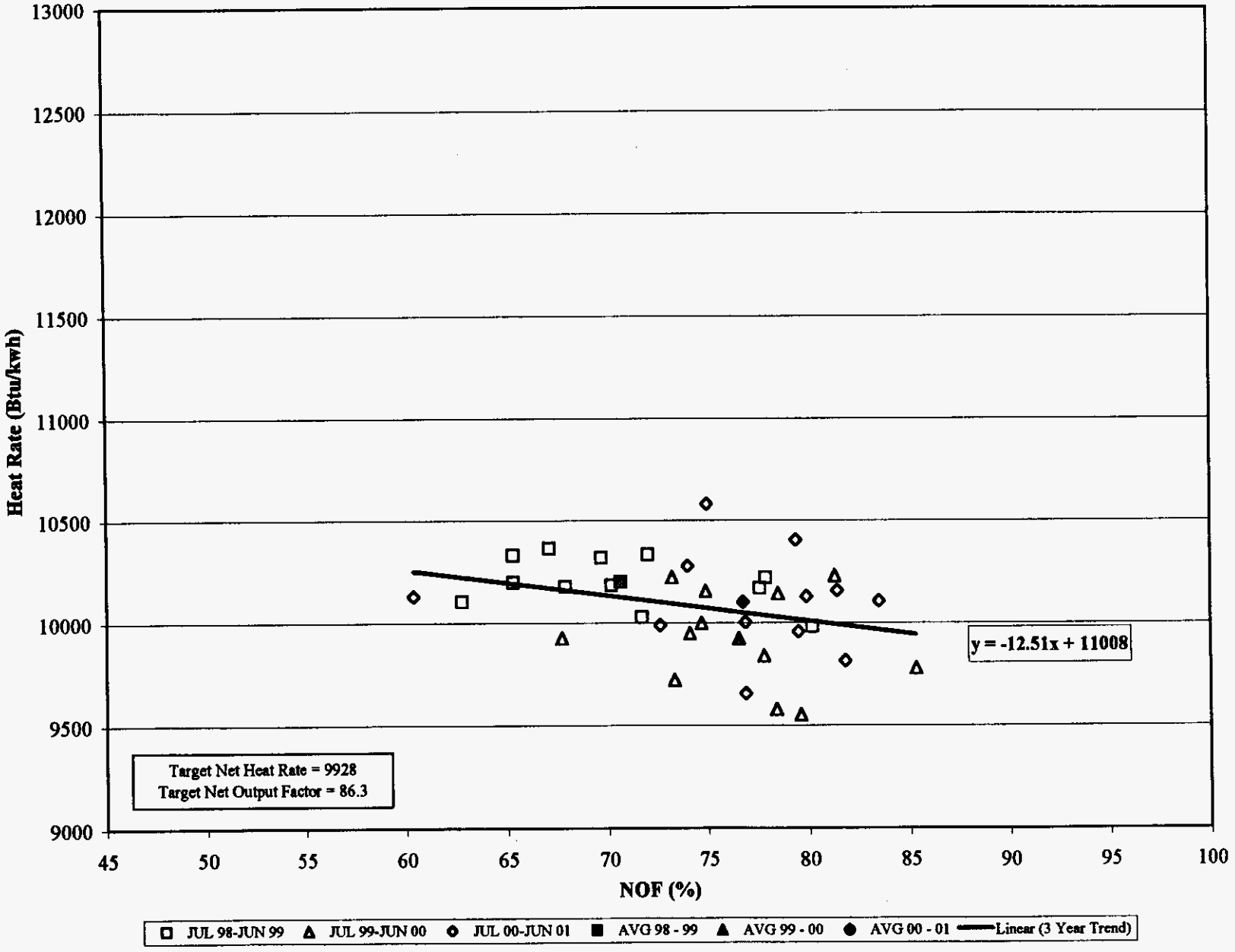


12 MRA = 12 Month Rolling Average

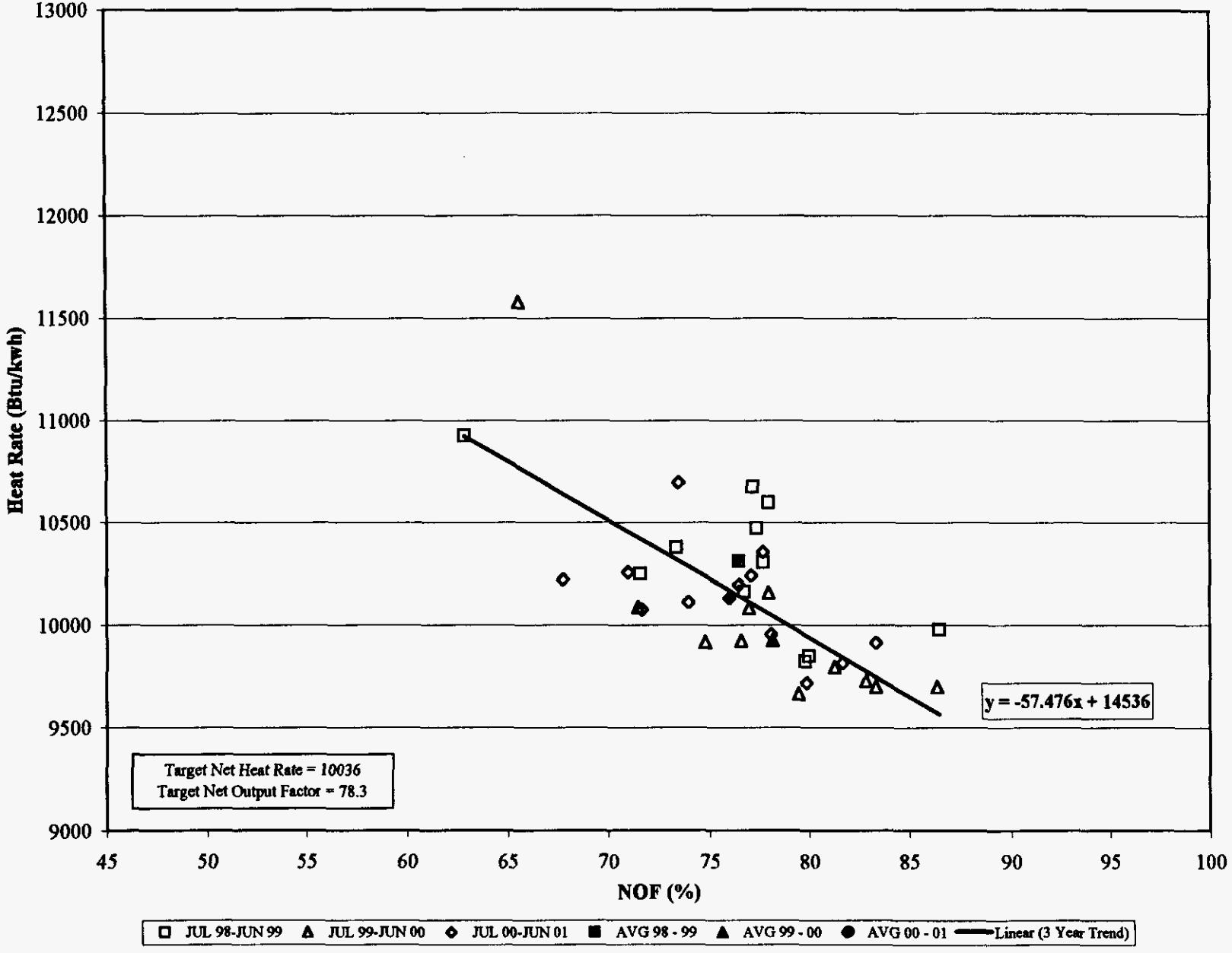
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #1



Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #2

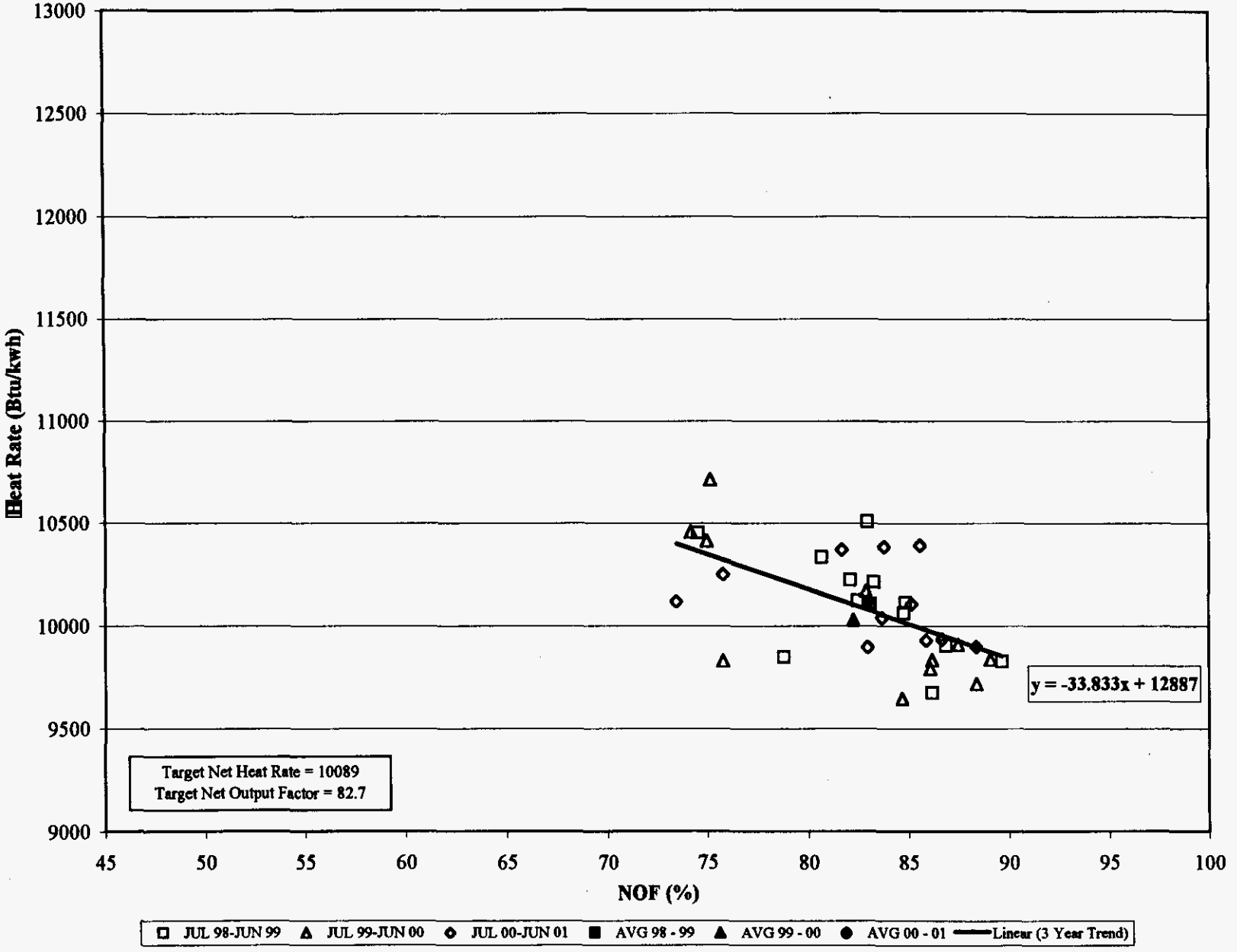


Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #3

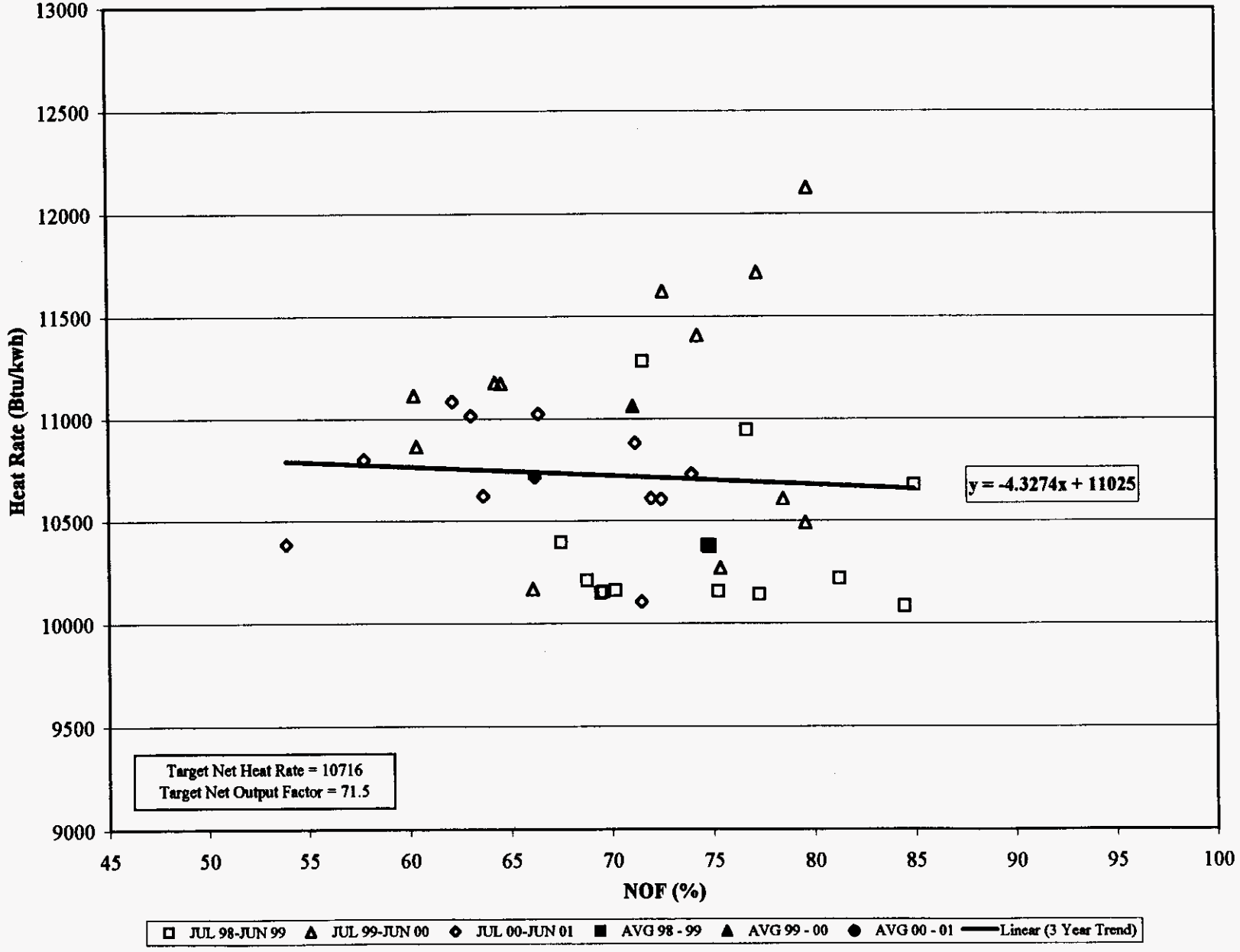


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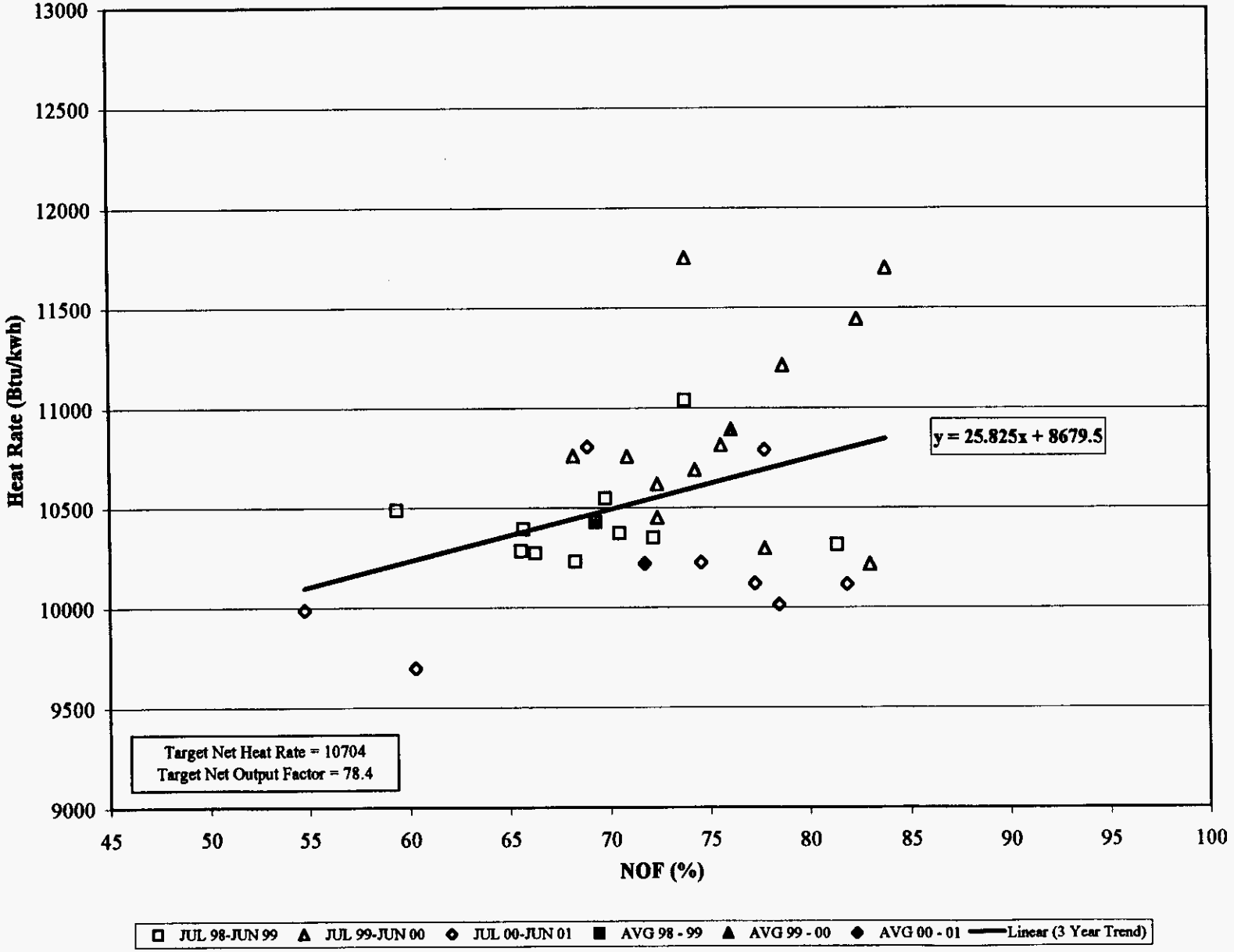
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #4



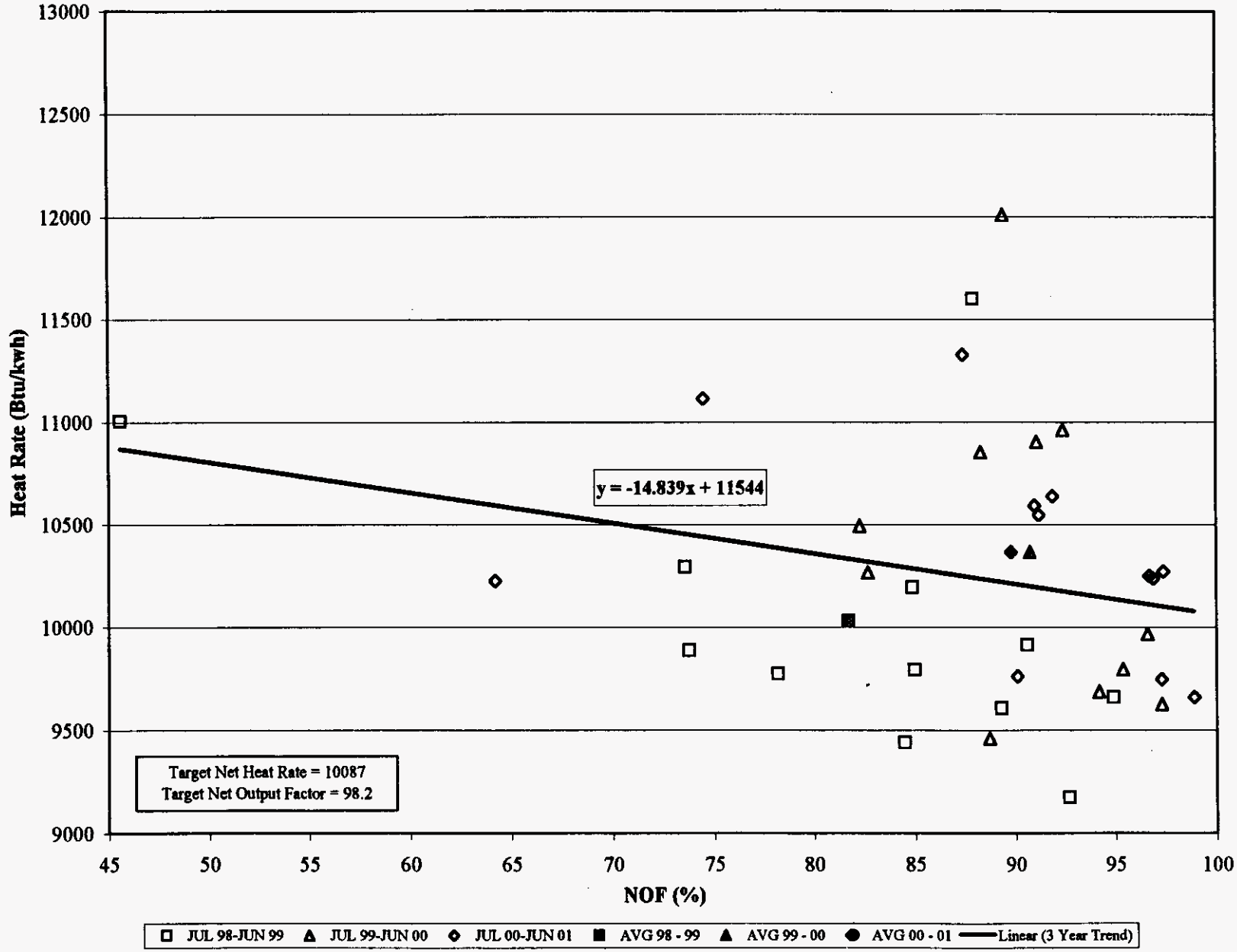
Tampa Electric Company
Heat Rate vs Net Output Factor
Gannon Unit #5



Tampa Electric Company
Heat Rate vs Net Output Factor
Gannon Unit #6



Tampa Electric Company
Heat Rate vs Net Output Factor
Polk Unit #1



TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2002 - DECEMBER 2002

PLANT / UNIT	ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1 w/o FGD	440	426
BIG BEND 2 w/o FGD	440	426
BIG BEND 3	450	433
BIG BEND 4	473	445
GANNON 5	230	217.5
GANNON 6	395	382
POLK 1	315	250
GPIF TOTAL	2743	2579
SYSTEM TOTAL	**3824**	**3624.5**
% OF SYSTEM TOTAL	**71.72%**	**71.15%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2002 - DECEMBER 2002

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
GANNON 1		120	114
GANNON 2		105	98
GANNON 3		155	145
GANNON 4		175	164
GANNON 5		230	217.5
GANNON 6		395	382
	GANNON TOTAL	1180	1120.5
BIG BEND 1 w/o FGD		440	426
BIG BEND 2 w/o FGD		440	426
BIG BEND 3		450	433
BIG BEND 4		473	445
	BIG BEND TOTAL	1803	1730
BIG BEND CT1		15	15
BIG BEND CT2		73	73
BIG BEND CT3		73	73
	CT TOTAL	160.5	160.5
PHILLIPS 1		18	17
PHILLIPS 2		18	17
	PHILLIPS TOTAL	36	34
POLK 1		315	250
POLK 2		165	165
POLK 3		165	165
	POLK TOTAL	645	580
	SYSTEM TOTAL	**3824**	**3625**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2002 - DECEMBER 2002

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BIG BEND	4	2,678,252	15.74%	15.74%
BIG BEND	1	2,567,761	15.09%	30.82%
BIG BEND	2	2,385,112	14.01%	44.84%
BIG BEND	3	2,164,880	12.72%	57.55%
GANNON	6	1,633,391	9.60%	67.15%
POLK	1	1,632,916	9.59%	76.74%
GANNON	5	834,032	4.90%	81.65%
GANNON	4	652,823	3.84%	85.48%
GANNON	3	608,896	3.58%	89.06%
GANNON	1	502,729	2.95%	92.01%
POLK	2	474,854	2.79%	94.80%
GANNON	2	361,526	2.12%	96.93%
POLK	3	277,939	1.63%	98.56%
PHILLIPS	1	67,659	0.40%	98.96%
PHILLIPS	2	64,179	0.38%	99.33%
BIG BEND CT	2	54,379	0.32%	99.65%
BIG BEND CT	3	50,380	0.30%	99.95%
BIG BEND CT	1	8,712	0.05%	100.00%
TOTAL GENERATION		17,020,420	100.00%	

GENERATION BY COAL UNITS: 16,022,318 MWH
% GENERATION BY COAL UNITS: 94.14%

GENERATION BY NATURAL GAS UNITS: 752,793 MWH
% GENERATION BY NATURAL GAS UNITS: 4.42%

GENERATION BY OIL UNITS: 245,309 MWH
% GENERATION BY OIL UNITS: 1.44%

GENERATION BY GPIF UNITS: 13,896,344 MWH
% GENERATION BY GPIF UNITS: 81.65%

EXHIBITS TO THE TESTIMONY OF

GEORGE A. KESELOWSKY

DOCKET NO. 010001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2002 - DECEMBER 2002

DOCUMENT NO. 1

PART B - UNIT PERFORMANCE DATA

TAMPA ELECTRIC COMPANY
ESTIMATED UNIT PERFORMANCE DATA
JANUARY 2002 - DECEMBER 2002
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BIG BEND 2 - ESTIMATED UNIT PERFORMANCE DATA	3
BIG BEND 3 - ESTIMATED UNIT PERFORMANCE DATA	4
BIG BEND 4 - ESTIMATED UNIT PERFORMANCE DATA	5
GANNON 1 - ESTIMATED UNIT PERFORMANCE DATA	6
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GANNON 3 - ESTIMATED UNIT PERFORMANCE DATA	8
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POLK 1 - ESTIMATED UNIT PERFORMANCE DATA	17
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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2002 - DECEMBER 2002

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 1 FADJ (w/ FGD)	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	80.2	43.0	77.7	80.3	80.2	80.3	80.2	80.2	80.3	80.3	80.3	80.2	77.2
2. POF	0.0	46.4	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8
3. EUOF	19.8	10.6	19.1	19.7	19.8	19.7	19.8	19.8	19.7	19.7	19.7	19.8	18.9
4. EUOR	19.8	19.7	19.7	19.7	19.8	19.7	19.8	19.8	19.7	19.7	19.7	19.8	19.7
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	653	315	614	623	653	626	645	644	632	653	632	644	7334
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	91	357	130	96	91	94	99	100	88	92	88	100	1426
9. POH	0	312	24	0	0	0	0	0	0	0	0	0	336
10. FOH & EFOH	65	31	63	63	65	63	65	65	63	65	63	65	733
11. MOH & EMOH	82	40	79	79	82	79	82	82	79	82	79	82	927
12. OPER BTU (GBTU)	2220.964	1117.153	2153.506	2168.629	2287.050	2252.829	2346.574	2349.387	2292.101	2298.891	2222.237	2253.594	25962.915
13. NET GEN (MWH)	219,162	110,206	211,098	212,847	222,883	219,187	226,492	226,762	223,051	225,679	218,051	222,343	2,537,761
14. ANOHR (Btu/kwh)	10,134	10,137	10,201	10,189	10,261	10,278	10,361	10,361	10,276	10,187	10,191	10,136	10,231
15. NOF (%)	78.8	82.0	80.7	82.1	82.1	84.1	84.4	84.6	84.9	81.2	81.0	81.0	82.2
16. NPC (MW)	426	426	426	416	416	416	416	416	416	426	426	426	421
17. ANOHR EQUATION	ANOHR = NOF(-12.328) + 11244												

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BIG BEND 2 FADJ (w/ FGD)	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	82.5	82.6	82.5	82.5	82.5	82.5	82.5	82.5	55.0	0.0	2.8	82.5	66.7
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.3	100.0	96.7	0.0	19.2
3. EUOF	17.5	17.4	17.5	17.5	17.5	17.5	17.5	17.5	11.7	0.0	0.6	17.5	14.1
4. EUOR	17.5	17.4	17.5	17.5	17.5	17.5	17.5	17.5	17.5	#DIV/0!	16.7	17.5	17.5
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	682	616	682	660	682	660	682	682	440	0	22	682	6487
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	62	56	62	59	62	60	62	62	280	745	698	62	2273
9. POH	0	0	0	0	0	0	0	0	240	745	696	0	1681
10. FOH & EFOH	65	59	65	63	65	63	65	65	42	0	2	65	623
11. MOH & EMOH	65	58	65	63	65	63	65	65	42	0	2	65	616
12. OPER BTU (GBTU)	2448.219	2274.744	2398.394	2309.441	2453.320	2396.963	2488.984	2489.211	1610.412	0.000	80.439	2435.281	23385.410
13. NET GEN (MWH)	246,809	229,392	242,333	233,660	247,631	241,084	249,193	249,205	162,060	0	8,106	245,639	2,355,112
14. ANOHR (Btu/kwh)	9,919	9,916	9,897	9,884	9,907	9,942	9,988	9,989	9,937	#DIV/0!	9,923	9,914	9,930
15. NOF (%)	85.0	87.5	83.5	85.1	87.3	87.8	87.9	87.9	88.5	#DIV/0!	87.2	84.6	86.2
16. NPC (MW)	426	426	426	416	416	416	416	416	416	426	426	426	421
17. ANOHR EQUATION	ANOHR = NOF(-12.51) + 11008												

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BIG BEND 3	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	79.7	79.8	2.6	10.4	79.7	79.7	79.7	79.7	79.7	79.7	79.7	79.7	67.5
2. POF	0.0	0.0	96.8	86.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3
3. EUOF	20.3	20.2	0.7	2.8	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	17.2
4. EUOR	20.3	20.2	20.8	21.1	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	562	592	22	79	658	628	649	649	636	644	622	643	6383
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	182	80	722	640	86	92	95	95	84	101	98	101	2377
9. POH	0	0	720	624	0	0	0	0	0	0	0	0	1344
10. FOH & EFOH	60	54	2	8	60	58	60	60	58	60	58	60	601
11. MOH & EMOH	91	82	3	12	91	88	91	91	88	91	88	91	905
12. OPER BTU (GBTU)	1752.441	2010.356	79.059	218.753	2090.826	2213.359	2283.025	2305.535	2322.122	2170.584	2194.868	2085.003	21725.933
13. NET GEN (MWH)	175,015	201,224	7,910	21,612	208,430	220,566	225,390	227,683	231,809	216,688	220,175	208,378	2,164,880
14. ANOHR (Btu/kwh)	10,013	9,991	9,995	10,122	10,031	10,035	10,129	10,126	10,017	10,017	9,969	10,006	10,036
15. NOF (%)	72.0	78.5	84.3	62.8	73.2	81.1	80.2	81.0	84.2	77.8	81.8	74.9	78.3
16. NPC (MW)	433	433	433	433	433	433	433	433	433	433	433	433	433
17. ANOHR EQUATION	ANOHR = NOF(-57.476) + 14536												

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BIG BEND 4	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	87.8	87.6	87.8	87.6	87.8	87.6	87.8	87.8	87.6	87.8	84.9	31.2	82.6
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	64.5	5.8
3. EUOF	12.2	12.4	12.2	12.4	12.2	12.4	12.2	12.2	12.4	12.2	11.8	4.3	11.6
4. EUOR	12.2	12.4	12.2	12.4	12.2	12.4	12.2	12.2	12.4	12.2	12.2	12.1	12.3
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	691	570	646	645	603	625	672	671	665	687	616	197	7287
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	53	102	98	74	141	95	72	73	55	58	104	547	1473
9. POH	0	0	0	0	0	0	0	0	0	0	24	480	504
10. FOH & EFOH	45	41	45	44	45	44	45	45	44	45	42	16	504
11. MOH & EMOH	46	42	46	45	46	45	46	46	45	46	43	16	512
12. OPER BTU (GBTU)	2481.054	2034.728	2329.232	2343.517	2148.367	2351.869	2557.026	2568.677	2523.161	2692.294	2287.650	703.338	27020.914
13. NET GEN (MWH)	247,723	202,839	231,577	233,507	212,788	231,752	250,787	251,891	248,921	268,698	227,633	70,136	2,678,252
14. ANOHR (Btu/kwh)	10,015	10,031	10,058	10,036	10,096	10,148	10,196	10,198	10,136	10,020	10,050	10,028	10,089
15. NOF (%)	80.2	79.7	80.2	82.0	79.8	83.8	84.5	85.0	84.7	87.4	82.7	79.8	82.7
16. NPC (MW)	447	447	447	442	442	442	442	442	442	447	447	447	445
17. ANOHR EQUATION	ANOHR = NOF(-33.833) + 12887												

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GANNON 1	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	75.0	75.0	70.2	9.9	75.0	75.0	75.0	75.0	75.0	58.1	40.0	75.0	64.9
2. POF	0.0	0.0	6.5	86.8	0.0	0.0	0.0	0.0	0.0	22.6	46.7	0.0	13.4
3. EUOF	25.0	25.0	23.4	3.3	25.0	25.0	25.0	25.0	25.0	19.3	13.3	25.0	21.6
4. EUOR	25.0	25.0	25.0	25.3	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	455	464	415	55	432	486	481	486	520	394	249	470	4908
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	289	208	329	664	312	234	263	258	200	351	471	274	3852
9. POH	0	0	48	624	0	0	0	0	0	168	336	0	1176
10. FOH & EFOH	134	121	125	17	134	130	134	134	130	104	69	134	1365
11. MOH & EMOH	52	47	49	7	52	50	52	52	50	40	27	52	531
12. OPER BTU (GBTU)	497.049	537.396	482.306	66.927	498.186	588.222	578.656	585.663	633.525	476.432	301.355	526.813	5772.530
13. NET GEN (MWH)	43,403	47,196	42,173	5,856	43,119	50,829	49,973	50,593	55,129	41,799	26,532	46,127	502,729
14. ANOHR (Btu/kwh)	11,452	11,386	11,436	11,429	11,554	11,573	11,579	11,576	11,492	11,398	11,358	11,421	11,482
15. NOF (%)	83.6	89.3	89.1	93.9	87.5	91.8	91.0	91.4	93.0	93.1	93.4	86.0	89.9
16. NPC (MW)	114	114	114	114	114	114	114	114	114	114	114	114	114

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GANNON 2	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	41.3	32.9	71.0	54.4	71.0	71.1	71.0	71.0	71.1	55.0	37.9	71.0	60.1
2. POF	41.9	53.6	0.0	23.4	0.0	0.0	0.0	0.0	0.0	22.6	46.7	0.0	15.3
3. EUOF	16.8	13.5	29.0	22.3	29.0	28.9	29.0	29.0	28.9	22.4	15.4	29.0	24.6
4. EUOR	28.9	29.2	29.0	29.0	29.0	28.9	29.0	29.0	28.9	28.9	28.9	29.0	29.0
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	199	156	370	305	313	372	387	393	430	440	217	371	3951
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	545	516	374	414	431	348	357	351	290	305	503	373	4809
9. POH	312	360	0	168	0	0	0	0	0	168	336	0	1344
10. FOH & EFOH	95	69	164	121	164	158	164	164	158	127	84	164	1632
11. MOH & EMOH	30	22	52	39	52	50	52	52	50	40	27	52	519
12. OPER BTU (GBTU)	199.303	167.654	402.256	347.531	342.310	434.186	448.724	456.375	498.846	498.346	245.162	379.546	4420.239
13. NET GEN (MWH)	16,657	14,126	33,334	28,717	27,559	34,588	35,703	36,332	40,577	41,525	20,591	31,817	361,526
14. ANOHR (Btu/kwh)	11,965	11,868	12,067	12,102	12,421	12,553	12,568	12,561	12,294	12,001	11,906	11,929	12,227
15. NOF (%)	85.6	92.4	92.0	96.2	89.9	94.9	94.1	94.4	96.3	96.3	97.0	87.6	93.4
16. NPC (MW)	98	98	98	98	98	98	98	98	98	98	98	98	98

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GANNON 3	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	71.0	71.0	71.0	54.4	71.0	71.1	71.0	71.0	63.9	13.8	71.1	71.0	64.2
2. POF	0.0	0.0	0.0	23.4	0.0	0.0	0.0	0.0	10.0	80.5	0.0	0.0	9.6
3. EUOF	29.0	29.0	29.0	22.3	29.0	28.9	29.0	29.0	26.1	5.6	28.9	29.0	26.2
4. EUOR	29.0	29.0	29.0	29.0	29.0	28.9	29.0	29.0	29.0	29.0	28.9	29.0	29.0
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	473	442	431	320	382	444	457	457	413	87	442	460	4808
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	271	230	313	399	362	276	287	287	307	658	278	284	3952
9. POH	0	0	0	168	0	0	0	0	72	600	0	0	840
10. FOH & EFOH	164	148	164	121	164	158	164	164	143	32	158	164	1742
11. MOH & EMOH	52	47	52	39	52	50	52	52	45	10	50	52	554
12. OPER BTU (GBTU)	696.415	679.911	659.506	499.324	561.854	690.950	706.895	708.716	649.411	137.683	683.537	691.909	7366.111
13. NET GEN (MWH)	57,783	56,639	54,755	41,356	46,016	56,700	57,971	58,139	53,588	11,460	56,951	57,538	608,896
14. ANOHR (Btu/kwh)	12,052	12,004	12,045	12,074	12,210	12,186	12,194	12,190	12,119	12,014	12,002	12,025	12,097
15. NOF (%)	84.3	88.4	87.5	89.1	83.1	88.1	87.5	87.8	89.5	90.9	88.8	86.2	87.3
16. NPC (MW)	145	145	145	145	145	145	145	145	145	145	145	145	145

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GANNON 4	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	65.1	64.9	65.1	65.1	65.1	65.0	65.1	65.1	65.0	52.5	17.4	65.1	60.0
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.3	73.3	0.0	7.7
3. EUOF	34.9	35.1	34.9	34.9	34.9	35.0	34.9	34.9	35.0	28.2	9.3	34.9	32.3
4. EUOR	34.9	35.1	34.9	34.9	34.9	35.0	34.9	34.9	35.0	34.9	34.9	34.9	35.0
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	457	421	419	408	436	398	408	409	441	353	110	445	4706
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	287	251	325	311	308	322	336	335	279	392	610	299	4054
9. POH	0	0	0	0	0	0	0	0	0	144	528	0	672
10. FOH & EFOH	171	155	171	165	171	166	171	171	166	138	44	171	1860
11. MOH & EMOH	89	81	89	86	89	86	89	89	86	72	23	89	971
12. OPER BTU (GBTU)	745.656	725.323	719.441	683.443	631.046	669.060	680.220	684.734	747.418	595.647	196.615	745.802	7824.405
13. NET GEN (MWH)	61,946	60,575	59,766	56,538	58,233	54,660	55,503	55,904	61,563	49,570	16,432	62,133	652,823
14. ANOHR (Btu/kwh)	12,037	11,974	12,038	12,088	10,837	12,240	12,256	12,248	12,141	12,016	11,965	12,003	11,985
15. NOF (%)	80.3	85.1	84.3	87.1	83.9	86.5	85.5	85.9	87.8	83.2	88.1	82.6	84.6
16. NPC (MW)	169	169	169	159	159	159	159	159	159	169	169	169	164

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GANNON 5	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	66.9	35.9	0.0	40.2	66.9	66.9	66.9	66.9	66.9	67.0	66.9	66.9	56.7
2. POF	0.0	46.4	100.0	40.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3
3. EUOF	33.1	17.7	0.0	19.7	33.1	33.1	33.1	33.1	33.1	33.0	33.1	33.1	27.9
4. EUOR	33.1	33.1	0.0	32.9	33.1	33.1	33.1	33.1	33.1	33.0	33.1	33.1	33.0
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	538	261	0	311	538	521	538	538	521	538	521	538	5361
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	206	411	744	408	206	199	206	206	199	207	199	206	3399
9. POH	0	312	744	288	0	0	0	0	0	0	0	0	1344
10. FOH & EFOH	186	90	0	108	186	180	186	186	180	186	180	186	1854
11. MOH & EMOH	60	29	0	34	60	58	60	60	58	60	58	60	593
12. OPER BTU (GBTU)	859.534	433.307	0.000	506.387	847.046	891.330	899.839	905.256	923.239	944.017	863.521	863.669	8937.146
13. NET GEN (MWH)	82,068	41,414	0	47,252	77,777	81,330	81,938	82,477	85,615	89,514	82,208	82,439	834,032
14. ANOHR (Btu/kwh)	10,473	10,463	0	10,717	10,891	10,959	10,982	10,976	10,784	10,546	10,504	10,476	10,716
15. NOF (%)	67.2	70.0	0.0	73.0	69.5	75.1	73.2	73.7	79.1	73.3	69.6	67.5	71.5
16. NPC (MW)	227	227	227	208	208	208	208	208	208	227	227	227	218
17. ANOHR EQUATION	ANOHR = NOF(-4.3274) + 11025												

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TAMPA ELECTRIC COMPANY

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GANNON 6	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	78.0	78.0	78.0	67.6	62.9	78.1	78.0	78.0	78.1	45.4	0.0	45.3	63.9
2. POF	0.0	0.0	0.0	13.4	19.4	0.0	0.0	0.0	0.0	41.9	100.0	41.9	18.1
3. EUOF	22.0	22.0	22.0	19.1	17.7	21.9	22.0	22.0	21.9	12.8	0.0	12.8	18.0
4. EUOR	22.0	22.0	22.0	22.0	22.0	21.9	22.0	22.0	21.9	21.9	0.0	22.0	22.0
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	565	511	565	475	456	547	565	565	547	329	0	328	5454
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	179	161	179	244	288	173	179	179	173	416	720	416	3307
9. POH	0	0	0	96	144	0	0	0	0	312	720	312	1584
10. FOH & EFOH	112	101	112	93	90	108	112	112	108	65	0	65	1076
11. MOH & EMOH	52	47	52	44	42	50	52	52	50	30	0	30	502
12. OPER BTU (GBTU)	1771.122	1642.639	1816.412	1492.794	1372.987	1761.459	1819.788	1832.828	1830.106	1090.587	0.000	1053.391	17484.111
13. NET GEN (MWH)	167,645	155,198	170,436	139,572	127,028	162,603	168,152	169,458	170,362	103,191	0	99,746	1,633,391
14. ANOHR (Btu/kwh)	10,565	10,584	10,657	10,696	10,809	10,833	10,822	10,816	10,742	10,569	0	10,561	10,704
15. NOF (%)	75.6	77.5	76.9	79.0	74.9	79.9	80.0	80.6	83.7	80.1	0.0	77.7	78.4
16. NPC (MW)	392	392	392	372	372	372	372	372	372	392	392	392	382
17. ANOHR EQUATION	ANOHR = NOF(25.825) + 8679.5												

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PHILLIPS 1	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	91.0	90.9	85.1	54.5	91.0	91.0	91.0	91.0	91.0	91.0	91.0	91.0	87.5
2. POF	0.0	0.0	6.5	40.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8
3. EUOF	9.0	9.1	8.5	5.4	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	8.7
4. EUOR	9.0	9.1	9.1	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	178	190	276	166	252	373	448	455	534	454	416	356	4098
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	566	482	468	553	492	347	296	289	186	291	304	388	4662
9. POH	0	0	48	288	0	0	0	0	0	0	0	0	336
10. FOH & EFOH	30	27	28	17	30	29	30	30	29	30	29	30	337
11. MOH & EMOH	37	34	35	22	37	36	37	37	36	37	36	37	421
12. OPER BTU (GBTU)	27.576	29.579	43.248	25.412	37.076	58.672	68.757	70.271	83.482	70.663	65.023	52.670	632.430
13. NET GEN (MWH)	2,948	3,162	4,623	2,719	3,975	6,271	7,358	7,519	8,927	7,557	6,953	5,647	67,659
14. ANOHR (Btu/kwh)	9,354	9,355	9,355	9,346	9,327	9,356	9,345	9,346	9,352	9,351	9,352	9,327	9,347
15. NOF (%)	97.3	98.0	98.4	96.4	92.7	98.9	96.7	97.3	98.4	98.0	98.2	93.4	97.1
16. NPC (MW)	17	17	17	17	17	17	17	17	17	17	17	17	17

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PHILLIPS 2	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	91.0	90.9	91.0	36.4	41.1	91.0	91.0	91.0	91.0	91.0	91.0	91.0	82.3
2. POF	0.0	0.0	0.0	60.1	54.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.6
3. EUOF	9.0	9.1	9.0	3.5	4.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	8.1
4. EUOR	9.0	9.1	9.0	8.7	8.9	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	174	186	275	125	108	369	444	451	530	450	413	348	3872
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	570	486	469	594	636	351	300	294	190	295	307	396	4888
9. POH	0	0	0	432	408	0	0	0	0	0	0	0	840
10. FOH & EFOH	30	27	30	11	13	29	30	30	29	30	29	30	317
11. MOH & EMOH	37	34	37	14	17	36	37	37	36	37	36	37	396
12. OPER BTU (GBTU)	27.024	29.149	43.146	19.150	15.893	58.195	68.244	69.711	82.968	70.158	64.527	51.784	599.948
13. NET GEN (MWH)	2,889	3,116	4,612	2,049	1,704	6,220	7,303	7,459	8,872	7,503	6,900	5,552	64,179
14. ANOHR (Btu/kwh)	9,354	9,355	9,355	9,346	9,327	9,356	9,345	9,346	9,352	9,351	9,352	9,327	9,348
15. NOF (%)	97.8	98.3	98.7	96.5	93.2	99.1	96.8	97.4	98.5	98.1	98.4	93.7	97.5
16. NPC (MW)	17	17	17	17	17	17	17	17	17	17	17	17	17

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BIG BEND CT1	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	64.9	51.0	62.9	65.0	64.9	65.0	64.9	64.9	65.0	65.0	65.0	64.9	63.8
2. POF	0.0	21.4	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9
3. EUOF	35.1	27.5	33.9	35.0	35.1	35.0	35.1	35.1	35.0	35.0	35.0	35.1	34.3
4. EUOR	35.1	35.0	35.0	35.0	35.1	35.0	35.1	35.1	35.0	35.0	35.0	35.1	35.0
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	12	16	32	70	15	95	128	107	61	48	54	23	661
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	732	656	712	649	729	625	616	637	659	697	666	721	8099
9. POH	0	144	24	0	0	0	0	0	0	0	0	0	168
10. FOH & EFOH	149	106	144	144	149	144	149	149	144	149	144	149	1718
11. MOH & EMOH	112	79	108	108	112	108	112	112	108	112	108	112	1289
12. OPER BTU (GBTU)	3.655	4.848	9.632	16.344	3.391	22.119	29.735	24.898	14.342	14.386	16.392	6.680	166.422
13. NET GEN (MWH)	203	269	535	831	172	1,120	1,507	1,264	729	800	912	370	8,712
14. ANOHR (Btu/kwh)	18,005	18,022	18,004	19,668	19,715	19,749	19,731	19,698	19,674	17,983	17,974	18,054	19,103
15. NOF (%)	97.6	97.7	97.8	99.0	98.5	97.8	98.1	98.7	99.0	98.6	98.5	96.6	90.9
16. NPC (MW)	17	17	17	12	12	12	12	12	12	17	17	17	15

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BIG BEND CT2	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	69.1	69.0	53.5	69.1	69.1	68.9	69.1	69.1	68.9	69.1	68.9	69.1	67.7
2. POF	0.0	0.0	22.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9
3. EUOF	30.9	31.0	23.9	30.9	30.9	31.1	30.9	30.9	31.1	30.9	31.1	30.9	30.4
4. EUOR	30.9	31.0	30.9	30.9	30.9	31.1	30.9	30.9	31.1	30.9	31.1	30.9	31.0
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	18	29	34	83	19	116	154	140	75	55	64	36	823
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	726	643	710	636	725	604	590	604	645	690	656	708	7937
9. POH	0	0	168	0	0	0	0	0	0	0	0	0	168
10. FOH & EFOH	115	104	89	111	115	112	115	115	112	115	112	115	1332
11. MOH & EMOH	115	104	89	111	115	112	115	115	112	115	112	115	1332
12. OPER BTU (GBTU)	19.763	32.721	39.618	83.325	18.278	116.638	154.330	135.857	74.340	65.630	75.826	39.661	855.987
13. NET GEN (MWH)	1,269	2,102	2,553	5,279	1,155	7,377	9,767	8,510	4,685	4,242	4,905	2,535	54,379
14. ANOHR (Btu/kwh)	15,574	15,567	15,518	15,784	15,825	15,811	15,801	15,964	15,868	15,471	15,459	15,645	15,741
15. NOF (%)	90.5	90.8	93.6	96.0	94.3	96.0	96.4	92.1	94.6	95.9	95.4	87.6	90.5
16. NPC (MW)	80	80	80	66	66	66	66	66	66	80	80	80	73

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BIG BEND CT3	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	69.1	69.0	53.5	69.1	69.1	68.9	69.1	69.1	68.9	69.1	68.9	69.1	67.7
2. POF	0.0	0.0	22.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9
3. EUOF	30.9	31.0	23.9	30.9	30.9	31.1	30.9	30.9	31.1	30.9	31.1	30.9	30.4
4. EUOR	30.9	31.0	30.9	30.9	30.9	31.1	30.9	30.9	31.1	30.9	31.1	30.9	31.0
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	15	25	31	80	17	110	145	124	70	53	62	30	761
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	729	647	713	639	727	610	599	620	650	692	658	714	7999
9. POH	0	0	168	0	0	0	0	0	0	0	0	0	168
10. FOH & EFOH	115	104	89	111	115	112	115	115	112	115	112	115	1332
11. MOH & EMOH	115	104	89	111	115	112	115	115	112	115	112	115	1332
12. OPER BTU (GBTU)	17.139	28.405	35.883	79.288	16.826	109.132	145.570	122.432	69.432	63.075	72.601	32.399	792.182
13. NET GEN (MWH)	1,101	1,824	2,312	5,019	1,062	6,897	9,208	7,727	4,388	4,079	4,693	2,070	50,380
14. ANOHR (Btu/kwh)	15,567	15,573	15,520	15,798	15,844	15,823	15,809	15,845	15,823	15,463	15,470	15,652	15,724
15. NOF (%)	90.7	90.3	93.3	95.5	93.7	95.4	95.9	94.5	95.3	96.1	94.8	87.3	90.6
16. NPC (MW)	80	80	80	66	66	66	66	66	66	80	80	80	73

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POLK 1	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	84.5	84.4	84.5	53.4	38.2	84.6	84.5	84.5	84.6	84.6	84.6	84.5	78.0
2. POF	0.0	0.0	0.0	36.7	54.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.7
3. EUOF	15.5	15.6	15.5	9.9	7.0	15.4	15.5	15.5	15.4	15.4	15.4	15.5	14.3
4. EUOR	15.5	15.6	15.5	15.6	15.5	15.4	15.5	15.5	15.4	15.4	15.4	15.5	15.5
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	576	520	576	427	576	557	576	576	557	576	557	576	6652
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	168	152	168	292	168	163	168	168	163	169	163	168	2108
9. POH	0	0	0	264	408	0	0	0	0	0	0	0	672
10. FOH & EFOH	89	81	89	55	40	86	89	89	86	89	86	89	971
11. MOH & EMOH	26	24	26	16	12	25	26	26	25	26	25	26	283
12. OPER BTU (GBTU)	1420.694	1289.281	1427.784	1052.620	1388.930	1385.545	1430.622	1431.565	1390.353	1436.760	1389.052	1427.708	16470.914
13. NET GEN (MWH)	140,791	127,795	141,528	104,354	137,635	137,375	141,850	141,949	137,880	142,483	137,743	141,533	1,632,916
14. ANOHR (Btu/kwh)	10,091	10,089	10,088	10,087	10,091	10,086	10,085	10,085	10,084	10,084	10,084	10,087	10,087
15. NOF (%)	97.8	98.2	98.3	97.7	95.6	98.6	98.5	98.6	98.9	98.9	98.8	98.3	98.2
16. NPC (MW)	250	250	250	250	250	250	250	250	250	250	250	250	250
17. ANOHR EQUATION	ANOHR = NOF(-14.839) + 11544												

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POLK 2	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)	83.5	41.7	83.5	83.4	83.5	83.5	83.5	83.5	83.5	83.5	83.5	83.5	80.3
2. POF	0.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8
3. EUOF	16.5	8.3	16.5	16.6	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	15.9
4. EUOR	16.5	16.7	16.5	16.6	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5
5. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
6. SH	135	79	231	289	221	331	340	341	428	341	290	183	3208
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	610	593	513	430	523	389	404	403	292	404	430	561	5552
9. POH	0	336	0	0	0	0	0	0	0	0	0	0	336
10. FOH & EFOH	60	27	60	58	60	58	60	60	58	60	58	60	674
11. MOH & EMOH	63	29	63	61	63	61	63	63	61	63	61	63	716
12. OPER BTU (GBTU)	201.122	129.306	365.380	460.282	328.336	509.315	523.668	522.980	668.759	537.274	465.305	267.662	4979.389
13. NET GEN (MWH)	19,134	12,529	35,166	44,208	31,075	48,342	49,721	49,621	63,625	51,317	44,732	25,384	474,854
14. ANOHR (Btu/kwh)	10,511	10,321	10,390	10,412	10,566	10,536	10,532	10,539	10,511	10,470	10,402	10,545	10,486
15. NOF (%)	79.0	87.9	84.6	102.1	93.7	97.5	97.6	97.0	99.0	83.7	85.8	77.0	89.7
16. NPC (MW)	180	180	180	150	150	150	150	150	150	180	180	180	165

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POLK 3	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	2002
1. EAF (%)					69.9	70.0	69.9	69.9	70.0	69.9	53.6	69.9	68.7
2. POF					0.0	0.0	0.0	0.0	0.0	0.0	23.3	0.0	1.9
3. EUOF					30.1	30.0	30.1	30.1	30.0	30.1	23.1	30.1	29.4
4. EUOR					30.1	30.0	30.1	30.1	30.0	30.1	30.1	30.1	30.0
5. PH					744	720	744	744	720	745	720	744	8760
6. SH					161	268	276	274	351	283	177	114	1903
7. RSH					0	0	0	0	0	0	0	0	0
8. UH					583	452	468	470	369	462	543	630	6857
9. POH					0	0	0	0	0	0	168	0	168
10. FOH & EFOH					112	108	112	112	108	112	83	112	1289
11. MOH & EMOH					112	108	112	112	108	112	83	112	1289
12. OPER BTU (GBTU)					235.602	409.519	423.671	417.285	537.615	448.825	287.210	162.841	2922.568
13. NET GEN (MWH)					22,266	38,856	40,222	39,600	50,857	43,018	27,729	15,391	277,939
14. ANOHR (Btu/kwh)					10,581	10,539	10,533	10,538	10,571	10,433	10,358	10,580	10,515
15. NOF (%)					92.3	96.7	97.1	96.5	96.6	84.5	86.8	75.0	88.5
16. NPC (MW)					150	150	150	150	150	180	180	180	165

FILED:
SUSPENDED:
EFFECTIVE: 09/20/01
DOCKET NO: 010001-EI

EXHIBITS TO THE TESTIMONY OF

GEORGE A. KESELOWSKY

DOCKET NO. 010001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2002 - DECEMBER 2002

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2002 - DECEMBER 2002

	Availability			Net
Unit	EAF	POF	EUOF	Heat Rate
Big Bend 1	77.3	3.8	18.9	10,231[1/]
Big Bend 2	66.7	19.2	14.2	9,928[2/]
Big Bend 3	67.5	15.3	17.2	10,036[3/]
Big Bend 4	82.6	5.8	11.6	10,089[4/]
Gannon 5	56.7	15.3	27.9	10,716[5/]
Gannon 6	63.9	18.1	18.0	10,704[6/]
Polk 1	78.0	7.7	14.3	10,087[7/]

[1/] Original Sheet 8.401.02E, Page 14

[2/] Original Sheet 8.401.02E, Page 15

[3/] Original Sheet 8.401.02E, Page 16

[4/] Original Sheet 8.401.02E, Page 17

[5/] Original Sheet 8.401.02E, Page 18

[6/] Original Sheet 8.401.02E, Page 19

[7/] Original Sheet 8.401.02E, Page 20

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EXHIBIT NO. ___
DOCKET NO. 010001-EI
TAMPA ELECTRIC COMPANY
(JTW-1)
PAGE 1 OF 2

2000 TRANSPORTATION BENCHMARK CALCULATION

Average Rail Mileage to Tampa		1,218.00	Miles	(Note 1)
x	Average of Lowest Two Publicly Available Florida Rail Rates	2.01 24.48	¢/ton mile	(Note 2)
+	Costs of Privately Owned Rail Cars	1.75		(Note 3)
Transportation Benchmark for the Year Ended 12/31/00		26.23		(Note 4)

Notes

1/ Weighted average domestic rail miles from all Tampa Electric waterborne coal supplies to plants. Rail miles for imported coal sources are measured from port of entry.

2/ Cents per ton-mile for publicly available Florida utility rail coal transportation rates including discounts for volume and private rail cars. The current publicly available rail rates to Florida utilities on a cents per ton-mile basis for 2000 are as follows:

JEA	¢	2.30
Orlando	¢	2.48
Lakeland	¢	1.95*
Gainesville	¢	2.07*
* Average of Lowest Two	¢	2.01

3/ The cost of private rail cars was approved in the original stipulation as $2.00 per ton. Subsequent negotiation between Tampa Electric and Public Service Commission Staff resulted in an agreed upon estimated cost of $1.75 per ton.

4/ Calculated by multiplying average domestic rail mileage to Tampa by Florida rail coal market costs (cents per ton-mile), then adding the costs of privately-owned rail cars.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 21
COMPANY/ WITNESS: Wehle
DATE: 10-20-21-01

CONFIDENTIAL

2000 TRANSPORTATION MARKET PRICE APPLICATION

Tampa Electric Weighted Average per ton Water Transportation Price from All Tampa Electric Coal Sources ([redacted] divided by 6,187,276.74)	[redacted]
Transportation Benchmark	$ 26.23
Over/(Under) Benchmark	[redacted]
Total Tons Transported in 2000	6,187,276.74
Total Transportation Cost in 2000	[redacted]
Total Amount Allowable for Recovery Using Benchmark ($26.23 x 6,187,276.74)	$162,292,268.80
Total Cost Over/(Under) Benchmark – 2000	[redacted]
Prior Year's Cumulative Benefit (1988 – 1999)	[redacted]
Net Benefit for 1988 – 2000	[redacted]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010001-EI EXHIBIT NO. 22
COMPANY/
WITNESS: Bachmann
DATE: 11-20 & 21-01

22
GMB-2

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002

SCHEDULE E1
PAGE 1 OF 2

	MARIANNA DIVISION	(a) DOLLARS		(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)			0	
2	Nuclear Fuel Disposal Costs (E2)				
3	Coal Car Investment				
4	Adjustments to Fuel Cost				
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0		0	0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	6,620,206		322,937	2.05000
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)				
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)				
9	Energy Cost of Sched E Economy Purch (E9)				
10	Demand & Transformation Cost of Purch Power (E2)	4,927,523		322,937	1.52585
10a	Demand Costs of Purchased Power	4,537,163	*		
10b	Transformation Energy & Customer Costs of Purchased Power	390,360	*		
11	Energy Payments to Qualifying Facilities (E8a)				
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	11,547,729		322,937	3.57585
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	11,547,729		322,937	3.57585
14	Fuel Cost of Economy Sales (E6)				
15	Gain on Economy Sales (E6)				
16	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)				
17	Fuel Cost of Other Power Sales				
18	TOTAL FUEL COST AND GAINS OF POWER SALES	0		0	0.00000
19	Net Inadvertent Interchange				
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	11,547,729		322,937	3.57585
21	Net Unbilled Sales	0	*	0	0.00000
22	Company Use	8,940	*	250	0.00295
23	T & D Losses	692,320	*	19,361	0.22824
24	SYSTEM MWH SALES	11,547,729		303,326	3.80704
25	Less Total Demand Cost Recovery	4,537,163	***		
26	Jurisdictional MWH Sales	7,010,566		303,326	2.31123
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	7,010,566		303,326	2.31123
28	GPIF **				
29	TRUE-UP **	62,173		303,326	0.02050
30	TOTAL JURISDICTIONAL FUEL COST	7,072,739		303,326	2.33173
31	Revenue Tax Factor				1.00072
32	Fuel Factor Adjusted for Taxes				2.33341
33	FUEL FAC ROUNDED TO NEAREST .001 CENTS/KWH				2.333

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
***Calculation on Schedule E1 Page 2

EXHIBIT NO._____
DOCKET NO. 010001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 1 OF 14

DOCUMENT NUMBER-DATE
11801 SEP 20 a
FPSC-COMMISSION CLERK

FLORIDA PUBLIC UTLITIES COMPANY
FUEL FACTOR ADJUSTED FOR
LINE LOSS MULTIPLIER
ESTIMATED FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002

MARIANNA DIVISION

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*4,380)			(3)*(4)	(1)*(5)	(6)/Total Col. (6)	(7)/Total Col. (7)
	Rate Schedule	KWH Sales	12 CP Load Factor	CP KW At Meter	Demand Loss Factor	Energy Loss Factor	CP KW At GEN.	KWH At GEN.	12 CP Demand Percentage	Energy Percentage
34	RS	135,832,621	58.269848%	53,221.4	1.089	1.000	57,958.1	135,832,621	52.22%	44.79%
35	GS	26,903,512	58.862369%	10,435.1	1.089	1.000	11,363.8	26,903,512	10.24%	8.87%
36	GSD	92,437,398	77.395927%	27,268.1	1.083	1.000	29,531.4	92,437,398	26.61%	30.47%
37	GSLD	43,499,952	85.767459%	11,579.6	1.038	1.000	12,019.6	43,499,952	10.83%	14.34%
38	OL, OL1	3,711,483	979.964079%	86.5	1.089	1.000	94.2	3,711,483	0.08%	1.22%
39	SL1, SL2 & SL3	941,265	979.964079%	21.9	1.089	1.000	23.8	941,265	0.02%	0.31%
40	TOTAL	303,326,231		102,612.6			110,990.9	303,326,231	100.00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11)	(13) Tot. Col. 13 * (12)	(14) (13)/(1)	(15) (14) * 1.00072	(16)	(17) (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Demand Allocation Percentage	Demand Dollars	Demand Cost Recovery	Demand Cost Recovery Adj for Taxes	Other Charges	Levelized Adjustment
41	RS	48.21%	3.46%	51.67%	$2,344,352	0.01726	0.01727	0.02333	$0.04060
42	GS	9.45%	0.68%	10.13%	459,615	0.01708	0.01709	0.02333	$0.04042
43	GSD	24.56%	2.34%	26.90%	1,220,497	0.01320	0.01321	0.02333	$0.03654
44	GSLD	10.00%	1.10%	11.10%	503,625	0.01158	0.01159	0.02333	$0.03492
45	OL, OL1	0.07%	0.09%	0.16%	7,259	0.00196	0.00196	0.02333	$0.02529
46	SL1, SL2 & SL3	0.02%	0.02%	0.04%	1,815	0.00193	0.00193	0.02333	$0.02526
47	TOTAL	92.31%	7.69%	100.00%	$4,537,163				

(2) From Gulf Power Co. 1999 Load Research results.
(4) From Fernandina Rate Case.

EXHIBIT NO._____
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FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 2 OF 14

SCHEDULE E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2001 - DECEMBER 2001
BASED ON SIX MONTHS ACTUAL & SIX MONTHS ESTIMATED

Marianna Division

Under-recovery of purchased power costs for the period January 2001 - December 2001. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2001)(Estimated)	$	(62,173)
Estimated kilowatt hour sales for the months of January 2002 - December 2002 as per estimate filed with the Commission.		303,326,231
Cents per kilowatt hour necessary to collect under-recovered *purchased power costs over the period January 2002 - December 2002.*		-0.02050

Exhibit No._____
DOCKET NO. 010001-EI
Florida Public Utilities Company
(GMB-2)
Page 3 of 14

SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002

LINE NO.			(a) 2002 JANUARY	(b) 2002 FEBRUARY	(c) ESTIMATED 2002 MARCH	(d) 2002 APRIL	(e) 2002 MAY	2002 JUNE	2002 JULY	2002 AUGUST	2002 SEPTEMBER	2002 OCTOBER	2002 NOVEMBER	(f) 2002 DECEMBER	(g) TOTAL PERIOD	LINE NO.
1	FUEL COST OF SYSTEM GENERATION														0	1
1a	NUCLEAR FUEL DISPOSAL														*0*	*1a*
2	FUEL COST OF POWER SOLD														0	2
3	FUEL COST OF PURCHASED POWER		587,667	451,844	450,882	464,503	568,865	605,785	672,257	680,816	620,175	485,808	462,649	568,955	6,620,206	3
3a	DEMAND & TRANSFORMATION CHARGE OF PURCHASED POWER		438,824	410,651	334,843	337,340	412,574	447,737	461,037	465,504	418,820	380,339	376,551	443,303	4,927,523	3a
3b	QUALIFYING FACILITIES														0	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		1,026,491	862,495	785,725	801,843	981,439	1,053,522	1,133,294	1,146,320	1,038,995	866,147	839,200	1,012,258	11,547,729	5
6	LESS: TOTAL DEMAND COST RECOVERY		406,294	378,121	302,313	304,810	380,044	415,207	428,507	432,974	386,290	347,809	344,021	410,773	4,537,163	6
7	TOTAL OTHER COST TO BE RECOVERED		620,197	484,374	483,412	497,033	601,395	638,315	704,787	713,346	652,705	518,338	495,179	601,485	7,010,566	7
7a	SYSTEM KWH SOLD (MWH)		27,563	22,846	21,133	20,772	21,607	27,256	29,267	30,246	31,513	25,667	21,093	24,363	303,326	7a
7b	COST PER KWH SOLD (CENTS/KWH)		2.25011	2.12017	2.28747	2.3928	2.78333	2.34192	2.40813	2.35848	2.07122	2.01947	2.3476	2.46885	2.31123	7b
8	JURISDICTIONAL LOSS MULTIPLIER		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)		2.25011	2.12017	2.28747	2.39280	2.78333	2.34192	2.40813	2.35848	2.07122	2.01947	2.34760	2.46885	2.31123	9
10	GPIF (CENTS/KWH)															10
11	TRUE-UP (CENTS/KWH)		0.02050	0.02050	0.02050	0.02050	0.02050	0.02050	0.02050	0.02050	0.02050	0.02050	0.02050	0.02050	0.02050	11
12	TOTAL		2.27061	2.14067	2.30797	2.41330	2.80383	2.36242	2.42863	2.37898	2.09172	2.03997	2.36810	2.48935	2.33173	12
13	REVENUE TAX FACTOR	0.00072	0.00163	0.00154	0.00166	0.00174	0.00202	0.00170	0.00175	0.00171	0.00151	0.00147	0.00171	0.00179	0.00168	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		2.27224	2.14221	2.30963	2.41504	2.80585	2.36412	2.43038	2.38069	2.09323	2.04144	2.36981	2.49114	2.33341	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		2.272	2.142	2.310	2.415	2.806	2.364	2.430	2.381	2.093	2.041	2.370	2.491	2.333	15

EXHIBIT NO. _____
DOCKET NO. 010001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
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SCHEDULE E7

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH		PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY	2002	GULF POWER COMPANY	RE	28,666,679			28,666,679	2.050000	3.580781	587,667
FEBRUARY	2002	GULF POWER COMPANY	RE	22,041,166			22,041,166	2.050000	3.913110	451,844
MARCH	2002	GULF POWER COMPANY	RE	21,994,244			21,994,244	2.050000	3.572412	450,882
APRIL	2002	GULF POWER COMPANY	RE	22,658,678			22,658,678	2.050000	3.538790	464,503
MAY	2002	GULF POWER COMPANY	RE	27,749,510			27,749,510	2.050000	3.536780	568,865
JUNE	2002	GULF POWER COMPANY	RE	29,550,501			29,550,501	2.050000	3.565158	605,785
JULY	2002	GULF POWER COMPANY	RE	32,793,020			32,793,020	2.050000	3.455900	672,257
AUGUST	2002	GULF POWER COMPANY	RE	33,210,540			33,210,540	2.050000	3.451675	680,816
SEPTEMBER	2002	GULF POWER COMPANY	RE	30,252,456			30,252,456	2.050000	3.434415	620,175
OCTOBER	2002	GULF POWER COMPANY	RE	23,697,970			23,697,970	2.050000	3.654942	485,808
NOVEMBER	2002	GULF POWER COMPANY	RE	22,568,243			22,568,243	2.050000	3.718499	462,649
DECEMBER	2002	GULF POWER COMPANY	RE	27,753,904			27,753,904	2.050000	3.647263	568,955
TOTAL				322,936,911	0	0	322,936,911	2.050000	3.575847	6,620,206

EXHIBIT NO. _____
DOCKET NO. 010001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 5 OF 14

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY

MARIANNA DIVISION

RESIDENTIAL BILL COMPARISON

FOR MONTHLY USAGE OF 1000 KWH

ESTIMATED FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002

	JANUARY 2002	FEBRUARY 2002	MARCH 2002	APRIL 2002	MAY 2002	JUNE 2002	JULY 2002
BASE RATE REVENUES ** $	20.86	20.86	20.86	20.86	20.86	20.86	20.86
FUEL RECOVERY FACTOR CENTS/KWH	4.06	4.06	4.06	4.06	4.06	4.06	4.06
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	40.60	40.60	40.60	40.60	40.60	40.60	40.60
GROSS RECEIPTS TAX	1.58	1.58	1.58	1.58	1.58	1.58	1.58
TOTAL REVENUES *** $	63.04	63.04	63.04	63.04	63.04	63.04	63.04

	AUGUST 2002	SEPTEMBER 2002	OCTOBER 2002	NOVEMBER 2002	DECEMBER 2002	PERIOD TOTAL
BASE RATE REVENUES ** $	20.86	20.86	20.86	20.86	20.86	250.32
FUEL RECOVERY FACTOR CENTS/KWH	4.06	4.06	4.06	4.06	4.06	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	40.60	40.60	40.60	40.60	40.60	487.20
GROSS RECEIPTS TAX	1.58	1.58	1.58	1.58	1.58	18.96
TOTAL REVENUES *** $	63.04	63.04	63.04	63.04	63.04	756.48

* MONTHLY AND CUMULATIVE SIX MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	8.30
CENTS/KWH	12.13
CONSERVATION FACTOR	0.430
	20.86

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. _____
DOCKET NO. 010001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

	FERNANDINA BEACH DIVISON	(a) DOLLARS		(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)				
2	Nuclear Fuel Disposal Costs (E2)				
3	Coal Car Investment				
4	Adjustments to Fuel Cost				
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0		0	0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	8,923,811		483,675	1.84500
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)				
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)				
9	Energy Cost of Sched E Economy Purch (E9)				
10	Demand & Non Fuel Cost of Purch Power (E2)	7,514,269		483,675	1.55358
10a	Demand Costs of Purchased Power	7,003,710	*		
10b	Non-fuel Energy & Customer Costs of Purchased Power	510,559	*		
11	Energy Payments to Qualifying Facilities (E8a)	89,760		4,800	1.87000
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	16,527,840		488,475	3.38356
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	16,527,840		488,475	3.38356
14	Fuel Cost of Economy Sales (E6)				
15	Gain on Economy Sales (E6)				
16	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)				
17	Fuel Cost of Other Power Sales				
18	TOTAL FUEL COST AND GAINS OF POWER SALES	0		0	0.00000
19	Net Inadvertent Interchange				
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	16,527,840		488,475	3.38356
21	Net Unbilled Sales	0	*	0	0.00000
22	Company Use	14,752	*	436	0.00316
23	T & D Losses	728,988	*	21,545	0.15627
24	SYSTEM MWH SALES	16,527,840		466,494	3.54299
25	Wholesale MWH Sales				
26	Jurisdictional MWH Sales	16,527,840		466,494	3.54299
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	16,527,840		466,494	3.54299
27a	GSLD MWH Sales			147,237	
27b	Other Classes MWH Sales			319,257	
27c	GSLD CP KW			258,000	*
28	GPIF **				
29	TRUE-UP (OVER) UNDER RECOVERY **	16,863		466,494	0.00361
30	TOTAL JURISDICTIONAL FUEL COST	16,544,703		466,494	3.54661
30a	Demand Purchased Power Costs (Line 10a)	7,003,710	*		
30b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	9,524,130	*		
30c	True up Over/Under Recovery (Line 29)	16,863	*		

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

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

	FERNANDINA BEACH DIVISON	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
	APPORTIONMENT OF DEMAND COSTS			
31	Total Demand Costs (Line 30a)	7,003,710		
32	GSLD Portion of Demand Costs (Line 30a) Including Line Losses(Line 27c x $6.18)	1,594,440	258,000 (KW)	$6.18 /KW
33	Balance to Other Classes	5,409,270	319,257	1.69433
	APPORTIONMENT OF NON-DEMAND COSTS			
34	Total Non-demand Costs(Line 30b)	9,524,130		
35	Total KWH Purchased (Line 12)		488,475	
36	Average Cost per KWH Purchased			1.94977
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)			2.00825
38	GSLD Non-demand Costs (Line 27a x Line 37)	2,956,914	147,237	2.00827
39	Balance to Other Classes	6,567,216	319,257	2.05703
	GSLD PURCHASED POWER COST RECOVERY FACTORS			
40a	Total GSLD Demand Costs (Line 32)	1,594,440	258,000 (KW)	$6.18 /KW
40b	Revenue Tax Factor			1.01597
40c	GSLD Demand Purchased Power Factor Adjusted for Taxes & Rounded			$6.28 /KW
40d	Total Current GSLD Non-demand Costs(Line 38)	2,956,914	147,237	2.00827
40e	Total Non-demand Costs Including True-up	2,956,914	147,237	2.00827
40f	Revenue Tax Factor			1.01597
40g	GSLD Non-demand Costs Adjusted for Taxes & Rounded			2.04034
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	11,976,486	319,257	3.75136
41b	Less: Total Demand Cost Recovery	5,409,270 ***		
41c	Total Other Costs to be Recovered	6,567,216	319,257	2.05703
41d	Other Classes' Portion of True-up (Line 30c)	16,863	319,257	0.00528
41e	Total Demand & Non-demand Costs Including True-up	6,584,079	319,257	2.06231
42	Revenue Tax Factor			1.01597
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded			2.095

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

FERNANDINA BEACH DIVISON

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*4,380)			(3)*(4)	(1)*(5)	(6)/Total Col. (6)	(7)/Total Col. (7)
	Rate Schedule	KWH Sales	12 CP Load Factor	CP KW At Meter	Demand Loss Factor	Energy Loss Factor	CP KW At GEN.	KWH At GEN.	12 CP Demand Percentage	Energy Percentage
44	RS	181,554,188	60.938%	68,021.1	1.089	1.000	74,075.0	181,554,188	62.82%	56.87%
45	GS	32,395,169	71.059%	10,408.5	1.089	1.000	11,334.9	32,395,169	9.61%	10.15%
46	GSD	102,536,322	78.573%	29,794.1	1.083	1.000	32,267.0	102,536,322	27.37%	32.12%
47	OL, SL, CSL	2,771,057	297.393%	212.7	1.089	1.000	231.6	2,771,057	0.20%	0.87%
48	TOTAL	319,256,736		108,436.4			117,908.5	319,256,736	100.00%	100.01%

		(10) 12/13 * (8)	**(11)** 1/13 * (9)	**(12)** (10) + (11)	**(13)** Tot. Col. 13 * (12)	**(14)** (13)/(1)	**(15)** (14) * 1.01597	**(16)**	**(17)** (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Demand Allocation Percentage	Demand Dollars	Demand Cost Recovery	Demand Cost Recovery Adj for Taxes	Other Charges	Levelized Adjustment
49	RS	58.00%	4.37%	62.37%	$3,373,762	0.01858	0.01888	0.02095	0.03983
50	GS	8.87%	0.78%	9.65%	521,995	0.01611	0.01637	0.02095	0.03732
51	GSD	25.26%	2.47%	27.73%	1,499,991	0.01463	0.01486	0.02095	0.03581
52	OL, OL2, SL1, SL3 & CSL	0.18%	0.07%	0.25%	13,523	0.00488	0.00496	0.02095	0.02591
53	TOTAL	92.31%	7.69%	100.00%	$5,409,270				

(2) From Florida Power & Light Co. 1999 Load Research results.
(4) From Fernandina Beach Rate Case 881056-EI.

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FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2001 - DECEMBER 2001
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

Fernandina Beach Division

Under-recovery of purchased power costs for the period January 2001 - December 2001. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2001.)(Estimated)	$	(16,863)
Estimated kilowatt hour sales for the months of January 2002 - December 2002 as per estimate filed with the Commission. (Excludes GSLD customers)		319,256,736
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2002 - December 2002.		-0.00528

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SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY

FERNANDINA BEACH DIVISION

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

LINE NO.			(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(h) JULY	(i) AUGUST	(j) SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) TOTAL PERIOD	LINE NO.
			ESTIMATED													
1	FUEL COST OF SYSTEM GENERATION														0	1
1a	NUCLEAR FUEL DISPOSAL														0	1a
2	FUEL COST OF POWER SOLD														0	2
3	FUEL COST OF PURCHASED POWER		695,616	644,921	692,144	635,370	746,642	852,679	925,759	851,661	750,893	716,078	670,557	741,491	8,923,811	3
3a	DEMAND & NON FUEL COST OF PUR POWER		672,297	588,844	576,627	540,330	598,971	679,087	710,510	695,926	657,443	599,871	544,805	649,558	7,514,269	3a
3b	QUALIFYING FACILITIES		7,480	7,480	7,480	7,480	7,480	7,480	7,480	7,480	7,480	7,480	7,480	7,480	89,760	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		1,375,393	1,241,245	1,276,251	1,183,180	1,353,093	1,539,246	1,643,749	1,555,067	1,415,816	1,323,429	1,222,842	1,398,529	16,527,840	5
5a	LESS: TOTAL DEMAND COST RECOVERY		477,984	397,416	382,512	349,446	401,754	475,836	503,100	492,732	459,984	404,394	351,918	452,634	5,149,710	5a
5b	TOTAL OTHER COST TO BE RECOVERED		897,409	843,829	893,739	833,734	951,339	1,063,410	1,140,649	1,062,335	955,832	919,035	870,924	945,895	11,378,130	5b
6	APPORTIONMENT TO GSLD CLASS		359,046	373,289	419,829	360,704	390,792	439,235	418,312	421,402	402,989	422,976	432,039	370,294	4,810,907	6
6a	BALANCE TO OTHER CLASSES		538,363	470,540	473,910	473,030	560,547	624,175	722,337	640,933	552,843	496,059	438,885	575,601	6,567,223	6a
6b	SYSTEM KWH SOLD (MWH)		37,943	36,051	36,545	32,978	35,317	43,541	45,391	45,107	42,067	39,969	35,808	35,777	466,494	6b
7	GSLD MWH SOLD		10,185	10,895	13,212	10,268	11,766	14,178	13,136	13,290	12,373	13,369	13,820	10,745	147,237	7
7a	BALANCE MWH SOLD OTHER CLASSES		27,758	25,156	23,333	22,710	23,551	29,363	32,255	31,817	29,694	26,600	21,988	25,032	319,257	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES		1.93949	1.87049	2.03107	2.08292	2.38014	2.12572	2.23946	2.01444	1.8618	1.86488	1.99602	2.29946	2.05703	7b
8	JURISDICTIONAL LOSS MULTIPLIER		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)		1.93949	1.87049	2.03107	2.08292	2.38014	2.12572	2.23946	2.01444	1.86180	1.86488	1.99602	2.29946	2.05703	9
10	GPIF (CENTS/KWH)															10
11	TRUE-UP (CENTS/KWH)	16,863	0.00528	0.00528	0.00528	0.00528	0.00528	0.00528	0.00528	0.00528	0.00528	0.00528	0.00528	0.00528	0.00528	11
12	TOTAL		1.94477	1.87577	2.03635	2.08820	2.38542	2.13100	2.24474	2.01972	1.86708	1.87016	2.00130	2.30474	2.06231	12
13	REVENUE TAX FACTOR	0.01597	0.03106	0.02996	0.03252	0.03335	0.03810	0.03403	0.03585	0.03225	0.02982	0.02987	0.03196	0.03681	0.03294	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		1.97583	1.90573	2.06887	2.12155	2.42352	2.16503	2.28059	2.05197	1.89690	1.90003	2.03326	2.34155	2.09525	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		1.976	1.906	2.069	2.122	2.424	2.165	2.281	2.052	1.897	1.9	2.033	2.342	2.095	15

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FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2002	JACKSONVILLE ELECTRIC AUTHORITY	MS	37,702,753			37,702,753	1.845001	3.628152	695,616
FEBRUARY 2002	JACKSONVILLE ELECTRIC AUTHORITY	MS	34,955,087			34,955,087	1.844999	3.529572	644,921
MARCH 2002	JACKSONVILLE ELECTRIC AUTHORITY	MS	37,514,607			37,514,607	1.844999	3.382072	692,144
APRIL 2002	JACKSONVILLE ELECTRIC AUTHORITY	MS	34,437,380			34,437,380	1.845001	3.414023	635,370
MAY 2002	JACKSONVILLE ELECTRIC AUTHORITY	MS	40,468,427			40,468,427	1.844999	3.325093	746,642
JUNE 2002	JACKSONVILLE ELECTRIC AUTHORITY	MS	46,215,658			46,215,658	1.845000	3.314388	852,679
JULY 2002	JACKSONVILLE ELECTRIC AUTHORITY	MS	50,176,641			50,176,641	1.845000	3.261017	925,759
AUGUST 2002	JACKSONVILLE ELECTRIC AUTHORITY	MS	46,160,491			46,160,491	1.845000	3.352622	851,661
SEPTEMBER 2002	JACKSONVILLE ELECTRIC AUTHORITY	MS	40,698,822			40,698,822	1.844999	3.460385	750,893
OCTOBER 2002	JACKSONVILLE ELECTRIC AUTHORITY	MS	38,811,789			38,811,789	1.845001	3.390591	716,078
NOVEMBER 2002	JACKSONVILLE ELECTRIC AUTHORITY	MS	36,344,540			36,344,540	1.845001	3.344002	670,557
DECEMBER 2002	JACKSONVILLE ELECTRIC AUTHORITY	MS	40,189,229			40,189,229	1.844999	3.461248	741,491
TOTAL			483,675,424	0	0	483,675,424	1.845000	3.398577	8,923,811

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SCHEDULE E8

FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
PURCHASED POWER
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL KWH PURCHASED	(5) KWH FOR OTHER UTILITIES	(6) KWH FOR INTERRUPTIBLE	(7) KWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2002	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
FEBRUARY 2002	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
MARCH 2002	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
APRIL 2002	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
MAY 2002	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
JUNE 2002	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
JULY 2002	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
AUGUST 2002	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
SEPTEMBER 2002	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
OCTOBER 2002	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
NOVEMBER 2002	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
DECEMBER 2002	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
TOTAL			4,800,000	0	0	4,800,000	1.870000	1.870000	89,760

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FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2002 THROUGH DECEMBER 2002

	JANUARY 2002	FEBRUARY 2002	MARCH 2002	APRIL 2002	MAY 2002	JUNE 2002	JULY 2002
BASE RATE REVENUES ** $	19.47	19.47	19.47	19.47	19.47	19.47	19.47
FUEL RECOVERY FACTOR CENTS/KWH	3.98	3.98	3.98	3.98	3.98	3.98	3.98
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	39.83	39.83	39.83	39.83	39.83	39.83	39.83
GROSS RECEIPTS TAX	0.61	0.61	0.61	0.61	0.61	0.61	0.61
TOTAL REVENUES *** $	59.91	59.91	59.91	59.91	59.91	59.91	59.91

	AUGUST 2002	SEPTEMBER 2002	OCTOBER 2002	NOVEMBER 2002	DECEMBER 2002	PERIOD TOTAL
BASE RATE REVENUES ** $	19.47	19.47	19.47	19.47	19.47	233.64
FUEL RECOVERY FACTOR CENTS/KWH	3.98	3.98	3.98	3.98	3.98	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	39.83	39.83	39.83	39.83	39.83	477.96
GROSS RECEIPTS TAX	0.61	0.61	0.61	0.61	0.61	7.32
TOTAL REVENUES *** $	59.91	59.91	59.91	59.91	59.91	718.92

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	7.00
CENTS/KWH	12.20
CONSERVATION FACTOR	0.27
	19.47

*** EXCLUDES FRANCHISE TAXES

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FLORIDA PUBLIC SERVICE COMMISSION

DIVISION OF REGULATORY OVERSIGHT
BUREAU OF AUDITING SERVICES

Miami District Office

FLORIDA POWER AND LIGHT

FUEL ADJUSTMENT

TWELVE MONTHS ENDED DECEMBER 31, 2000

AUDIT CONTROL NO. 01-053-4-1

DOCKET NUMBER 010001-EI

Iliana Piedra

Iliana Piedra, Audit Manager

Kathy L. Welch

Kathy L. Welch
Miami District Office Audit Supervisor

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO 23
COMPANY/ WITNESS. Welch
DATE 11-20-21-01

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DIVISION OF REGULATORY OVERSIGHT
AUDITOR'S REPORT

JULY 19, 2001

TO: FLORIDA PUBLIC SERVICE COMMISSION AND OTHER INTERESTED PARTIES

We have applied the procedures described in this report to audit the Fuel Cost Recovery schedules for the historical 12 month period ended December 31, 2000 for Florida Power and Light Company.

This is an internal accounting report prepared after performing a limited scope audit. Accordingly, this report should not be relied upon for any purpose except to assist the Commission staff in the performance of their duties. Substantial additional work would have to be performed to satisfy generally accepted auditing standards and produce audited financial statements for public use.

SUMMARY OF SIGNIFICANT PROCEDURES

Our audit was performed by examining, on a test basis, certain transactions and account balances which we believe are sufficient to base our opinion. Our examination did not entail a complete review of all financial transactions of the company. Our more important audit procedures are summarized below. The following definitions apply when used in this report:

Scanned- The documents or accounts were read quickly looking for obvious errors.

Compiled- The exhibit amounts were reconciled with the general ledger, and accounts were scanned for error or inconsistency.

Reviewed- The exhibit amounts were reconciled with the general ledger. The general ledger account balances were traced to subsidiary ledgers, and selective analytical review procedures were applied.

Examined- The exhibit amounts were reconciled with the general ledger. The general legder account balances were traced to subsidiary ledgers. Selective analytical review procedures were applied, and account balances were tested to the extent further described.

Confirmed- Evidential matter supporting an account balance, transaction, or other information was obtained directly from an independent third party.

Verify- The item was tested for accuracy and compared to the substantiating documentation.

REVENUES: Recalculated the revenues and traced the billing factor to the appropriate order. Reconciled revenues and KWH from the Revenue and Rate Report to Schedule A2. Traced KWH from the exhibit to the billing summary.

EXPENSES: Prepared a trial balance and reconciled it to Schedule A2. Performed an analytical review for nuclear expenses . Reviewed nuclear expenses. Scanned the contract with FPL Fuels, Inc. for the leasing of fuel, and the contracts for purchases of uranium, conversion, enrichment and fabrication. Verified contract prices with invoices. Recalculated the monthly amortization of nuclear fuel costs and monthly calculation of disposal costs on a random basis. Recalculated the yearly payment to the DOE for the decommissioning fund on a random basis; determined company's treatment of "last core" for nuclear fuel.

Verified the adjustment to Coal inventory due to the aerial surveys. Determined compliance with the Commission Order.

Used the audit analyzer software to select a gas purchase sample. Reconciled the sample to the "Natural Gas Consumption" reports and to "Gas Closing Reports". Verified the amounts in the sample to vendor invoices, to invoice calculation worksheets and/or to gas publications. Compiled gas usage from the "Station Gas Volume Statements" and compared it to the "Natural Gas Consumption" reports and to Schedule A3 and A4.

Determined compliance of Schedule A6 - "Power Sold" to the Commission Order. Recalculated gains and reconciled the sales to "Sales Summaries", FPL invoices and to transaction logs.

Verified a sample of expenses recorded in Schedule A7 - "Purchased Power" by tracing amounts to the Southern Company invoices and to ST. John River Power Plant Schedules .

Verified a sample of expenses recorded in Schedule A9 - "Economy Purchased Power" by tracing amounts to the Power Deal Reports and tracing the fuel savings to the Lambda reports.

Verified a sample of expenses recorded in Schedule A8 - "Qualifying Facilities" by tracing amounts to the Daily Hour Schedules and tracing the rates to the tariff. Traced the avoided costs to a "Cogen Unit Energy Cost Report".

TRUE-UP CALCULATION: Recalculated the true-up provision for the twelve months ended December 31, 2000 to determine the accuracy of the current true-up amount for the period under audit. Traced the prior period true up and interest for the beginning of the period to the last audit and to Commission Order.

Traced the interest rates to the Wall Street Journal 30-day Commercial Paper Rate.

OTHER

Scanned various internal audits, and the 1997-1999 Unit Power Sales audit.

AUDIT DISCLOSURE NO. 1

SUBJECT: ADJUSTMENTS TO COAL INVENTORY

STATEMENT OF FACTS: An audit of the adjustments to the coal inventory for aerial surveys was performed to determine if the company was following Order No. PSC 97-0359-FOF-EI.

The company has two sources for coal. It has a 20% interest in the coal at St. Johns River Park Plant in Jacksonville, and an interest in Scherer Unit #4 in Georgia. The company states that since Scherer Unit #4 is run by Georgia Power Company, it does not fall under the PSC order. Georgia Power Company follows the rules of the Georgia Public Service Commission.

St. Johns River Park
FPL has followed all the procedures as outlined in the Commission order for St. Johns River Park except as follows:

1. The order states that the adjustment should be booked in the month the survey is conducted. The first survey was conducted for the six months ended March 31, 2000. However, the adjustment was not booked until the May 2000 accounting month. The second survey was conducted for the six months ended August 31, 2000. However, the adjustment was not booked until the October 2000 account month. The company explained that it needed time to process the paperwork.

2. Instead of notifying the Commission by letter with the results of the semi-annual surveys by the 15th of the month, FPL method is to include footnotes to the A5 schedules that are submitted each month including any adjustments for coal surveys.

Scherer
Some of the Scherer procedures performed fall within the Commission Order mentioned above. Others, although not what the Commission ordered, appear to satisfy Commission standards. There are also items that do not agree with the Commission order.

1. Aerial surveys were conducted four times in 2000 rather than the semi-annual requirement of the Commission order.

2. Each Scherer plant is considered separately as stated in the order.

3. Each quarterly difference is greater than 3%. The order states that if this occurs, the adjustment should be + or - 3% of the survey results and the total difference. The total differences were adjusted which were all over 3%.

4. The adjustment should be calculated prior to the total available tons and dollars for

that month. Each variance adjustment was calculated prior to the total available dollars for that month.

5. The quantity was to be adjusted at a weighted average cost as described in the Order. The order states that the most recent six months inventory data should be used. For Scherer the cost used was a weighted average unit cost for the month prior to the survey.

6. The order states that the adjustment for the differences in inventory and survey results should be booked in the month the survey is conducted. All four Scherer surveys were booked in the first week of the month following the survey.

7. The offsetting entries for all four adjustments were made to fuel expense as required by the Commission order.

8. Notification of any adjustments are supposed to be made to the Commission on the 15th of the month subsequent to the survey. The methodology used by FPL to notify the Commission is notes to the A5 schedules submitted each month.

EXHIBITS

CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: Florida Power & Light Company

Month of: December 2000

LINE NO.		CURRENT MONTH ACTUAL	CURRENT MONTH UPDATED ESTIMATES (a)	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH DIFFERENCE %	YEAR TO DATE ACTUAL	YEAR TO DATE UPDATED ESTIMATES (a)	YEAR TO DATE DIFFERENCE AMOUNT	YEAR TO DATE DIFFERENCE %
A	**Fuel Costs & Net Power Transactions**								
1	a Fuel Cost of System Net Generation	$ 171,601,808	$ 128,657,830	$ 42,943,978	33.4 %	$ 2,119,254,505	$ 2,009,938,005	$ 109,316,500	5.4 %
	b Nuclear Fuel Disposal Costs	2,032,265	2,023,466	8,799	0.4 %	22,914,549	22,531,560	382,989	1.7 %
	c Coal Cars Depreciation & Return	324,142	324,142	0	0.0 %	4,104,516	4,104,516	0	0.0 %
	d Gas Pipelines Depreciation & Return	216,049	216,049	0	0.0 %	2,688,657	2,692,657	(4,000)	(0.1) %
	e DOE D&D Fund Payment	0	0	0	N/A	5,776,464	5,930,000	(153,536)	(2.6) %
2	a Fuel Cost of Power Sold & Transmission Reactive Fuel (Per A6)	(22,747,689)	(5,321,250)	(17,426,439)	327.5 %	(99,626,893)	(75,117,362)	(24,509,532)	32.6 %
	b Revenues from Off-System Sales	(15,208,352)	(30,550)	(15,177,802)	49681.8 %	(37,560,276)	(20,673,259)	(16,887,017)	81.7 %
3	a Fuel Cost of Purchased Power (Per A7)	13,761,156	12,384,480	1,376,676	11.1 %	154,837,932	148,930,708	5,907,224	4.0 %
	b Energy Payments to Qualifying Facilities (Per A8)	12,320,289	12,668,260	(347,971)	(2.7) %	137,173,404	137,949,465	(776,061)	(0.6) %
4	Energy Cost of Economy Purchases (Per A9)	1,822,072	4,589,886	(2,767,814)	N/A	66,896,351	57,050,832	9,845,519	17.3 %
5	Total Fuel Costs & Net Power Transactions	$ 164,121,740	$ 155,512,313	$ 8,609,427	5.5 %	$ 2,376,459,208	$ 2,293,337,123	$ 83,122,085	3.6 %
6	**Adjustments to Fuel Cost**								
	a Sales to Fl. Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (2,397,036)	$ (1,851,992)	$ (545,044)	29.4 %	$ (30,722,987)	$ (25,353,354)	$ (5,369,633)	21.2 %
	b Variable cost of power sold	(33,329)	0	(33,329)	N/A	(793,898)	(621,267)	(172,631)	27.8 %
	c Inventory Adjustments	(173,846)	0	(173,846)	N/A	(1,362,556)	(903,224)	(459,332)	50.9 %
	d Non Recoverable Oil/Tank Bottoms	0	0	0	N/A	292,882	462,051	(169,169)	(36.6) %
	e Modifications to Burn Low Gravity Oil	(834)	0	(834)	N/A	21,387	22,221	(834)	(3.8) %
7	Adjusted Total Fuel Costs & Net Power Transactions	$ 161,516,695	$ 153,660,321	$ 7,856,374	5.1 %	$ 2,343,894,036	$ 2,266,943,550	$ 76,950,486	3.4 %
B	**kWh Sales**								
1	Jurisdictional kWh Sales (RTP @ CBL)	6,806,086,660	6,563,089,000	242,997,660	3.7 %	87,931,992,861	87,896,045,657	35,947,204	0.0 %
2	Sale for Resale (excluding FKEC & CKW)	569,607	609,000	(39,393)	(6.5) %	6,230,535	6,861,289	(630,754)	(9.2) %
3	Sub-Total Sales (excluding FKEC & CKW)	6,806,656,267	6,563,698,000	242,958,267	3.7 %	87,938,223,396	87,902,906,946	35,316,450	0.0 %
4	Sales to Fl. Keys Elect Coop (FKEC) & City of Key West (CKW)	100,000,572	75,335,000	24,665,572	32.7 %	1,021,728,312	982,694,000	39,034,312	4.0 %
5	Total Sales (Excluding RTP Incremental)	6,906,656,839	6,639,033,000	267,623,839	4.0 %	88,959,951,708	88,885,600,946	74,350,762	0.1 %
6	Jurisdictional % of Total kWh Sales (lines B1/B3)	99.99163 %	99.99072 %	0.00091 %	0.0 %	99.99291 %	99.99219 %	0.00072 %	0.0 %

SEE FOOTNOTES ON PAGE 2

FLORIDA POWER & LIGHT COMPANY

SCHEDULE A1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
MONTH OF: JANUARY 2000 THROUGH DECEMBER 2000

		DOLLARS				MWH				¢/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1	Fuel Cost of System Net Generation (A3)	2,119,254,505	2,009,938,005	109,316,500	5.4	79,200,433	78,606,617	593,816	0.8	2.6758	2.5570	0.1188	4.6
2	Nuclear Fuel Disposal Costs	22,914,549	22,531,561	382,988	1.7	24,583,722	24,316,923	266,799	1.1	0.0932	0.0927	0.0005	0.5
3	Coal Car Investment	4,104,516	4,104,516	0	NA	0	0	0	NA	0.0000	0.0000	0.0000	NA
3a	Nuclear Thermal Uprate	0	0	0	NA	0	0	0	NA	0.0000	0.0000	0.0000	NA
3b	DOE Decontamination and Decommissioning Cost	5,776,464	5,930,000	(153,536)	(2.6)	0	0	0	NA	0.0000	0.0000	0.0000	NA
3c	Gas Pipeline Enhancements	2,688,657	2,692,657	(4,000)	(0.1)	0	0	0	NA	0.0000	0.0000	0.0000	NA
4	Adjustments to Fuel Cost (A2, page 1)	(32,565,172)	(26,393,573)	(6,171,599)	23.4	0	0	0	NA	0.0000	0.0000	0.0000	NA
5	TOTAL COST OF GENERATED POWER	2,122,173,518	2,018,803,165	103,370,353	5.1	79,200,433	78,606,617	593,816	0.8	2.6795	2.5682	0.1113	4.3
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	154,837,933	148,930,709	5,907,224	4.0	10,911,069	10,340,801	570,268	5.5	1.4191	1.4402	(0.0211)	(1.5)
7	Energy Cost of Sched OS & X Econ Purch (FL) (A9)	38,032,036	27,185,019	10,847,017	39.9	1,038,275	886,643	151,632	17.1	3.6630	3.0661	0.5969	19.5
8	Energy Cost of Other Econ Purch (Non-FL) (A9)	28,864,315	29,865,813	(1,001,497)	(3.4)	730,328	803,272	(72,944)	(9.1)	3.9522	3.7180	0.2342	6.3
9	Energy Cost of Sched E Economy Purch (A9)	0	0	0	NA	0	0	0	NA	0.0000	0.0000	0.0000	NA
10	Capacity Cost of Sched E Economy Purchases	0	0	0	NA	0	0	0	NA	0.0000	0.0000	0.0000	NA
11	Energy Payments to Qualifying Facilities (A8)	137,173,404	137,949,465	(776,061)	(0.6)	6,695,967	6,824,577	(128,610)	(1.9)	2.0486	2.0214	0.0272	1.3
12	TOTAL COST OF PURCHASED POWER	358,907,688	343,931,005	14,976,682	4.4	19,375,639	18,855,293	520,346	2.8	1.8524	1.8241	0.0283	1.6
13	TOTAL AVAILABLE (LINE 5 + LINE 12)	2,481,081,206	2,362,734,170	118,347,035	5.0	98,576,072	97,461,910	1,114,162	1.1	2.5169	2.4243	0.0926	3.8
14	Fuel Cost of Economy and Other Power Sales (A6)	(97,154,346)	(73,730,722)	(23,423,624)	31.8	(2,301,320)	(1,751,798)	(549,522)	31.4	4.2217	4.2089	0.0128	0.3
15	Gain on Economy Sales (A6a)	0	0	0	NA	(200,000)	(625,000)	425,000	(68.0)	0.0000	0.0000	0.0000	NA
16	Fuel Cost of Unit Power Sales (SL2 Partpts) (A6)	(2,472,546)	(1,386,639)	(1,085,907)	78.3	(533,377)	(327,373)	(206,004)	62.9	0.4636	0.4236	0.0400	9.4
17	Revenues from Off-System Sales (A6)	(37,560,276)	(20,673,259)	(16,887,017)	81.7								
18	TOTAL FUEL COST AND GAINS OF POWER SALES	(137,187,168)	(95,790,620)	(41,396,548)	43.2	(2,834,697)	(2,079,171)	(755,526)	36.3	4.8396	4.6072	0.2324	5.0
19	Net Inadvertent Interchange	0	0	0	NA	0	0	0	NA				
20	ADJUSTED TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 17 + 18 + 19)	2,343,894,036	2,266,943,550	76,950,487	3.4	95,741,375	95,382,739	358,636	0.4	2.4482	2.3767	0.0715	3.0
21	Net Unbilled Sales*	3,751,254	9,293,729	(5,542,475)	NA	153,225	391,035	(237,810)	NA	0.0043	0.0106	(0.0063)	NA
22	Company Use*	3,547,057	3,986,753	(439,696)	NA	144,884	167,743	(22,859)	NA	0.0040	0.0045	(0.0005)	NA
23	T & D Losses*	184,226,879	164,927,752	19,299,127	NA	7,524,993	6,939,359	585,634	NA	0.2095	0.1876	0.0219	NA
24	SYSTEM KWH SALES (EXCL FKEC & CKW A2,p1)	2,343,894,036	2,266,943,550	76,950,486	3.4	87,938,223,396	87,902,906,946	35,316,450	0.0	2.6654	2.5789	0.0865	3.4
25	Wholesale KWH Sales (EXCL FKEC & CKW A2,p1)	159,020	172,554	(13,534)	(7.8)	6,230,535	6,861,289	(630,754)	(9.2)	2.6654	2.5789	0.0865	3.4
26	Jurisdictional KWH Sales	2,343,735,016	2,266,770,997	76,964,019	3.4	87,931,992,861	87,896,045,657	35,947,204	0.0	2.6654	2.5789	0.0865	3.4
26a	Jurisdictional Loss Multiplier	-	-	-	-	-	-	-	-	1.00064	1.00064	0.0000	-
27	Jurisdictional KWH Sales Adjusted for Line Losses	2,345,235,007	2,268,221,731	77,013,276	3.4	87,931,992,861	87,896,045,657	35,947,204	0.0	2.6671	2.5806	0.0865	3.4
28	TRUE-UP **	(42,377,580)	(42,377,581)	1	(0.0)	87,931,992,861	87,896,045,657	35,947,204	0.0	(0.0482)	(0.0482)	0.0000	(0.0)
29	TOTAL JURISDICTIONAL FUEL COST	2,302,857,427	2,225,844,150	77,013,277	3.5	87,931,992,861	87,896,045,657	35,947,204	0.0	2.6189	2.5324	0.0865	3.4
30	Revenue Tax Factor									1.01597	1.01597	0.0000	NA
31	Fuel Factor Adjusted for Taxes									2.6607	2.5728	0.0879	3.4
32	GPIF **	11,367,066	11,367,066	0	NA	87,931,992,861	87,896,045,657	35,947,204	0.0	0.01293	0.01293	0.0000	NA
33	Fuel Factor Including GPIF									2.674	2.586	0.0879	3.4
34	FUEL FAC ROUNDED TO NEAREST .001 CENTS/KWH									2.674	2.586	0.088	3.4

* For Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

Exhibit KLW-1 (Page 10 of 11)

CALCU[illegible]N OF TRUE-UP AND [illegible]TEREST PROVISION

Compan[illegible]rida Power & Light Company

Month of: December 2000

LINE NO.			CURRENT MONTH ACTUAL	CURRENT MONTH UPDATED ESTIMATES (a)	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH DIFFERENCE %	YEAR TO DATE ACTUAL	YEAR TO DATE UPDATED ESTIMATES (a)	YEAR TO DATE DIFFERENCE AMOUNT	YEAR TO DATE DIFFERENCE %
C		**True-up Calculation**								
	1	Jurisdictional Fuel Revenues (Incl. RTP @ CBL) Net of Revenue Taxes	$ 154,153,029	$ 148,578,097	$ 5,574,932	3.8 %	$ 1,833,786,993	$ 1,832,417,732	$ 1,369,261	0.1 %
	2	**Fuel Adjustment Revenues Not Applicable to Period**								
	a1	Prior Period True-up Provision	3,531,465	3,531,465	0	0.0 %	42,377,583	42,377,583	0	0.0 %
	a2	Prior Period True-up Provision	(14,824,048)	(14,824,048)	0	0.0 %	(96,356,314)	(96,356,314)	(0)	0.0 %
	b	GPIF, Net of Revenue Taxes (b)	(932,365)	(932,365)	0	0.0 %	(11,188,376)	(11,188,376)	0	0.0 %
	c	Oil Backout Revenues, Net of revenue taxes	8	0	8	N/A	330	306	24	7.8 %
	3	Jurisdictional Fuel Revenues Applicable to Period	$ 141,928,089	$ 136,353,148	$ 5,574,941	4.1 %	$ 1,768,620,216	$ 1,767,250,931	$ 1,369,285	0.1 %
	4 a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 161,516,695	$ 153,660,321	$ 7,856,374	5.1 %	$ 2,343,894,036	$ 2,266,943,550	$ 76,950,486	3.4 %
	b	Nuclear Fuel Expense - 100% Retail	0	0	0	N/A	0	0	0	N/A
	c	RTP Incremental Fuel -100% Retail	102,365	0	102,365	N/A	1,093,208	712,026	381,182	53.5 %
	d	D&D Fund Payments -100% Retail	0	0	0	N/A	5,776,464	5,930,000	(153,536)	(2.6) %
	e	Adj. Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	161,414,330	153,660,321	7,754,009	5.0 %	2,337,024,365	2,260,301,524	76,569,304	3.4 %
	5	Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.99163 %	99.99072 %	0.00091 %	0.0 %	N/A	N/A	N/A	N/A
	6	Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00064(c)) +(Lines C4b,c,d)	$ 161,606,481	$ 153,744,395	$ 7,862,086	5.1 %	$ 2,345,231,242	$ 2,268,218,080	$ 77,013,162	3.4 %
	7	True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (19,678,392)	$ (17,391,247)	$ (2,287,145)	13.2 %	$ (576,611,026)	$ (500,967,149)	$ (75,643,877)	15.1 %
	8	Interest Provision for the Month (Line D10)	(3,218,488)	(2,774,335)	(444,153)	16.0 %	(18,201,421)	(17,038,223)	(1,163,198)	6.8 %
	9	True-up & Interest Provision Beg of Period-Over/(Under) Recovery	(568,384,101)	(346,067,844)	(222,316,257)	64.2 %	42,377,583	42,377,583	0	0.0 %
	a	Deferred True-up Beginning of Period - Over/(Under) Recovery	(14,824,048)	(163,064,531)	148,240,483	(90.9) %	(96,356,314)	(96,356,314)	0	0.0 %
	10 a	Prior Period True-up Collected/(Refunded) This Period	(3,531,465)	(3,531,465)	0	0.0 %	(42,377,583)	(42,377,583)	0	0.0 %
	b	Prior Period True-up Collected/(Refunded) This Period	14,824,048	14,824,048	(0)	0.0 %	96,356,314	96,356,314	0	0.0 %
	11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (594,812,447)	$ (518,005,376)	$ (76,807,071)	14.8 %	$ (594,812,447)	$ (518,005,376)	$ (76,807,071)	14.8 %
D		**Interest Provision**								
	1	Beginning True-up Amount (Lines C9 + C9a)	$ (583,208,149)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	2	Ending True-up Amount Before Interest (C7+C9+C9a+C10)	$ (591,593,958)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	3	Total of Beginning & Ending True-up Amount	$ (1,174,802,107)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	4	Average True-up Amount (50% of Line D3)	$ (587,401,054)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	5	Interest Rate - First Day Reporting Business Month	6.65000 %	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	6	Interest Rate - First Day Subsequent Business Month	6.50000 %	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	7	Total (Line D5 + Line D6)	13.15000 %	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	8	Average Interest Rate (50% of Line D7)	6.57500 %	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	9	Monthly Average Interest Rate (Line D8 / 12)	0.54792 %	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	10	Interest Provision (Line D4 x Line D9)	$ (3,218,488)	N/A	N/A	N/A	N/A	N/A	N/A	N/A

NOTES

(a) **Per Estimated/Actual, Appendix I, page 3, filed August 23, 2000**

(b) **Generation Performance Incentive Factor is (($11,367,066/12) x 98.4280%) - See Order No. PSC-99-2512-FOF-EI.**

(c) **Jurisdictional Loss Multiplier per Schedule E2 revised December 15, 1999.**

Exhibit KLW-1 (Page 11 of 11)

FLORIDA PUBLIC SERVICE COMMISSION

DIVISION OF REGULATORY OVERSIGHT
BUREAU OF AUDITING SERVICES

Miami District Office

FLORIDA POWER AND LIGHT

NATURAL GAS AUDIT

TWELVE MONTHS ENDED DECEMBER 31, 2000

AUDIT CONTROL NO. 00-353-4-1

Iliana H. Piedra, Audit Manager

Raymond Grant, Audit Staff

Gabriela Leon, Audit Staff

Yen Ngo, Audit Staff

Ruth Young, Audit Staff

Kathy L. Welch
Miami District Office Audit Supervisor

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DIVISION OF REGULATORY OVERSIGHT
AUDITOR'S REPORT

MARCH 26, 2001

TO: FLORIDA PUBLIC SERVICE COMMISSION AND OTHER INTERESTED PARTIES

We have applied the procedures described in this report to audit the purchasing and selling practices of natural gas by Florida Power and Light and FPL Energy Services, Inc., a subsidiary of FPL Group, Inc. during the year 2000.

This is an internal accounting report prepared after performing a limited scope audit. Accordingly, this report should not be relied upon for any purpose except to assist the Commission staff in the performance of their duties. Substantial additional work would have to be performed to satisfy generally accepted auditing standards and produce audited financial statements for public use.

SUMMARY OF SIGNIFICANT PROCEDURES

Our audit was performed by examining, on a test basis, certain transactions and account balances which we believe are sufficient to base our opinion. Our examination did not entail a complete review of all financial transactions of the company. Our more important audit procedures are summarized below. The following definitions apply when used in this report:

Scanned- The documents or accounts were read quickly looking for obvious errors.

Compiled- The exhibit amounts were reconciled with the general ledger, and accounts were scanned for error or inconsistency.

Reviewed- The exhibit amounts were reconciled with the general ledger. The general ledger account balances were traced to subsidiary ledgers, and selective analytical review procedures were applied.

Examined- The exhibit amounts were reconciled with the general ledger. The general legder account balances were traced to subsidiary ledgers. Selective analytical review procedures were applied, and account balances were tested to the extent further described.

Confirmed- Evidential matter supporting an account balance, transaction, or other information was obtained directly from an independent third party.

Verify- The item was tested for accuracy and compared to the substantiating documentation.

FPL ENERGY SERVICES (FPLES) : In order to determine if sales to affiliates were following affiliate transaction rules, verified selected purchases of gas from FPL's Energy Management and Trading invoices. Compared spot trades for Florida Power and Light, FPL Energy Services and FPL Energy.

In order to determine if FPLES was charging its customers reduced rates subsidized by FPL, verified gas revenues to monthly billing records. Read contracts with selected customers and recalculated bills.

In order to determine whether there was cross-subsidy, compiled the calculations of the Management Fee to determine the accuracy of all the components included in the fee and allocation basis to the companies and reviewed types of charges included in the Risk Management Fee.

Read company procedures for the purchase of gas and the code of conduct policy.

Read PSC Order No. 00-2235-FOF-EI - Cost Allocation and Affiliate Transactions. Read applicable FERC orders. Read NARUC White Paper on Affiliate Transactions.

FLORIDA POWER AND LIGHT (FPL):

In order to determine if a cross-subsidy existed because of common use of employees and whether employees selling gas represented themselves as FPL employees, scanned a payroll listing of all utility employees who worked for FPL Energy Services during various months in 2000. Selected employees for interviews. Verified information provided by interviewees. Verified that the related payroll charged to FPL Energy Servicesincludes overhead costs; also, verified that charges for rent expense and furniture and computer charges were also charged to FPL Energy Services.

To determine cost of gas sold, scanned selected months of the utility's Monthly Gas Closing Reports and the Natural Gas Price Computations worksheets. Verified any selected adjustments.

Determined from the Natural Gas Receiving Reports and Natural Gas Requisitions how the sales to FPL Energy Services are recorded.

Compared the unit prices from various sales, including FPL Energy Services, for 2000, from the Miscellaneous Bills for Natural Gas Sales to determine if market rate was charged.

Compared the gas usage from the Natural Gas Price Computations worksheets to actual meter readings.

Read company procedures for the purchase of gas and the code of conduct policy.

Read any related Internal Audits.

Recalculated various electric utility bills for Florida Power and Light customers who are also FPL Energy Services, Inc. customers to determine if FPL customers using FPLES were getting discounts on electric service.

SCOPE LIMITATION:

We were not able to perform a test of the actual Utility purchases of gas because the answer to Document/Record Request 34 (dated 2/22/01) was not complete. The answer to the request (dated 3/7/01) provided a list of gas vendors for the utility for requested months, however, no invoice amounts were included. On 3/8/01 we notified

our FPL coordinator that additional information was needed. As of the end of the audit , this was not provided. Initially, Document/Record Request 9 (1/23/01) asked for documentation related to various gas purchases, the answer provided (dated 2/9/01) was copies of the Monthly Gas Closing Reports, which detail the gas purchases by vendor. However, these amounts represent various invoices and our sample could not be selected from these reports. Request 34 was written as a follow up to Request 9, in order to receive more detail for the amounts included in the Monthly Gas Closing Reports and to be able to select a sample. We will follow up this work in the upcoming Fuel Clause Audit.

AUDIT DISCLOSURE NO. 1

Subject: Fuel Clause And Transportation

Statement of Fact: One of the objectives of this audit was to determine if the sales of gas to FPL Services and other gas companies were removed from the cost of fuel that flowed through the fuel clause and whether transportation was included in the amounts charged to the affiliate.

Schedule A-2 from the Fuel Recovery Clause was reviewed to determine the gas accounts that flow through the fuel clause. It was determined that accounts 501.120-Recoverable Fuel Gas Steam Generation and account 547.120-Recoverable Fuel Gas Other Power Generation relate to gas. Accounts 547.121 and 547.122 also relate to gas in that they are the depreciation of the Fort Lauderdale and Martin Gas pipelines. These relate to the actual utility plant projects and not to the transportation related to sales of gas on the Florida Gas Transmission pipeline.

A few charges to account 501.120 and 547.120 were traced to source documentation to determine how the items were charged (ie. from inventory or directly), and whether sales to other companies were removed from the accounts that went to the fuel clause.

Source documentation consisted of the Natural Gas Requisition. The requisition shows the gas used at each location for each unit times an average unit price that is determined as follows:

Total Cost of Commodity for the Month +
Total Transportation Cost for the Month +
FGT Gas Lateral Payments -
Less Sales of Gas +
Plus or Minus Imbalance Adjustments +
Gas Adjustments To True-Up Accruals=
Total Cost / (Divided by)
Gas Used from CFIS (Plant Metering) =
Unit Price to Cost to Expense

Opinion: The sales of gas to affiliates and other gas companies are removed from the inventory cost at the sales price which is based on the daily market. This cost is sometimes higher than the purchase price and sometimes lower. Prices lower than the FPL purchase price usually occur because the company buying the fuel ordered it at a fixed price the prior month.

The attached schedule summarizes the monthly transactions. The schedule shows that for the year, Florida Power and Light made a profit on the gas sales based on the commodity price alone. However, we cannot determine from the sales schedules provided, which sales are bundled (with transportation) and which are unbundled

(without transportation). A review of the daily sales tickets to Florida Power and Light Energy Services (FPLES) shows that there were occasions where FPLES bought bundled gas from FPL and this is probably true for other sales. When FPL sells gas to other companies, including the affiliate, it is usually sold unbundled (without transportation). The tickets do show, however, that when a bundled sale is made, the charge is high enough to include a charge for transportation.

The schedule also shows that FPLES paid more than the average price of gas sold in each month and that there were sales at lower prices and higher prices. Review of the daily tickets show that the sales were made to Florida Power and Light Energy Services at an amount over the daily market rate.

FLORIDA POWER AND LIGHT
ANALYSIS OF GAS SALES
TEST YEAR 2000

MONTH	SALES TOTAL MMBTU	SALES TOTAL DOLLARS	AVERAGE PRICE	FPL COMM. PURCHASES MMBTU	FPL COMM. PURCHASES DOLLARS	NOTE A AVERAGE PURCHASE PRICE FPL	AVERAGE FPL PRICE BUNDLED	MMBTU SOLD TO SERVICES	DOLLARS SOLD TO SERVICES	UNIT PRICE TO SERVICES	HIGHEST UNIT PRICE ALL SALES	LOWEST UNIT PRICE ALL SALES
JANUARY	1,563,096	3,890,782.25	2.49	21,650,528	51,435,026.25	2.38	2.87	362,183	906,168.51	2.37	4.86	2.23
FEBRUARY	1,081,773	2,869,749.91	2.65	18,433,739	50,074,156.40	2.72	3.26	398,671	1,051,119.74	2.64	4.50	2.63
MARCH	602,008	1,645,475.51	2.73	21,864,439	60,242,748.34	2.74	3.23	406,111	1,072,301.01	2.64	4.25	2.64
APRIL	1,845,204	5,513,495.55	2.99	23,107,057	69,239,058.33	2.96	3.51	416,560	1,231,978.18	2.96	3.08	2.96
MAY	885,508	3,107,747.37	3.51	22,776,227	72,092,775.43	3.17	3.77	505,842	1,782,065.87	3.52	5.00	3.12
JUNE	3,119,914	13,852,224.78	4.44	20,908,318	91,607,663.69	4.38	5.08	459,090	2,141,899.10	4.67	4.90	4.29
JULY	987,007	4,516,161.63	4.58	21,509,918	93,624,798.00	4.35	5.07	479,357	2,204,549.63	4.60	5.10	4.18
AUGUST	1,445,314	6,388,801.94	4.42	21,937,131	85,666,435.32	3.91	4.56	494,684	2,263,087.09	4.57	5.04	4.10
SEPTEMBER	1,245,119	6,406,966.01	5.15	19,388,253	91,419,972.18	4.72	5.45	500,112	2,624,863.51	5.25	5.81	4.62
OCTOBER	772,081	4,082,765.38	5.29	17,214,633	91,069,146.70	5.29	6.06	563,128	3,030,043.69	5.38	5.43	4.68
NOVEMBER	1,646,973	8,229,332.57	5.00	14,976,561	69,657,263.06	4.65	5.40	580,050	2,924,193.40	5.04	6.18	4.52
DECEMBER	3,965,330	34,032,807.34	8.58	13,963,370	86,979,508.60	6.23	6.25	638,640	4,680,349.49	7.33	10.26	7.22
TOTAL	19,159,327	94,536,310.24	4.93	237,820,174	913,108,552.30	3.84		5,824,428	25,912,619.22	4.45		

NOTE A: BEFORE IMBALANCE AND ACCRUAL ADJUSTMENTS AND FGT LATERAL PAYMENTS

AUDIT DISCLOSURE NO. 2

Subject: Cost Allocation Order

Statement of Fact: According to the Cost Allocation and Affiliate Transaction Order PSC-00-2235-FOF-EI, dated November 27, 2000, an affiliate must be charged the higher of fully allocated costs or market, however, the rule is not applicable to "fuel and related transportation services that are subject to Commission review and approval in a cost recovery proceeding".

Deal tickets for several days in the year were obtained and compared for prices charged to all companies FPL sold gas to and to what FPL paid for the gas.

Opinion: The utility sells gas to the non-regulated subsidiary, Florida Power and Light Energy Services (FPLES) and prices it at market price plus a profit margin.

Fully allocated costs would include an allocation of costs of the Energy Marketing and Trading Group since it is making the purchases for FPLES, in addition to bundled or unbundled commodity costs. FPLES has its own buyer, but is not allowed to purchase commodity from anyone but FPL Energy Marketing and Trading (a division of the utility). This requirement was made because of risk management.

Since gas purchases are recovered through the fuel clause, and fuel transactions recovered through the clause are exempt from the affiliate rule requiring the company to transfer costs at the higher of fully allocated costs or market, it appears that FPL is exempt from the affiliate transaction rule.

AUDIT DISCLOSURE NO. 3

Subject: Competitive Pricing

Statement of Fact: Allegations were made that FPLES is charging lower prices than the rest of the industry because it is being subsidized by FPL. Subsidization is being discussed in another disclosure. FPLES did have a higher cost of gas than sales revenue for the year 2000. Review of FPLES sales contracts revealed another reason for the loss that may relate to the low pricing.



Opinion: The pricing model used by FPLES may contribute to the low prices that caused the complaint. The ability of FPL Group to be able to support FPLES so that it can stay in the market in spite of a loss condition may contribute to an anti-competitive environment since many small companies could not sustain a similar loss. However, there are other marketers that also have parent companies that are in a position similar to FPLES.

If FPLES changes the billing methodology for its customers from one that is [redacted] FPLES and FPL may never recover the loss incurred this year.

AUDIT DISCLOSURE NO. 4

Subject: Utility V.S. FPLES

Statement of Fact: Florida Power and Light Energy Services (FPLES), the non-regulated gas marketing affiliate of Florida Power and Light, only records revenues and cost of gas, and sales and administrative costs related to customers that are outside of Florida Power and Light's utility territory. If customers of FPLES are in Florida Power and Light's utility territory, the revenue, cost of gas and other sales and administrative costs related to those customers are recorded as utility revenue and expenses. FPLES customers that are out of territory are approximately 30% of all of its customers. Therefore, approximately 70% of the business of FPLES is recorded in the utility. The percent varies based on the usage of the in-territory customers and direct payroll which is charged based on work orders to in-territory, or out-of-territory time.

FPL employees are selling the service which is being billed by FPLES but recorded by FPL. They represent themselves as FPL employees and not as FPLES employees. The number of customers of FPLES increased 57% (from 91 to 214) in July of 1999 because FPL utility employees participated in a sales blitz that occurred from February to April of 1999.

Opinion: Although the customers receive bills from FPLES, the non-regulated subsidiary, the revenues, cost of gas and transportation, and the sales and administrative costs related to customers in FPL utility territory are recorded in the regulated utility books. FPL representatives believe that in-territory business is base revenue enhancement and should be recorded in the utility business. Whether non-regulated revenues and expenses should be included in regulatory operations needs to be determined.

In addition, because gas sales operated at a loss in the year 2000, the loss related to in-territory customers was passed through utility operations. The company provided an income statement of in-territory revenues and expenses charged to utility operations. It follows this disclosure. It shows a loss of $216,363 for in-territory unregulated gas sales that is recorded in utility books. However, the loss does not include an allocation of corporate overhead costs ($123,133.18 see management fee disclosure) or overhead on payroll charged ($192,622.78 see payroll disclosure). In addition, the income statement was provided the last week of the audit and could not be verified.

CONFIDENTIAL

AUDIT DISCLOSURE NO. 5

SUBJECT: MANAGEMENT FEE

STATEMENT OF FACTS: Costs that relate to all divisions are accumulated and allocated to non-regulated operations using a three-part formula consisting of revenues, plant, and payroll. Overall, 7.22% of these costs were allocated to non-regulated and 92.78% to regulated. The 7.22%, or $8,886,285 was charged to FPL Group Capital, Inc. The company does not charge this amount down to the individual divisions that make up Group Capital. Therefore, the amount related to FPLES is not on the FPLES income statement. However, the affiliate allocation basis for 2000 shows .25% of the 7.22% relates to FPLES.

The types of costs allocated include information management, human resources, finance, corporate communications, auditing, and resource analysis and planning. These amounted to $87,521,399.

In addition, in the year 2000, a category called change in control was charged. Several of the officers contracts contained performance incentive provisions relating to bonuses and stock options that would be received over the life of the contract if certain performance goals were met. The contracts also stated that 100% of the incentives would be paid when the stockholders approved a merger. Therefore, on December 15, the incentives that relate to future performance were required to be paid. An amount of $35,611,782 was recorded for this change of control provision. Of this amount, $33,041,748 was recorded in utility operations (Account 930.299) and $2,570,034 was allocated to non-regulated operations and charged to FPL Group Capital, Inc. It is included in the $8,886,285 above.

Total of the affiliated costs for common business units of $87,521,399 and the change of control of $35,611,782 is $123,133,181.

Because FPLES's in-territory revenues and payroll are recorded in the utility and not in the FPLES books, these revenues and payroll are not included in the percentage allocation used to allocate common management fee related costs.

OPINION: Common overhead costs that relate to the operation of in-territory gas are not separated and not charged on the FPLES in-territory gas income statement.

A revised allocation schedule was prepared that included the revenues shown in the income statement in disclosure four and in-territory payroll provided in another request. Inclusion of these items increases the management fee allocation to FPLES from .25% to .35% or an increase of .10%. Since total management fee allocation costs are $123,133,181, if in-territory gas operations were recorded in FPLES instead of the utility, an additional $123,133.18 would have been removed from FPL utility operations and charged to FPL Group Capital.

2000 FPL Affiliate Allocation Basis

	Revenues 2000 Actual	%	Gross PP&E 2000 Average	%	Total Payroll 2000 Act/Fcst	%	Avg %
FPL UTILITY	$6,360,801,290	89.62%	$18,460,940,678	91.66%	$654,350,722	95.52%	92.27%
FPL ENERGY	$631,610,301	8.90%	$1,557,241,274	7.73%	$21,462,913	3.13%	6.59%
PALM INSURANCE	$30,935,445	0.44%	$0	0.00%	$0	0.00%	0.15%
FPLES	$33,442,352	0.47%	$14,298,811	0.07%	$3,503,087	0.51%	0.35%
FIBERNET	$40,635,859	0.57%	$108,480,893	0.54%	$5,700,000	0.83%	0.65%
TOTAL	$7,097,425,247	100.00%	$20,140,961,656	100.00%	685,016,722	100.00%	100.00%

AUDIT DISCLOSURE NO. 6.

Subject: Charges to FPLES

Statement of Fact: A list of all payroll charged by the utility to FPLES for May and June 1999 and May, June and November 2000 was obtained. This list provided includes payroll charged to FPLES for Expense Requisition (ER) 99 - affiliate charges, which represents affiliate charges for Energy Services for out-of-territory business and charged to FPL utility business for ER 94 - revenue enhancement charges which represents charges for the in-territory business. This is explained further in Disclosure No. 4.

Approximately 15 employees from this list were selected for interviews based on the different locations charged and on whether they charged time to specific months and not others. An additional 10 employees were selected from organizational charts for specific business units which includes sales representatives and account managers. These employees were interviewed to determine the duties they performed, if it appeared they charged enough time, if they knew of any other individuals in their business unit who worked in the gas business and to obtain any other information which could be relevant to the audit. Some of the interviewees mentioned other employees in their business unit who may have charged to the gas business. These employee names were verified to time records to determine that they charged some of their time. The auditors also verified that the payroll charged to FPLES is inclusive of overheads. These overheads (79.22%) are not recorded on in-territory gas payroll. They, therefore, are not included in the Income Statement for in-territory operations shown in Disclosure 4. Therefore, a larger loss would be shown in this statement if these overheads were included. (Payroll in-territory $243,199.67 times 79.22% = $192,662.78 additional expense, additional loss)

Various employees mentioned training given to them and a sales blitz they attended. The number of customers of FPLES increased 135% (from 91 to 214) in July of 1999 because the FPL utility employees participated in the sales blitz that occurred from February to April 1999.

The cost of some brochures and mailings used to promote the sale of gas was paid by Florida Power and Light, charged to in-territory (charged to ER 94). The invoices related to these costs provided by the company total approximately $25,303 and are dated March, April, June and July 2000. FPLES gas operations is charged rent expense along with furniture and computer charges for its two employees which work exclusively for gas.

In addition, it was determined that the salary of the managers that supervise some of the people interviewed were not charged to the in-territory gas operations. The portion of salary related to revenue producing products for these people and the other administrative staff are charged to a utility work order number 2830. Total charges for

this work order are $338,933.87 for the year 2000. These people did also charge a percentage of their time to an out-of-territory work order.

Audit Opinion: For the employees that were interviewed, it appears the time spent on the Gas business correlates with the information given to us in the interviews.

However, the time the utility employees charge to ER 94, as mentioned above, represents amounts that are charged directly to the utility for in-territory business. Therefore, these utility employees are working for the non-regulated gas business.

Payroll overheads, of $192,662.78 for in-territory employees, are never charged to FPLES and are not on the In-Territory Income Statement. It is therefore, included in FPL Utility costs.

It could not be determined if one of the risk managment employees was properly allocated to FPLES. We requested information March 20 which was still not received at the conclussion of the audit.

The costs for some sales brochures and mailings mentioned in the interviews, which totaled approximately $25,303, were charged to in-territory only. The costs are, therefore, included in utility expenses. Because of the timing of receiving the answers to these audit requests, we were unable to do further testing on charges made to FPL utility costs related to in-territory gas to determine if other charges such as this were also charged 100% to the utility. Using the company's methodology of charging in-territory revenues and expenses to the utility and out-of-territory revenues and expenses to FPLES, costs of items used for both in-territory and out-of-territory should have been allocated. They were not. If the Commission determines that non-regulated operations should not be included in utility books, the entire amount of revenue and expense related to in-territory gas should be removed and transferred to FPLES.

Some of the payroll for the managers that was charged to work order 2830 of $338,933.87 also relates to in-territory gas and is not included in the income statement attached to disclosure four. If the Commission determines that non-regulated operations should not be included in utility books, the amount that relates to FPLES products should be charged to FPLES. We were unable to determine the portion of this amount that relates strictly to gas since there are other revenue enhancing products. Because we received the response the last week of the audit, we were unable to obtain information necessary to determine an allocation methodology.

AUDIT DISCLOSURE NO. 7

SUBJECT: RISK MANAGEMENT EXPENSES

STATEMENT OF FACTS: FPLES purchases gas through FPL Energy Marketing and Trading (utility) exclusively. A company representative explained that this is because FPL Energy Marketing and Trading is responsible for risk management.

The risk management system is called the "nucleus" system. Traders input all trades into the system, and the system matches the deal tickets with the confirmations. The system reports are reviewed by FPL Utility personnel. Before July 2000, risk management for FPLES was being performed by FPLES which had its own version of "nucleus."

By FPLES using the utility's risk management system and personnel, two objectives are met. One, a separation of duties and; two, there is no duplication of the system which monitors the trades (nucleus).

Three different situations occurred with regard to FPLES payments for the use of the "nucleus" system.

1. FPLES incurred expenses in 1998 and 1999 for the installation and implementation of the "nucleus" system. The amounts follow:

Total 1998	$612,000
Total 1999	$611,434

None of these expenses were allocated back to FPL Utility for the costs associated with the "in-territory sales." "In-territory sales and costs are " are discussed in Audit Disclosure 4.

2. The expense for the use of "nucleus" for FPLES for the year 2000 is $15,000. This was paid in November 2000 and charged to FPLES. None of this is allocated to FPL utility operations for "in-territory cost of sales."

3. The expense for utility personnel to review the "nucleus" reports for July through December 2000 was $3,282.48 and charged to FPL utility "in-territory" account. The only personnel charge to FPLES for "out-of-territory cost of sales" was $343 in the month of July 2000.

OPINION: It appears that the treatment of risk management expenses is inconsistent from year to year. For the years ended 12/31/98 and 12/31/99, FPLES appears to be paying for both the "in-territory" and "out-of-territory" risk management costs.

For the year ended 12/31/00, FPLES is paying for nucleus but not for any of the payroll associated with risk management except for a minor amount of $343.

Using the company methodology of charging in-territory to the utility and out-of-territory to FPLES, the charges should have all been allocated. If the "in-territory sales and expenses" should be included on FPLES books only and not separated as noted in Disclosure 4, then the entire risk management expense should be on FPL Energy Services books.

FLORIDA PUBLIC SERVICE COMMISSION

DIVISION OF REGULATORY OVERSIGHT
BUREAU OF AUDITING SERVICES

Miami District Office

FLORIDA PUBLIC UTILITIES.

FUEL ADJUSTMENT CLAUSE

YEAR ENDED DECEMBER 31, 2000

DOCKET #010001-EI

AUDIT CONTROL NO. 01-053-4-2

Kathy L. Welch
Audit Manager

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Public Utilities Analyst

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DIVISION OF REGULATORY OVERSIGHT
AUDITOR'S REPORT

June 29, 2000

TO: FLORIDA PUBLIC SERVICE COMMISSION AND OTHER INTERESTED PARTIES

We have applied the procedures described later in this report to the attached Fuel Recovery schedules for the period ended December 31, 2000 for Florida Public Utilities Company. This schedule was prepared as part of the petition for fuel recovery in Docket 010001-EI.

This is an internal accounting report prepared after performing a limited scope audit. Accordingly, this report should not be relied upon for any purpose except to assist the Commission staff in performance of their duties. Substantial additional work would have to be performed to satisfy generally accepted auditing standards and produce audited financial statements for public use.

SUMMARY OF SIGNIFICANT PROCEDURES

Our audit was performed by examining, on a test basis, certain transactions and account balances which we believe are sufficient to base our opinion. Our examination did not entail a complete review of all financial transactions of the company. Our more important audit procedures are summarized below. The following definitions apply when used in this report:

Scanned- The documents or accounts were read quickly looking for obvious errors.

Compiled- The exhibit amounts were reconciled with the general ledger, and accounts were scanned for error or inconsistency.

Reviewed- The exhibit amounts were reconciled with the general ledger. The general ledger account balances were traced to subsidiary ledgers, and selective analytical review procedures were applied.

Examined- The exhibit amounts were reconciled with the general ledger. The general ledger account balances were traced to subsidiary ledgers. Selective analytical review procedures were applied and account balances were tested to the extent further described.

Confirmed- Evidential matter supporting an account balance, transaction or other information was obtained directly from an independent third party.

Verified- The item was tested for accuracy, and substantiating documentation was examined.

Fuel Recovery Schedules: Traced the filing to the general ledger. Reconciled revenues to the revenue and rate reports. Recalculated revenues to verify that the correct rate was used. Traced the beginning period true-up to the order.

Traced fuel costs to invoices and verified GSLD amounts to invoices of customers. Recalculated true-up and verified interest rates.

AUDIT DISCLOSURE NO. 1

SUBJECT: BILLING ERROR

STATEMENT OF FACT: In October 2000, the company implemented a new billing system. When the system was first implemented, several errors occurred. The company underbilled several customers during this time period. It decided not to retroactively bill the customers because the time it would take to determine who should be billed and to correct the billing would cost more than the revenue loss.
When October revenues were recomputed using killowats times approved rates, the revenue that should have been billed was $2,686 more than what was actually billed. The majority of the error, $1,829 was because the company did not bill GSD customers .00988 of the approved .03596 rate.

OPINION: The schedules should and do reflect actual billings. However, actual billings are less than the approved revenues.

EXHIBITS

COMPANY PREPARED SCHEDULES MARIANNA

COMPANY PREPARED SCHEDULES FERNANDINA

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF PURCHASED POWER COSTS AND
CALCULATION OF TRUE-UP AND INTEREST PROVISION
ESTIMATED FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000
BASED ON TWELVE MONTHS ACTUAL

Schedule M1

MARIANNA DIVISION

			ACTUAL JANUARY 2000	ACTUAL FEBRUARY 2000	ACTUAL MARCH 2000	ACTUAL APRIL 2000	ACTUAL MAY 2000	ACTUAL JUNE 2000	ACTUAL JULY 2000	ACTUAL AUGUST 2000	ACTUAL SEPTEMBER 2000	ACTUAL OCTOBER 2000	ACTUAL NOVEMBER 2000	ACTUAL DECEMBER 2000	Total
Total System Sales - KWH			23,029,605	23,761,000	18,854,074	19,329,169	21,014,038	28,078,346	29,392,249	29,248,098	25,702,440	27,708,108	19,889,689	25,373,073	291,379,889
Total System Purchases - KWH			25,405,283	21,869,978	20,533,214	20,259,345	27,972,125	29,492,228	33,080,036	32,724,504	28,981,380	22,816,880	23,473,554	26,995,369	313,803,896
System Billing Demand - KW			60,710	55,374	36,278	41,772	59,415	63,052	69,237	60,214	52,179	54,964	56,676	70,400	680,271
Purchased Power Rates:															
Base Fuel Costs - $/KWH			0.02000	0.02000	0.02000	0.02000	0.02000	0.02000	0.02000	0.02000	0.02000	0.02000	0.02000	0.02000	
Demand and Non-Fuel:															
Demand Charge - $/KW			6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	
Customer Charge - $			550.00	550.00	550.00	550.00	550.00	550.00	550.00	550.00	550.00	550.00	550.00	550.00	
Transformation Charge			31,979	31,980	31,980	31,979	31,979	31,980	32,104	32,105	32,104	32,104	32,104	32,105	
Purchased Power Costs:															
Base Fuel Costs			508,106	437,400	410,664	405,187	559,443	589,845	661,601	654,490	539,628	456,338	469,471	579,907	6,272,080
Subtotal Fuel Costs			508,106	437,400	410,664	405,187	559,443	589,845	661,601	654,490	539,628	456,338	469,471	579,907	6,272,080
Demand and Non-Fuel Costs:															
Demand Charge			386,723	352,732	231,090	266,068	378,474	401,841	441,040	383,563	332,380	350,121	381,027	448,448	4,333,327
Customer Charge			550	550	550	550	550	550	550	550	550	550	550	550	6,600
Transformation Charge			31,979	31,980	31,980	31,979	31,979	31,980	32,104	32,105	32,104	32,104	32,104	32,105	384,504
Subtotal Demand & Non-Fuel Costs			419,252	385,262	263,620	298,617	411,003	434,171	473,694	416,218	385,035	382,775	413,681	481,103	4,724,431
Total System Purchased Power Costs			927,358	822,662	674,284	703,804	970,446	1,024,016	1,135,295	1,070,708	904,663	839,113	883,152	1,061,010	10,996,511
Sales Revenues															
Fuel Adjustment Revenues:		Rates													
Residential	RS	0.03940	456,870	475,299	315,198	316,887	341,310	512,358	551,222	540,083	465,009	464,135	316,966	490,041	5,245,377
Commercial	GS	0.03922	78,147	81,002	68,834	69,032	74,064	100,260	105,954	104,138	92,971	100,621	69,011	81,269	1,026,263
Commercial	GSD	0.03596	223,034	231,362	214,441	224,381	243,125	308,452	308,528	316,659	286,214	323,845	232,597	253,295	3,163,933
Industrial	GSLD	0.03354	96,490	96,971	94,686	99,915	113,857	123,701	127,916	126,001	108,429	133,247	109,228	116,096	1,346,737
Outside Lighting	OL,OL-2	0.02643	5,481	5,566	5,589	5,604	5,610	5,633	5,665	5,947	6,414	5,679	6,191	6,178	69,557
Other	SL-1,SL-2,SL-3	0.02606	2,502	2,500	2,499	2,501	2,494	2,494	2,435	2,571	2,505	2,493	1,481	1,453	27,908
Total Fuel Revenues			864,524	892,760	701,447	718,320	780,460	1,050,898	1,101,720	1,095,399	961,541	1,030,020	736,354	948,332	10,881,775
Non-Fuel Revenues			494,761	507,224	439,837	425,967	464,533	561,319	580,406	580,273	531,450	549,802	456,540	542,294	6,134,406
Total Sales Revenue			1,359,285	1,399,984	1,141,284	1,144,287	1,244,993	1,612,217	1,682,126	1,675,672	1,492,991	1,579,822	1,192,894	1,490,626	17,016,181
KWH Sales:															
Residential	RS		11,594,905	12,062,577	7,999,291	8,042,325	8,662,006	13,002,978	13,989,297	13,706,583	11,801,076	11,780,071	8,044,618	12,506,210	133,192,137
Commercial	GS		1,992,538	2,066,844	1,755,072	1,760,125	1,888,418	2,556,338	2,701,532	2,655,239	2,370,501	2,565,551	1,762,545	2,072,123	26,166,824
Commercial	GSD		6,202,276	6,433,860	5,963,311	6,239,735	6,760,995	8,522,031	8,579,762	8,805,875	7,959,223	9,079,144	6,515,359	7,043,804	88,105,375
Industrial	GSLD		2,936,508	2,891,202	2,829,052	2,978,970	3,394,670	3,688,154	3,813,848	3,756,724	3,232,818	3,972,788	3,256,660	3,461,416	40,212,810
Outside Lighting	OL,OL-2		207,378	210,577	211,468	212,033	212,242	213,133	214,354	225,027	242,694	214,883	234,249	233,755	2,831,793
Other	SL-1,SL-2,SL-3		96,000	95,940	95,880	95,981	95,709	95,712	93,458	98,650	96,128	95,671	56,068	55,765	1,070,950
Total KWH Sales			23,029,605	23,761,000	18,854,074	19,329,169	21,014,038	28,078,346	29,392,249	29,248,098	25,702,440	27,708,108	19,889,689	25,373,073	291,379,889
															Period to Date
True-up Calculation:															
Fuel Revenues			864,524	892,760	701,447	718,320	780,460	1,050,898	1,101,720	1,095,399	961,541	1,030,020	736,354	948,332	10,881,775
True-up Provision		DIVIDED BY 12	(16,076)	(16,076)	(16,076)	(16,076)	(16,076)	(16,076)	(16,076)	(16,076)	(16,076)	(16,076)	(16,076)	(16,072)	(192,906)
Gross Receipts Tax Refund			0	0				0	0	0	0	0	0	0	0
Fuel Revenue			880,600	908,836	717,523	734,396	796,536	1,066,974	1,117,796	1,111,475	977,617	1,046,096	752,430	964,404	11,074,683
Total Purchased Power Costs			927,358	822,662	674,284	703,804	970,445	1,024,016	1,135,295	1,070,708	904,663	839,113	883,152	1,061,010	10,996,510
True-up Provision for the Period			(46,758)	86,174	43,239	30,592	(173,909)	42,958	(17,499)	40,767	72,954	206,983	(110,722)	(96,606)	78,173
Interest Provision for the Period			767	802	1,065	1,211	801	383	365	340	563	1,237	1,433	786	9,753
True-up and Interest Provision Beginning of Period			192,908	130,841	201,741	229,969	245,696	56,512	83,777	50,567	75,598	133,039	325,183	199,818	192,908
True-up Collected or (Refunded)			(16,076)	(16,076)	(16,076)	(16,076)	(16,076)	(16,076)	(16,076)	(16,076)	(16,076)	(16,076)	(16,076)	(16,072)	(192,906)
End of Period, Net True-up			130,841	201,741	229,969	245,696	56,512	83,777	50,567	75,598	133,039	325,183	199,818	87,926	87,926
10% Rule															0.80%
Interest Provision:															
Beginning True-up Amount			192,908	130,841	201,741	229,969	245,696	56,512	83,777	50,567	75,598	133,039	325,183	199,818	
Ending True-up Amount Before Interest			130,074	200,939	228,904	244,485	56,711	83,394	50,202	75,258	132,476	323,946	198,385	87,140	
Total Beginning and Ending True-up			322,982	331,780	430,645	474,454	301,407	139,906	133,979	125,825	208,074	456,985	523,568	286,958	
Average True-up Amount			161,491	165,890	215,323	237,227	150,704	69,953	66,990	62,913	104,037	228,493	261,784	143,479	
Average Annual Interest Rate			5.7000%	5.8000%	5.9350%	6.1250%	6.3750%	6.5750%	6.5400%	6.4900%	6.4900%	6.4950%	6.5700%	6.5750%	
Monthly Average Interest Rate			0.4750%	0.4833%	0.4946%	0.5104%	0.5313%	0.5479%	0.5450%	0.5408%	0.5408%	0.5413%	0.5475%	0.5479%	
Interest Provision			767	802	1,065	1,211	801	383	365	340	563	1,237	1,433	786	

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF PURCHASED POWER COSTS AND
CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD
ESTIMATED FOR THE PERIOD: JANUARY 2000 THROUGH DECEMBER 2000
BASED ON TWELVE MONTHS ACTUAL
(EXCLUDES LINE LOSS , EXCLUDES TAXES)

Schedule F1

FERNANDINA BEACH		ACTUAL JANUARY 2000	ACTUAL FEBRUARY 2000	ACTUAL MARCH 2000	ACTUAL APRIL 2000	ACTUAL MAY 2000	ACTUAL JUNE 2000	ACTUAL JULY 2000	ACTUAL AUGUST 2000	ACTUAL SEPTEMBER 2000	ACTUAL OCTOBER 2000	ACTUAL NOVEMBER 2000	ACTUAL DECEMBER 2000	Total Estimated
Total System Sales - KWH		33,985,617	37,358,607	34,816,926	31,111,088	39,758,285	40,566,272	43,549,150	42,845,733	39,396,119	42,806,663	33,483,001	36,072,639	455,750,100
JSC Purchases - KWH		3,700	234,000	2,100	23,100	7,700	16,700	7,600	3,700	31,600	322,500	32,600	22,800	708,100
JEA Purchases - KWH		37,867,703	35,377,574	36,973,473	30,455,275	48,126,903	44,020,882	47,654,084	45,576,745	40,913,612	39,755,139	34,867,841	39,006,831	481,615,862
System Billing Demand - KW		90,854	77,938	75,757	66,618	87,270	89,510	95,200	94,662	84,179	81,088	78,848	98,381	1,020,005
Purchased Power Rates:														
CCA Fuel Costs - $/KWH		0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	
Base Fuel Costs - $/KWH		0.01845	0.01845	0.01845	0.01845	0.01845	0.01845	0.01845	0.01845	0.01845	0.01845	0.01845	0.01845	
Fuel Adjustment - $/KWH		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	
Demand and Non-Fuel:														
Demand Charge - $/KW		6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	
Customer Charge - $		225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	
Energy Charge (Excl. Fuel) $/KWH		0.00105	0.00105	0.00105	0.00105	0.00105	0.00105	0.00105	0.00105	0.00105	0.00105	0.00105	0.00105	
Purchased Power Costs:														
CCA Fuel Costs		69	4,376	39	432	144	312	142	69	591	6,031	610	426	13,241
JEA Base Fuel Costs		698,659	652,716	682,161	561,900	887,941	812,185	879,218	859,341	754,860	733,482	643,677	719,672	8,885,812
JEA Fuel Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Fuel Costs		698,728	657,092	682,200	562,332	888,085	812,497	879,360	859,410	755,451	739,513	644,287	720,098	8,899,053
Demand and Non-Fuel Costs:														
Demand Charge		545,124	465,828	454,545	399,708	523,620	537,060	571,200	567,972	505,074	486,528	473,088	590,286	6,120,031
Customer Charge		225	225	225	225	225	225	225	225	225	225	225	225	2,700
Energy Charge		39,761	37,146	38,822	31,978	50,533	46,222	50,037	48,906	42,959	41,743	36,632	40,957	505,698
Subtotal Demand & Non-Fuel Costs		585,110	503,197	493,592	431,911	574,378	583,507	621,462	617,103	548,258	528,496	509,945	631,468	6,628,427
Total System Purchased Power Costs		1,283,838	1,160,289	1,175,792	994,243	1,462,463	1,396,004	1,500,822	1,476,513	1,303,709	1,268,009	1,154,232	1,351,566	15,527,480
Less Direct Billing To GSLD Class:														
Demand		226,227	66,982	246,746	135,614	164,168	223,501	160,707	178,776	138,945	147,592	118,667	127,560	1,935,485
Commodity		225,628	240,868	324,272	217,290	348,767	256,365	242,897	234,048	248,520	315,015	256,552	228,229	3,138,447
Net Purchased Power Costs		831,983	850,439	604,774	641,343	949,528	916,138	1,097,218	1,065,689	916,244	805,402	779,013	995,777	10,453,548
Sales Revenues														
Fuel Adjustment Revenues:	Rate													
RS	0.03401	453,063	533,256	335,045	353,841	414,902	577,503	641,135	605,638	549,231	487,486	357,209	482,459	5,790,768
GS	0.03339	67,445	73,702	60,783	67,676	70,133	88,720	94,839	98,737	81,975	91,711	71,119	81,300	948,140
GSD	0.03126	227,055	229,172	214,350	241,340	248,416	250,580	300,380	320,958	258,164	308,478	239,355	240,869	3,079,115
OL	0.02405	1,762	1,812	1,736	1,780	1,791	1,790	1,909	2,028	2,021	2,270	1,890	2,050	22,819
SL,CSL	0.02405	1,818	1,796	1,796	1,821	1,831	1,846	1,858	1,875	1,872	1,891	1,483	1,487	21,372
Total Fuel Revenues (Excl. GSLD)		751,141	839,738	613,710	666,438	737,073	920,439	1,040,121	1,029,236	893,263	891,834	671,056	808,165	9,862,214
GSLD Fuel Revenues		451,655	309,850	571,018	352,900	512,935	479,866	403,604	410,824	387,465	462,607	375,219	355,789	5,073,932
Non-Fuel Revenues		555,777	578,707	511,153	498,553	547,850	631,044	665,364	669,281	608,779	909,107	529,970	573,993	7,281,548
Total Sales Revenue		1,758,773	1,729,295	1,695,881	1,518,891	1,797,858	2,031,349	2,109,089	2,109,341	1,889,507	2,263,548	1,576,245	1,737,917	22,217,694
KWH Sales:														
RS		13,323,524	15,680,153	9,852,676	10,404,924	12,200,527	16,982,008	18,853,078	17,806,991	16,150,575	14,338,904	10,500,640	14,425,358	170,521,356
GS		2,019,915	2,207,298	1,820,401	2,026,835	2,100,415	2,657,069	2,840,355	2,957,091	2,455,083	2,746,672	2,129,955	2,434,865	28,395,954
GSD		7,263,436	7,331,153	6,856,993	7,720,411	7,946,759	8,016,010	9,609,080	10,267,381	8,258,604	9,868,078	7,656,895	7,705,336	98,500,134
GSLD		11,230,000	11,990,000	10,140,000	10,810,000	17,360,000	12,760,000	12,090,000	11,650,000	12,370,000	15,680,000	12,770,000	11,360,000	156,210,000
OL		73,250	75,335	72,188	73,195	74,458	74,429	79,396	84,317	84,018	94,371	78,594	85,256	948,805
SL,CSL		75,492	74,668	74,008	75,723	76,128	76,758	77,241	77,953	77,839	78,640	61,662	61,824	886,616
Total KWH Sales		33,985,617	37,358,607	34,816,926	31,111,088	39,758,285	40,566,272	43,549,150	42,845,733	39,396,119	42,806,663	33,197,766	36,072,639	455,464,865
True-up Calculation (Excl. GSLD):														
Fuel Revenues		751,141	839,738	613,710	666,438	737,073	920,439	1,040,121	1,029,236	893,263	891,834	671,056	808,165	9,862,214
True-up Provision		(87,280)	(87,280)	(87,280)	(87,280)	(87,280)	(87,280)	(87,280)	(87,280)	(87,280)	(87,280)	(87,280)	(87,287)	(1,047,367)
Gross Receipts Tax Refund		0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Revenue		838,421	927,018	700,990	753,718	824,353	1,007,719	1,127,401	1,116,516	980,543	979,114	758,336	895,452	10,909,581
Net Purchased Power Costs		831,983	850,439	604,774	641,343	949,529	916,138	1,097,218	1,065,689	916,244	805,402	779,013	995,777	10,453,549
True-up Provision for the Period		6,438	76,579	96,216	112,375	(125,176)	91,581	30,183	50,827	64,299	173,712	(20,677)	(100,325)	456,032
Interest Provision for the Period		4,783	4,668	4,796	5,061	4,797	4,403	4,260	3,997	3,858	4,054	4,064	3,280	52,021
True-up and Interest Provision														
Beginning of Period		1,047,367	971,308	965,275	979,007	1,009,163	801,504	810,208	757,371	724,915	705,792	796,278	692,385	1,047,367
True-up Collected or (Refunded)		(87,280)	(87,280)	(87,280)	(87,280)	(87,280)	(87,280)	(87,280)	(87,280)	(87,280)	(87,280)	(87,280)	(87,287)	(1,047,367)
End of Period, Net True-up		971,308	965,275	979,007	1,009,163	801,504	810,208	757,371	724,915	705,792	796,278	692,385	508,053	508,053
10% Rule Interest Provision:														4.86%
Beginning True-up Amount		1,047,367	971,308	965,275	979,007	1,009,163	801,504	810,208	757,371	724,915	705,792	796,278	692,385	
Ending True-up Amount Before Interest		966,525	960,607	974,211	1,004,102	796,707	805,805	753,111	720,918	701,934	792,224	688,321	504,773	
Total Beginning and Ending True-up		2,013,892	1,931,915	1,939,486	1,983,109	1,805,870	1,607,309	1,563,319	1,478,289	1,426,849	1,498,016	1,484,599	1,197,158	
Average True-up Amount		1,006,946	965,958	969,743	991,555	902,935	803,655	781,660	739,145	713,425	749,008	742,300	598,579	
Average Interest Rate		5.7000%	5.8000%	5.9350%	6.1250%	6.3750%	6.5750%	6.5400%	6.4900%	6.4900%	6.4950%	6.5700%	6.5750%	
Monthly Average Interest Rate		0.4750%	0.4833%	0.4946%	0.5104%	0.5313%	0.5479%	0.5450%	0.5408%	0.5408%	0.5413%	0.5475%	0.5479%	
Interest Provision		4,783	4,668	4,796	5,061	4,797	4,403	4,260	3,997	3,858	4,054	4,064	3,280	

APPENDIX I
FUEL COST RECOVERY
FORECAST ASSUMPTIONS

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DOCKET NO. 010001-EI
EXHIBIT_____
PAGES 1-15
AUGUST 31, 2001

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010001-EI EXHIBIT NO. 24
COMPANY/
WITNESS: Yupp
DATE: 11-26-21-01

APPENDIX I
FUEL COST RECOVERY
FORECAST ASSUMPTIONS

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FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

HEAVY FUEL OIL ($/BBL)

JANUARY THROUGH DECEMBER, 2002

BASE CASE

	2002											
SULFUR GRADE	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
0.7% SULFUR	$25.09	$23.64	$22.53	$22.54	$23.46	$24.07	$24.59	$24.60	$25.47	$25.34	$23.84	$20.71
1.0% SULFUR	$23.73	$22.39	$21.45	$21.57	$22.22	$23.00	$23.53	$23.56	$24.43	$24.41	$22.52	$19.37
1.5% SULFUR	$22.61	$21.09	$20.09	$20.18	$20.84	$21.72	$22.38	$22.44	$23.26	$23.19	$21.40	$18.17
2.0% SULFUR	$21.49	$19.79	$18.74	$18.79	$19.46	$20.44	$21.24	$21.32	$22.08	$21.97	$20.28	$16.96
2.5% SULFUR	$20.36	$18.48	$17.38	$17.40	$18.08	$19.16	$20.09	$20.21	$20.91	$20.75	$19.16	$15.76
3.0% SULFUR	$19.24	$17.18	$16.02	$16.00	$16.70	$17.88	$18.94	$19.09	$19.73	$19.53	$18.04	$14.56

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

LIGHT FUEL OIL ($/BBL)

JANUARY THROUGH DECEMBER, 2002

BASE CASE

	2002											
SULFUR GRADE	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
0.3% SULFUR	$31.95	$30.23	$28.84	$28.16	$28.24	$28.14	$28.93	$30.53	$32.87	$32.05	$30.85	$28.34
0.5% SULFUR	$31.13	$29.44	$28.07	$27.40	$27.46	$27.36	$28.19	$29.72	$32.01	$31.25	$30.00	$27.57

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COST

SOLID FUELS ($/MMBTU)

JANUARY THROUGH DECEMBER, 2002

BASE CASE

	2002											
FUEL TYPE	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
SOLID FUEL	$1.52	$1.49	$1.48	$1.47	$1.49	$1.49	$1.49	$1.53	$1.51	$1.50	$1.51	$1.51

FLORIDA POWER & LIGHT COMPANY

PROJECTED TOTAL NATURAL GAS PRICES AND TRANSPORTATION CAPACITY AVAILABILITY

JANUARY THROUGH DECEMBER, 2002

BASE CASE

NATURAL GAS TRANSPORTATION CAPACITY AVAILABILITY TO FPL BY SERVICE TYPE (MMBTU/DAY) (000'S)	2002											
	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
FIRM TRANSPORTATION	710	710	710	839	874	874	874	874	874	839	750	750
NON-FIRM	707	753	639	617	683	409	175	113	214	431	695	630
WEIGHTED-AVERAGE DISPATCH PRICE BY TYPE OF TRANSPORTATION SERVICE ($/MMBTU)												
FIRM TRANSPORTATION	$4.11	$4.04	$3.88	$3.59	$3.62	$3.70	$3.68	$3.78	$3.73	$3.76	$3.89	$4.08
NON-FIRM	$4.51	$4.44	$4.27	$3.99	$4.00	$4.09	$4.07	$4.17	$4.12	$4.15	$4.29	$4.48

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

HEAVY FUEL OIL ($/BBL)

JANUARY THROUGH DECEMBER, 2002

LOW CASE

	2002											
SULFUR GRADE	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
0.7% SULFUR	$16.74	$15.77	$15.03	$15.04	$15.65	$16.05	$16.40	$16.41	$16.99	$16.90	$15.90	$13.81
1.0% SULFUR	$15.83	$14.94	$14.31	$14.39	$14.82	$15.34	$15.70	$15.71	$16.30	$16.28	$15.02	$12.92
1.5% SULFUR	$15.08	$14.07	$13.40	$13.46	$13.90	$14.49	$14.93	$14.97	$15.51	$15.47	$14.27	$12.12
2.0% SULFUR	$14.33	$13.20	$12.50	$12.53	$12.98	$13.63	$14.16	$14.22	$14.73	$14.65	$13.53	$11.31
2.5% SULFUR	$13.58	$12.33	$11.59	$11.60	$12.06	$12.78	$13.40	$13.48	$13.94	$13.84	$12.78	$10.51
3.0% SULFUR	$12.83	$11.46	$10.69	$10.67	$11.14	$11.93	$12.63	$12.73	$13.16	$13.03	$12.03	$9.71

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

LIGHT FUEL OIL ($/BBL)

JANUARY THROUGH DECEMBER, 2002

LOW CASE

	2002											
SULFUR GRADE	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
0.3% SULFUR	$21.31	$20.16	$19.24	$18.78	$18.84	$18.77	$19.29	$20.36	$21.92	$21.38	$20.57	$18.91
0.5% SULFUR	$20.76	$19.63	$18.73	$18.28	$18.32	$18.25	$18.80	$19.82	$21.35	$20.84	$20.01	$18.39

FLORIDA POWER & LIGHT COMPANY

PROJECTED TOTAL NATURAL GAS PRICES AND TRANSPORTATION CAPACITY AVAILABILITY

JANUARY THROUGH DECEMBER, 2002

LOW CASE

NATURAL GAS TRANSPORTATION CAPACITY AVAILABILITY TO FPL BY SERVICE TYPE (MMBTU/DAY) (000'S)	2002											
	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
FIRM TRANSPORTATION	710	710	710	839	874	874	874	874	874	839	750	750
NON-FIRM	707	753	639	617	683	409	175	113	214	431	695	630
WEIGHTED-AVERAGE DISPATCH PRICE BY TYPE OF TRANSPORTATION SERVICE ($/MMBTU)												
FIRM TRANSPORTATION	$2.74	$2.71	$2.59	$2.39	$2.42	$2.49	$2.44	$2.53	$2.48	$2.49	$2.58	$2.71
NON-FIRM	$3.11	$3.08	$2.96	$2.76	$2.78	$2.85	$2.81	$2.90	$2.85	$2.86	$2.95	$3.08

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

HEAVY FUEL OIL ($/BBL)

JANUARY THROUGH DECEMBER, 2002

HIGH CASE

	2002											
SULFUR GRADE	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
0.7% SULFUR	$33.45	$31.52	$30.03	$30.05	$31.27	$32.09	$32.78	$32.80	$33.95	$33.78	$31.78	$27.61
1.0% SULFUR	$31.64	$29.85	$28.59	$28.76	$29.61	$30.66	$31.37	$31.40	$32.57	$32.53	$30.02	$25.82
1.5% SULFUR	$30.14	$28.11	$26.79	$26.90	$27.78	$28.95	$29.84	$29.91	$31.00	$30.91	$28.53	$24.22
2.0% SULFUR	$28.64	$26.38	$24.98	$25.05	$25.94	$27.25	$28.31	$28.42	$29.43	$29.28	$27.03	$22.61
2.5% SULFUR	$27.15	$24.64	$23.17	$23.19	$24.10	$25.54	$26.78	$26.94	$27.87	$27.66	$25.54	$21.01
3.0% SULFUR	$25.65	$22.90	$21.36	$21.33	$22.26	$23.84	$25.25	$25.45	$26.30	$26.03	$24.05	$19.40

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

LIGHT FUEL OIL ($/BBL)

JANUARY THROUGH DECEMBER, 2002

HIGH CASE

	2002											
SULFUR GRADE	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
0.3% SULFUR	$42.60	$40.30	$38.44	$37.54	$37.64	$37.51	$38.56	$40.70	$43.81	$42.72	$41.12	$37.78
0.5% SULFUR	$41.50	$39.24	$37.42	$36.52	$36.61	$36.47	$37.57	$39.61	$42.67	$41.65	$39.99	$36.75

FLORIDA POWER & LIGHT COMPANY

PROJECTED TOTAL NATURAL GAS PRICES AND TRANSPORTATION CAPACITY AVAILABILITY

JANUARY THROUGH DECEMBER, 2002

HIGH CASE

NATURAL GAS TRANSPORTATION CAPACITY AVAILABILITY TO FPL BY SERVICE TYPE (MMBTU/DAY) (000'S)	2002											
	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
FIRM TRANSPORTATION	710	710	710	839	874	874	874	874	874	839	750	750
NON-FIRM	707	753	639	617	683	409	175	113	214	431	695	630
WEIGHTED-AVERAGE DISPATCH PRICE BY TYPE OF TRANSPORTATION SERVICE ($/MMBTU)												
FIRM TRANSPORTATION	$5.48	$5.38	$5.16	$4.80	$4.81	$4.91	$4.91	$5.02	$4.98	$5.02	$5.21	$5.45
NON-FIRM	$5.92	$5.81	$5.58	$5.21	$5.23	$5.33	$5.33	$5.44	$5.40	$5.44	$5.64	$5.88

FLORIDA POWER & LIGHT
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
PERIOD OF: JANUARY THROUGH DECEMBER, 2002

PLANT/UNIT	PROJECTED FORCED OUTAGE FACTOR (%)	PROJECTED MAINTENANCE OUTAGE FACTOR (%)	PLANNED OUTAGE FACTOR (%)	OVERHAUL DATES *	OVERHAUL DATES *
Cape Canaveral 1	1.2	4.3	0.0	NONE	
Cape Canaveral 2	1.2	4.3	3.8	04/03/02 - 04/17/02	
Cutler 5	1.0	1.5	0.0	NONE	
Cutler 6	1.4	2.0	0.0	NONE	
Lauderdale 4	0.6	4.8	2.7	03/09/02 - 03/18/02	
Lauderdale 5	0.6	4.8	2.8	09/28/02 - 10/07/02	
Ft. Myers Repower	0.6	6.0	0.0	NONE	
Manatee 1	1.0	4.0	7.7	04/15/02 - 05/12/02	
Manatee 2	1.0	3.8	7.7	04/20/02 - 05/19/02	
Martin 1	1.0	3.6	3.8	11/30/02 - 12/15/02	
Martin 2	0.9	3.0	3.8	03/02/02 - 03/17/02	
Martin 3	0.6	5.2	0.0	NONE	
Martin 4	0.6	4.9	4.2	04/20/02 - 05/14/02	10/01/02 - 10/08/02 **
Port Everglades 1	1.9	2.8	0.0	NONE	
Port Everglades 2	1.9	2.8	3.8	04/06/02 - 04/21/02	
Port Everglades 3	1.1	4.0	0.0	NONE	
Port Everglades 4	1.0	4.0	7.7	11/02/02 - 12/01/02	
Putnam 1	1.1	4.0	5.5	10/26/02 - 11/30/02 **	
Putnam 2	1.1	3.7	7.7	09/28/02 - 10/26/02	** 03/23/02 - 04/20/02 **
Riviera 3	3.0	3.6	0.0	NONE	
Riviera 4	3.1	4.7	0.0	NONE	
Sanford 3	1.7	2.7	3.8	11/16/02 - 11/30/02	
Sanford 4	0.0	0.3	0.0	NONE	
Sanford Repower 5	0.6	4.5	0.0	NONE	-
Turkey Point 1	1.1	4.1	7.7	11/30/02 - 12/27/02	
Turkey Point 2	1.2	4.3	0.0	NONE	
Turkey Point 3	1.3	1.3	0.0	NONE	
Turkey Point 4	1.1	1.1	8.2	03/25/02 - 04/24/02	
St. Lucie 1	1.1	1.1	8.2	09/30/02 - 10/30/02	
St. Lucie 2	1.3	1.3	0.0	NONE	
St. Johns River 1	2.0	5.2	0.0	NONE	
St. Johns River 2	1.8	4.8	8.2	03/16/02 - 04/15/02	
Scherer 4	1.7	4.8	12.1	11/09/02 - 12/22/02	

* Note: Overhaul dates shown in parentheses begin before or end after the projected period.
** Partial Planned Outage

Based on outage hours submitted for IRP
FOF=FOH/8760 ; POF=POH/8760 ; POF=POH/8760

Changes in Continuous Ratings in FPL Units for 2002

Month	Ft. Myers Repowering	(1) Ft. Myers Repowering CTs	(2) Sanford 5 Repowering	Sanford 4 Repowering	(3) Sanford 4	Total Net MW Change
Janurary	0	0	0	0	0	+ 0
February	0	0	0	0	0	+ 0
March	0	-1086	0	0	-390	-1476
April	0	-978	0	0	-390	-1368
May	0	-978	0	0	-390	-1368
June	+ 1473	-894	0	0	-390	+ 189
July	+ 1473	-894	+ 957	0	-390	+ 1146
August	+ 1473	-894	+ 957	0	-390	+ 1146
September	+ 1473	-894	+ 957	0	-390	+ 1146
October	+ 1498	-978	+ 986	0	-390	+ 1116
November	+ 1498	-978	+ 986	0	-390	+ 1116
December	+ 1617	-1086	+ 1065	+ 1065	-390	+ 2271

Notes:

(1) Part of the Ft. Myers repowering work involves the installation of 6 CTs which have been working in a stand-alone CT mode since late 2000 and will continue to operate in this mode until February 2002. In March they will come off-line and will return to service in combined cycle mode in June 2002 as part of the Ft. Myers Repowered plant. The continuous rating of each CT is 149 MW in Summer, 163 MW in Spring/Fall, and 181 MW in Winter.

(2) Sanford 5 will return to service in combined cycle mode beginning in July 2002

(3) Sanford 4 will come off-line beginning in March 2002 and will return to service in December 2002 in combined cycle mode.

FPL NETWORK RESOURCE ADDITIONS

POWER PURCHASE SUMMARY

TERMS	FPC	WHIDDEN/PROGRESS ENERGY VENTURES	SHADY HILLS/ RELIANT	OLEANDER/CONSTELLATION UNIT 1	OLEANDER/CONSTELLATION UNIT 2
LOCATION/COUNTY	FPC SYSTEM	DESOTO	PASCO	BREVARD	BREVARD
START DATE	Apr-01	Jun-02	Feb-02	Jun-02	Jun-02
END DATE	Dec-04	May-05	Feb-07	May-05	Apr-03
SUMMER MEGAWATTS	50	298	447	149	149
WINTER MEGAWATTS	50	362	543	181	181
UNITS	-	2 CT'S	3 CT'S	1 CT	1 CT
TOLLING	-	YES	YES	YES	YES
2002 CAPACITY PAYMENTS IN DOLLARS	$11,538,000	$17,100,000	$30,084,780	$8,381,250	$9,607,650
NOTE 1:	FPL can increase summer output by 15 megawatts when utilizing power augmentation				

APPENDIX I

FUEL COST RECOVERY

TRUE UP CALCULATION

KMD - 1
DOCKET NO. 010001 - EI
FPL WITNESS: K. M. DUBIN
April 2, 2001

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010001-EI EXHIBIT NO. 25
COMPANY/
WITNESS. Dubin
DATE: 11-20 & 21-01

APPENDIX I

FUEL COST RECOVERY

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3	SUMMARY OF NET TRUE UP AMOUNT
4	CALCULATION OF FINAL TRUE UP AMOUNT
6	CALCULATION OF FINAL TRUE UP VARIANCES

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP FOR THE
PERIOD JANUARY THROUGH DECEMBER 2000

1	End of Period True-up for the period January through December 2000 (from page 6, lines D7 & D8)	$	(594,812,447)
2	Less - Estimated/Actual True-up for the same period *		(518,005,376)
3	Net True-up for the period January through December 1999	$	(76,807,071)

( ) Reflects Underrecovery

* Approved in FPSC Order No. PSC-00-2385-FOF-EI dated December 12, 2000.

COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2000
CALCULATION OF FINAL TRUE UP AMOUNT

LINE NO.			(1) JANUARY	(2) FEBRUARY	(3) MARCH	(4) APRIL	(5) MAY	(6) JUNE
A		Fuel Costs & Net Power Transactions						
1	a	Fuel Cost of System Net Generation	$ 96,801,931	$ 89,681,397	$ 115,028,695	$ 125,719,236	$ 176,849,754	$ 225,361,627
	b	Nuclear Fuel Disposal Costs	2,036,555	1,944,914	1,602,326	1,866,226	1,661,490	2,034,696
	c	Coal Cars Depreciation & Return	365,614	363,669	361,724	359,780	348,349	334,538
	d	Gas Pipelines Depreciation & Return	232,060	230,605	229,149	227,694	226,238	224,783
	e	DOE D&D Fund Payment	0	0	0	0	0	0
2	a	Fuel Cost of Power Sold	(6,982,435)	(5,004,820)	(2,742,110)	(3,361,014)	(6,434,607)	(7,951,877)
	b	Revenues from Off-System Sales	(2,032,199)	(1,088,469)	(98,998)	(437,291)	(3,754,203)	(2,079,107)
3	a	Fuel Cost of Purchased Power	9,940,690	10,374,712	11,077,393	14,831,564	14,023,674	12,679,928
	b	Energy Payments to Qualifying Facilities	9,460,941	10,963,890	11,294,122	11,672,716	9,682,160	7,388,362
4		Energy Cost of Economy Purchases	2,108,781	4,097,320	5,607,152	5,167,404	4,631,898	6,452,372
5		Total Fuel Costs & Net Power Transactions	$ 111,931,938	$ 111,563,218	$ 142,359,453	$ 156,046,315	$ 197,234,753	$ 244,445,322
6		Adjustments to Fuel Cost:						
	a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(1,506,387)	(1,541,736)	(1,556,068)	(2,075,885)	(2,183,063)	(2,605,378)
	b	Reactive and Voltage Control Fuel Revenue	(78,230)	(150,593)	(137,195)	(34,543)	(106,948)	(77,375)
	c	Inventory Adjustments	(119,002)	(110,259)	(283,106)	(89,610)	(397,453)	303,295
	d	Non Recoverable Oil/Tank Bottoms	79,085	44,306	13,455	231,797	93,408	0
	e	Modifications to Burn Low Gravity Oil	1,154	21	21,046	0	0	0
7		Adjusted Total Fuel Costs & Net Power Transactions	$ 110,308,558	$ 109,804,957	$ 140,417,585	$ 154,078,074	$ 194,640,697	$ 242,065,864
B		kWh Sales						
1		Jurisdictional kWh Sales (RTP @ CBL)	6,532,531,363	6,336,618,395	6,196,013,924	6,345,577,574	6,738,781,471	8,226,383,453
2		Sale for Resale ($Excluding FKEC & CKW)	528,971	729,525	422,718	676,003	584,008	654,258
3		Sub-Total Sales ($Excluding FKEC & CKW)	6,533,060,334	6,337,347,920	6,196,436,642	6,346,253,577	6,739,365,479	8,227,037,711
		Jurisdictional % of Total kWh Sales (lines B1/B3)	99.99190 %	99.98849 %	99.99318 %	99.98935 %	99.99133 %	99.99205 %
C		True-up Calculation						
1		Jurisdictional Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 120,687,586	$ 116,379,027	$ 113,813,705	$ 116,555,386	$ 123,906,914	$ 164,957,826
2		Fuel Adjustment Revenues Not Applicable to Period:						
	a 1	Prior Period True-up Provision	3,531,465	3,531,465	3,531,465	3,531,465	3,531,465	3,531,465
	a 2	Prior Period True-up Provision	0	0	0	0	0	(7,412,024)
	b	GPIF, Net of Revenue Taxes (b)	(932,365)	(932,365)	(932,365)	(932,365)	(932,365)	(932,365)
	c	Oil Backout Revenues, Net of revenue Taxes	2	43	(3)	6	43	214
3		Jurisdictional Fuel Revenues Applicable to Period	$ 123,286,688	$ 118,978,170	$ 116,412,802	$ 119,154,492	$ 126,506,057	$ 160,145,117
4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 110,308,558	$ 109,804,957	$ 140,417,585	$ 154,078,074	$ 194,640,697	$ 242,065,864
	b	Nuclear Fuel Expense - 100% Retail	0	0	0	0	0	0
	c	RTP Incremental Fuel -100% Retail	70,392	43,654	83,536	58,870	117,510	97,742
	d	D&D Fund Payments -100% Retail	0	0	0	0	0	0
	e	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	110,238,166	109,761,303	140,334,048	154,019,204	194,523,187	241,968,122
5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.99190 %	99.98849 %	99.99318 %	99.98935 %	99.99133 %	99.99205 %
6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00064) +(Lines C4b,c,d)	$ 110,370,175	$ 109,862,563	$ 140,497,821	$ 154,160,233	$ 194,748,315	$ 242,201,475
7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ 12,916,513	$ 9,115,607	$ (24,085,019)	$ (35,005,738)	$ (68,242,258)	$ (82,056,358)
8		Interest Provision for the Month (Line D10)	(234,109)	(203,171)	(263,389)	(442,000)	(755,399)	(1,194,043)
9		True-up & Interest Provision Beg of Period-Over/(Under) Recovery	42,377,583	51,528,521	56,909,492	29,029,619	(9,949,584)	(82,478,707)
		Deferred True-up Beginning of Period - Over/(Under) Recovery	(96,356,314)	(96,356,314)	(96,356,314)	(96,356,314)	(96,356,314)	(96,356,314)
10	a	Prior Period True-up Collected/(Refunded) This Period	(3,531,465)	(3,531,465)	(3,531,465)	(3,531,465)	(3,531,465)	(3,531,465)
	b	Prior Period True-up Collected/(Refunded) This Period						7,412,024
11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (44,827,793)	$ (39,446,822)	$ (67,326,696)	$ (106,305,898)	$ (178,835,021)	$ (258,204,863)

NOTES

(a) Per Order No. PSC-00-1081-PCO-EI, FPL was authorized to collect 60% of the $231 million expense increase anticipated in the 2000 Midcourse Correction.
(b) Generation Performance Incentive Factor is (($11,367,066/12) x 98.4280%) - See Order No. PSC-99-2512-FOF-EI.
(c) Jurisdictional Loss Multiplier per Schedule E2 revised December 15, 1999.

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COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2000
CALCULATION OF FINAL TRUE UP AMOUNT

	LINE NO.			(7) JULY	(8) AUGUST	(9) SEPTEMBER	(10) OCTOBER	(11) NOVEMBER	(12) DECEMBER	(13) TOTAL PERIOD
A			Fuel Costs & Net Power Transactions							
	1	a	Fuel Cost of System Net Generation	$ 241,544,424	$ 248,469,620	$ 263,516,625	$ 212,033,477	$ 152,645,910	$ 171,601,808	$ 2,119,254,505
		b	Nuclear Fuel Disposal Costs	1,996,306	2,098,706	1,960,807	1,593,707	2,086,551	2,032,265	22,914,548
		c	Coal Cars Depreciation & Return	332,805	331,073	329,340	327,607	325,875	324,142	4,104,516
		d	Gas Pipelines Depreciation & Return	223,327	221,871	220,416	218,960	217,505	216,049	2,688,657
		e	DOE D&D Fund Payment	0	0	0	0	5,776,464	0	5,776,464
	2	a	Fuel Cost of Power Sold	(12,522,898)	(13,088,555)	(6,879,491)	(5,761,015)	(6,150,382)	(22,747,689)	(99,626,894)
		b	Revenues from Off-System Sales	(4,460,012)	(5,340,651)	(1,146,537)	(524,735)	(1,389,722)	(15,208,352)	(37,560,276)
	3	a	Fuel Cost of Purchased Power	14,169,527	15,440,626	13,057,466	13,114,310	12,366,886	13,761,156	154,837,932
		b	Energy Payments to Qualifying Facilities	16,041,026	13,407,118	11,968,165	15,617,484	7,357,131	12,320,289	137,173,404
	4		Energy Cost of Economy Purchases	6,605,747	6,488,008	11,663,945	9,067,913	3,183,739	1,822,072	66,896,351
	5		Total Fuel Costs & Net Power Transactions	$ 263,930,252	$ 268,027,816	$ 294,690,736	$ 245,687,708	$ 176,419,958	$ 164,121,740	$ 2,376,459,208
	6		Adjustments to Fuel Cost:							
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(3,174,826)	(3,685,463)	(3,461,679)	(3,469,913)	(3,065,552)	(2,397,036)	(30,722,986)
		b	Reactive and Voltage Control Fuel Revenue	(36,383)	(29,386)	(29,880)	(23,417)	(56,618)	(33,329)	(793,897)
		c	Inventory Adjustments	(207,089)	(208,856)	(55,586)	(126,894)	105,849	(173,846)	(1,362,557)
		d	Non Recoverable Oil/Tank Bottoms	0	0	0	(169,170)	0	0	292,881
		e	Modifications to Burn Low Gravity Oil	0	(43)	0	0	43	(834)	21,387
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 260,511,954	$ 264,104,068	$ 291,143,591	$ 241,898,314	$ 173,403,680	$ 161,516,695	$ 2,343,894,036
B			kWh Sales							
	1		Jurisdictional kWh Sales (RTP @ CBL)	8,509,495,477	8,739,080,561	8,874,449,923	7,955,150,648	6,671,823,412	6,806,086,660	87,931,992,861
	2		Sale for Resale ($Excluding FKEC & CKW)	328,806	152,716	502,199	553,362	528,362	569,607	6,230,535
	3		Sub-Total Sales ($Excluding FKEC & CKW)	8,509,824,283	8,739,233,277	8,874,952,122	7,955,704,010	6,672,351,774	6,806,656,267	87,938,223,396
			Jurisdictional % of Total kWh Sales (lines B1/B3)	99.99614 %	99.99825 %	99.99434 %	99.99304 %	99.99208 %	99.99163 %	N/A
C			True-up Calculation							
	1		Jurisdictional Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 192,977,164	$ 197,883,559	$ 201,095,236	$ 180,219,172	$ 151,158,389	$ 154,153,029	$ 1,833,786,993
	2		Fuel Adjustment Revenues Not Applicable to Period:							
		a 1	Prior Period True-up Provision	3,531,465	3,531,465	3,531,465	3,531,465	3,531,465	3,531,465	42,377,583
		a 2	Prior Period True-up Provision	(14,824,048)	(14,824,048)	(14,824,048)	(14,824,048)	(14,824,048)	(14,824,048)	(96,356,314)
		b	GPIF, Net of Revenue Taxes (b)	(932,365)	(932,365)	(932,365)	(932,365)	(932,365)	(932,365)	(11,188,376)
		c	Oil Backout Revenues, Net of revenue Taxes	1	(1)	(1)	10	7	8	330
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 180,752,217	$ 185,658,610	$ 188,870,287	$ 167,994,234	$ 138,933,448	$ 141,928,089	$ 1,768,620,216
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 260,511,954	$ 264,104,068	$ 291,143,591	$ 241,898,314	$ 173,403,680	$ 161,516,695	$ 2,343,894,036
		b	Nuclear Fuel Expense - 100% Retail	0	0	0	0	0	0	0
		c	RTP Incremental Fuel -100% Retail	240,322	(33,788)	154,621	55,289	102,696	102,365	1,093,208
		d	D&D Fund Payments -100% Retail	0	0	0	0	5,776,464	0	5,776,464
		e	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	260,271,632	264,137,856	290,988,970	241,843,025	167,524,520	161,414,330	2,337,024,365
	5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.99614 %	99.99825 %	99.99434 %	99.99304 %	99.99208 %	99.99163 %	100.00000 %
	6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00064) +(Lines C4b,c,d)	$ 260,668,475	$ 264,268,491	$ 291,313,343	$ 242,036,250	$ 173,497,619	$ 161,606,481	$ 2,345,231,241
	7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (79,916,257)	$ (78,609,881)	$ (102,443,056)	$ (74,042,016)	$ (34,564,171)	$ (19,678,393)	$ (576,611,026)
	8		Interest Provision for the Month (Line D10)	(1,594,216)	(1,958,245)	(2,397,356)	(2,828,685)	(3,112,319)	(3,218,488)	(18,201,421)
	9		True-up & Interest Provision Beg of Period-Over/(Under) Recovery	(169,260,574)	(224,654,416)	(279,105,911)	(446,773,981)	(527,176,146)	(568,384,101)	42,377,583
			Deferred True-up Beginning of Period - Over/(Under) Recovery	(88,944,290)	(103,768,338)	(118,592,386)	(44,472,145)	(29,648,097)	(14,824,048)	(96,356,314)
	10	a	Prior Period True-up Collected/(Refunded) This Period	(3,531,465)	(3,531,465)	(3,531,465)	(3,531,465)	(3,531,465)	(3,531,465)	(42,377,583)
		b	Prior Period True-up Collected/(Refunded) This Period	14,824,048	14,824,048	14,824,048	14,824,048	14,824,048	14,824,048	96,356,314
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (328,422,754)	$ (397,698,297)	$ (491,246,125)	$ (556,824,243)	$ (583,208,148)	$ (594,812,447)	$ (594,812,447)

NOTES

(a) Per Order No. PSC-00-1081-PCO-EI, FPL was authorized to collect 60% of the $231 million expense increase anticipated in the 2000 Midcourse Correction.
(b) Generation Performance Incentive Factor is (($11,367,066/12) x 98.4280%) - See Order No. PSC-99-2512-FOF-EI.
(c) Jurisdictional Loss Multiplier per Schedule E2 revised December 15, 1999.

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCE
FOR THE PERIOD JANUARY THROUGH DECEMBER 2000

	LINE NO.			(1) ACTUAL	(2) ESTIMATED / ACTUAL (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
A	1	a	Fuel Cost of System Net Generation	$ 2,119,254,505	$ 2,009,938,005	$ 109,316,500	5.4 %
		b	Nuclear Fuel Disposal Costs	22,914,549	22,531,560	382,989	1.7 %
		c	Coal Cars Depreciation & Return	4,104,516	4,104,516	0	0.0 %
		d	Gas Pipelines Depreciation & Return	2,688,657	2,692,657	(4,000)	(0.1) %
		e	DOE D&D Fund Payment	5,776,464	5,930,000	(153,536)	0.2 %
	2	a	Fuel Cost of Power Sold	(99,626,893)	(75,117,362)	(24,509,532)	32.6 %
		b	Revenues from Off-System Sales	(37,560,276)	(20,673,259)	(16,887,017)	81.7 %
	3	a	Fuel Cost of Purchased Power	154,837,932	148,930,708	5,907,224	4.0 %
		b	Energy Payments to Qualifying Facilities	137,173,404	137,949,465	(776,061)	(0.6) %
	4		Energy Cost of Economy Purchases	66,896,351	57,050,832	9,845,519	17.3 %
	5		Total Fuel Costs & Net Power Transactions	$ 2,376,459,208	$ 2,293,337,123	$ 83,122,085	3.6 %
	6		Adjustments to Fuel Cost:				
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (30,722,987)	$ (25,353,354)	$ (5,369,633)	21.2 %
		b	Reactive and Voltage Control Fuel Revenue	(793,898)	(621,267)	(172,631)	27.8 %
		c	Inventory Adjustments	(1,362,556)	(903,224)	(459,332)	50.9 %
		d	Non Recoverable Oil/Tank Bottoms	292,882	462,051	(169,169)	N/A
		e	Modifications to Burn Low Gravity Oil	21,387	22,221	(834)	(3.8) %
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 2,343,894,036	$ 2,266,943,549	$ 76,950,486	3.4 %
C	1		Jurisdictional kWh Sales	87,931,992,861	87,896,045,657	35,947,204	0.0 %
	2		Sale for Resale	6,230,535	6,861,289	(630,754)	(9.2) %
	3		Total Sales (Excluding RTP Incremental)	87,938,223,396	87,902,906,946	35,316,450	0.0 %
	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)	$ 1,833,786,993	1,832,417,732	$ 1,369,261.44	0.1 %
		a1	Prior Period True-up Provision	42,377,583	42,377,583	0	0.0 %
		a2	Prior Period True-up Provision	(96,356,314)	(96,356,314)	(0)	N/A
		b	Generation Performance Incentive Factor Net (b)	(11,188,376)	(11,188,380)	4	0.0 %
		c	Oil Backout Revenues, Net of revenue Taxes	330	306	24	N/A
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 1,768,620,216	$ 1,767,250,927	$ 1,369,289	0.1 %
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 2,343,894,036	$ 2,266,943,549	$ 76,950,486	3.4 %
		b	Nuclear Fuel Expense - 100% Retail	0	0	0	N/A
		c	RTP Incremental Fuel -100% Retail	1,093,208	712,026	381,182	53.5 %
		d	D&D Fund Payments -100% Retail (Line A 1 e)	5,776,464	5,930,000	(153,536)	(2.6) %
		e	Adj. Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (D4a-D4b-D4c-D4d)	2,337,024,365	2,260,301,524	76,569,304	3.4 %
	5		Jurisdictional Sales % of Total kWh Sales	N/A	N/A	N/A	N/A
	6		Jurisdictional Total Fuel Costs & Net Power Transactions	$ 2,345,231,242	$ 1,767,250,927	$ 577,980,315	32.7 %
	7		True-up Provision for the Period- Over/(Under) Recovery (Line D3 - Line D6)	$ (576,611,026)	$ (500,967,153)	$ (75,643,873)	N/A
	8		Interest Provision for the Month	(18,201,421)	(17,038,223)	(1,163,198)	6.8 %
	9		True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	42,377,583	42,377,583	0	0.0 %
		a	Deferred True-up Beginning of Period - Over/(Under) Recovery	(96,356,314)	(96,356,314)	0	0.0 %
	10	a	Prior Period True-up Collected/(Refunded) This Period	(42,377,583)	(42,377,583)	0	0.0 %
	10	b	Prior Period True-up Collected/(Refunded) This Period	96,356,314	96,356,314	0	0.0 %
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines D7 through D10)	$ (594,812,447)	$ (518,005,376)	$ (76,807,071)	N/A

NOTES

(a) Per Appendix I, page 3 of K. M. Dubin's testimony filed August 23, 2000 approved in FPSC Order No. PSC-00-2385-FOF-EI, dated December 12, 2000.

(b) Generation Performance Incentive Factor is ($11,367,066 x 98.4280%) - See Order No. PSC-99-2512-FOF-EI.

APPENDIX II

CAPACITY COST RECOVERY

TRUE UP CALCULATION

KMD - 2
DOCKET NO. 010001 - EI
FPL WITNESS: K. M. DUBIN
April 2, 2001

APPENDIX II

CAPACITY COST RECOVERY

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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP FOR THE
PERIOD JANUARY THROUGH DECEMBER 2000

1.	End of Period True-up for the period January through December 2000 (from page 6, lines 15 & 16)	$ 39,560,855
2.	Less - Estimated/Actual True-up for the same period *	42,411,275
3.	Net True-up for the period January through December 2000	$ (2,850,420)

( ) Reflects Underrecovery

* Approved in FPSC Order No. PSC-00-2385-FOF-EI dated December 12, 2000

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2000

LINE NO.		(1) JAN 2000	(2) FEB 2000	(3) MAR 2000	(4) APR 2000	(5) MAY 2000	(6) JUN 2000
1.	UPS Capacity Charges	$ 9,093,678.00	$ 9,499,081.00	$ 9,320,275.00	$ 9,219,263.00	$ 9,019,651.00	$ 9,196,312.00
2.	Short Term Capacity Purchases CCR	0.00	0.00	0.00	0.00	0.00	3,779,000.00
3.	QF Capacity Charges	26,406,493.27	26,498,606.07	25,962,121.20	26,759,341.94	26,608,232.57	26,567,549.89
4.	SJRPP Capacity Charges	7,274,434.99	7,282,165.88	7,707,571.14	7,625,508.83	7,433,150.86	7,423,269.10
4a.	SJRPP Suspension Accrual	391,667.00	391,667.00	391,667.00	364,775.00	364,775.00	364,775.00
4b.	Return on SJRPP Suspension Liability	(106,038.28)	(109,894.20)	(113,750.15)	(117,473.71)	(121,064.90)	(124,656.10)
5.	SJRPP Deferred Interest Payment	(308,458.17)	(308,458.17)	(233,106.95)	(233,106.95)	(233,106.95)	(233,106.95)
6.	Cypress Settlement (Capacity)	0.00	0.00	0.00	1,530,589.14	0.00	0.00
7.	Trans. of Electricity by Others - FPL Sales	34,414.07	12,890.00	13,739.50	(3,667.20)	50,560.70	355,975.81
8.	Revenues from Capacity Sales	(657,825.63)	(269,478.09)	(290,773.14)	(356,613.43)	(501,496.25)	(275,795.86)
9.	Total (Lines 1 through 8)	$ 42,128,365.25	$ 42,996,579.49	$ 42,757,743.60	$ 44,788,616.62	$ 42,620,702.03	$ 47,053,322.89
10.	Jurisdictional Separation Factor (a)	97.87297%	97.87297%	97.87297%	97.87297%	97.87297%	97.87297%
11.	Jurisdictional Capacity Charges	41,232,282.28	42,082,029.35	41,848,273.57	43,835,949.31	41,714,146.91	46,052,484.60
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)
13.	Jurisdictional Capacity Charges Authorized	$ 36,486,816.28	$ 37,336,563.35	$ 37,102,807.57	$ 39,090,483.31	$ 36,968,680.91	$ 41,307,018.60
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 30,219,886.13	$ 29,996,057.19	$ 28,692,655.49	$ 29,715,040.03	$ 31,392,464.44	$ 37,706,366.65
15.	Prior Period True-up Provision	7,022,407.00	7,022,407.00	7,022,407.00	7,022,407.00	7,022,407.00	7,022,407.00
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 37,242,293.13	$ 37,018,464.19	$ 35,715,062.49	$ 36,737,447.03	$ 38,414,871.44	$ 44,728,773.65
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	755,476.85	(318,099.16)	(1,387,745.08)	(2,353,036.28)	1,446,190.52	3,421,755.06
18.	Interest Provision for Month	463,570.11	441,058.87	414,556.24	384,553.27	362,576.91	350,797.70
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	84,268,889.00	78,465,528.96	71,566,081.67	63,570,485.83	54,579,595.82	49,365,956.26
20.	Deferred True-up - Over/(Under) Recovery	16,458,284.00	16,458,284.00	16,458,284.00	16,458,284.00	16,458,284.00	16,458,284.00
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(7,022,407.00)	(7,022,407.00)	(7,022,407.00)	(7,022,407.00)	(7,022,407.00)	(7,022,407.00)
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ 94,923,812.96	$ 88,024,365.67	$ 80,028,769.83	$ 71,037,879.82	$ 65,824,240.26	$ 62,574,386.01
	monthly entry	(5,803,360.04)	(6,899,447.29)	(7,995,595.84)	(8,990,890.01)	(5,213,639.56)	(3,249,854.25)

Notes: (a) Per K. M. Dubin's Testimony Appendix III Page 3, Docket No. 990001-EI, filed October 1, 1999
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, 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.

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2000

LINE NO.		(7) JUL 2000	(8) AUG 2000	(9) SEP 2000	(10) OCT 2000	(11) NOV 2000	(12) DEC 2000	(13) TOTAL	LINE NO.
1.	UPS Capacity Charges	$ 7,721,900.00	$ 9,077,699.00	$ 9,092,974.00	$ 8,945,049.00	$ 8,816,443.00	$ 8,754,184.00	$107,756,509.00	1.
2.	Short Term Capacity Purchases CCR	3,779,000.00	3,862,200.00	1,821,500.00	0.00	0.00	0.00	13,241,700.00	2.
3.	QF Capacity Charges	26,452,487.44	26,099,044.75	27,040,455.45	26,244,778.38	26,586,533.18	26,676,485.71	317,902,129.85	3.
4.	SJRPP Capacity Charges	7,117,693.35	6,943,956.15	6,280,669.74	7,324,915.04	7,198,354.18	6,091,872.15	85,703,561.41	4.
4a.	SJRPP Suspension Accrual	364,775.00	364,775.00	364,775.00	364,775.00	364,775.00	364,775.00	4,457,976.00	4a.
4b.	Return on SJRPP Suspension Liability	(128,247.29)	(131,838.48)	(135,429.65)	(139,020.85)	(142,612.05)	(146,203.23)	(1,516,228.89)	4b.
5.	SJRPP Deferred Interest Payment	(233,106.95)	(233,106.95)	(234,464.05)	(310,545.87)	(310,545.87)	(310,545.87)	(3,181,659.70)	5.
6.	Cypress Settlement (Capacity)	0.00	0.00	0.00	1,530,589.14	136,279.40	0.00	3,197,457.68	6.
7.	Trans. of Electricity by Others - FPL Sales	356,545.88	174,764.33	54,485.10	(901.01)	34,824.00	10,441.43	1,094,072.61	7.
8.	Revenues from Capacity Sales	(524,499.07)	(825,064.82)	(216,067.16)	(320,629.27)	(448,975.98)	(1,878,424.19)	(6,565,642.89)	8.
9.	Total (Lines 1 through 8)	$ 44,906,548.36	$ 45,332,428.98	$ 44,068,898.43	$ 43,639,009.56	$ 42,235,074.86	$ 39,562,585.00	$522,089,875.07	9.
10.	Jurisdictional Separation Factor (a)	97.87297%	97.87297%	97.87297%	97.87297%	97.87297%	97.87297%	N/A	10.
11.	Jurisdictional Capacity Charges	43,951,372.60	44,368,194.62	43,131,539.74	42,710,794.73	41,336,722.15	38,721,076.95	510,984,866.80	11.
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(56,945,592.00)	12.
13.	Jurisdictional Capacity Charges Authorized	$ 39,205,906.60	$ 39,622,728.62	$ 38,386,073.74	$ 37,965,328.73	$ 36,591,256.15	$ 33,975,610.95	$454,039,274.80	13.
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 38,504,653.20	$ 39,765,128.10	$ 39,996,776.93	$ 36,682,353.26	$ 31,010,497.95	$ 31,220,141.85	$404,902,021.20	14.
15.	Prior Period True-up Provision	7,022,407.00	7,022,407.00	7,022,407.00	7,022,407.00	7,022,407.00	7,022,407.00	84,268,889.00	15.
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 45,527,060.20	$ 46,787,535.10	$ 47,019,183.93	$ 43,704,760.26	$ 38,032,904.95	$ 38,242,548.85	$489,170,910.20	16.
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	6,321,153.59	7,164,806.48	8,633,110.19	5,739,431.52	1,441,648.80	4,266,937.90	35,131,635.40	17.
18.	Interest Provision for Month	339,119.49	336,849.67	343,412.15	346,422.35	333,529.80	312,773.30	4,429,219.84	18.
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	46,116,102.01	45,753,968.09	46,233,217.24	48,187,332.58	47,250,779.45	42,003,551.04	84,268,889.00	19.
20.	Deferred True-up - Over/(Under) Recovery	16,458,284.00	16,458,284.00	16,458,284.00	16,458,284.00	16,458,284.00	16,458,284.00	16,458,284.00	20.
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(7,022,407.00)	(7,022,407.00)	(7,022,407.00)	(7,022,407.00)	(7,022,407.00)	(7,022,407.00)	(84,268,889.00)	21.
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ 62,212,252.09	$ 62,691,501.24	$ 64,645,616.58	$ 63,709,063.45	$ 58,461,835.04	$ 56,019,139.25	$ 56,019,139.25	22.
	monthly entry	(362,133.92)	479,249.15	1,954,115.34	(936,553.13)	(5,247,228.40)	(2,442,695.80)		

Notes: (a) Per K. M. Dubin's Testimony Appendix III Page 3, Docket No. 990001-EI, filed October 1, 1999
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, 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 FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY THROUGH DECEMBER 2000

Line No.		(1) ACTUAL	(2) ESTIMATED / ACTUAL (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
1.	Payments to Non-cogenerators	$ 203,520,111	$ 206,952,618	$ (3,432,507)	(1.7) %
2	Payments to Cogenerators	317,902,130	323,901,237	(5,999,107)	(1.9) %
3.	SJRPP Suspension Accrual	4,457,976	4,457,976	0	0.0 %
4.	Return Requirements on SJRPP Suspension Liability	(1,516,229)	(1,516,229)	0	0.0 %
4b.	Cypress Settlement (Capacity)	3,197,458	3,264,178	(66,720)	(2.0) %
5.	Transmission of Electricity by Others - FPL Sales	1,094,074	820,459	273,615	33.3 %
6.	Revenues from Capacity Sales	(6,565,643)	(4,562,493)	(2,003,149)	43.9 %
7.	Total (Lines 1 through 6)	$ 522,089,876	$ 533,317,746	$ (11,227,870)	(2.1) %
8.	Jurisdictional Separation Factor	N/A	N/A	N/A	N/A
9.	Jurisdictional Capacity Charges	$ 510,984,867	$ 521,973,918	$ (10,989,051)	(2.1) %
10.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	$ (56,945,592)	(56,945,592)	0	N/A
11.	Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$ 454,039,275	$ 465,028,326	$ (10,989,051)	(2.4) %
12.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 404,902,021	$ 418,598,080	$ (13,696,059)	(3.3) %
13.	Prior Period True-up Provision	84,268,889	84,268,889	0	N/A
14.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 489,170,910	$ 502,866,969	$ (13,696,059)	(2.7) %
15.	True-up Provision for Period - Over/(Under) Recovery (Line 14 - Line 11)	$ 35,131,635	$ 37,838,644	$ (2,707,008)	N/A
16.	Interest Provision for Period	4,429,220	4,572,632	(143,412)	N/A
17.	True-up & Interest Provision Beginning of Period - Over/(Under) Recovery	84,268,889	84,268,889	0	N/A
18.	Deferred True-up - Over/(Under) Recovery	16,458,284	16,458,284	0	N/A
19.	Prior Period True-up Provision - Collected/(Refunded) this Period	(84,268,889)	(84,268,889)	0	N/A
20.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 15 through 19)	$ 56,019,139	$ 58,869,559	$ (2,850,420)	(4.8) %

Notes:
(a) Per K. M. Dubin's Testimony Appendix II, Page 3, Docket No. 000001-EI, filed August 23, 2000.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, 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.

APPENDIX I
FUEL COST RECOVERY
2001 ESTIMATED/ACTUAL TRUE UP

Pages(s)	Description	Sponsor
2-3	Calculation of Estimated/Actual True-Up Amount	Dubin
4	Variance Original Estimate Compared to Estimated/Actual	Dubin

KMD-3
DOCKET NO. 010001-EI
FPL Witness: K.M. Dubin
Exhibit ____
Pages 1-4
August 20, 2001

CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2001
ACTUALS THROUGH JULY 2001 - REVISED ESTIMATES FOR AUGUST THROUGH DECEMBER 2001

LINE NO.			(1) ACTUAL JANUARY	(2) ACTUAL FEBRUARY	(3) ACTUAL MARCH	(4) ACTUAL APRIL	(5) ACTUAL MAY	(6) ACTUAL JUNE
A		Fuel Costs & Net Power Transactions						
1	a	Fuel Cost of System Net Generation	$ 244,785,143	$ 159,425,167	$ 177,190,313	$ 204,132,267	$ 196,155,831	$ 221,272,763
	b	Nuclear Fuel Disposal Costs	2,068,407	1,843,450	2,015,390	1,551,446	1,946,294	2,012,166
	c	Coal Cars Depreciation & Return	322,410	320,677	318,944	317,212	315,479	172,197
	d	Gas Pipelines Depreciation & Return	214,594	213,138	211,683	210,227	208,772	207,316
	e	DOE D&D Fund Payment	0	0	0	0	0	0
2	a	Fuel Cost of Power Sold	(12,968,637)	(3,779,258)	(6,789,117)	(5,276,186)	(10,230,516)	(5,307,573)
	b	Revenues from Off-System Sales	(5,127,829)	(619,875)	(1,841,828)	(1,255,420)	(2,917,249)	(1,588,846)
3	a	Fuel Cost of Purchased Power	14,199,440	13,029,285	13,378,077	15,628,813	15,938,203	13,199,193
	b	Energy Payments to Qualifying Facilities	11,896,881	10,643,682	10,958,522	11,686,756	11,099,683	12,227,370
4		Energy Cost of Economy Purchases	2,778,540	2,938,601	7,310,367	15,227,982	8,076,737	5,296,225
5		Total Fuel Costs & Net Power Transactions	$ 258,168,949	$ 184,014,867	$ 202,752,351	$ 242,223,096	$ 220,593,234	$ 247,490,811
6		Adjustments to Fuel Cost:						
	a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(2,550,139)	(3,387,586)	(2,617,769)	(3,111,502)	(3,235,559)	(3,139,331)
	b	Reactive and Voltage Control Fuel Revenue	(74,105)	(63,307)	(43,864)	(35,075)	(33,718)	(26,851)
	c	Inventory Adjustments	(169,260)	167,695	40,100	(413,216)	(134,375)	(311,926)
	d	Non Recoverable Oil/Tank Bottoms	0	171,000	0	(60,609)	0	0
	e	Modifications to Burn Low Gravity Oil	0	0	0	0	0	0
7		Adjusted Total Fuel Costs & Net Power Transactions	$ 255,375,445	$ 180,902,669	$ 200,130,818	$ 238,602,694	$ 217,189,582	$ 244,012,703
B		kWh Sales						
1		Jurisdictional kWh Sales (RTP @ CBL) (a)	7,629,849,502	6,715,059,955	6,512,773,908	6,579,965,506	6,735,706,835	8,075,952,989
2		Sale for Resale ($Excluding FKEC & CKW)	549,963	440,917	463,088	597,708	538,692	518,879
3		Sub-Total Sales ($Excluding FKEC & CKW)	7,630,399,465	6,715,500,872	6,513,236,996	6,580,563,214	6,736,245,527	8,076,471,868
		Jurisdictional % of Total kWh Sales (lines B1/B3)	99.99279 %	99.99343 %	99.99289 %	99.99092 %	99.99200 %	99.99358 %
C		True-up Calculation						
1		Jurisdictional Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 214,633,368	$ 193,031,956	$ 187,300,172	$ 231,916,374	$ 242,218,141	$ 290,936,279
2		Fuel Adjustment Revenues Not Applicable to Period:						
	a1	Amortize 1/24 of $518,005,376 (b)	(21,583,557)	(21,583,557)	(21,583,557)	(21,583,557)	(21,583,557)	(21,583,557)
	a2	2000 Final True-up Collected per Midcourse Order PSC-01-0963-PCO	0	0	0	(8,534,119)	(8,534,119)	(8,534,119)
	b	GPIF, Net of Revenue Taxes (c)	(581,146)	(581,146)	(581,146)	(581,146)	(581,146)	(581,146)
	c	Oil Backout Revenues, Net of revenue Taxes	(23)	1	3	49	0	(303)
3		Jurisdictional Fuel Revenues Applicable to Period	$ 192,468,642	$ 170,867,254	$ 165,135,472	$ 201,217,601	$ 211,519,319	$ 260,237,154
4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 255,375,445	$ 180,902,669	$ 200,130,818	$ 238,602,694	$ 217,189,582	$ 244,012,703
	b	Nuclear Fuel Expense - 100% Retail	0	0	0	0	0	0
	c	RTP Incremental Fuel -100% Retail	47,129	37,120	47,714	(41,788)	(150,080)	(64,137)
	d	D&D Fund Payments -100% Retail	0	0	0	0	0	0
	e	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	255,328,316	180,865,550	200,083,104	239,752,841	217,339,661	244,076,840
5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.99279 %	99.99343 %	99.99289 %	99.99092 %	99.99200 %	99.99358 %
6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00046(d)) +(Lines C4b,c,d)	$ 255,474,478	$ 180,973,980	$ 200,208,624	$ 239,799,560	$ 217,272,162	$ 244,109,301
7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (63,005,836)	$ (10,106,726)	$ (35,073,152)	$ (38,581,959)	$ (5,752,843)	$ 16,127,853
8		Interest Provision for the Month	(543,803)	(648,282)	(713,247)	(788,344)	(749,090)	(655,872)
9		True-up & Interest Provision Beg of Period-Over/(Under) Recovery	0	(63,549,639)	(74,304,647)	(110,091,046)	(149,461,349)	(155,963,282)
		Deferred True-up Beginning of Period - Over/(Under) Recovery	(76,807,071)	(76,807,071)	(76,807,071)	(76,807,071)	(68,272,952)	(59,738,833)
10	a	Prior Period True-up Collected/(Refunded) This Period	0	0	0	0	0	0
	b	Prior Period True-up Collected/(Refunded) This Period	0	0	0	8,534,119	8,534,119	8,534,119
11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (140,356,710)	$ (151,111,718)	$ (186,898,117)	$ (217,734,301)	$ (215,702,115)	$ (191,696,015)

NOTES:
(a) Real Time Pricing (RTP) sales are shown at the Customer Base Load (CBL) KWH. The incremental/decremental kwh sales are excluded.
The incremental/decremental RTP fuel revenues (net of revenue taxes) are included in jurisdictional fuel revenues.
(b) Amortization of $518,005,376 fuel underrecovery over 24 months per PSC Order No. PSC-00-2385-FOF-EI.
(c) Generation Performance Incentive Factor is ((56,973,751/12) x 98.4200 %) - See Order No. PSC-00-2385-FOF-EI.
(d) Per Estimated Schedule E-1, filed September 21, 2000.

CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2001
ACTUALS THROUGH JULY 2001 - REVISED ESTIMATES FOR AUGUST THROUGH

LINE NO.			(7) ACTUAL JULY	(8) ESTIMATED AUGUST	(9) ESTIMATED SEPTEMBER	(10) ESTIMATED OCTOBER	(11) ESTIMATED NOVEMBER	(12) ESTIMATED DECEMBER	(13) TOTAL PERIOD
A		Fuel Costs & Net Power Transactions							
1	a	Fuel Cost of System Net Generation	$ 204,642,334	$ 229,579,080	$ 219,664,750	$ 180,917,780	$ 136,535,650	$ 147,939,170	$ 2,322,240,248
	b	Nuclear Fuel Disposal Costs	1,982,870	1,980,798	1,916,901	1,528,800	1,775,711	1,746,523	22,368,756
	c	Coal Cars Depreciation & Return	312,014	310,281	308,549	306,816	305,083	303,351	3,613,013
	d	Gas Pipelines Depreciation & Return	205,860	204,405	202,949	201,494	200,038	198,583	2,479,059
	e	DOE D&D Fund Payment	0	0	0	0	6,104,000	0	6,104,000
2	a	Fuel Cost of Power Sold	(5,516,006)	(8,079,280)	(7,257,190)	(4,892,730)	(3,312,290)	(5,234,420)	(78,643,204)
	b	Revenues from Off-System Sales	(1,465,801)	(1,569,312)	(511,210)	(18,090)	(27,652)	(83,887)	(17,026,999)
3	a	Fuel Cost of Purchased Power	13,823,744	14,827,870	14,290,570	14,715,550	14,287,680	14,567,720	171,886,145
	b	Energy Payments to Qualifying Facilities	11,919,593	13,195,270	13,112,110	13,369,440	10,377,920	12,608,400	143,095,627
4		Energy Cost of Economy Purchases	4,279,572	6,361,566	8,893,050	7,404,655	5,855,162	6,243,907	80,666,364
5		Total Fuel Costs & Net Power Transactions	$ 230,184,180	$ 256,810,679	$ 250,620,479	$ 213,533,715	$ 172,101,303	$ 178,289,347	$ 2,656,783,009
6		Adjustments to Fuel Cost:							
	a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(3,063,295)	(2,976,238)	(3,043,183)	(2,931,480)	(2,721,998)	(2,450,625)	(35,228,705)
	b	Reactive and Voltage Control Fuel Revenue	(108,066)	0	0	0	0	0	(384,986)
	c	Inventory Adjustments	(392,674)	0	0	0	0	0	(1,213,656)
	d	Non Recoverable Oil/Tank Bottoms	(43,783)	0	0	0	0	0	66,608
	e	Modifications to Burn Low Gravity Oil	0	0	0	0	0	0	0
7		Adjusted Total Fuel Costs & Net Power Transactions	$ 226,576,362	$ 253,834,441	$ 247,577,296	$ 210,602,235	$ 169,379,305	$ 175,838,722	$ 2,620,022,270
B		kWh Sales							
1		Jurisdictional kWh Sales (RTP @ CBL) (a)	8,541,653,012	8,887,376,000	9,011,298,000	8,322,130,000	7,000,363,000	7,135,726,000	91,147,854,707
2		Sale for Resale ($Excluding FKEC & CKW)	422,743	606,000	578,000	531,000	609,000	576,000	6,431,990
3		Sub-Total Sales ($Excluding FKEC & CKW)	8,542,075,755	8,887,982,000	9,011,876,000	8,322,661,000	7,000,972,000	7,136,302,000	91,154,286,697
		Jurisdictional % of Total kWh Sales (lines B1/B3)	99.99505 %	99.99318 %	99.99359 %	99.99362 %	99.99130 %	99.99193 %	N/A
C		True-up Calculation							
1		Jurisdictional Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 307,531,802	$ 320,164,592	$ 324,628,838	$ 299,801,804	$ 252,185,613	$ 257,062,017	3,121,410,957
2		Fuel Adjustment Revenues Not Applicable to Period:							
	a1	Amortize 1/24 of $518,005,376 (b)	(21,583,557)	(21,583,557)	(21,583,557)	(21,583,557)	(21,583,557)	(21,583,558)	(259,002,685)
	a2	2000 Final True-up Collected per Midcourse Order PSC-01-0963-PCO	(8,534,119)	(8,534,119)	(8,534,119)	(8,534,119)	(8,534,119)	(8,534,119)	(76,807,071)
	b	GPIF, Net of Revenue Taxes (c)	(581,146)	(581,146)	(581,146)	(581,146)	(581,146)	(581,146)	(6,973,752)
	c	Oil Backout Revenues, Net of revenue Taxes	2						(271)
3		Jurisdictional Fuel Revenues Applicable to Period	$ 276,832,982	$ 289,465,770	$ 293,930,016	$ 269,102,982	$ 221,486,791	$ 226,363,194	$ 2,778,627,177
4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 226,576,362	$ 253,834,441	$ 247,577,296	$ 210,602,235	$ 169,379,305	$ 175,838,722	$ 2,620,022,270
	b	Nuclear Fuel Expense - 100% Retail	0	0	0	0	0	0	0
	c	RTP Incremental Fuel -100% Retail	41,507	0	0	0	0	0	(82,535)
	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)	226,534,855	253,834,440.69	247,577,295.62	210,602,234.59	169,379,304.58	175,838,721.74	2,620,104,805
			99.99505 %	99.99318 %	99.99359 %	99.99362 %	99.99130 %	99.99193 %	N/A
5		Jurisdictional Sales % of Total kWh Sales (Line B-6)							
6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00046(d)) +(Lines C4b,c,d)	$ 226,669,349	$ 253,933,885	$ 247,675,304	$ 210,685,669	$ 169,442,476	$ 175,905,411	$ 2,622,150,199
7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ 50,163,633	$ 35,531,885	$ 46,254,712	$ 58,417,313	$ 52,044,315	$ 50,457,783	$ 156,476,979
8		Interest Provision for the Month	(510,712)	(348,362)	(194,990)	(5,381)	193,868	381,303	(4,582,912)
9		True-up & Interest Provision Beg of Period-Over/(Under) Recovery	(140,491,301)	(90,838,379)	(55,654,857)	(9,595,135)	48,816,798	101,054,981	0
		Deferred True-up Beginning of Period - Over/(Under) Recovery	(51,204,714)	(42,670,595)	(34,136,476)	(25,602,357)	(17,068,238)	(8,534,119)	(76,807,071)
10	a	Prior Period True-up Collected/(Refunded) This Period	0	0	0	0	0	0	0
	b	Prior Period True-up Collected/(Refunded) This Period	8,534,119	8,534,119	8,534,119	8,534,119	8,534,119	8,534,119	76,807,071
11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (133,508,974)	$ (89,791,333)	$ (35,197,492)	$ 31,748,560	$ 92,520,862	$ 151,894,067	$ 151,894,067

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF VARIANCE - ESTIMATED/ACTUAL vs MIDCOURSE CORRECTION
FOR THE PERIOD JANUARY THROUGH DECEMBER 2001

	LINE NO.			(1) ESTIMATED / ACTUAL	(2) MIDCOURSE ESTIMATED (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
A	1	a	Fuel Cost of System Net Generation	$ 2,322,240,248	$ 2,492,362,530	$ (170,122,282)	(6.8) %
		b	Nuclear Fuel Disposal Costs	22,368,756	22,014,285	354,471	1.6 %
		c	Coal Cars Depreciation & Return	3,613,013	3,754,563	(141,550)	(3.8) %
		d	Gas Pipelines Depreciation & Return	2,479,059	2,479,059	0	0.0 %
		e	DOE D&D Fund Payment	6,104,000	6,100,000	4,000	0.1 %
	2	a	Fuel Cost of Power Sold	(78,643,204)	(93,358,290)	14,715,086	(15.8) %
		b	Revenues from Off-System Sales	(17,026,999)	(13,356,370)	(3,670,629)	27.5 %
	3	a	Fuel Cost of Purchased Power	171,886,145	141,145,630	30,740,515	21.8 %
		b	Energy Payments to Qualifying Facilities	143,095,627	151,785,515	(8,689,888)	(5.7) %
	4		Energy Cost of Economy Purchases	80,666,364	52,716,020	27,950,344	53.0 %
	5		*Total Fuel Costs & Net Power Transactions*	$ 2,656,783,009	$ 2,765,642,942	$ (108,859,933)	(3.9) %
	6		Adjustments to Fuel Cost:				
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (35,228,705)	$ (31,314,261)	$ (3,914,444)	12.5 %
		b	Reactive and Voltage Control Fuel Revenue	(384,986)		(384,986)	N/A
		c	Inventory Adjustments	(1,213,656)		(1,213,656)	N/A
		d	Non Recoverable Oil/Tank Bottoms	66,608		66,608	N/A
		e	Modifications to Burn Low Gravity Oil	-		0	N/A
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 2,620,022,270	$ 2,734,328,681	$ (114,306,411)	(4.2) %
C	1		Jurisdictional kWh Sales	91,147,854,707	89,266,732,000	1,881,122,707	2.1 %
	2		Sale for Resale	6,431,990	6,814,000	(382,010)	(5.6) %
	3		Total Sales (Excluding RTP Incremental)	91,154,286,697	89,273,546,000	1,880,740,697	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)	$ 3,121,410,957	3,078,369,979	$ 43,040,978	1.4 %
		a1	*Prior Period True-up Provision* (b)	(259,002,685)	(259,002,685)	0	0.0 %
		a2	Prior Period True-up Provision	(76,807,071)	(76,807,071)	0	N/A
		b	Generation Performance Incentive Factor Net (c)	(6,973,752)	(6,973,752)	0	0.0 %
		c	Oil Backout Revenues, Net of revenue Taxes	(271)	0	(271)	N/A
	3		*Jurisdictional Fuel Revenues Applicable to Period*	$ 2,778,627,178	$ 2,735,586,471	$ 43,040,707	1.6 %
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 2,620,022,270	$ 2,734,328,681	$ (114,306,411)	(4.2) %
		b	Nuclear Fuel Expense - 100% Retail	-	0	0	N/A
		c	RTP Incremental Fuel -100% Retail	(82,535)	0	(82,535)	N/A
		d	D&D Fund Payments -100% Retail (Line A 1 e)	-	0	0	N/A
		e	Adj. Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (D4a-D4b-D4c-D4d)	2,620,104,805	2,734,328,681	(114,223,876)	(4.2) %
	5		Jurisdictional Sales % of Total kWh Sales	N/A	N/A	N/A	N/A
	6		Jurisdictional Total Fuel Costs & Net Power Transactions	$ 2,622,150,199	$ 2,735,586,471	$ (113,436,272)	(4.1) %
	7		True-up Provision for the Period- Over/(Under) Recovery (Line D3 - Line D6)	$ 156,476,979	$ 0	$ 156,476,979	N/A
	8		Interest Provision for the Month	(4,582,912)	0	(4,582,912)	N/A
	9		True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	0	0	0	N/A
		a	Deferred True-up Beginning of Period - Over/(Under) Recovery	(76,807,071)	(76,807,071)	0	0.0 %
	10	a	*Prior Period True-up Collected/(Refunded) This Period*	0	0	0	N/A
	10	b	Prior Period True-up Collected/(Refunded) This Period	76,807,071	76,807,071	0	0.0 %
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines D7 through D10)	$ 151,894,067	$ -	$ 151,894,067	N/A

NOTES

(a) Per Midcourse Correction, filed February 2, 2001.

(b) Amortization of $518,005,376 fuel underrecovery over 24 months per FPSC Order No. PSC-00-2385-FOF-EI.

(c) Generation Performance Incentive Factor is (($6,973,751/12) x 98.4280%) - See Order No. PSC-00-2385-FOF-EI.

APPENDIX II
CAPACITY COST RECOVERY
2001 ESTIMATED/ACTUAL TRUE UP

Pages(s)	Description	Sponsor
2-3	Calculation of Estimated/Actual True-Up Amount	Dubin
4	Variance	Dubin

KMD-4
DOCKET NO. 010001-EI
FPL Witness: K.M. Dubin
Exhibit ____
Pages 1-4
August 20, 2001

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2001

LINE NO.		(1) JAN 2001	(2) FEB 2001	(3) MAR 2001	(4) APR 2001	(5) MAY 2001	(6) JUN 2001
1.	UPS Capacity Charges	$ 9,405,570.00	$ 9,350,830.00	$ 8,534,569.00	$ 9,020,204.00	$ 8,329,952.00	$ 8,976,256.00
2.	Short Term Capacity Purchases CCR	0.00	0.00	0.00	961,500.00	3,619,100.00	4,899,588.00
3.	QF Capacity Charges	24,590,700.21	26,704,892.68	26,008,146.70	26,466,192.76	26,226,248.57	26,341,889.09
4.	SJRPP Capacity Charges	7,367,204.48	7,666,884.36	7,840,198.21	7,668,625.57	7,316,990.34	7,232,505.30
4a.	SJRPP Suspension Accrual	364,775.00	364,775.00	364,775.00	364,775.00	364,775.00	364,775.00
4b.	Return on SJRPP Suspension Liability	(149,794.52)	(153,385.72)	(156,976.90)	(160,568.09)	(164,159.28)	(167,750.47)
5.	SJRPP Deferred Interest Payment	(310,545.87)	(310,545.87)	(310,545.87)	(310,545.87)	(310,545.87)	(310,545.87)
6.	Cypress Settlement (Capacity)	0.00	0.00	0.00	1,530,589.14	0.00	0.00
7.	Trans. of Electricity by Others - FPL Sales	4,227.67	(4,452.00)	350.00	234,914.00	502,599.96	521,443.00
8.	Revenues from Capacity Sales	(1,526,403.55)	(991,620.28)	(977,935.98)	(444,461.99)	(753,189.28)	(281,737.40)
9.	Total (Lines 1 through 8)	$ 39,745,733.42	$ 42,627,378.17	$ 41,302,580.16	$ 45,331,224.52	$ 45,131,771.44	$ 47,576,422.65
10.	Jurisdictional Separation Factor (a)	99.01014%	99.01014%	99.01014%	99.01014%	99.01014%	99.01014%
11.	Jurisdictional Capacity Charges	39,352,306.30	42,205,426.80	40,893,742.44	44,882,508.86	44,685,030.09	47,105,482.67
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)
13.	Jurisdictional Capacity Charges Authorized	$ 34,606,840.30	$ 37,459,960.80	$ 36,148,276.44	$ 40,137,042.86	$ 39,939,564.09	$ 42,360,016.67
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 36,914,301.34	$ 32,808,068.94	$ 31,384,613.55	$ 31,848,137.61	$ 32,228,720.86	$ 38,069,850.96
15.	Prior Period True-up Provision	4,905,797.00	4,905,797.00	4,905,797.00	4,905,797.00	4,905,797.00	4,905,797.00
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 41,820,098.34	$ 37,713,865.94	$ 36,290,410.55	$ 36,753,934.61	$ 37,134,517.86	$ 42,975,647.96
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	7,213,258.04	253,905.14	142,134.11	(3,383,108.25)	(2,805,046.23)	615,631.29
18.	Interest Provision for Month	287,055.45	250,949.37	219,201.44	177,732.50	130,541.99	102,657.22
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	58,869,559.25	61,464,075.74	57,063,133.25	52,518,671.80	44,407,499.05	36,827,197.81
20.	Deferred True-up - Over/(Under) Recovery	(2,850,420.00)	(2,850,420.00)	(2,850,420.00)	(2,850,420.00)	(2,850,420.00)	(2,850,420.00)
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(4,905,797.00)	(4,905,797.00)	(4,905,797.00)	(4,905,797.00)	(4,905,797.00)	(4,905,797.00)
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ 58,613,655.74	$ 54,212,713.25	$ 49,668,251.80	$ 41,557,079.05	$ 33,976,777.81	$ 29,789,269.31

Notes:
(a) Per K. M. Dubin's Testimony Appendix III Page 3, Docket No. 000001-EI, filed September 21, 2000.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, 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.

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CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2001

LINE NO.		(7) JUL 2001	(8) AUG 2001	(9) SEP 2001	(10) OCT 2001	(11) NOV 2001	(12) DEC 2001	(13) TOTAL	LINE NO.
1.	UPS Capacity Charges	$ 8,949,781.00	$ 8,704,640.00	$ 8,704,640.00	$ 8,704,640.00	$ 8,704,640.00	$ 8,704,640.00	$106,090,362.00	1.
2.	Short Term Capacity Purchases CCR	4,899,588.00	5,277,344.00	3,256,700.00	961,500.00	961,500.00	961,500.00	25,798,320.00	2.
3.	QF Capacity Charges	26,541,038.20	26,469,351.44	26,469,351.44	26,469,351.44	26,469,351.44	26,469,351.44	315,225,865.43	3.
4.	SJRPP Capacity Charges	7,665,338.96	7,097,148.33	7,097,148.33	7,097,148.33	7,097,148.33	7,097,148.33	88,243,488.89	4.
4a.	SJRPP Suspension Accrual	364,775.00	364,775.00	364,775.00	364,775.00	364,775.00	364,775.00	4,377,300.00	4a.
4b.	Return on SJRPP Suspension Liability	(171,341.67)	(174,932.86)	(178,524.05)	(182,115.25)	(185,706.42)	(189,297.61)	(2,034,552.84)	4b.
5.	SJRPP Deferred Interest Payment	(310,545.87)	(310,545.87)	(310,545.87)	(310,545.87)	(310,545.87)	(310,545.87)	(3,726,550.44)	5.
6.	Cypress Settlement (Capacity)	0.00			1,530,589.14	164,588.85		3,225,767.13	6.
7.	Trans. of Electricity by Others ~~FPL Sales o~~	735,452.00	80,500.00	38,640.00	9,660.00	9,660.00	48,300.00	2,181,294.63	7.
8.	Revenues from Capacity Sales	(361,780.29)	(642,688.00)	(488,390.00)	(462,160.00)	(381,848.00)	(581,113.00)	(7,893,327.77)	8.
9.	Total (Lines 1 through 8)	$ 48,312,305.33	$ 46,865,592.05	$ 44,953,794.86	$ 44,182,842.80	$ 42,893,563.34	$ 42,564,758.30	$531,487,967.03	9.
10.	Jurisdictional Separation Factor (a)	99.01014%	99.01014%	99.01014%	99.01014%	99.01014%	99.01014%	N/A	10.
11.	Jurisdictional Capacity Charges	47,834,081.14	46,401,688.30	44,508,815.22	43,745,494.51	42,468,977.11	42,143,426.78	526,226,980.24	11.
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(56,945,592.00)	12.
13.	Jurisdictional Capacity Charges Authorized	$ 43,088,615.14	$ 41,656,222.30	$ 39,763,349.22	$ 39,000,028.51	$ 37,723,511.11	$ 37,397,960.78	$469,281,388.24	13.
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 40,201,822.73	$ 41,901,322.29	$ 42,485,577.49	$ 39,236,356.30	$ 33,004,619.84	$ 33,642,815.94	$433,726,207.85	14.
15.	Prior Period True-up Provision	4,905,797.00	4,905,797.00	4,905,797.00	4,905,797.00	4,905,797.00	4,905,797.00	58,869,559.00	15.
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 45,107,619.73	$ 46,807,119.29	$ 47,391,374.49	$ 44,142,153.30	$ 37,910,416.84	$ 38,548,612.94	$492,595,766.85	16.
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	2,019,004.59	5,150,896.99	7,628,025.27	5,142,124.79	186,905.72	1,150,652.15	23,314,378.61	17.
18.	Interest Provision for Month	89,171.39	84,731.87	89,633.11	94,535.95	87,827.37	74,861.15	1,688,898.82	18.
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	32,639,689.31	29,842,068.29	30,171,900.15	32,983,761.53	33,314,625.27	28,683,561.37	58,869,559.25	19.
20.	Deferred True-up - Over/(Under) Recovery	(2,850,420.00)	(2,850,420.00)	(2,850,420.00)	(2,850,420.00)	(2,850,420.00)	(2,850,420.00)	(2,850,420.00)	20.
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(4,905,797.00)	(4,905,797.00)	(4,905,797.00)	(4,905,797.00)	(4,905,797.00)	(4,905,797.00)	(58,869,559.00)	21.
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ 26,991,648.29	$ 27,321,480.15	$ 30,133,341.53	$ 30,464,205.27	$ 25,833,141.37	$ 22,152,857.68	$ 22,152,857.68	22.

Notes:

(a) Per K. M. Dubin's Testimony Appendix III Page 3, Docket No. 000001-EI, filed September 21, 2000.

(b) Per FPSC Order No. PSC-94-1092-FOF-EI, 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 ESTIMATED/ACTUAL TRUE-UP VARIANCE
FOR THE PERIOD JANUARY THROUGH DECEMBER 2001

Line No.		(1) ESTIMATED / ACTUAL	(2) ORIGINAL PROJECTIONS(a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
1.	Payments to Non-cogenerators	$ 216,405,620	$ 193,297,344	$ 23,108,276	12.0 %
2	Payments to Cogenerators	315,225,865	348,687,456	(33,461,591)	(9.6) %
3.	SJRPP Suspension Accrual	4,377,300	4,377,300	-	0.0 %
4.	Return Requirements on SJRPP Suspension Liability	(2,034,553)	(2,034,552)	(1)	0.0 %
4b.	Cypress Settlement (Capacity)	3,225,767	3,467,177	(241,410)	(7.0) %
5.	Transmission of Electricity by Others - FPL Sales	2,181,295	0	2,181,295	N/A
6.	Revenues from Capacity Sales	(7,893,328)	(5,738,050)	(2,155,278)	37.6 %
7.	Total (Lines 1 through 6)	$ 531,487,967	$ 542,056,675	$ (10,568,708)	(1.9) %
8.	Jurisdictional Separation Factor	N/A	N/A	N/A	N/A
9.	Jurisdictional Capacity Charges	$ 526,226,980	$ 536,691,072	$ (10,464,092)	(1.9) %
10.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	$ (56,945,592)	(56,945,592)	0	N/A
11.	Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$ 469,281,388	$ 479,745,480	$ (10,464,092)	(2.2) %
12.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 433,726,208	$ 420,875,921	$ 12,850,287	3.1 %
13.	Prior Period True-up Provision	58,869,559	58,869,559	0	N/A
14.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 492,595,767	$ 479,745,480	$ 12,850,287	2.7 %
15.	True-up Provision for Period - Over/(Under) Recovery (Line 14 - Line 11)	$ 23,314,379	$ -	$ 23,314,379	N/A
16.	Interest Provision for Period	1,688,899	0	1,688,899	N/A
17.	True-up & Interest Provision Beginning of Period - Over/(Under) Recovery	58,869,559	58,869,559	0	N/A
18.	Deferred True-up - Over/(Under) Recovery	(2,850,420)	0	(2,850,420)	N/A
19.	Prior Period True-up Provision - Collected/(Refunded) this Period	58,869,569	58,869,569	0	N/A
20.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 15 through 19)	$ 139,891,986	$ 117,739,128	$ 22,152,857	N/A

Notes:
(a) Per K. M. Dubin's Testimony Appendix III, Page 3, Docket No. 000001-EI, filed September 21, 2000
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, 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.

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APPENDIX II
FUEL COST RECOVERY
E SCHEDULES

KMD-5
DOCKET NO. 010001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT_____
PAGES 1-81
AUGUST 31, 2001

APPENDIX II
FUEL COST RECOVERY
E SCHEDULES
January 2002 – December 2002

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SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002

		(a)		(b)	(c)
		DOLLARS		MWH	¢/KWH
1	Fuel Cost of System Net Generation (E3)	$2,116,491,700		84,467,385	2.5057
2	Nuclear Fuel Disposal Costs (E2)	22,562,002		24,283,718	0.0929
3	Fuel Related Transactions (E2)	12,061,527		0	0.0000
4	Fuel Cost of Sales to FKEC / CKW (E2)	(30,989,536)		(1,022,607)	3.0304
5	TOTAL COST OF GENERATED POWER	$2,120,125,693		83,444,778	2.5408
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	175,916,510		11,576,275	1.5196
7	Energy Cost of Sched C & X Econ Purch (Florida) (E9)	38,260,579		1,301,681	2.9393
8	Energy Cost of Other Econ Purch (Non-Florida) (E9)	38,884,090		1,047,592	3.7118
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 (E2)	2,428,182		0	0.0000
11a	Okeelanta/Osceola Settlement (E2)	$10,942,995		0	0.0000
12	Payments to Qualifying Facilities (E8)	148,745,520		6,794,037	2.1894
13	TOTAL COST OF PURCHASED POWER	$415,177,876		20,719,585	2.0038
14	TOTAL AVAILABLE KWH (LINE 5 + LINE 13)			104,164,363	
15	Fuel Cost of Economy Sales (E6)	(71,497,100)		(1,815,000)	3.9392
16	Gain on Economy Sales (E6A)	0		0	0.0000
17	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(1,525,200)		(493,502)	0.3091
18	Fuel Cost of Other Power Sales (E6)	0		0	0.0000
18a	Revenues from Off-System Sales	(17,838,370)		(2,308,502)	0.7727
19	TOTAL FUEL COST AND GAINS OF POWER SALES	($90,860,670)		(2,308,502)	3.9359
19a	Net Inadvertent Interchange	0		0	
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 13 + 19 + 19a)	$2,444,442,899		101,855,861	2.3999
21	Net Unbilled Sales	(203,821)	**	(8,493)	(0.0002)
22	Company Use	7,333,329	**	305,568	0.0077
23	T & D Losses	158,888,788	**	6,620,631	0.1674
24	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$2,444,442,899		94,938,155	2.5748
25	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$5,377,286		208,844	2.5748
26	Jurisdictional MWH Sales	$2,439,065,613		94,729,311	2.5748
27	Jurisdictional Loss Multiplier	-		-	1.00052
28	Jurisdictional MWH Sales Adjusted for Line Losses	$2,440,333,927		94,729,311	2.5761
29	FINAL TRUE-UP JAN 00 - DEC 00 $259,002,688 underrecovery / EST/ACT TRUE-UP JAN 01 - DEC 01 $13,794,067 overrecovery	245,208,621		94,729,311	0.2589
30	TOTAL JURISDICTIONAL FUEL COST	$2,685,542,548		94,729,311	2.8350
31	Revenue Tax Factor				1.01597
32	Fuel Factor Adjusted for Taxes				2.8803
33	GPIF ***	$9,004,713		94,729,311	0.0095
34	Fuel Factor including GPIF (Line 32 + Line 33)				2.8898
35	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH				2.890

** 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: JANUARY 2002 - DECEMBER 2002

1. Estimated/Actual over/(under) recovery (January 2001 - December 2001) (Schedule E-1B)	$ 151,894,067
2. Over/(under) recovery for January 2001 - December 2001 to be included in theJanuary 2002 - December 2002 projected period ($151,894,067 - $138,100,000 included in Oct. 2001 fuel reduction)	$ 13,794,067
3.Over/(under) recovery from January 2000 - December 2000 to be included in theJanuary 2002 - December 2002 projected period (50% of $518,005,376 underrecovery from Jan - Dec 2000)	$ (259,002,688)
4.Total over/(under) recovery to be included in the January 2002 - December 2002 projected period (Schedule E1, Line 29)	$ (245,208,621)
5. TOTAL JURISDICTIONAL SALES (MWH) (Projected period)	94,729,311
6. True-Up Factor (Lines 3/4) c/kWh:	(0.2589)

CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2001
ACTUALS THROUGH JULY 2001 - REVISED ESTIMATES FOR AUGUST THROUGH DECEMBER 2001

	LINE NO.			(1) ACTUAL JANUARY	(2) ACTUAL FEBRUARY	(3) ACTUAL MARCH	(4) ACTUAL APRIL	(5) ACTUAL MAY	(6) ACTUAL JUNE
A			Fuel Costs & Net Power Transactions						
	1	a	Fuel Cost of System Net Generation	$ 244,785,143	$ 159,425,167	$ 177,190,313	$ 204,132,267	$ 196,155,831	$ 221,272,763
		b	Nuclear Fuel Disposal Costs	2,068,407	1,843,450	2,015,390	1,551,446	1,946,294	2,012,166
		c	Coal Cars Depreciation & Return	322,410	320,677	318,944	317,212	315,479	172,197
		d	Gas Pipelines Depreciation & Return	214,594	213,138	211,683	210,227	208,772	207,316
		e	DOE D&D Fund Payment	0	0	0	0	0	0
	2	a	Fuel Cost of Power Sold	(12,968,637)	(3,779,258)	(6,789,117)	(5,276,186)	(10,230,516)	(5,307,573)
		b	Revenues from Off-System Sales	(5,127,829)	(619,875)	(1,841,828)	(1,255,420)	(2,917,249)	(1,588,846)
	3	a	Fuel Cost of Purchased Power	14,199,440	13,029,285	13,378,077	15,628,813	15,938,203	13,199,193
		b	Energy Payments to Qualifying Facilities	11,896,881	10,643,682	10,958,522	11,686,756	11,099,683	12,227,370
	4		Energy Cost of Economy Purchases	2,778,540	2,938,601	7,310,367	15,227,982	8,076,737	5,296,225
	5		Total Fuel Costs & Net Power Transactions	$ 258,168,949	$ 184,014,867	$ 202,752,351	$ 242,223,096	$ 220,593,234	$ 247,490,811
	6		Adjustments to Fuel Cost:						
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(2,550,139)	(3,387,586)	(2,617,769)	(3,111,502)	(3,235,559)	(3,139,331)
		b	Reactive and Voltage Control Fuel Revenue	(74,105)	(63,307)	(43,864)	(35,075)	(33,718)	(26,851)
		c	Inventory Adjustments	(169,260)	167,695	40,100	(413,216)	(134,375)	(311,926)
		d	Non Recoverable Oil/Tank Bottoms	0	171,000	0	(60,609)	0	0
		e	Modifications to Burn Low Gravity Oil	0	0	0	0	0	0
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 255,375,445	$ 180,902,669	$ 200,130,818	$ 238,602,694	$ 217,189,582	$ 244,012,703
B			kWh Sales						
	1		Jurisdictional kWh Sales (RTP @ CBL) (a)	7,629,849,502	6,715,059,955	6,512,773,908	6,579,965,506	6,735,706,835	8,075,952,989
	2		Sale for Resale ($Excluding FKEC & CKW)	549,963	440,917	463,088	597,708	538,692	518,879
	3		Sub-Total Sales ($Excluding FKEC & CKW)	7,630,399,465	6,715,500,872	6,513,236,996	6,580,563,214	6,736,245,527	8,076,471,868
			Jurisdictional % of Total kWh Sales (lines B1/B3)	99.99279 %	99.99343 %	99.99289 %	99.99092 %	99.99200 %	99.99358 %
C			True-up Calculation						
	1		Jurisdictional Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 214,633,368	$ 193,031,956	$ 187,300,172	$ 231,916,374	$ 242,218,141	$ 290,936,279
	2		Fuel Adjustment Revenues Not Applicable to Period:						
		a 1	Amortize 1/24 of $518,005,376 (b)	(21,583,557)	(21,583,557)	(21,583,557)	(21,583,557)	(21,583,557)	(21,583,557)
		a 2	2000 Final True-up Collected per Midcourse Order PSC-01-0963-PCO	0	0	0	(8,534,119)	(8,534,119)	(8,534,119)
		b	GPIF, Net of Revenue Taxes (c)	(581,146)	(581,146)	(581,146)	(581,146)	(581,146)	(581,146)
		c	Oil Backout Revenues, Net of revenue Taxes	(23)	1	3	49	0	(303)
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 192,468,642	$ 170,867,254	$ 165,135,472	$ 201,217,601	$ 211,519,319	$ 260,237,154
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 255,375,445	$ 180,902,669	$ 200,130,818	$ 238,602,694	$ 217,189,582	$ 244,012,703
		b	Nuclear Fuel Expense - 100% Retail	0	0	0	0	0	0
		c	RTP Incremental Fuel -100% Retail	47,129	37,120	47,714	(41,788)	(150,080)	(64,137)
		d	D&D Fund Payments -100% Retail	0	0	0	0	0	0
		e	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	255,328,316	180,865,550	200,083,104	239,752,841	217,339,661	244,076,840
	5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.99279 %	99.99343 %	99.99289 %	99.99092 %	99.99200 %	99.99358 %
	6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00046(d)) +(Lines C4b,c,d)	$ 255,474,478	$ 180,973,980	$ 200,208,624	$ 239,799,560	$ 217,272,162	$ 244,109,301
	7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (63,005,836)	$ (10,106,726)	$ (35,073,152)	$ (38,581,959)	$ (5,752,843)	$ 16,127,853
	8		Interest Provision for the Month (Line D10)	(543,803)	(648,282)	(713,247)	(788,344)	(749,090)	(655,872)
	9		True-up & Interest Provision Beg of Period-Over/(Under) Recovery	0	(63,549,639)	(74,304,647)	(110,091,046)	(149,461,349)	(155,963,282)
	10		Deferred True-up Beginning of Period - Over/(Under) Recovery	(76,807,071)	(76,807,071)	(76,807,071)	(76,807,071)	(68,272,952)	(59,738,833)
		a	Prior Period True-up Collected/(Refunded) This Period	0	0	0	0	0	0
		b	Prior Period True-up Collected/(Refunded) This Period	0	0	0	8,534,119	8,534,119	8,534,119
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (140,356,710)	$ (151,111,718)	$ (186,898,117)	$ (217,734,301)	$ (215,702,115)	$ (191,696,015)

NOTES
(a) Real Time Pricing (RTP) sales are shown at the Customer Base Load (CBL) KWH. The incremental/decremental kwh sales are excluded. The incremental/decremental RTP fuel revenues (net of revenue taxes) are included in jurisdictional fuel revenues.
(b) Amortization of $518,005,376 fuel underrecovery over 24 months per FPSC Order No. PSC-00-2385-FOF-EI.
(c) Generation Performance Incentive Factor is (($6,973,751/12) x 98.4280%) - See Order No. PSC-00-2385-FOF-EI.
(d) Per Estimated Schedule E-2, filed September 21, 2000.

CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2001
ACTUALS THROUGH JULY 2001 - REVISED ESTIMATES FOR AUGUST THROUGH

LINE NO.				(7) ACTUAL JULY	(8) ESTIMATED AUGUST	(9) ESTIMATED SEPTEMBER	(10) ESTIMATED OCTOBER	(11) ESTIMATED NOVEMBER	(12) ESTIMATED DECEMBER	(13) TOTAL PERIOD
A			Fuel Costs & Net Power Transactions							
	1	a	Fuel Cost of System Net Generation	$ 204,642,334	$ 229,579,080	$ 219,664,750	$ 180,917,780	$ 136,535,650	$ 147,939,170	$ 2,322,240,248
		b	Nuclear Fuel Disposal Costs	1,982,870	1,980,798	1,916,901	1,528,800	1,775,711	1,746,523	22,368,756
		c	Coal Cars Depreciation & Return	312,014	310,281	308,549	306,816	305,083	303,351	3,613,013
		d	Gas Pipelines Depreciation & Return	205,860	204,405	202,949	201,494	200,038	198,583	2,479,059
		e	DOE D&D Fund Payment	0	0	0	0	6,104,000	0	6,104,000
	2	a	Fuel Cost of Power Sold	(5,516,006)	(8,079,280)	(7,257,190)	(4,892,730)	(3,312,290)	(5,234,420)	(78,643,204)
		b	Revenues from Off-System Sales	(1,465,801)	(1,569,312)	(511,210)	(18,090)	(27,652)	(83,887)	(17,026,999)
	3	a	Fuel Cost of Purchased Power	13,823,744	14,827,870	14,290,570	14,715,550	14,287,680	14,567,720	171,886,145
		b	Energy Payments to Qualifying Facilities	11,919,593	13,195,270	13,112,110	13,369,440	10,377,920	12,608,400	143,095,627
	4		Energy Cost of Economy Purchases	4,279,572	6,361,566	8,893,050	7,404,655	5,855,162	6,243,907	80,666,364
	5		Total Fuel Costs & Net Power Transactions	$ 230,184,180	$ 256,810,679	$ 250,620,479	$ 213,533,715	$ 172,101,303	$ 178,289,347	$ 2,656,783,009
	6		Adjustments to Fuel Cost:							
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(3,063,295)	(2,976,238)	(3,043,183)	(2,931,480)	(2,721,998)	(2,450,625)	(35,228,705)
		b	Reactive and Voltage Control Fuel Revenue	(108,066)	0	0	0	0	0	(384,986)
		c	Inventory Adjustments	(392,674)	0	0	0	0	0	(1,213,656)
		d	Non Recoverable Oil/Tank Bottoms	(43,783)	0	0	0	0	0	66,608
		e	Modifications to Burn Low Gravity Oil	0	0	0	0	0	0	0
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 226,576,362	$ 253,834,441	$ 247,577,296	$ 210,602,235	$ 169,379,305	$ 175,838,722	$ 2,620,022,270
B			kWh Sales							
	1		Jurisdictional kWh Sales (RTP @ CBL) (a)	8,541,653,012	8,887,376,000	9,011,298,000	8,322,130,000	7,000,363,000	7,135,726,000	91,147,854,707
	2		Sale for Resale ($Excluding FKEC & CKW)	422,743	606,000	578,000	531,000	609,000	576,000	6,431,990
	3		Sub-Total Sales ($Excluding FKEC & CKW)	8,542,075,755	8,887,982,000	9,011,876,000	8,322,661,000	7,000,972,000	7,136,302,000	91,154,286,697
			Jurisdictional % of Total kWh Sales (lines B1/B3)	99.99505 %	99.99318 %	99.99359 %	99.99362 %	99.99130 %	99.99193 %	N/A
C			True-up Calculation							
	1		Jurisdictional Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 307,531,802	$ 320,164,592	$ 324,628,838	$ 299,801,804	$ 252,185,613	$ 257,062,017	3,121,410,957
	2		Fuel Adjustment Revenues Not Applicable to Period:							
		a 1	Amortize 1/24 of $518,005,376 (b)	(21,583,557)	(21,583,557)	(21,583,557)	(21,583,557)	(21,583,557)	(21,583,558)	(259,002,685)
		a 2	2000 Final True-up Collected per Midcourse Order PSC-01-0963-PCO	(8,534,119)	(8,534,119)	(8,534,119)	(8,534,119)	(8,534,119)	(8,534,119)	(76,807,071)
		b	GPIF, Net of Revenue Taxes (c)	(581,146)	(581,146)	(581,146)	(581,146)	(581,146)	(581,146)	(6,973,752)
		c	Oil Backout Revenues, Net of revenue Taxes	2						(271)
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 276,832,982	$ 289,465,770	$ 293,930,016	$ 269,102,982	$ 221,486,791	$ 226,363,194	$ 2,778,627,178
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 226,576,362	$ 253,834,441	$ 247,577,296	$ 210,602,235	$ 169,379,305	$ 175,838,722	$ 2,620,022,270
		b	Nuclear Fuel Expense - 100% Retail	0	0	0	0	0	0	0
		c	RTP Incremental Fuel -100% Retail	41,507	0	0	0	0	0	(82,535)
		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)	226,534,855	253,834,440.69	247,577,295.62	210,602,234.59	169,379,304.58	175,838,721.74	2,620,104,805
	5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.99505 %	99.99318 %	99.99359 %	99.99362 %	99.99130 %	99.99193 %	N/A
	6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00046(d)) +(Lines C4b,c,d)	$ 226,669,349	$ 253,933,885	$ 247,675,304	$ 210,685,669	$ 169,442,476	$ 175,905,411	$ 2,622,150,199
	7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ 50,163,633	$ 35,531,885	$ 46,254,712	$ 58,417,313	$ 52,044,315	$ 50,457,783	$ 156,476,979
	8		Interest Provision for the Month (Line D10)	(510,712)	(348,362)	(194,990)	(5,381)	193,868	381,303	(4,582,912)
	9		True-up & Interest Provision Beg of Period-Over/(Under) Recovery	(140,491,301)	(90,838,379)	(55,654,857)	(9,595,135)	48,816,798	101,054,981	0
			Deferred True-up Beginning of Period - Over/(Under) Recovery	(51,204,714)	(42,670,595)	(34,136,476)	(25,602,357)	(17,068,238)	(8,534,119)	(76,807,071)
	10	a	Prior Period True-up Collected/(Refunded) This Period	0	0	0	0	0	0	0
		b	Prior Period True-up Collected/(Refunded) This Period	8,534,119	8,534,119	8,534,119	8,534,119	8,534,119	8,534,119	76,807,071
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (133,508,974)	$ (89,791,333)	$ (35,197,492)	$ 31,748,560	$ 92,520,862	$ 151,894,067	$ 151,894,067

NOTES
(a) Real Time Pricing (RTP) sales are shown at the Customer Base Lo
The incremental/decremental RTP fuel revenues (net of revenue tax
(b) Amortization of $518,005,376 fuel underrecovery over 24 months
(c) Generation Performance Incentive Factor is (($6,975,751/12) x 98.4
(d) Per Estimated Schedule E-2, filed September 21, 2000.

SCHEDULE E - 1C

CALCULATION OF GENERATING PERFORMANCE
INCENTIVE FACTOR AND TRUE - UP FACTOR
FLORIDA POWER AND LIGHT COMPANY
FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002

1. TOTAL AMOUNT OF ADJUSTMENTS:	254,213,334
A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)	$9,004,713
B. TRUE-UP (OVER)/UNDER RECOVERED	$ 245,208,621
2. TOTAL JURISDICTIONAL SALES (MWH)	94,729,311
3. ADJUSTMENT FACTORS c/kWh:	0.2684
A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0095
B. TRUE-UP FACTOR	0.2589

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1D

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

JANUARY 2002 - DECEMBER 2002

NET ENERGY FOR LOAD (%)		FUEL COST (%)
ON PEAK	30.58	33.56
OFF PEAK	69.42	66.44
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$2,444,442,899	$820,355,037	$1,624,087,862
2	MWH SALES	94,938,155	29,032,088	65,906,067
3	COST PER KWH SOLD	2.5748	2.8257	2.4642
4	JURISDICTIONAL LOSS FACTOR	1.00052	1.00052	1.00052
5	JURISDICTIONAL FUEL FACTOR	2.5761	2.8272	2.4655
6	TRUE-UP	0.2589	0.2589	0.2589
7				
8	TOTAL	2.8350	3.0861	2.7244
9	REVENUE TAX FACTOR	1.01597	1.01597	1.01597
10	RECOVERY FACTOR	2.8803	3.1354	2.7679
11	GPIF	0.0095	0.0095	0.0095
12	RECOVERY FACTOR including GPIF	2.8898	3.1449	2.7774
13	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	2.890	3.145	2.777

HOURS:		
	ON-PEAK	24.73 %
	OFF-PEAK	75.27 %

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1E

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

JANUARY 2002 - DECEMBER 2002

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1, GS-1, SL-2		2.890	1.00210	2.896
A-1*	SL-1, OL-1, PL-1		2.836	1.00210	2.842
B	GSD-1		2.890	1.00202	2.896
C	GSLD-1 & CS-1		2.890	1.00078	2.892
D	GSLD-2, CS-2, OS-2 & MET		2.890	0.99429	2.873
E	GSLD-3 & CS-3		2.890	0.95233	2.752
A	RST-1, GST-1	ON-PEAK	3.145	1.00210	3.152
		OFF-PEAK	2.777	1.00210	2.783
B	GSDT-1 CILC-1(G)	ON-PEAK	3.145	1.00202	3.151
		OFF-PEAK	2.777	1.00202	2.783
C	GSLDT-1 & CST-1	ON-PEAK	3.145	1.00078	3.147
		OFF-PEAK	2.777	1.00078	2.780
D	GSLDT-2 & CST-2	ON-PEAK	3.145	0.99429	3.127
		OFF-PEAK	2.777	0.99429	2.762
E	GSLDT-3,CST-3, CILC -1(T) & ISST-1(T)	ON-PEAK	3.145	0.95233	2.995
		OFF-PEAK	2.777	0.95233	2.645
F	CILC -1(D) & ISST-1(D)	ON-PEAK	3.145	0.99331	3.124
		OFF-PEAK	2.777	0.99331	2.759

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

2000 Actual Energy Losses by Rate Class

Line No	Rate Class	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	RS-1 Sec	46,367,391	1.07543311	49,865,027	0.929858	3,497,636	1.00210
2							
3	GS-1 Sec	5,464,345	1.07543311	5,876,538	0.929858	412,193	1.00210
4							
5	GSD-1 Pri	56,036	1.04619093	58,625	0.955848	2,588	
6	GSD-1 Sec	20,128,609	1.07543311	21,646,972	0.929858	1,518,364	
7	Subtotal GSD-1	20,184,645	1.07535193	21,705,597	0.929928	1,520,952	1.00202
8							
9	OS-2 Pri	8,453	1.04619093	8,844	0.955848	390	
10	OS-2 Sec	11,561	1.07543311	12,433	0.929858	872	
11	Subtotal OS-2	20,014	1.06308240	21,277	0.940661	1,263	0.99059
12							
13	GSLD-1 Pri	393,929	1.04619093	412,125	0.955848	18,196	
14	GSLD-1 Sec	8,335,690	1.07543311	8,964,477	0.929858	628,787	
15	Subtotal GSLD-1	8,729,619	1.07411354	9,376,602	0.931000	646,983	1.00087
16							
17	CS-1 Pri	36,561	1.04619093	38,250	0.955848	1,689	
18	CS-1 Sec	174,142	1.07543311	187,278	0.929858	13,136	
19	Subtotal CS-1	210,703	1.07035900	225,528	0.934266	14,825	0.99737
20							
21	Subtotal GSLD-1 / CS-1	8,940,322	1.07402505	9,602,130	0.931077	661,808	1.00078
22							
23	GSLD-2 Pri	262,833	1.04619093	274,974	0.955848	12,141	
24	GSLD-2 Sec	861,635	1.07543311	926,631	0.929858	64,996	
25	Subt GSLD-2	1,124,468	1.06859804	1,201,605	0.935806	77,136	0.99573
26							
27	CS-2 Pri	19,278	1.04619093	20,169	0.955848	890	
28	CS-2 Sec	54,547	1.07543311	58,662	0.929858	4,115	
29	Subtotal CS-2	73,826	1.06779710	78,831	0.936508	5,005	0.99498
30							
31	Subtotal GSLD-2 / CS-2	1,198,294	1.06854869	1,280,435	0.935849	82,141	0.99568
32							
33	GSLD-3 Tm	456,170	1.02202368	466,216	0.978451	10,047	0.95233
34							
35	CS-3 Tm	0	1.02202368	0	0.000000	0	0.00000
36							
37	Subtotal GSLD-3 / CS-3	456,170	1.02202368	466,216	0.978451	10,047	0.95233
38							
39	ISST-1 Sec	0	1.07543311	0	0.000000	0	0.00000
40							
41	SST-1 Pri	60,927	1.04619093	63,741	0.955848	2,814	
42	SST-1 Sec	879	1.07543311	945	0.929858	66	
43	Subtotal SST-1 (D)	61,806	1.04660678	64,686	0.955489	2,881	0.97524
44							
45	SST-1 Tm	84,548	1.02202368	86,410	0.978451	1,862	0.95233
46							
47	CILC-1D Pri	948,847	1.04619093	992,676	0.955848	43,828	
48	CILC-1D Sec	1,995,213	1.07543311	2,145,718	0.929858	150,505	
49	Subtotal CILC-1D	2,944,060	1.06600858	3,138,393	0.938079	194,333	0.99331
50							
51	CILC-1G Pri	2,387	1.04619093	2,497	0.955848	110	
52	CILC-1G Sec	246,349	1.07543311	264,932	0.929858	18,583	
53	Subtotal CILC-1G	248,736	1.07515249	267,429	0.930101	18,693	1.00183
54							
55	Subtotal CILC-1D / CILC-1G	3,192,796	1.06672094	3,405,823	0.937452	213,026	0.99398
56							
57	Subtotal GSD-1 & CILC-1G	20,433,382	1.07534950	21,973,027	0.929930	1,539,645	1.00202
58							
59	CILC-1T Tm	1,138,377	1.02202368	1,163,448	0.978451	25,071	0.95233
60							
61	Subtotal ISST-D & CILC-1D	2,944,060	1.06600858	3,138,393	0.938079	194,333	0.99331
62							
63	MET Pri	81,616	1.04619093	85,386	0.955848	3,770	0.97485
64							
65	Subtotal OS-2, GSLD-2, CS-2, & MET	1,299,924	1.06706079	1,387,098	0.937154	87,174	0.99429
66							
67	OL-1 Sec	111,128	1.07543311	119,510	0.929858	8,383	1.00210
68							
69	SL-1 Sec	383,419	1.07543311	412,341	0.929858	28,922	1.00210
70							
71	Subtotal OL-1 / SL-1	494,547	1.07543311	531,852	0.929858	37,305	1.00210
72							
73	SL-2 Sec	80,580	1.07543311	86,658	0.929858	6,078	1.00210
74							
75	RTP-1 Pri	4,512	1.04619093	4,720	0.955848	208	
76	RTP-1 Sec	113,325	1.07543311	121,873	0.929858	8,548	
77	Subtotal RTP-1	117,837	1.07431343	126,593	0.930827	8,757	1.00105
78							
79	RTP-2 Pri	99,544	1.04619093	104,142	0.955848	4,598	
80	RTP-2 Sec	117,978	1.07543311	126,877	0.929858	8,899	
81	Subtotal RTP-2	217,522	1.06205109	231,019	0.941574	13,497	0.98963
82							
83	RTP-3 Tm	27,298	1.02202368	27,899	0.978451	601	0.95233
84							
85	Total FPSC	88,128,107	1.07374365	94,626,996	0.931321	6,498,889	1.00052
86							
87	Total FERC Sales	971,491	1.02202368	992,887	0.978451	21,396	
88							
89	Total Company	89,099,599	1.07317973	95,619,883	0.931810	6,520,284	
90							
91	Company Use	146,221	1.07543311	157,251	0.929858	11,030	
92							
93	Total FPL	89,245,820	1.07318342	95,777,134	0.931807	6,531,314	1.00000
94							
95	**Summary of Sales by Voltage:**						
96							
97	Transmission	2,677,884	1.02202368	2,736,861	0.978451	58,977	
98							
99	Primary	1,974,925	1.04619093	2,066,148	0.955848	91,224	
###							
###	Secondary	84,446,790	1.07543311	90,816,874	0.929858	6,370,084	
###							
###	Total	89,099,599	1.07317973	95,619,883	0.931810	6,520,284	

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2002 - DECEMBER 2002

LINE NO.	(a) JANUARY	(b) FEBRUARY	(c) ESTIMATED MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) 6 MONTH SUB-TOTAL	LINE NO.
A1 FUEL COST OF SYSTEM GENERATION	$144,490,880	$130,054,960	$144,246,760	$167,466,970	$174,656,190	$206,092,950	$967,008,710	A1
1a NUCLEAR FUEL DISPOSAL	2,030,598	1,834,089	1,921,482	1,570,368	1,980,798	1,916,901	11,254,236	1a
1b COAL CAR INVESTMENT	301,618	299,886	298,153	296,420	294,688	292,955	1,783,720	1b
1c NUCLEAR THERMAL UPRATE	0	0	0	0	0	0	0	1c
1d GAS LATERAL ENHANCEMENTS	197,127	195,672	194,216	192,761	191,305	189,849	1,160,930	1d
1e DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	0	0	0	1e
1f LOW GRAVITY FUEL MODIFICATIONS	0	0	0	0	0	0	0	1f
2 FUEL COST OF POWER SOLD	(8,929,020)	(5,607,490)	(4,585,070)	(5,131,180)	(6,579,550)	(7,363,120)	(38,195,430)	2
2a REVENUES FROM OFF-SYSTEM SALES	(2,128,787)	(1,209,425)	(757,677)	(129,202)	(546,425)	(2,645,912)	(7,417,428)	2a
3 FUEL COST OF PURCHASED POWER	15,386,080	13,719,250	14,339,070	13,670,880	15,125,030	14,644,620	86,884,930	3
3a MISSION SETTLEMENT	0	88,109	0	1,108,358	0	0	1,196,467	3a
3b OKEELANTA/OSCEOLA SETTLEMENT	925,479	923,013	920,547	918,081	915,615	913,149	5,515,886	3b
3c QUALIFYING FACILITIES	12,810,300	11,912,760	12,909,160	11,696,060	13,494,290	13,105,070	75,927,640	3c
4 ENERGY COST OF ECONOMY PURCHASES	5,713,795	5,946,499	6,527,886	7,864,690	7,345,417	6,588,630	39,986,917	4
4a FUEL COST OF SALES TO FKEC / CKW	(2,265,915)	(2,185,620)	(2,232,890)	(2,389,973)	(2,527,905)	(2,676,203)	(14,278,505)	4a
5 TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$168,532,156	$155,971,704	$173,781,637	$197,134,234	$204,349,454	$231,058,889	$1,130,828,073	5
6 SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	7,221,594	7,096,667	6,611,268	7,025,572	7,208,422	8,629,966	43,793,489	6
7 COST PER KWH SOLD (¢/KWH)	2.3337	2.1978	2.6286	2.8060	2.8349	2.6774	2.5822	7
7a JURISDICTIONAL LOSS MULTIPLIER	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052	7a
7b JURISDICTIONAL COST (¢/KWH)	2.3349	2.1990	2.6299	2.8074	2.8363	2.6788	2.5835	7b
9 TRUE-UP (¢/KWH)	0.2830	0.2880	0.3091	0.2909	0.2835	0.2368	0.2800	9
10 TOTAL	2.6179	2.4870	2.9390	3.0983	3.1198	2.9156	2.8635	10
11 REVENUE TAX FACTOR 0.01597	0.0418	0.0397	0.0469	0.0495	0.0498	0.0466	0.0457	11
12 RECOVERY FACTOR ADJUSTED FOR TAXES	2.6597	2.5267	2.9859	3.1478	3.1696	2.9622	2.9092	12
13 GPIF (¢/KWH)	0.0104	0.0106	0.0114	0.0107	0.0104	0.0087	0.0103	13
14 RECOVERY FACTOR Including GPIF	2.6701	2.5373	2.9973	3.1585	3.1800	2.9709	2.9195	14
15 RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	2.670	2.537	2.997	3.159	3.180	2.971	2.920	15

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2002 - DECEMBER 2002

LINE NO.	(h) JULY	(i) AUGUST	(j) ESTIMATED SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) 12 MONTH PERIOD	LINE NO.
A1 FUEL COST OF SYSTEM GENERATION	$228,335,790	$234,652,280	$219,875,220	$188,297,590	$136,276,370	$142,045,740	$2,116,491,700	A1
1a NUCLEAR FUEL DISPOSAL	1,980,798	1,980,798	1,898,660	1,451,817	1,965,095	2,030,598	$22,562,002	1a
1b COAL CAR INVESTMENT	291,223	289,490	287,757	286,025	284,292	282,560	$3,505,067	1b
1c NUCLEAR THERMAL UPRATE	0	0	0	0	0	0	$0	1c
1d GAS LATERAL ENHANCEMENTS	188,394	186,938	185,483	184,027	182,572	181,116	$2,269,460	1d
1e DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	6,287,000	0	$6,287,000 $0	1e
1f LOW GRAVITY FUEL MODIFICATIONS	0	0	0	0	0	0	$0	1f
2 FUEL COST OF POWER SOLD	(8,266,030)	(8,572,130)	(6,595,720)	(4,016,910)	(3,556,960)	(3,819,120)	($73,022,300)	2
2a REVENUES FROM OFF-SYSTEM SALES	(4,049,000)	(3,743,000)	(1,237,225)	(144,990)	(239,430)	(1,007,297)	($17,838,370)	2a
3 FUEL COST OF PURCHASED POWER	15,076,390	15,336,550	14,780,760	15,193,510	14,235,170	14,409,200	$175,916,510	3
3a MISSION SETTLEMENT	0	0	0	1,108,358	123,357	0	$2,428,182	3a
3b OKEELANTA/OSCEOLA SETTLEMENT	910,683	908,217	905,751	903,285	900,819	898,353	$10,942,995	3b
3c QUALIFYING FACILITIES	13,425,790	13,336,590	13,044,160	12,975,790	9,330,950	10,704,600	$148,745,520	3c
4 ENERGY COST OF ECONOMY PURCHASES	5,654,775	5,772,707	8,479,396	6,840,782	5,429,090	4,981,000	$77,144,667	4
4a FUEL COST OF SALES TO FKEC / CKW	(2,837,258)	(2,953,278)	(2,959,330)	(2,879,222)	(2,678,376)	(2,403,567)	($30,989,536)	4a
5 TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$250,711,555	$257,195,162	$248,664,912	$220,200,063	$168,539,949	$168,303,183	$2,444,442,898	5
6 SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	9,000,511	9,258,209	9,386,004	8,680,413	7,327,658	7,491,872	94,938,156	6
7 COST PER KWH SOLD (¢/KWH)	2.7855	2.7780	2.6493	2.5367	2.3001	2.2465	2.5748	7
7a JURISDICTIONAL LOSS MULTIPLIER	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052	7a
7b JURISDICTIONAL COST (¢/KWH)	2.7870	2.7795	2.6507	2.5381	2.3012	2.2476	2.5761	7b
9 TRUE-UP (¢/KWH)	0.2279	0.2215	0.2185	0.2363	0.2801	0.2740	0.2589	9
10 TOTAL	3.0149	3.0010	2.8692	2.7744	2.5813	2.5216	2.8350	10
11 REVENUE TAX FACTOR 0.01597	0.0481	0.0479	0.0458	0.0443	0.0412	0.0403	0.0453	11
12 RECOVERY FACTOR ADJUSTED FOR TAXES	3.0630	3.0489	2.9150	2.8187	2.6225	2.5619	2.8803	12
13 GPIF (¢/KWH)	0.0084	0.0081	0.0080	0.0087	0.0103	0.0101	0.0095	13
14 RECOVERY FACTOR Including GPIF	3.0714	3.0570	2.9230	2.8274	2.6328	2.5720	2.8898	14
15 RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	3.071	3.057	2.923	2.827	2.633	2.572	2.890	15

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Generating System Comparative Data by Fuel Type

		Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02
	Fuel Cost of System Net Generation ($)						
1	Heavy Oil	$61,294,030	$61,095,950	$71,168,310	$76,800,200	$74,983,290	$87,974,660
2	Light Oil	$792,190	$25,490	$37,750	$2,852,650	$4,498,890	$1,124,420
3	Coal	$10,572,270	$9,605,270	$10,092,230	$9,766,680	$10,730,280	$10,392,710
4	Gas	$64,924,200	$53,099,630	$56,403,030	$72,664,470	$77,686,920	$100,094,270
5	Nuclear	$6,908,190	$6,228,620	$6,545,440	$5,382,970	$6,756,810	$6,506,890
6	***Total***	$144,490,880	$130,054,960	$144,246,760	$167,466,970	$174,656,190	$206,092,950
	System Net Generation (MWH)						
7	Heavy Oil	1,630,295	1,694,795	2,073,989	2,243,489	2,171,923	2,467,689
8	Light Oil	9,690	319	492	36,392	60,944	15,310
9	Coal	625,612	565,068	579,282	555,534	617,898	597,965
10	Gas	1,565,515	1,276,356	1,393,880	1,842,608	1,987,390	2,848,846
11	Nuclear	2,185,554	1,974,049	2,068,111	1,690,203	2,131,954	2,063,180
12	***Total***	6,016,666	5,510,587	6,115,754	6,368,226	6,970,109	7,993,190
	Units of Fuel Burned						
13	Heavy Oil (BBLS)	2,561,764	2,662,569	3,258,853	3,558,987	3,439,224	3,928,805
14	Light Oil (BBLS)	22,718	689	1,028	83,728	139,125	35,236
15	Coal (TONS)	333,450	300,626	315,322	305,691	332,746	322,073
16	Gas (MCF)	12,244,393	9,872,129	10,782,397	15,563,690	16,896,890	22,705,816
17	Nuclear (MBTU)	23,362,712	21,101,814	22,107,716	18,417,964	23,281,562	22,530,554
	BTU Burned (MMBTU)						
18	Heavy Oil	16,395,289	17,040,442	20,856,656	22,777,516	22,011,038	25,144,352
19	Light Oil	132,116	3,997	5,965	485,772	807,341	204,405
20	Coal	6,342,469	5,728,681	5,901,118	5,714,840	6,326,755	6,122,670
21	Gas	12,244,393	9,872,129	10,782,397	15,563,690	16,896,890	22,705,816
22	Nuclear	23,362,712	21,101,814	22,107,716	18,417,964	23,281,562	22,530,554
23	***Total***	58,476,979	53,747,063	59,653,852	62,959,782	69,323,586	76,707,797

Florida Power & Light Company

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Generating System Comparative Data by Fuel Type

		Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02
	Generation Mix (%MWH)						
24	Heavy Oil	27.10%	30.76%	33.91%	35.23%	31.16%	30.87%
25	Light Oil	0.16%	0.01%	0.01%	0.57%	0.87%	0.19%
26	Coal	10.40%	10.25%	9.47%	8.72%	8.86%	7.48%
27	Gas	26.02%	23.16%	22.79%	28.93%	28.51%	35.64%
28	Nuclear	36.33%	35.82%	33.82%	26.54%	30.59%	25.81%
29	***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Fuel Cost per Unit						
30	Heavy Oil ($/BBL)	23.9265	22.9462	21.8385	21.5792	21.8024	22.3922
31	Light Oil ($/BBL)	34.8706	36.9956	36.7218	34.0704	32.3370	31.9111
32	Coal ($/ton)	31.7057	31.9509	32.0061	31.9495	32.2477	32.2682
33	Gas ($/MCF)	5.3024	5.3787	5.2310	4.6688	4.5977	4.4083
34	Nuclear ($/MBTU)	0.2957	0.2952	0.2961	0.2923	0.2902	0.2888
	Fuel Cost per MMBTU ($/MMBTU)						
35	Heavy Oil	3.7385	3.5854	3.4123	3.3718	3.4066	3.4988
36	Light Oil	5.9962	6.3773	6.3286	5.8724	5.5725	5.5009
37	Coal	1.6669	1.6767	1.7102	1.7090	1.6960	1.6974
38	Gas	5.3024	5.3787	5.2310	4.6688	4.5977	4.4083
39	Nuclear	0.2957	0.2952	0.2961	0.2923	0.2902	0.2888
	BTU burned per KWH (BTU/KWH)						
40	Heavy Oil	10,057	10,055	10,056	10,153	10,134	10,189
41	Light Oil	13,634	12,530	12,124	13,348	13,247	13,351
42	Coal	10,138	10,138	10,187	10,287	10,239	10,239
43	Gas	7,821	7,735	7,736	8,447	8,502	7,970
44	Nuclear	10,690	10,690	10,690	10,897	10,920	10,920
	Generated Fuel Cost per KWH (cents/KWH)						
45	Heavy Oil	3.7597	3.6049	3.4315	3.4232	3.4524	3.5648
46	Light Oil	8.1753	7.9906	7.6728	7.8387	7.3820	7.3444
47	Coal	1.6899	1.6998	1.7422	1.7581	1.7366	1.7380
48	Gas	4.1471	4.1603	4.0465	3.9436	3.9090	3.5135
49	Nuclear	0.3161	0.3155	0.3165	0.3185	0.3169	0.3154
50	***Total***	2.4015	2.3601	2.3586	2.6297	2.5058	2.5784

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Generating System Comparative Data by Fuel Type

		Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Total
	Fuel Cost of System Net Generation ($)							
1	Heavy Oil	$89,226,600	$89,841,330	$85,994,680	$69,734,910	$33,845,960	$26,307,430	$828,267,350
2	Light Oil	$1,491,390	$2,771,690	$1,284,700	$393,540	$0	$0	$15,272,710
3	Coal	$10,735,170	$10,834,140	$10,500,730	$10,830,000	$4,441,550	$4,368,160	$112,869,190
4	Gas	$120,253,980	$124,576,800	$115,737,740	$102,425,090	$91,445,550	$104,582,390	$1,083,894,070
5	Nuclear	$6,628,650	$6,628,320	$6,357,370	$4,914,050	$6,543,310	$6,787,760	$76,188,380
6	***Total***	$228,335,790	$234,652,280	$219,875,220	$188,297,590	$136,276,370	$142,045,740	$2,116,491,700
	System Net Generation (MWH)							
7	Heavy Oil	2,442,330	2,433,491	2,269,978	1,838,442	934,143	781,709	22,982,473
8	Light Oil	22,601	44,302	18,544	5,482	0	0	214,076
9	Coal	617,898	617,898	597,965	616,754	275,131	276,185	6,543,190
10	Gas	3,623,651	3,656,300	3,442,568	2,983,020	2,727,931	3,095,863	30,443,928
11	Nuclear	2,131,954	2,131,954	2,043,547	1,562,606	2,115,052	2,185,554	24,283,718
12	***Total***	8,838,434	8,883,945	8,372,602	7,006,304	6,052,257	6,339,311	84,467,385
	Units of Fuel Burned							
13	Heavy Oil (BBLS)	3,888,866	3,873,176	3,610,765	2,915,163	1,462,251	1,231,455	36,391,878
14	Light Oil (BBLS)	45,483	83,161	38,320	11,693	0	0	461,181
15	Coal (TONS)	332,497	332,820	322,054	332,278	127,722	126,795	3,484,074
16	Gas (MCF)	28,122,426	28,442,086	26,657,464	22,694,786	19,699,938	21,888,614	235,570,629
17	Nuclear (MBTU)	23,281,562	23,281,562	22,318,024	17,118,058	22,609,080	23,362,712	262,773,320
	BTU Burned (MMBTU)							
18	Heavy Oil	24,888,742	24,788,324	23,108,898	18,657,046	9,358,408	7,881,310	232,908,021
19	Light Oil	264,193	483,505	222,532	67,889	0	0	2,677,715
20	Coal	6,326,755	6,326,755	6,122,670	6,315,054	2,727,634	2,734,745	66,690,146
21	Gas	28,122,426	28,442,086	26,657,464	22,694,786	19,699,938	21,888,614	235,570,629
22	Nuclear	23,281,562	23,281,562	22,318,024	17,118,058	22,609,080	23,362,712	262,773,320
23	***Total***	82,883,678	83,322,232	78,429,588	64,852,833	54,395,060	55,867,381	800,619,831

Florida Power & Light Company

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Generating System Comparative Data by Fuel Type

		Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Total
	Generation Mix (%MWH)							
24	Heavy Oil	27.63%	27.39%	27.11%	26.24%	15.43%	12.33%	27.21%
25	Light Oil	0.26%	0.50%	0.22%	0.08%	0.00%	0.00%	0.25%
26	Coal	6.99%	6.96%	7.14%	8.80%	4.55%	4.36%	7.75%
27	Gas	41.00%	41.16%	41.12%	42.58%	45.07%	48.84%	36.04%
28	Nuclear	24.12%	24.00%	24.41%	22.30%	34.95%	34.48%	28.75%
29	***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Fuel Cost per Unit							
30	Heavy Oil ($/BBL)	22.9441	23.1958	23.8162	23.9214	23.1465	21.3629	22.7597
31	Light Oil ($/BBL)	32.7901	33.3292	33.5256	33.6560	0.0000	0.0000	33.1165
32	Coal ($/ton)	32.2865	32.5526	32.6055	32.5932	34.7751	34.4506	32.3957
33	Gas ($/MCF)	4.2761	4.3800	4.3417	4.5132	4.6419	4.7779	4.6011
34	Nuclear ($/MBTU)	0.2847	0.2847	0.2849	0.2871	0.2894	0.2905	0.2899
	Fuel Cost per MMBTU ($/MMBTU)							
35	Heavy Oil	3.5850	3.6243	3.7213	3.7377	3.6166	3.3380	3.5562
36	Light Oil	5.6451	5.7325	5.7731	5.7968	0.0000	0.0000	5.7036
37	Coal	1.6968	1.7124	1.7151	1.7149	1.6284	1.5973	1.6924
38	Gas	4.2761	4.3800	4.3417	4.5132	4.6419	4.7779	4.6011
39	Nuclear	0.2847	0.2847	0.2849	0.2871	0.2894	0.2905	0.2899
	BTU burned per KWH (BTU/KWH)							
40	Heavy Oil	10,191	10,186	10,180	10,148	10,018	10,082	10,134
41	Light Oil	11,689	10,914	12,000	12,384	0	0	12,508
42	Coal	10,239	10,239	10,239	10,239	9,914	9,902	10,192
43	Gas	7,761	7,779	7,743	7,608	7,222	7,070	7,738
44	Nuclear	10,920	10,920	10,921	10,955	10,690	10,690	10,821
	Generated Fuel Cost per KWH (cents/KWH)							
45	Heavy Oil	3.6533	3.6919	3.7883	3.7932	3.6232	3.3654	3.6039
46	Light Oil	6.5988	6.2564	6.9278	7.1788	0.0000	0.0000	7.1342
47	Coal	1.7374	1.7534	1.7561	1.7560	1.6143	1.5816	1.7250
48	Gas	3.3186	3.4072	3.3620	3.4336	3.3522	3.3781	3.5603
49	Nuclear	0.3109	0.3109	0.3111	0.3145	0.3094	0.3106	0.3137
50	***Total***	2.5834	2.6413	2.6261	2.6875	2.2517	2.2407	2.5057

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jan-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	398	122,146	45.8	94.9	91.2	9,846	Heavy Oil BBLS ->	186,097	6,399,998	1,191,019	4,571,612	3.7427
2			13,572					Gas MCF ->	145,269	1,000,000	145,269	597,227	4.4005
3													
4	TRKY O 2	398	28,108	10.5	94.5	89.4	10,291	Heavy Oil BBLS ->	44,552	6,400,005	285,136	1,094,466	3.8938
5			3,123					Gas MCF ->	36,267	1,000,000	36,267	149,098	4.7740
6													
7	TRKY N 3	717	520,110	97.5	97.5	100.0	10,686	Nuclear Othr ->	5,557,947	1,000,000	5,557,947	1,731,300	0.3329
8													
9	TRKY N 4	717	520,110	97.5	97.5	100.0	10,686	Nuclear Othr ->	5,557,947	1,000,000	5,557,947	1,548,444	0.2977
10													
11	FT LAUD4	440	291	79.5	94.7	96.7	7,195	Light Oil BBLS ->	342	5,829,575	1,991	10,876	3.7387
12			259,940					Gas MCF ->	1,870,317	1,000,000	1,870,317	7,689,202	2.9581
13													
14	FT LAUD5	440	291	88.7	94.7	99.1	7,166	Light Oil BBLS ->	341	5,829,662	1,985	10,844	3.7265
15			289,956					Gas MCF ->	2,077,923	1,000,000	2,077,923	8,542,706	2.9462
16													
17	PT EVER1	212	8,385	5.9	95.3	94.5	10,651	Heavy Oil BBLS ->	13,757	6,400,022	88,042	330,633	3.9431
18			932					Gas MCF ->	11,195	1,000,000	11,195	46,023	4.9397
19													
20	PT EVER2	212	22,271	15.7	95.4	91.1	10,363	Heavy Oil BBLS ->	35,599	6,400,001	227,836	855,617	3.8419
21			2,475					Gas MCF ->	28,610	1,000,000	28,610	117,620	4.7533
22													
23	PT EVER3	392	98,596	37.6	94.9	94.2	9,960	Heavy Oil BBLS ->	152,018	6,400,002	972,915	3,653,688	3.7057
24			10,955					Gas MCF ->	118,168	1,000,000	118,168	485,807	4.4345
25													
26	PT EVER4	404	160,746	59.4	95.1	94.5	9,945	Heavy Oil BBLS ->	247,479	6,400,001	1,583,866	5,948,056	3.7003
27			17,861					Gas MCF ->	192,321	1,000,000	192,321	790,664	4.4268

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jan-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
29	RIV 3	280	103,732	55.3	93.5	96.2	9,900	Heavy Oil BBLS ->	158,881	6,400,001	1,016,835	3,522,419	3.3957
30			11,526					Gas MCF ->	124,217	1,000,000	124,217	510,676	4.4307
32	RIV 4	292	118,140	60.4	92.3	95.3	10,115	Heavy Oil BBLS ->	184,631	6,400,000	1,181,640	4,093,319	3.4648
33			13,127					Gas MCF ->	146,170	1,000,000	146,170	600,929	4.5779
35	ST LUC 1	853	618,763	97.5	97.5	100.0	10,693	Nuclear Othr ->	6,616,331	1,000,000	6,616,331	1,947,186	0.3147
37	ST LUC 2	726	526,572	97.5	97.5	100.0	10,693	Nuclear Othr ->	5,630,488	1,000,000	5,630,488	1,681,264	0.3193
39	CAP CN 1	398	140,859	52.9	94.6	95.5	9,679	Heavy Oil BBLS ->	211,220	6,400,001	1,351,808	5,071,061	3.6001
40			15,651					Gas MCF ->	163,081	1,000,000	163,081	670,456	4.2838
42	CAP CN 2	398	102,273	38.4	94.7	92.3	10,031	Heavy Oil BBLS ->	158,552	6,399,998	1,014,735	3,806,593	3.7220
43			11,364					Gas MCF ->	125,101	1,000,000	125,101	514,310	4.5259
45	SANFRD 3	144	4,079	3.8	95.7	95.1	11,123	Heavy Oil BBLS ->	6,972	6,399,989	44,619	165,434	4.0562
46			0					Gas MCF ->	746	1,000,000	746	3,065	
48	SANFRD 4	374	11,068	4.0	97.8	88.8	9,506	Heavy Oil BBLS ->	16,297	6,400,021	104,301	386,717	3.4940
49			0					Gas MCF ->	918	1,000,000	918	3,773	
51	SANFRD 5	384		0.0	0.0		0						
53	PUTNAM 1	250	77,305	41.6	95.0	92.8	9,412	Gas MCF ->	727,584	1,000,000	727,584	2,991,226	3.8694

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jan-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
55	PUTNAM 2	250	66,997	36.0	95.3	91.9	9,418	Gas MCF ->	631,002	1,000,000	631,002	2,594,158	3.8720
57	MANATE 1	805	203,122	33.9	95.1	91.0	10,459	Heavy Oil BBLS ->	331,950	6,399,999	2,124,478	8,003,758	3.9404
59	MANATE 2	805	292,607	48.9	95.2	89.3	10,343	Heavy Oil BBLS ->	472,890	6,400,000	3,026,495	11,402,016	3.8967
61	FT MY 1	0		0.0	0.0		0						
63	FT MY 2	0		0.0	0.0		0						
65	CUTLER 5	72	1,266	2.4	95.0	87.0	13,213	Gas MCF ->	16,728	1,000,000	16,728	68,771	5.4321
67	CUTLER 6	145	2,753	2.6	95.3	88.5	11,928	Gas MCF ->	32,841	1,000,000	32,841	135,013	4.9039
69	MARTIN 1	833	27,948	6.4	95.6	86.8	10,603	Heavy Oil BBLS ->	45,501	6,400,005	291,205	1,119,752	4.0065
70			11,978					Gas MCF ->	132,120	1,000,000	132,120	543,169	4.5348
72	MARTIN 2	821	186,216	43.6	96.1	91.1	10,324	Heavy Oil BBLS ->	295,369	6,400,000	1,890,359	7,268,885	3.9035
73			79,807					Gas MCF ->	856,081	1,000,000	856,081	3,519,498	4.4100
75	MARTIN 3	470	326,088	93.3	94.3	99.6	7,038	Gas MCF ->	2,295,010	1,000,000	2,295,010	9,435,188	2.8935
77	MARTIN 4	470	329,582	94.3	94.6	100.0	6,986	Gas MCF ->	2,302,321	1,000,000	2,302,321	9,465,244	2.8719
79	FM GT	624	4,869	1.0	81.6	95.2	13,185	Light Oil BBLS ->	11,068	5,800,022	64,196	412,811	8.4787
81	FL GT	768	1,123	0.5	91.9	88.8	20,006	Light Oil BBLS ->	3,746	5,830,041	21,837	116,587	10.3799

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jan-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
82			1,556					Gas MCF ->	31,753	1,000,000	31,753	130,542	8.3923
84	PE GT	384	1,303	0.7	88.6	92.3	19,270	Light Oil BBLS ->	4,236	5,829,997	24,698	131,864	10.1239
85			626					Gas MCF ->	12,454	1,000,000	12,454	51,202	8.1858
87	SJRPP 1O	130	89,740	92.8	92.9	100.0	9,817	Coal TONS ->	35,636	24,720,868	880,958	1,326,748	1.4784
89	SJRPP 2O	130	89,763	92.8	93.5	100.0	9,526	Coal TONS ->	34,591	24,720,820	855,115	1,287,828	1.4347
91	SCHER #4	648	446,109	92.5	93.6	100.0	10,326	Coal TONS ->	263,223	17,500,002	4,606,396	7,957,695	1.7838
93	FMREP 1	1,498		0.0	0.0		0						
95	SNREP4	986		0.0	0.0		0						
97	SNREP5	986		0.0	0.0		0						
99	MR SC	181	1,814	1.4	94.3	91.8	9,851	Light Oil BBLS ->	2,986	5,829,918	17,409	109,210	6.0207
100			2,031					Gas MCF ->	20,468	1,000,000	20,468	84,149	4.1430
102	FMCT	165	15,046	2.0	95.5	94.9	9,685	Gas MCF ->	145,728	1,000,000	145,728	599,115	3.9819
104	TOTAL	19,600	6,016,667				9,719				58,476,976	129,905,514	2.1591

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Feb-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	398	124,937	51.9	94.3	95.3	9,841	Heavy Oil BBLS ->	190,304	6,399,999	1,217,943	4,538,026	3.6322
2			13,882					Gas MCF ->	148,213	1,000,000	148,213	599,418	4.3180
3													
4	TRKY O 2	398	36,855	15.3	93.9	84.1	10,268	Heavy Oil BBLS ->	58,417	6,400,002	373,869	1,393,026	3.7797
5			4,095					Gas MCF ->	46,619	1,000,000	46,619	188,540	4.6042
6													
7	TRKY N 3	717	469,777	97.5	97.5	100.0	10,686	Nuclear Othr ->	5,020,092	1,000,000	5,020,092	1,557,734	0.3316
8													
9	TRKY N 4	717	469,777	97.5	97.5	100.0	10,686	Nuclear Othr ->	5,020,092	1,000,000	5,020,092	1,393,577	0.2966
10													
11	FT LAUD4	440	214,662	72.6	94.1	95.8	7,199	Gas MCF ->	1,545,426	1,000,000	1,545,426	6,250,152	2.9116
12													
13	FT LAUD5	440	29	84.0	94.2	98.6	7,169	Light Oil BBLS ->	34	5,831,361	197	1,077	3.7266
14			248,258					Gas MCF ->	1,779,884	1,000,000	1,779,884	7,198,365	2.8995
15													
16	PT EVER1	212	3,495	2.7	94.8	84.4	10,591	Heavy Oil BBLS ->	5,733	6,400,000	36,691	131,975	3.7765
17			388					Gas MCF ->	4,435	1,000,000	4,435	17,934	4.6186
18													
19	PT EVER2	212	31,672	24.7	94.9	89.7	10,353	Heavy Oil BBLS ->	50,629	6,400,001	324,028	1,165,500	3.6799
20			3,519					Gas MCF ->	40,300	1,000,000	40,300	162,986	4.6315
21													
22	PT EVER3	392	132,752	56.0	94.4	96.2	9,962	Heavy Oil BBLS ->	204,672	6,400,000	1,309,900	4,711,593	3.5492
23			14,750					Gas MCF ->	159,510	1,000,000	159,510	645,102	4.3735
24													
25	PT EVER4	404	145,831	59.7	94.5	96.8	9,940	Heavy Oil BBLS ->	224,490	6,400,001	1,436,737	5,167,813	3.5437
26			16,204					Gas MCF ->	173,934	1,000,000	173,934	703,438	4.3413
27													

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Feb-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
28	RIV 3	280	113,348	66.9	92.8	96.6	9,908	Heavy Oil BBLS ->	173,609	6,400,000	1,111,094	3,602,746	3.1785
29			12,594					Gas MCF ->	136,717	1,000,000	136,717	552,924	4.3903
30													
31	RIV 4	292	111,769	63.3	91.5	97.0	10,105	Heavy Oil BBLS ->	174,665	6,400,000	1,117,855	3,624,668	3.2430
32			12,419					Gas MCF ->	137,107	1,000,000	137,107	554,500	4.4650
33													
34	ST LUC 1	853	558,883	97.5	97.5	100.0	10,693	Nuclear Othr ->	5,976,030	1,000,000	5,976,030	1,758,746	0.3147
35													
36	ST LUC 2	726	475,613	97.5	97.5	100.0	10,693	Nuclear Othr ->	5,085,601	1,000,000	5,085,601	1,518,561	0.3193
37													
38	CAP CN 1	398	156,215	64.9	94.0	96.8	9,683	Heavy Oil BBLS ->	234,215	6,400,000	1,498,977	5,437,145	3.4806
39			17,357					Gas MCF ->	181,755	1,000,000	181,755	735,070	4.2350
40													
41	CAP CN 2	398	111,356	46.3	94.1	93.7	10,021	Heavy Oil BBLS ->	172,629	6,399,999	1,104,824	4,007,460	3.5988
42			12,373					Gas MCF ->	135,019	1,000,000	135,019	546,054	4.4133
43													
44	SANFRD 3	144	983	1.0	95.2	89.6	11,069	Heavy Oil BBLS ->	1,680	6,399,786	10,751	39,782	4.0491
45			0					Gas MCF ->	124	1,000,000	124	503	
46													
47	SANFRD 4	374	2,600	1.0	97.6	80.2	9,497	Heavy Oil BBLS ->	3,829	6,400,021	24,504	90,673	3.4881
48			0					Gas MCF ->	184	1,000,000	184	742	
49													
50	SANFRD 5	384		0.0	0.0		0						
51													
52	PUTNAM 1	250	13,553	8.1	94.4	87.4	9,379	Gas MCF ->	127,106	1,000,000	127,106	514,052	3.7930
53													
54	PUTNAM 2	250	10,737	6.4	94.8	88.9	9,382	Gas MCF ->	100,734	1,000,000	100,734	407,398	3.7944

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Feb-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
55													
56	MANATE 1	805	220,692	40.8	94.5	89.1	10,456	Heavy Oil BBLS ->	360,550	6,400,001	2,307,522	8,312,207	3.7664
57													
58	MANATE 2	805	277,954	51.4	94.7	90.0	10,356	Heavy Oil BBLS ->	449,750	6,400,000	2,878,401	10,368,636	3.7303
59													
60	FT MY 1	0		0.0	0.0		0						
61													
62	FT MY 2	0		0.0	0.0		0						
63													
64	CUTLER 5	72	105	0.2	97.3	93.4	12,854	Gas MCF ->	1,347	1,000,000	1,347	5,446	5.1966
65													
66	CUTLER 6	145	542	0.6	96.3	85.2	11,967	Gas MCF ->	6,484	1,000,000	6,484	26,223	4.8400
67													
68	MARTIN 1	833	36,301	9.3	95.1	84.1	10,604	Heavy Oil BBLS ->	59,141	6,400,000	378,499	1,407,319	3.8768
69			15,557					Gas MCF ->	171,403	1,000,000	171,403	693,202	4.4558
70													
71	MARTIN 2	821	188,037	48.7	95.7	88.6	10,328	Heavy Oil BBLS ->	298,257	6,399,999	1,908,845	7,097,384	3.7745
72			80,588					Gas MCF ->	865,484	1,000,000	865,484	3,500,269	4.3434
73													
74	MARTIN 3	470	285,429	90.4	93.7	98.8	7,040	Gas MCF ->	2,009,352	1,000,000	2,009,352	8,126,401	2.8471
75													
76	MARTIN 4	470	296,187	93.8	94.0	99.8	6,986	Gas MCF ->	2,069,215	1,000,000	2,069,215	8,368,503	2.8254
77													
78	FM GT	624	290	0.1	79.6	93.0	13,113	Light Oil BBLS ->	655	5,799,878	3,800	24,409	8.4227
79													
80	FL GT	768	42	0.0	91.0	90.3	19,819	Gas MCF ->	830	1,000,000	830	3,358	8.0143
81													

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Feb-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
82	PE GT	384	65	0.0	87.3	95.3	19,462	Gas	MCF ->	1,271	1,000,000	1,271	5,140	7.8714
84	SJRPP 1O	130	81,055	92.8	92.2	100.0	9,817	Coal	TONS ->	31,906	24,938,689	795,704	1,185,600	1.4627
86	SJRPP 2O	130	81,076	92.8	92.8	100.0	9,526	Coal	TONS ->	30,970	24,938,716	772,362	1,150,821	1.4194
88	SCHER #4	648	402,937	92.5	92.9	100.0	10,326	Coal	TONS ->	237,749	17,500,001	4,160,615	7,268,847	1.8040
90	FMREP 1	1,498		0.0	0.0		0							
92	SNREP4	986		0.0	0.0		0							
94	SNREP5	986		0.0	0.0		0							
96	MR SC	181	389	0.2	93.7	84.5	10,005	Gas	MCF ->	3,895	1,000,000	3,895	15,751	4.0460
98	FMCT	165	2,661	0.4	95.5	92.2	9,688	Gas	MCF ->	25,783	1,000,000	25,783	104,276	3.9181
100	TOTAL	19,600	5,510,587				9,753					53,747,061	116,881,072	2.1210

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Mar-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	398	163,901	61.5	94.9	96.5	9,831	Heavy Oil BBLS ->	249,667	6,400,002	1,597,866	5,704,229	3.4803
2			18,211					Gas MCF ->	192,538	1,000,000	192,538	746,480	4.0990
3													
4	TRKY O 2	398	73,225	27.5	94.5	82.1	10,263	Heavy Oil BBLS ->	116,079	6,399,997	742,905	2,652,098	3.6218
5			8,136					Gas MCF ->	92,128	1,000,000	92,128	357,185	4.3901
6													
7	TRKY N 3	717	520,110	97.5	97.5	100.0	10,686	Nuclear Othr ->	5,557,947	1,000,000	5,557,947	1,721,296	0.3309
8													
9	TRKY N 4	717	402,666	75.5	75.5	100.0	10,686	Nuclear Othr ->	4,302,951	1,000,000	4,302,951	1,192,778	0.2962
10													
11	FT LAUD4	440	15	56.4	62.4	97.5	7,196	Light Oil BBLS ->	17	5,824,561	100	544	3.7517
12			184,768					Gas MCF ->	1,329,665	1,000,000	1,329,665	5,155,185	2.7901
13													
14	FT LAUD5	440	63	88.7	94.7	98.0	7,174	Light Oil BBLS ->	74	5,825,911	432	2,358	3.7310
15			290,385					Gas MCF ->	2,083,344	1,000,000	2,083,344	8,077,246	2.7816
16													
17	PT EVER1	212	10,602	7.5	95.3	80.8	10,565	Heavy Oil BBLS ->	17,393	6,400,000	111,315	381,601	3.5993
18			1,178					Gas MCF ->	13,141	1,000,000	13,141	50,947	4.3249
19													
20	PT EVER2	212	53,571	37.7	95.4	91.9	10,356	Heavy Oil BBLS ->	85,645	6,400,000	548,128	1,879,044	3.5076
21			5,952					Gas MCF ->	68,318	1,000,000	68,318	264,875	4.4500
22													
23	PT EVER3	392	175,259	66.8	94.9	97.7	9,949	Heavy Oil BBLS ->	270,218	6,399,999	1,729,397	5,928,565	3.3827
24			19,473					Gas MCF ->	208,047	1,000,000	208,047	806,609	4.1421
25													
26	PT EVER4	404	188,531	69.7	95.1	97.4	9,932	Heavy Oil BBLS ->	290,252	6,400,000	1,857,613	6,368,104	3.3777
27			20,948					Gas MCF ->	223,037	1,000,000	223,037	864,728	4.1280

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Mar-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
28													
29	RIV 3	280	142,992	76.3	93.5	96.4	9,896	Heavy Oil BBLS ->	219,153	6,400,000	1,402,578	4,251,278	2.9731
30			15,888					Gas MCF ->	169,649	1,000,000	169,649	657,737	4.1398
31													
32	RIV 4	292	136,179	69.6	92.3	95.8	10,105	Heavy Oil BBLS ->	212,870	6,399,999	1,362,369	4,129,403	3.0323
33			15,131					Gas MCF ->	166,646	1,000,000	166,646	646,097	4.2700
34													
35	ST LUC 1	853	618,763	97.5	97.5	100.0	10,693	Nuclear Othr ->	6,616,331	1,000,000	6,616,331	1,947,848	0.3148
36													
37	ST LUC 2	726	526,572	97.5	97.5	100.0	10,693	Nuclear Othr ->	5,630,488	1,000,000	5,630,488	1,683,516	0.3197
38													
39	CAP CN 1	398	196,619	73.8	94.6	96.8	9,676	Heavy Oil BBLS ->	294,957	6,400,001	1,887,727	6,558,714	3.3358
40			21,847					Gas MCF ->	226,035	1,000,000	226,035	876,352	4.0114
41													
42	CAP CN 2	398	151,055	56.7	94.7	95.4	10,009	Heavy Oil BBLS ->	234,183	6,400,000	1,498,773	5,207,334	3.4473
43			16,784					Gas MCF ->	181,177	1,000,000	181,177	702,434	4.1852
44													
45	SANFRD 3	144	2,076	1.9	95.7	85.4	11,003	Heavy Oil BBLS ->	3,550	6,400,006	22,721	83,930	4.0423
46			0					Gas MCF ->	124	1,000,000	124	482	
47													
48	SANFRD 4	374		0.0	0.0		0						
49													
50	SANFRD 5	384		0.0	0.0		0						
51													
52	PUTNAM 1	250	33,554	18.0	95.0	86.4	9,371	Gas MCF ->	314,436	1,000,000	314,436	1,219,087	3.6332
53													
54	PUTNAM 2	250	18,100	9.7	80.8	78.5	9,470	Gas MCF ->	171,400	1,000,000	171,400	664,528	3.6715

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Mar-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
55													
56	MANATE 1	805	289,735	48.4	95.1	91.1	10,474	Heavy Oil BBLS ->	474,192	6,400,000	3,034,827	10,398,704	3.5890
57													
58	MANATE 2	805	340,429	56.8	95.2	92.2	10,359	Heavy Oil BBLS ->	550,993	6,399,999	3,526,352	12,082,894	3.5493
59													
60	FT MY 1	0		0.0	0.0		0						
61													
62	FT MY 2	0		0.0	0.0		0						
63													
64	CUTLER 5	72	595	1.1	97.6	87.1	13,029	Gas MCF ->	7,753	1,000,000	7,753	30,059	5.0511
65													
66	CUTLER 6	145	1,455	1.3	96.7	82.2	11,833	Gas MCF ->	17,220	1,000,000	17,220	66,764	4.5880
67													
68	MARTIN 1	833	45,032	10.4	95.6	73.4	10,604	Heavy Oil BBLS ->	73,393	6,400,002	469,716	1,697,010	3.7684
69			19,300					Gas MCF ->	212,450	1,000,000	212,450	823,681	4.2679
70													
71	MARTIN 2	821	104,782	24.5	51.0	92.6	10,344	Heavy Oil BBLS ->	166,308	6,399,999	1,064,370	3,845,401	3.6699
72			44,906					Gas MCF ->	484,024	1,000,000	484,024	1,876,590	4.1789
73													
74	MARTIN 3	470	325,507	93.1	94.3	99.2	7,042	Gas MCF ->	2,292,137	1,000,000	2,292,137	8,886,745	2.7301
75													
76	MARTIN 4	470	328,523	93.9	94.6	99.7	6,988	Gas MCF ->	2,295,728	1,000,000	2,295,728	8,900,669	2.7093
77													
78	FM GT	624	414	0.1	81.6	90.1	13,113	Light Oil BBLS ->	937	5,799,872	5,434	34,844	8.4083
79													
80	FL GT	768	20	0.0	91.9	86.1	19,819	Gas MCF ->	389	1,000,000	389	1,508	7.6939
81													

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Mar-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
82	PE GT	384	55	0.0	88.6	92.8	19,462	Gas MCF ->	1,066	1,000,000	1,066	4,135	7.5456
84	SJRPP 1O	130	89,740	92.8	92.9	100.0	9,817	Coal TONS ->	35,450	24,850,991	880,958	1,338,405	1.4914
86	SJRPP 2O	130	43,433	44.9	41.9	100.0	9,526	Coal TONS ->	16,650	24,850,983	413,764	628,616	1.4473
88	SCHER #4	648	446,109	92.5	93.6	100.0	10,326	Coal TONS ->	263,223	17,500,002	4,606,396	8,125,214	1.8214
90	FMREP 1	1,498		0.0	0.0		0						
92	SNREP4	986		0.0	0.0		0						
94	SNREP5	986		0.0	0.0		0						
96	MR SC	181	2,065	0.8	94.3	80.5	10,032	Gas MCF ->	20,716	1,000,000	20,716	80,316	3.8894
98	FMCT	165		0.0	0.0		0						
100	TOTAL	19,600	6,114,654				9,754				59,642,624	129,604,167	2.1196

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Apr-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	167,765	65.7	94.7	96.9	9,920	Heavy Oil BBLS ->	257,912	6,399,999	1,650,633	5,762,941	3.4351
2			18,641					Gas MCF ->	198,497	1,000,000	198,497	713,543	3.8279
3													
4	TRKY O 2	394	141,302	55.3	94.3	96.1	10,239	Heavy Oil BBLS ->	223,763	6,399,999	1,432,083	4,999,905	3.5385
5			15,700					Gas MCF ->	175,533	1,000,000	175,533	630,994	4.0190
6													
7	TRKY N 3	693	486,491	97.5	97.5	100.0	11,026	Nuclear Othr ->	5,364,243	1,000,000	5,364,243	1,624,829	0.3340
8													
9	TRKY N 4	693	113,513	22.7	22.8	100.0	11,027	Nuclear Othr ->	1,251,655	1,000,000	1,251,655	365,859	0.3223
10													
11	FT LAUD4	422	438	93.1	94.5	99.5	7,252	Light Oil BBLS ->	519	5,829,545	3,027	16,529	3.7720
12			282,561					Gas MCF ->	2,049,276	1,000,000	2,049,276	7,366,607	2.6071
13													
14	FT LAUD5	422	461	94.1	94.6	99.6	7,228	Light Oil BBLS ->	545	5,829,783	3,175	17,339	3.7595
15			285,560					Gas MCF ->	2,064,201	1,000,000	2,064,201	7,420,261	2.5985
16													
17	PT EVER1	211	51,803	37.9	95.2	92.4	10,675	Heavy Oil BBLS ->	85,590	6,399,996	547,774	1,854,893	3.5807
18			5,756					Gas MCF ->	66,677	1,000,000	66,677	239,685	4.1642
19													
20	PT EVER2	211	32,637	23.9	48.6	95.1	10,415	Heavy Oil BBLS ->	52,543	6,400,004	336,272	1,138,697	3.4889
21			3,626					Gas MCF ->	41,417	1,000,000	41,417	148,882	4.1055
22													
23	PT EVER3	390	179,309	71.0	94.8	97.9	9,993	Heavy Oil BBLS ->	277,772	6,400,001	1,777,740	6,019,846	3.3573
24			19,923					Gas MCF ->	213,281	1,000,000	213,281	766,690	3.8482
25													
26	PT EVER4	402	195,919	75.2	94.9	97.1	9,985	Heavy Oil BBLS ->	303,392	6,400,000	1,941,711	6,575,089	3.3560
27			21,769					Gas MCF ->	231,827	1,000,000	231,827	833,356	3.8282

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Apr-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
28													
29	RIV 3	278	156,259	86.7	93.3	97.8	9,997	Heavy Oil BBLS ->	242,483	6,400,000	1,551,888	4,569,036	2.9240
30			17,362					Gas MCF ->	183,846	1,000,000	183,846	660,876	3.8065
31													
32	RIV 4	290	152,211	81.0	92.1	96.7	10,190	Heavy Oil BBLS ->	240,603	6,400,000	1,539,859	4,533,619	2.9785
33			16,912					Gas MCF ->	183,501	1,000,000	183,501	659,637	3.9003
34													
35	ST LUC 1	839	588,980	97.5	97.5	100.0	10,826	Nuclear Othr ->	6,376,045	1,000,000	6,376,045	1,820,361	0.3091
36													
37	ST LUC 2	714	501,219	97.5	97.5	100.0	10,826	Nuclear Othr ->	5,426,024	1,000,000	5,426,024	1,571,919	0.3136
38													
39	CAP CN 1	394	204,241	80.0	94.4	97.2	9,729	Heavy Oil BBLS ->	308,308	6,399,999	1,973,170	6,766,553	3.3130
40			22,694					Gas MCF ->	234,715	1,000,000	234,715	843,737	3.7180
41													
42	CAP CN 2	394	76,471	30.0	47.8	96.7	10,119	Heavy Oil BBLS ->	119,893	6,400,001	767,313	2,631,333	3.4410
43			8,497					Gas MCF ->	92,482	1,000,000	92,482	332,449	3.9127
44													
45	SANFRD 3	142	30,122	29.5	95.5	94.3	11,141	Heavy Oil BBLS ->	52,104	6,400,003	333,465	1,205,089	4.0008
46			0					Gas MCF ->	2,113	1,000,000	2,113	7,594	
47													
48	SANFRD 4	371		0.0	0.0		0						
49													
50	SANFRD 5	381		0.0	0.0		0						
51													
52	PUTNAM 1	239	130,361	75.8	94.8	96.0	9,460	Gas MCF ->	1,233,154	1,000,000	1,233,154	4,432,863	3.4005
53													
54	PUTNAM 2	239	67,300	39.1	94.8	66.6	10,058	Gas MCF ->	676,923	1,000,000	676,923	2,433,360	3.6157

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Apr-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
56	MANATE 1	798	154,145	26.8	41.6	93.2	10,581	Heavy Oil BBLS ->	254,846	6,400,000	1,631,017	5,529,335	3.5871
58	MANATE 2	798	251,123	43.7	58.4	96.4	10,448	Heavy Oil BBLS ->	409,939	6,400,001	2,623,610	8,894,338	3.5418
60	FT MY 1	0		0.0	0.0		0						
62	FT MY 2	0		0.0	0.0		0						
64	CUTLER 5	71	10,865	21.3	97.5	87.2	13,286	Gas MCF ->	144,351	1,000,000	144,351	518,903	4.7759
66	CUTLER 6	144	24,604	23.7	96.5	86.0	12,095	Gas MCF ->	297,589	1,000,000	297,589	1,069,755	4.3479
68	MARTIN 1	814	202,246	49.3	95.4	90.3	10,713	Heavy Oil BBLS ->	332,600	6,400,000	2,128,637	7,437,054	3.6772
69			86,677					Gas MCF ->	966,511	1,000,000	966,511	3,474,351	4.0084
71	MARTIN 2	806	247,936	61.0	96.0	96.7	10,438	Heavy Oil BBLS ->	397,241	6,400,000	2,542,343	8,882,464	3.5826
72			106,258					Gas MCF ->	1,154,893	1,000,000	1,154,893	4,151,534	3.9070
74	MARTIN 3	448	303,462	94.1	94.1	99.9	7,138	Gas MCF ->	2,166,198	1,000,000	2,166,198	7,786,912	2.5660
76	MARTIN 4	448	303,946	94.2	76.1	100.0	7,086	Gas MCF ->	2,153,649	1,000,000	2,153,649	7,741,802	2.5471
78	FM GT	552	33,354	8.4	81.0	94.6	13,701	Light Oil BBLS ->	78,793	5,800,000	457,000	2,682,065	8.0412
80	FL GT	684	249	2.7	91.6	91.8	15,428	Light Oil BBLS ->	629	5,829,730	3,667	19,578	7.8532
81			13,247					Gas MCF ->	204,558	1,000,000	204,558	735,332	5.5509

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Apr-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
82													
83	PE GT	348	2,070	0.8	88.2	94.0	17,514	Gas MCF ->	36,248	1,000,000	36,248	130,302	6.2960
84													
85	SJRPP 1O	127	84,840	92.8	92.7	100.0	9,912	Coal TONS ->	33,999	24,734,102	840,927	1,243,597	1.4658
86													
87	SJRPP 2O	127	42,431	46.4	46.6	100.0	9,613	Coal TONS ->	16,491	24,734,009	407,884	603,195	1.4216
88													
89	SCHER #4	643	428,263	92.5	93.3	100.0	10,428	Coal TONS ->	255,202	17,500,004	4,466,029	7,919,892	1.8493
90													
91	FMREP 1	1,473		0.0	0.0		0						
92													
93	SNREP4	957		0.0	0.0		0						
94													
95	SNREP5	957		0.0	0.0		0						
96													
97	MR SC	149	1,889	19.9	94.1	91.4	10,487	Light Oil BBLS ->	3,243	5,830,039	18,904	117,136	6.2016
98			40,774					Gas MCF ->	428,490	1,000,000	428,490	1,540,310	3.7777
99													
100	FMCT	154		0.0	0.0		0						
101													
102	TOTAL	19,011	6,334,180				9,882				62,596,020	149,442,226	2.3593

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : May-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	167,538	63.5	94.9	97.2	9,921	Heavy Oil BBLS ->	257,574	6,400,001	1,648,472	5,797,922	3.4607
2			18,615					Gas MCF ->	198,442	1,000,000	198,442	717,470	3.8542
3													
4	TRKY O 2	394	124,371	47.1	94.5	95.2	10,245	Heavy Oil BBLS ->	196,949	6,399,999	1,260,472	4,433,269	3.5645
5			13,819					Gas MCF ->	155,239	1,000,000	155,239	561,269	4.0616
6													
7	TRKY N 3	693	502,707	97.5	97.5	100.0	11,026	Nuclear Othr ->	5,543,048	1,000,000	5,543,048	1,654,045	0.3290
8													
9	TRKY N 4	693	502,707	97.5	97.5	100.0	11,026	Nuclear Othr ->	5,543,048	1,000,000	5,543,048	1,597,506	0.3178
10													
11	FT LAUD4	422	877	93.1	94.7	99.7	7,250	Light Oil BBLS ->	1,038	5,830,011	6,053	33,039	3.7686
12			291,498					Gas MCF ->	2,113,575	1,000,000	2,113,575	7,641,674	2.6215
13													
14	FT LAUD5	422	886	94.4	94.7	99.9	7,225	Light Oil BBLS ->	1,046	5,829,747	6,095	33,266	3.7563
15			295,481					Gas MCF ->	2,135,192	1,000,000	2,135,192	7,719,832	2.6126
16													
17	PT EVER1	211	46,317	32.8	95.3	94.4	10,693	Heavy Oil BBLS ->	76,526	6,400,002	489,767	1,686,298	3.6408
18			5,146					Gas MCF ->	60,524	1,000,000	60,524	218,827	4.2520
19													
20	PT EVER2	211	68,411	48.4	95.4	94.8	10,414	Heavy Oil BBLS ->	110,134	6,400,002	704,860	2,426,875	3.5475
21			7,601					Gas MCF ->	86,759	1,000,000	86,759	313,680	4.1267
22													
23	PT EVER3	390	177,409	67.9	94.9	97.7	9,996	Heavy Oil BBLS ->	274,826	6,400,000	1,758,884	6,055,945	3.4135
24			19,712					Gas MCF ->	211,487	1,000,000	211,487	764,634	3.8790
25													
26	PT EVER4	402	192,556	71.5	95.1	97.2	9,989	Heavy Oil BBLS ->	298,173	6,400,001	1,908,309	6,570,425	3.4122
27			21,395					Gas MCF ->	228,745	1,000,000	228,745	827,030	3.8655

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : May-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
28													
29	RIV 3	278	145,327	78.1	93.5	96.0	10,018	Heavy Oil BBLS ->	225,596	6,399,999	1,443,811	4,295,093	2.9555
30			16,147					Gas MCF ->	173,815	1,000,000	173,815	628,430	3.8918
31													
32	RIV 4	290	138,064	71.1	92.3	96.2	10,206	Heavy Oil BBLS ->	218,136	6,399,999	1,396,069	4,153,068	3.0081
33			15,340					Gas MCF ->	169,563	1,000,000	169,563	613,059	3.9964
34													
35	ST LUC 1	839	608,613	97.5	97.5	100.0	10,826	Nuclear Othr ->	6,588,576	1,000,000	6,588,576	1,880,380	0.3090
36													
37	ST LUC 2	714	517,926	97.5	97.5	100.0	10,826	Nuclear Othr ->	5,606,891	1,000,000	5,606,891	1,624,877	0.3137
38													
39	CAP CN 1	394	206,865	78.4	94.6	97.0	9,735	Heavy Oil BBLS ->	312,387	6,400,000	1,999,275	6,936,123	3.3530
40			22,985					Gas MCF ->	238,405	1,000,000	238,405	861,957	3.7501
41													
42	CAP CN 2	394	152,261	57.7	94.7	95.9	10,120	Heavy Oil BBLS ->	238,712	6,399,999	1,527,758	5,300,279	3.4810
43			16,918					Gas MCF ->	184,360	1,000,000	184,360	666,557	3.9400
44													
45	SANFRD 3	142	27,107	25.7	95.7	95.4	11,154	Heavy Oil BBLS ->	46,891	6,399,994	300,103	1,069,136	3.9441
46			0					Gas MCF ->	2,237	1,000,000	2,237	8,087	
47													
48	SANFRD 4	371		0.0	0.0		0						
49													
50	SANFRD 5	381		0.0	0.0		0						
51													
52	PUTNAM 1	239	155,632	87.5	95.0	97.8	9,452	Gas MCF ->	1,471,000	1,000,000	1,471,000	5,318,430	3.4173
53													
54	PUTNAM 2	239	142,470	80.1	95.3	95.9	9,461	Gas MCF ->	1,347,890	1,000,000	1,347,890	4,873,324	3.4206

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : May-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
55													
56	MANATE 1	798	174,988	29.5	56.4	89.4	10,579	Heavy Oil BBLS ->	289,244	6,400,001	1,851,162	6,326,463	3.6154
57													
58	MANATE 2	798	133,056	22.4	40.4	95.8	10,451	Heavy Oil BBLS ->	217,277	6,399,999	1,390,569	4,752,358	3.5717
59													
60	FT MY 1	0		0.0	0.0		0						
61													
62	FT MY 2	0		0.0	0.0		0						
63													
64	CUTLER 5	71	10,661	20.2	97.6	87.2	13,332	Gas MCF ->	142,141	1,000,000	142,141	513,915	4.8203
65													
66	CUTLER 6	144	23,735	22.2	96.7	88.4	12,096	Gas MCF ->	287,091	1,000,000	287,091	1,037,984	4.3732
67													
68	MARTIN 1	814	180,543	42.6	95.6	92.0	10,716	Heavy Oil BBLS ->	296,905	6,400,000	1,900,189	6,659,304	3.6885
69			77,376					Gas MCF ->	863,708	1,000,000	863,708	3,122,756	4.0358
70													
71	MARTIN 2	806	237,110	56.5	96.1	96.1	10,440	Heavy Oil BBLS ->	379,896	6,400,000	2,431,335	8,520,731	3.5936
72			101,618					Gas MCF ->	1,104,939	1,000,000	1,104,939	3,994,931	3.9313
73													
74	MARTIN 3	448	313,797	94.1	94.3	100.0	7,138	Gas MCF ->	2,239,792	1,000,000	2,239,792	8,098,016	2.5807
75													
76	MARTIN 4	448	314,145	94.2	75.2	100.0	7,085	Gas MCF ->	2,225,860	1,000,000	2,225,860	8,047,645	2.5618
77													
78	FM GT	552	52,992	12.9	81.6	96.1	13,701	Light Oil BBLS ->	125,183	5,800,000	726,061	4,031,184	7.6072
79													
80	FL GT	684	1,546	5.5	91.9	93.5	15,410	Light Oil BBLS ->	3,902	5,829,951	22,751	121,014	7.8270
81			26,236					Gas MCF ->	405,361	1,000,000	405,361	1,465,590	5.5862

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : May-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
83	PE GT	348	5,292	2.1	88.6	95.0	17,518	Gas MCF ->	92,699	1,000,000	92,699	335,155	6.3338
85	SJRPP 1O	127	87,668	92.8	92.9	100.0	9,912	Coal TONS ->	35,044	24,796,140	868,958	1,283,725	1.4643
87	SJRPP 2O	127	87,691	92.8	93.5	100.0	9,612	Coal TONS ->	33,993	24,796,186	842,904	1,245,235	1.4200
89	SCHER #4	643	442,538	92.5	93.6	100.0	10,428	Coal TONS ->	263,708	17,500,003	4,614,893	8,201,318	1.8532
91	FMREP 1	1,473		0.0	0.0		0						
93	SNREP4	957		0.0	0.0		0						
95	SNREP5	957		0.0	0.0		0						
97	MR SC	149	4,645	20.1	94.3	94.4	10,433	Light Oil BBLS ->	7,955	5,830,002	46,380	280,387	6.0370
98			39,813					Gas MCF ->	417,459	1,000,000	417,459	1,509,333	3.7910
100	FMCT	154		0.0	0.0		0						
102	TOTAL	19,011	6,938,152				9,943				68,982,976	156,828,850	2.2604

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jun-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	162,229	63.5	94.7	97.7	9,921	Heavy Oil BBLS ->	249,389	6,399,999	1,596,088	5,735,598	3.5355
2			18,026					Gas MCF ->	192,133	1,000,000	192,133	710,968	3.9442
3													
4	TRKY O 2	394	122,958	48.2	94.3	95.9	10,245	Heavy Oil BBLS ->	194,714	6,399,999	1,246,170	4,478,155	3.6420
5			13,662					Gas MCF ->	153,570	1,000,000	153,570	568,271	4.1595
6													
7	TRKY N 3	693	486,491	97.5	97.5	100.0	11,026	Nuclear Othr ->	5,364,243	1,000,000	5,364,243	1,582,452	0.3253
8													
9	TRKY N 4	693	486,491	97.5	97.5	100.0	11,026	Nuclear Othr ->	5,364,243	1,000,000	5,364,243	1,529,345	0.3144
10													
11	FT LAUD4	422	252	91.9	94.5	99.0	7,255	Light Oil BBLS ->	299	5,830,264	1,742	9,503	3.7695
12			278,849					Gas MCF ->	2,023,154	1,000,000	2,023,154	7,486,474	2.6848
13													
14	FT LAUD5	422	279	94.1	94.6	99.6	7,229	Light Oil BBLS ->	329	5,829,994	1,920	10,480	3.7576
15			285,491					Gas MCF ->	2,063,899	1,000,000	2,063,899	7,637,248	2.6751
16													
17	PT EVER1	211	41,587	30.4	95.2	92.1	10,687	Heavy Oil BBLS ->	68,711	6,400,000	439,749	1,554,049	3.7369
18			4,621					Gas MCF ->	54,074	1,000,000	54,074	200,093	4.3303
19													
20	PT EVER2	211	66,125	48.4	95.3	95.0	10,419	Heavy Oil BBLS ->	106,454	6,400,000	681,302	2,407,688	3.6411
21			7,347					Gas MCF ->	84,167	1,000,000	84,167	311,452	4.2391
22													
23	PT EVER3	390	171,806	68.0	94.8	97.8	9,995	Heavy Oil BBLS ->	266,139	6,400,000	1,703,290	6,019,338	3.5036
24			19,090					Gas MCF ->	204,798	1,000,000	204,798	757,834	3.9699
25													
26	PT EVER4	402	189,776	72.9	94.9	97.9	9,989	Heavy Oil BBLS ->	293,856	6,399,999	1,880,675	6,646,208	3.5021
27			21,086					Gas MCF ->	225,521	1,000,000	225,521	834,516	3.9577

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jun-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
29	RIV 3	278	132,879	73.8	93.3	96.6	10,019	Heavy Oil BBLS ->	206,165	6,400,000	1,319,454	4,061,713	3.0567
30			14,764					Gas MCF ->	159,736	1,000,000	159,736	591,087	4.0035
32	RIV 4	290	124,012	66.0	92.1	95.4	10,206	Heavy Oil BBLS ->	195,932	6,400,001	1,253,963	3,860,111	3.1127
33			13,779					Gas MCF ->	152,376	1,000,000	152,376	563,852	4.0921
35	ST LUC 1	839	588,980	97.5	97.5	100.0	10,826	Nuclear Othr ->	6,376,045	1,000,000	6,376,045	1,820,998	0.3092
37	ST LUC 2	714	501,219	97.5	97.5	100.0	10,826	Nuclear Othr ->	5,426,024	1,000,000	5,426,024	1,574,089	0.3141
39	CAP CN 1	394	202,245	79.2	94.4	97.8	9,734	Heavy Oil BBLS ->	305,365	6,399,999	1,954,336	6,943,780	3.4334
40			22,472					Gas MCF ->	232,947	1,000,000	232,947	861,997	3.8359
42	CAP CN 2	394	148,989	58.4	94.5	96.6	10,119	Heavy Oil BBLS ->	233,577	6,400,000	1,494,890	5,311,362	3.5649
43			16,554					Gas MCF ->	180,328	1,000,000	180,328	667,285	4.0309
45	SANFRD 3	142	23,819	23.3	95.5	93.3	11,154	Heavy Oil BBLS ->	41,200	6,400,000	263,679	932,836	3.9164
46			0					Gas MCF ->	1,988	1,000,000	1,988	7,358	
48	SANFRD 4	371		0.0	0.0		0						
50	SANFRD 5	381		0.0	0.0		0						
52	PUTNAM 1	239	144,045	83.7	94.8	97.1	9,459	Gas MCF ->	1,362,560	1,000,000	1,362,560	5,042,014	3.5003
54	PUTNAM 2	239	370	76.8	95.1	96.1	9,457	Light Oil BBLS ->	570	5,829,769	3,325	21,168	5.7180

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jun-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
55			131,800					Gas MCF ->	1,246,558	1,000,000	1,246,558	4,612,761	3.4998
56													
57	MANATE 1	798	283,406	49.3	94.9	93.4	10,594	Heavy Oil BBLS ->	469,114	6,400,000	3,002,327	10,543,680	3.7203
58													
59	MANATE 2	798	372,019	64.7	95.1	96.6	10,449	Heavy Oil BBLS ->	607,394	6,400,000	3,887,319	13,651,628	3.6696
60													
61	FT MY 1	0		0.0	0.0		0						
62													
63	FT MY 2	0		0.0	0.0		0						
64													
65	CUTLER 5	71	9,149	17.9	97.5	89.3	13,280	Gas MCF ->	121,496	1,000,000	121,496	449,583	4.9140
66													
67	CUTLER 6	144	20,713	20.0	96.5	88.7	12,071	Gas MCF ->	250,026	1,000,000	250,026	925,195	4.4667
68													
69	MARTIN 1	814	193,541	47.2	95.4	92.7	10,716	Heavy Oil BBLS ->	318,263	6,399,999	2,036,885	7,292,480	3.7679
70			82,946					Gas MCF ->	925,941	1,000,000	925,941	3,426,349	4.1308
71													
72	MARTIN 2	806	232,498	57.2	96.0	97.8	10,441	Heavy Oil BBLS ->	372,535	6,400,000	2,384,226	8,536,034	3.6714
73			99,642					Gas MCF ->	1,083,739	1,000,000	1,083,739	4,010,266	4.0247
74													
75	MARTIN 3	448	303,243	94.0	94.1	99.8	7,139	Gas MCF ->	2,164,829	1,000,000	2,164,829	8,010,730	2.6417
76													
77	MARTIN 4	448	303,693	94.2	94.4	99.9	7,086	Gas MCF ->	2,152,075	1,000,000	2,152,075	7,963,535	2.6222
78													
79	FM GT	552	14,409	3.6	81.0	93.9	13,701	Light Oil BBLS ->	34,038	5,799,997	197,417	1,083,267	7.5182
80													
81	FL GT	684	6,172	1.3	91.6	92.8	15,439	Gas MCF ->	95,287	1,000,000	95,287	352,598	5.7130

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jun-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
82														
83	PE GT	348	1,088	0.4	88.2	94.7	17,514	Gas	MCF ->	19,059	1,000,000	19,059	70,524	6.4808
84														
85	SJRPP 1O	127	84,840	92.8	92.7	100.0	9,912	Coal	TONS ->	33,945	24,773,376	840,927	1,243,315	1.4655
86														
87	SJRPP 2O	127	84,862	92.8	93.3	100.0	9,612	Coal	TONS ->	32,927	24,773,402	815,714	1,206,036	1.4212
88														
89	SCHER #4	643	428,263	92.5	93.3	100.0	10,428	Coal	TONS ->	255,202	17,500,004	4,466,029	7,943,363	1.8548
90														
91	FMREP 1	1,473	945,686	89.2	93.3	99.6	7,025	Gas	MCF ->	6,643,204	1,000,000	6,643,204	24,582,501	2.5994
92														
93	SNREP4	957		0.0	0.0		0							
94														
95	SNREP5	957		0.0	0.0		0							
96														
97	MR SC	149	34,749	16.2	94.1	91.9	10,474	Gas	MCF ->	363,952	1,000,000	363,952	1,346,766	3.8757
98														
99	FMCT	154		0.0	0.0		0							
100														
101	TOTAL	19,011	7,943,010				9,588					76,159,392	187,989,933	2.3667

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jul-02

Jul-2002

(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1 TRKY O 1	394	158,859	60.2	94.9	97.1	9,923	Heavy Oil BBLS ->	244,214	6,400,000	1,562,969	5,740,254	3.6134
2		17,651					Gas MCF ->	188,467	1,000,000	188,467	692,918	3.9256
4 TRKY O 2	394	120,188	45.6	94.5	95.0	10,249	Heavy Oil BBLS ->	190,332	6,400,000	1,218,122	4,473,749	3.7223
5		13,354					Gas MCF ->	150,571	1,000,000	150,571	553,590	4.1454
7 TRKY N 3	693	502,707	97.5	97.5	100.0	11,026	Nuclear Othr ->	5,543,048	1,000,000	5,543,048	1,610,809	0.3204
9 TRKY N 4	693	502,707	97.5	97.5	100.0	11,026	Nuclear Othr ->	5,543,048	1,000,000	5,543,048	1,562,585	0.3108
11 FT LAUD4	422	997	88.2	94.7	97.8	7,259	Light Oil BBLS ->	1,182	5,830,075	6,889	37,583	3.7696
12		275,938					Gas MCF ->	2,003,387	1,000,000	2,003,387	7,391,078	2.6785
14 FT LAUD5	422	1,109	91.9	94.7	98.5	7,234	Light Oil BBLS ->	1,311	5,829,925	7,641	41,681	3.7584
15		287,468					Gas MCF ->	2,080,063	1,000,000	2,080,063	7,677,512	2.6707
17 PT EVER1	211	42,013	29.7	95.3	92.4	10,690	Heavy Oil BBLS ->	69,415	6,399,998	444,258	1,611,839	3.8365
18		4,668					Gas MCF ->	54,753	1,000,000	54,753	201,307	4.3123
20 PT EVER2	211	65,256	46.2	95.4	95.2	10,422	Heavy Oil BBLS ->	105,055	6,399,998	672,351	2,439,399	3.7382
21		7,251					Gas MCF ->	83,279	1,000,000	83,279	306,184	4.2229
23 PT EVER3	390	169,901	65.1	94.9	97.8	9,997	Heavy Oil BBLS ->	263,192	6,400,000	1,684,426	6,111,370	3.5970
24		18,878					Gas MCF ->	202,800	1,000,000	202,800	745,615	3.9497
26 PT EVER4	402	185,223	68.8	95.1	97.8	9,990	Heavy Oil BBLS ->	286,807	6,400,001	1,835,568	6,659,737	3.5955
27		20,580					Gas MCF ->	220,462	1,000,000	220,462	810,552	3.9385

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jul-02

Jul-2002

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
28													
29	RIV 3	278	134,391	72.2	93.5	97.1	10,025	Heavy Oil BBLS ->	208,493	6,400,002	1,334,358	4,267,923	3.1758
30			14,932					Gas MCF ->	162,549	1,000,000	162,549	597,629	4.0023
31													
32	RIV 4	290	123,851	63.8	92.3	96.6	10,207	Heavy Oil BBLS ->	195,654	6,400,002	1,252,183	4,005,090	3.2338
33			13,761					Gas MCF ->	152,371	1,000,000	152,371	560,208	4.0710
34													
35	ST LUC 1	839	608,613	97.5	97.5	100.0	10,826	Nuclear Othr ->	6,588,576	1,000,000	6,588,576	1,853,366	0.3045
36													
37	ST LUC 2	714	517,926	97.5	97.5	100.0	10,826	Nuclear Othr ->	5,606,891	1,000,000	5,606,891	1,601,889	0.3093
38													
39	CAP CN 1	394	196,599	74.5	94.6	97.3	9,738	Heavy Oil BBLS ->	296,783	6,400,000	1,899,410	6,904,928	3.5122
40			21,844					Gas MCF ->	227,828	1,000,000	227,828	837,635	3.8346
41													
42	CAP CN 2	394	143,951	54.6	94.7	95.7	10,122	Heavy Oil BBLS ->	225,673	6,400,001	1,444,309	5,250,498	3.6474
43			15,995					Gas MCF ->	174,624	1,000,000	174,624	642,025	4.0140
44													
45	SANFRD 3	142	23,221	22.0	95.7	92.9	11,161	Heavy Oil BBLS ->	40,163	6,399,999	257,046	906,863	3.9054
46			0					Gas MCF ->	2,113	1,000,000	2,113	7,767	
47													
48	SANFRD 4	371		0.0	0.0		0						
49													
50	SANFRD 5	381		0.0	0.0		0						
51													
52	PUTNAM 1	239	1,830	79.7	95.0	96.7	9,456	Light Oil BBLS ->	2,822	5,830,055	16,450	101,883	5.5680
53			139,901					Gas MCF ->	1,323,730	1,000,000	1,323,730	4,930,157	3.5240
54													

Company: Florida Power & Light

Schedule E4

Jul-2002 Estimated For The Period of : Jul-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
55	PUTNAM 2	239	4,027	74.4	95.3	96.2	9,453	Light Oil BBLS ->	6,208	5,830,012	36,190	224,149	5.5659
56			128,191					Gas MCF ->	1,213,647	1,000,000	1,213,647	4,563,958	3.5603
57													
58	MANATE 1	798	288,041	48.5	95.1	93.4	10,595	Heavy Oil BBLS ->	476,825	6,400,001	3,051,682	10,972,438	3.8093
59													
60	MANATE 2	798	366,777	61.8	95.2	97.5	10,451	Heavy Oil BBLS ->	598,912	6,400,001	3,833,034	13,781,820	3.7575
61													
62	FT MY 1	0		0.0	0.0		0						
63													
64	FT MY 2	0		0.0	0.0		0						
65													
66	CUTLER 5	71	8,929	16.9	97.6	90.6	13,256	Gas MCF ->	118,370	1,000,000	118,370	435,201	4.8739
67													
68	CUTLER 6	144	20,403	19.0	96.7	90.1	12,059	Gas MCF ->	246,034	1,000,000	246,034	904,570	4.4336
69													
70	MARTIN 1	814	187,591	44.3	95.6	91.9	10,718	Heavy Oil BBLS ->	308,462	6,400,000	1,974,156	7,225,528	3.8518
71			80,396					Gas MCF ->	898,072	1,000,000	898,072	3,301,858	4.1070
72													
73	MARTIN 2	806	236,468	56.3	96.1	97.5	10,441	Heavy Oil BBLS ->	378,886	6,400,000	2,424,871	8,875,171	3.7532
74			101,344					Gas MCF ->	1,102,392	1,000,000	1,102,392	4,053,065	3.9993
75													
76	MARTIN 3	448	311,313	93.4	94.3	99.3	7,143	Gas MCF ->	2,223,816	1,000,000	2,223,816	8,176,102	2.6263
77													
78	MARTIN 4	448	313,048	93.9	94.6	99.6	7,088	Gas MCF ->	2,218,997	1,000,000	2,218,997	8,158,382	2.6061
79													
80	FM GT	552	13,689	3.3	81.6	94.1	13,701	Light Oil BBLS ->	32,338	5,799,999	187,559	1,029,110	7.5178
81													

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jul-02

Jul-2002

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
82	FL GT	684	6,136	1.2	91.9	93.0	15,439	Gas	MCF ->	94,733	1,000,000	94,733	348,295	5.6763
84	PE GT	348	1,086	0.4	88.6	94.8	17,514	Gas	MCF ->	19,027	1,000,000	19,027	69,953	6.4390
86	SJRPP 1O	127	87,668	92.8	92.9	100.0	9,912	Coal	TONS ->	34,918	24,885,832	868,959	1,274,496	1.4538
88	SJRPP 2O	127	87,691	92.8	93.5	100.0	9,612	Coal	TONS ->	33,871	24,885,793	842,904	1,236,282	1.4098
90	SCHER #4	643	442,538	92.5	93.6	100.0	10,428	Coal	TONS ->	263,708	17,500,003	4,614,893	8,224,393	1.8585
92	FMREP 1	1,473	1,053,609	96.1	93.5	100.0	7,025	Gas	MCF ->	7,401,205	1,000,000	7,401,205	27,211,336	2.5827
94	SNREP4	957		0.0	0.0		0							
96	SNREP5	957	672,112	94.4	95.0	99.7	7,074	Gas	MCF ->	4,754,591	1,000,000	4,754,591	17,480,770	2.6009
98	MR SC	149	949	14.9	94.3	91.2	10,459	Light Oil	BBLS ->	1,623	5,829,863	9,464	56,986	6.0061
99			32,050					Gas	MCF ->	335,683	1,000,000	335,683	1,248,521	3.8955
101	FMCT	154		0.0	0.0		0							
103	TOTAL	19,011	8,795,619				9,370					82,414,812	209,988,007	2.3874

Company: Florida Power & Light

Schedule E4

Aug-2002 Estimated For The Period of : Aug-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	159,510	60.5	94.9	97.3	9,922	Heavy Oil BBLS ->	245,215	6,400,000	1,569,374	5,823,134	3.6506
2			17,723					Gas MCF ->	189,213	1,000,000	189,213	714,763	4.0329
4	TRKY O 2	394	122,395	46.4	94.5	95.4	10,248	Heavy Oil BBLS ->	193,828	6,399,999	1,240,499	4,602,850	3.7607
5			13,599					Gas MCF ->	153,181	1,000,000	153,181	578,651	4.2550
7	TRKY N 3	693	502,707	97.5	97.5	100.0	11,026	Nuclear Othr ->	5,543,048	1,000,000	5,543,048	1,609,701	0.3202
9	TRKY N 4	693	502,707	97.5	97.5	100.0	11,026	Nuclear Othr ->	5,543,048	1,000,000	5,543,048	1,560,922	0.3105
11	FT LAUD4	422	2,081	91.2	94.7	98.7	7,255	Light Oil BBLS ->	2,467	5,830,016	14,381	78,529	3.7734
12			284,253					Gas MCF ->	2,062,896	1,000,000	2,062,896	7,830,224	2.7547
14	FT LAUD5	422	2,216	92.7	94.7	99.1	7,229	Light Oil BBLS ->	2,617	5,830,073	15,257	83,315	3.7606
15			288,973					Gas MCF ->	2,089,844	1,000,000	2,089,844	7,932,062	2.7449
17	PT EVER1	211	42,312	29.9	95.3	93.2	10,689	Heavy Oil BBLS ->	69,908	6,400,003	447,414	1,637,576	3.8702
18			4,701					Gas MCF ->	55,122	1,000,000	55,122	208,225	4.4291
20	PT EVER2	211	65,706	46.5	95.4	95.4	10,419	Heavy Oil BBLS ->	105,779	6,399,997	676,984	2,477,823	3.7711
21			7,301					Gas MCF ->	83,663	1,000,000	83,663	316,043	4.3290
23	PT EVER3	390	175,241	67.1	94.9	97.5	9,996	Heavy Oil BBLS ->	271,460	6,400,001	1,737,343	6,358,835	3.6286
24			19,471					Gas MCF ->	208,974	1,000,000	208,974	789,408	4.0542
26	PT EVER4	402	193,402	71.8	95.1	97.7	9,989	Heavy Oil BBLS ->	299,472	6,400,001	1,916,623	7,015,015	3.6272
27			21,489					Gas MCF ->	229,918	1,000,000	229,918	868,528	4.0418

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Aug-02

Aug-2002

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
28													
29	RIV 3	278	133,717	71.8	93.5	96.1	10,025	Heavy Oil BBLS ->	207,489	6,400,000	1,327,932	4,326,029	3.2352
30			14,857					Gas MCF ->	161,585	1,000,000	161,585	610,394	4.1084
31													
32	RIV 4	290	114,491	59.0	92.3	96.7	10,210	Heavy Oil BBLS ->	180,868	6,400,000	1,157,553	3,770,981	3.2937
33			12,721					Gas MCF ->	141,331	1,000,000	141,331	533,884	4.1968
34													
35	ST LUC 1	839	608,613	97.5	97.5	100.0	10,826	Nuclear Othr ->	6,588,576	1,000,000	6,588,576	1,854,684	0.3047
36													
37	ST LUC 2	714	517,926	97.5	97.5	100.0	10,826	Nuclear Othr ->	5,606,891	1,000,000	5,606,891	1,603,010	0.3095
38													
39	CAP CN 1	394	203,250	77.0	94.6	97.1	9,738	Heavy Oil BBLS ->	306,904	6,400,000	1,964,187	7,212,248	3.5485
40			22,583					Gas MCF ->	234,956	1,000,000	234,956	887,558	3.9301
41													
42	CAP CN 2	394	143,895	54.5	94.7	95.9	10,122	Heavy Oil BBLS ->	225,591	6,400,000	1,443,783	5,301,388	3.6842
43			15,988					Gas MCF ->	174,563	1,000,000	174,563	659,421	4.1244
44													
45	SANFRD 3	142	24,097	22.8	95.7	94.4	11,158	Heavy Oil BBLS ->	41,679	6,400,000	266,748	939,015	3.8969
46			0					Gas MCF ->	2,113	1,000,000	2,113	7,980	
47													
48	SANFRD 4	371		0.0	0.0		0						
49													
50	SANFRD 5	381		0.0	0.0		0						
51													
52	PUTNAM 1	239	6,579	82.3	95.0	96.5	9,451	Light Oil BBLS ->	10,161	5,830,030	59,240	354,039	5.3811
53			139,719					Gas MCF ->	1,323,448	1,000,000	1,323,448	5,105,552	3.6542
54													

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Aug-02

Aug-2002

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
55	PUTNAM 2	239	8,749	74.8	95.3	95.6	9,430	Light Oil BBLS ->	13,481	5,830,014	78,595	469,711	5.3686
56			124,202					Gas MCF ->	1,175,121	1,000,000	1,175,121	4,600,685	3.7042
57													
58	MANATE 1	798	278,536	46.9	95.1	92.7	10,597	Heavy Oil BBLS ->	461,177	6,400,000	2,951,536	10,723,484	3.8499
59													
60	MANATE 2	798	364,809	61.4	95.2	97.1	10,450	Heavy Oil BBLS ->	595,685	6,400,000	3,812,383	13,851,106	3.7968
61													
62	FT MY 1	0		0.0	0.0		0						
63													
64	FT MY 2	0		0.0	0.0		0						
65													
66	CUTLER 5	71	9,732	18.4	97.6	89.7	13,304	Gas MCF ->	129,473	1,000,000	129,473	489,091	5.0255
67													
68	CUTLER 6	144	21,678	20.2	96.7	90.1	12,084	Gas MCF ->	261,965	1,000,000	261,965	989,585	4.5650
69													
70	MARTIN 1	814	183,298	43.2	95.6	91.6	10,717	Heavy Oil BBLS ->	301,475	6,400,000	1,929,439	7,130,248	3.8900
71			78,557					Gas MCF ->	876,872	1,000,000	876,872	3,312,430	4.2166
72													
73	MARTIN 2	806	228,833	54.5	96.1	97.2	10,442	Heavy Oil BBLS ->	366,645	6,400,001	2,346,530	8,671,606	3.7895
74			98,071					Gas MCF ->	1,067,138	1,000,000	1,067,138	4,031,171	4.1105
75													
76	MARTIN 3	448	312,874	93.9	94.3	99.7	7,140	Gas MCF ->	2,234,027	1,000,000	2,234,027	8,439,157	2.6973
77													
78	MARTIN 4	448	313,452	94.0	94.6	99.8	7,087	Gas MCF ->	2,221,553	1,000,000	2,221,553	8,392,036	2.6773
79													
80	FM GT	552	18,680	4.5	81.6	94.3	13,701	Light Oil BBLS ->	44,128	5,800,007	255,940	1,429,091	7.6505
81													

Company: Florida Power & Light

Schedule E4

Aug-2002 Estimated For The Period of : Aug-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
82	FL GT	684	8,606	1.7	91.9	93.3	15,439	Gas MCF ->	132,861	1,000,000	132,861	501,889	5.8321
84	PE GT	348	1,743	0.7	88.6	95.4	17,514	Gas MCF ->	30,526	1,000,000	30,526	115,312	6.6161
86	SJRPP 1O	127	87,668	92.8	92.9	100.0	9,912	Coal TONS ->	35,082	24,769,355	868,959	1,321,357	1.5072
88	SJRPP 2O	127	87,691	92.8	93.5	100.0	9,612	Coal TONS ->	34,030	24,769,299	842,904	1,281,738	1.4617
90	SCHER #4	643	442,538	92.5	93.6	100.0	10,428	Coal TONS ->	263,708	17,500,003	4,614,893	8,231,046	1.8600
92	FMREP 1	1,473	1,053,609	96.1	93.5	100.0	7,025	Gas MCF ->	7,401,205	1,000,000	7,401,205	27,958,455	2.6536
94	SNREP4	957		0.0	0.0		0						
96	SNREP5	957	675,774	94.9	95.0	100.0	7,074	Gas MCF ->	4,780,480	1,000,000	4,780,480	18,058,523	2.6723
98	MR SC	149	5,080	17.3	94.3	93.2	10,423	Light Oil BBLS ->	8,704	5,830,024	50,742	303,027	5.9657
99			33,340					Gas MCF ->	349,700	1,000,000	349,700	1,355,639	4.0662
101	FMCT	154		0.0	0.0		0						
103	TOTAL	19,011	8,821,745				9,368				82,642,522	215,308,174	2.4407

Company: Florida Power & Light

Schedule E4

Sep-2002 Estimated For The Period of : Sep-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	159,708	62.6	94.7	97.8	9,921	Heavy Oil BBLS ->	245,513	6,399,999	1,571,281	5,984,789	3.7473
2			17,745					Gas MCF ->	189,239	1,000,000	189,239	706,411	3.9808
3													
4	TRKY O 2	394	126,963	49.7	94.3	95.4	10,242	Heavy Oil BBLS ->	201,058	6,400,001	1,286,772	4,901,132	3.8603
5			14,107					Gas MCF ->	158,034	1,000,000	158,034	589,928	4.1818
6													
7	TRKY N 3	693	486,491	97.5	97.5	100.0	11,026	Nuclear Othr ->	5,364,243	1,000,000	5,364,243	1,558,312	0.3203
8													
9	TRKY N 4	693	486,491	97.5	97.5	100.0	11,026	Nuclear Othr ->	5,364,243	1,000,000	5,364,243	1,511,644	0.3107
10													
11	FT LAUD4	422	675	85.7	94.5	96.8	7,263	Light Oil BBLS ->	801	5,829,878	4,667	25,516	3.7785
12			259,587					Gas MCF ->	1,885,508	1,000,000	1,885,508	7,066,023	2.7220
13													
14	FT LAUD5	422	736	82.6	84.6	98.3	7,239	Light Oil BBLS ->	870	5,829,731	5,071	27,721	3.7690
15			250,106					Gas MCF ->	1,810,826	1,000,000	1,810,826	6,792,289	2.7158
16													
17	PT EVER1	211	27,445	20.1	95.2	92.0	10,693	Heavy Oil BBLS ->	45,345	6,399,996	290,209	1,091,759	3.9780
18			3,049					Gas MCF ->	35,858	1,000,000	35,858	133,854	4.3895
19													
20	PT EVER2	211	64,802	47.4	95.3	94.8	10,416	Heavy Oil BBLS ->	104,324	6,400,001	667,672	2,511,763	3.8761
21			7,200					Gas MCF ->	82,265	1,000,000	82,265	307,087	4.2650
22													
23	PT EVER3	390	166,673	66.0	94.8	97.8	9,996	Heavy Oil BBLS ->	258,187	6,399,999	1,652,396	6,216,269	3.7296
24			18,519					Gas MCF ->	198,860	1,000,000	198,860	742,327	4.0084
25													
26	PT EVER4	402	179,694	69.0	94.9	97.7	9,991	Heavy Oil BBLS ->	278,258	6,400,000	1,780,852	6,699,516	3.7283
27			19,966					Gas MCF ->	213,875	1,000,000	213,875	798,375	3.9987

Company: Florida Power & Light

Schedule E4

Sep-2002 Estimated For The Period of : Sep-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
28													
29	RIV 3	278	125,375	69.6	93.3	96.5	10,024	Heavy Oil BBLS ->	194,499	6,400,000	1,244,794	4,160,453	3.3184
30			13,931					Gas MCF ->	151,671	1,000,000	151,671	566,173	4.0642
31													
32	RIV 4	290	88,496	47.1	92.1	95.6	10,208	Heavy Oil BBLS ->	139,803	6,400,000	894,741	2,990,478	3.3792
33			9,833					Gas MCF ->	109,048	1,000,000	109,048	407,068	4.1399
34													
35	ST LUC 1	839	569,347	94.3	94.3	100.0	10,826	Nuclear Othr ->	6,163,514	1,000,000	6,163,514	1,735,029	0.3047
36													
37	ST LUC 2	714	501,219	97.5	97.5	100.0	10,826	Nuclear Othr ->	5,426,024	1,000,000	5,426,024	1,552,385	0.3097
38													
39	CAP CN 1	394	189,008	74.0	94.4	97.7	9,740	Heavy Oil BBLS ->	285,331	6,399,999	1,826,120	6,887,354	3.6439
40			21,001					Gas MCF ->	219,278	1,000,000	219,278	818,544	3.8977
41													
42	CAP CN 2	394	149,114	58.4	94.5	97.0	10,119	Heavy Oil BBLS ->	233,767	6,400,001	1,496,108	5,642,689	3.7842
43			16,568					Gas MCF ->	180,470	1,000,000	180,470	673,678	4.0661
44													
45	SANFRD 3	142	21,087	20.6	95.5	92.4	11,146	Heavy Oil BBLS ->	36,474	6,399,998	233,435	822,994	3.9028
46			0					Gas MCF ->	1,616	1,000,000	1,616	6,031	
47													
48	SANFRD 4	371		0.0	0.0		0						
49													
50	SANFRD 5	381		0.0	0.0		0						
51													
52	PUTNAM 1	239	1,525	78.4	94.8	97.2	9,460	Light Oil BBLS ->	2,351	5,829,924	13,708	81,828	5.3675
53			133,400					Gas MCF ->	1,262,707	1,000,000	1,262,707	4,758,436	3.5670
54													

Company: Florida Power & Light

Schedule E4

Sep-2002 Estimated For The Period of : Sep-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
55	PUTNAM 2	239	2,774	70.5	95.1	94.2	9,490	Light Oil BBLS ->	4,289	5,829,984	25,005	149,264	5.3804
56			118,591					Gas MCF ->	1,126,747	1,000,000	1,126,747	4,312,569	3.6365
57													
58	MANATE 1	798	252,405	43.9	94.9	91.4	10,594	Heavy Oil BBLS ->	417,812	6,400,001	2,673,999	9,950,032	3.9421
59													
60	MANATE 2	798	331,578	57.7	95.1	96.6	10,452	Heavy Oil BBLS ->	541,524	6,400,000	3,465,750	12,896,162	3.8893
61													
62	FT MY 1	0		0.0	0.0		0						
63													
64	FT MY 2	0		0.0	0.0		0						
65													
66	CUTLER 5	71	8,142	15.9	97.5	92.0	13,218	Gas MCF ->	107,623	1,000,000	107,623	401,748	4.9341
67													
68	CUTLER 6	144	18,617	18.0	96.5	90.5	12,049	Gas MCF ->	224,320	1,000,000	224,320	837,367	4.4979
69													
70	MARTIN 1	814	185,156	45.1	95.4	92.0	10,715	Heavy Oil BBLS ->	304,456	6,399,999	1,948,519	7,377,830	3.9846
71			79,353					Gas MCF ->	885,817	1,000,000	885,817	3,306,679	4.1671
72													
73	MARTIN 2	806	202,474	49.8	96.0	95.3	10,443	Heavy Oil BBLS ->	324,414	6,400,000	2,076,249	7,861,462	3.8827
74			86,774					Gas MCF ->	944,429	1,000,000	944,429	3,525,470	4.0628
75													
76	MARTIN 3	448	300,226	93.1	94.1	99.1	7,145	Gas MCF ->	2,145,095	1,000,000	2,145,095	8,007,453	2.6671
77													
78	MARTIN 4	448	301,196	93.4	94.4	99.4	7,091	Gas MCF ->	2,135,653	1,000,000	2,135,653	7,972,208	2.6468
79													
80	FM GT	552	12,357	3.1	81.0	94.0	13,701	Light Oil BBLS ->	29,192	5,799,996	169,313	971,871	7.8648
81													

Company: Florida Power & Light

Schedule E4

Sep-2002 Estimated For The Period of : Sep-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
82	FL GT	684	5,451	1.1	91.6	92.8	15,439	Gas	MCF ->	84,163	1,000,000	84,163	314,172	5.7632
84	PE GT	348	941	0.4	88.2	94.6	17,514	Gas	MCF ->	16,483	1,000,000	16,483	61,530	6.5381
86	SJRPP 1O	127	84,840	92.8	92.7	100.0	9,912	Coal	TONS ->	33,935	24,780,530	840,927	1,285,573	1.5153
88	SJRPP 2O	127	84,862	92.8	93.3	100.0	9,612	Coal	TONS ->	32,918	24,780,551	815,714	1,247,027	1.4695
90	SCHER #4	643	428,263	92.5	93.3	100.0	10,428	Coal	TONS ->	255,202	17,500,004	4,466,029	7,968,134	1.8606
92	FMREP 1	1,473	1,019,622	96.1	93.3	100.0	7,025	Gas	MCF ->	7,162,457	1,000,000	7,162,457	26,736,830	2.6222
94	SNREP4	957		0.0	0.0		0							
96	SNREP5	957	653,605	94.9	94.8	99.9	7,075	Gas	MCF ->	4,624,007	1,000,000	4,624,007	17,261,014	2.6409
98	MR SC	149	477	13.6	94.1	90.1	10,491	Light Oil	BBLS ->	818	5,830,032	4,768	28,495	5.9763
99			28,660					Gas	MCF ->	300,909	1,000,000	300,909	1,135,295	3.9613
101	FMCT	154		0.0	0.0		0							
103	TOTAL	19,011	8,336,225				9,360					78,029,076	202,376,040	2.4277

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Oct-02

Oct-2002

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	128,723	48.8	94.9	94.4	9,928	Heavy Oil BBLS ->	197,895	6,400,001	1,266,525	4,869,228	3.7827
2			14,303					Gas MCF ->	153,486	1,000,000	153,486	576,418	4.0302
3													
4	TRKY O 2	394	85,845	32.5	94.5	92.2	10,254	Heavy Oil BBLS ->	135,942	6,400,000	870,026	3,344,864	3.8964
5			9,538					Gas MCF ->	108,050	1,000,000	108,050	405,782	4.2542
6													
7	TRKY N 3	693	502,707	97.5	97.5	100.0	11,026	Nuclear Othr ->	5,543,048	1,000,000	5,543,048	1,631,319	0.3245
8													
9	TRKY N 4	693	502,707	97.5	97.5	100.0	11,026	Nuclear Othr ->	5,543,048	1,000,000	5,543,048	1,583,094	0.3149
10													
11	FT LAUD4	422	264	77.5	94.7	97.3	7,261	Light Oil BBLS ->	313	5,829,923	1,824	9,971	3.7769
12			243,014					Gas MCF ->	1,764,564	1,000,000	1,764,564	6,626,824	2.7269
13													
14	FT LAUD5	422	33,526	10.7	71.8	96.5	7,241	Gas MCF ->	242,767	1,000,000	242,767	911,711	2.7194
15													
16	PT EVER1	211	16,180	11.5	95.3	89.0	10,678	Heavy Oil BBLS ->	26,733	6,400,001	171,094	648,348	4.0070
17			1,798					Gas MCF ->	20,884	1,000,000	20,884	78,430	4.3626
18													
19	PT EVER2	211	41,507	29.4	95.4	90.8	10,416	Heavy Oil BBLS ->	66,822	6,400,004	427,660	1,620,590	3.9043
20			4,612					Gas MCF ->	52,703	1,000,000	52,703	197,926	4.2916
21													
22	PT EVER3	390	145,433	55.7	94.9	96.5	10,004	Heavy Oil BBLS ->	225,298	6,400,000	1,441,905	5,464,002	3.7571
23			16,159					Gas MCF ->	174,708	1,000,000	174,708	656,115	4.0603
24													
25	PT EVER4	402	159,658	59.3	4.7	96.6	9,995	Heavy Oil BBLS ->	247,210	6,400,000	1,582,145	5,995,433	3.7552
26			17,740					Gas MCF ->	190,897	1,000,000	190,897	716,912	4.0413
27													

Company: Florida Power & Light

Schedule E4

Oct-2002 Estimated For The Period of : Oct-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
28	RIV 3	278	126,180	67.8	93.5	96.7	10,028	Heavy Oil BBLS ->	195,785	6,400,001	1,253,026	4,226,957	3.3499
29			14,020					Gas MCF ->	152,846	1,000,000	152,846	574,012	4.0942
31	RIV 4	290	119,907	61.7	92.3	95.5	10,215	Heavy Oil BBLS ->	189,459	6,400,000	1,212,538	4,090,375	3.4113
32			13,323					Gas MCF ->	148,354	1,000,000	148,354	557,143	4.1818
34	ST LUC 1	839	39,265	6.3	6.3	100.0	10,826	Nuclear Othr ->	425,073	1,000,000	425,073	119,615	0.3046
36	ST LUC 2	714	517,926	97.5	97.5	100.0	10,826	Nuclear Othr ->	5,606,891	1,000,000	5,606,891	1,580,022	0.3051
38	CAP CN 1	394	167,859	63.6	94.6	96.8	9,742	Heavy Oil BBLS ->	253,321	6,400,000	1,621,257	6,171,348	3.6765
39			18,651					Gas MCF ->	195,807	1,000,000	195,807	735,352	3.9427
41	CAP CN 2	394	113,881	43.2	94.7	93.1	10,128	Heavy Oil BBLS ->	178,538	6,400,001	1,142,646	4,349,505	3.8193
42			12,654					Gas MCF ->	138,838	1,000,000	138,838	521,407	4.1207
44	SANFRD 3	142	7,492	7.1	95.7	91.3	11,153	Heavy Oil BBLS ->	12,959	6,400,015	82,938	292,511	3.9042
45			0					Gas MCF ->	621	1,000,000	621	2,333	
47	SANFRD 4	371		0.0	0.0		0						
49	SANFRD 5	381		0.0	0.0		0						
51	PUTNAM 1	239	609	64.0	85.3	89.9	9,575	Light Oil BBLS ->	949	5,830,191	5,535	33,004	5.4194
52			113,262					Gas MCF ->	1,084,739	1,000,000	1,084,739	4,073,739	3.5967
54	PUTNAM 2	239	449	32.0	90.4	57.2	10,328	Light Oil BBLS ->	751	5,829,739	4,379	26,115	5.8189

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Oct-02

Oct-2002

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
55			56,392					Gas MCF ->	582,676	1,000,000	582,676	2,188,240	3.8804
57	MANATE 1	798	189,882	32.0	95.1	87.9	10,576	Heavy Oil BBLS ->	313,778	6,400,002	2,008,182	7,540,469	3.9711
59	MANATE 2	798	262,707	44.2	95.2	93.4	10,451	Heavy Oil BBLS ->	429,001	6,400,000	2,745,609	10,309,413	3.9243
61	FT MY 1	0		0.0	0.0		0						
63	FT MY 2	0		0.0	0.0		0						
65	CUTLER 5	71	2,822	5.3	97.6	91.2	13,221	Gas MCF ->	37,308	1,000,000	37,308	140,108	4.9650
67	CUTLER 6	144	6,582	6.1	96.7	89.6	12,066	Gas MCF ->	79,421	1,000,000	79,421	298,265	4.5313
69	MARTIN 1	814	113,910	26.9	95.6	88.7	10,703	Heavy Oil BBLS ->	187,294	6,399,999	1,198,679	4,577,075	4.0181
70			48,819					Gas MCF ->	542,998	1,000,000	542,998	2,039,232	4.1772
72	MARTIN 2	806	159,276	37.9	96.1	91.0	10,437	Heavy Oil BBLS ->	255,128	6,400,000	1,632,816	6,234,798	3.9145
73			68,261					Gas MCF ->	741,993	1,000,000	741,993	2,786,555	4.0822
75	MARTIN 3	448	281,443	84.4	94.3	98.4	7,147	Gas MCF ->	2,011,523	1,000,000	2,011,523	7,554,278	2.6841
77	MARTIN 4	448	256,193	76.9	81.7	86.2	7,188	Gas MCF ->	1,841,438	1,000,000	1,841,438	6,915,522	2.6993
79	FM GT	552	3,932	1.0	81.6	93.5	13,701	Light Oil BBLS ->	9,290	5,799,991	53,880	310,878	7.9056
81	FL GT	684	1,622	0.3	91.9	92.5	15,439	Gas MCF ->	25,042	1,000,000	25,042	94,044	5.7980

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Oct-02

Oct-2002

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
83	PE GT	348	275	0.1	88.6	94.4	17,514	Gas MCF ->	4,808	1,000,000	4,808	18,058	6.5785
85	SJRPP 1O	127	87,668	92.8	92.9	100.0	9,912	Coal TONS ->	35,146	24,723,969	868,959	1,321,627	1.5075
87	SJRPP 2O	127	87,691	92.8	93.5	100.0	9,612	Coal TONS ->	34,093	24,723,964	842,904	1,282,001	1.4620
89	SCHER #4	643	441,395	92.3	93.6	99.7	10,429	Coal TONS ->	263,040	17,500,001	4,603,192	8,226,368	1.8637
91	FMREP 1	1,473	1,053,609	96.1	93.5	100.0	7,025	Gas MCF ->	7,401,205	1,000,000	7,401,205	27,795,242	2.6381
93	SNREP4	957		0.0	0.0		0						
95	SNREP5	957	671,874	94.4	95.0	99.7	7,077	Gas MCF ->	4,754,584	1,000,000	4,754,584	17,855,848	2.6576
97	MR SC	149	227	4.6	94.3	90.1	10,478	Light Oil BBLS ->	390	5,830,595	2,272	13,578	5.9710
98			9,947					Gas MCF ->	104,329	1,000,000	104,329	391,806	3.9391
100	FMCT	154		0.0	0.0		0						
102	TOTAL	19,011	6,993,721				9,253				64,714,633	170,583,810	2.4391

Company: Florida Power & Light

Schedule E4

Nov-2002 Estimated For The Period of : Nov-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	398	79,925	31.0	91.3	87.5	9,859	Heavy Oil BBLS ->	121,795	6,400,002	779,488	2,941,554	3.6804
2			8,881					Gas MCF ->	96,073	1,000,000	96,073	374,116	4.2127
3													
4	TRKY O 2	398	7,136	2.8	94.3	73.4	10,232	Heavy Oil BBLS ->	11,313	6,400,023	72,404	273,232	3.8291
5			793					Gas MCF ->	8,720	1,000,000	8,720	33,956	4.2830
6													
7	TRKY N 3	717	503,332	97.5	97.5	100.0	10,686	Nuclear Othr ->	5,378,662	1,000,000	5,378,662	1,594,773	0.3168
8													
9	TRKY N 4	717	503,332	97.5	97.5	100.0	10,686	Nuclear Othr ->	5,378,662	1,000,000	5,378,662	1,547,979	0.3075
10													
11	FT LAUD4	440	178,264	56.3	94.5	97.0	7,202	Gas MCF ->	1,283,792	1,000,000	1,283,792	4,999,209	2.8044
12													
13	FT LAUD5	440	193,104	61.0	94.6	97.4	7,176	Gas MCF ->	1,385,767	1,000,000	1,385,767	5,396,310	2.7945
14													
15	PT EVER1	212	1,127	0.8	95.2	79.3	10,552	Heavy Oil BBLS ->	1,849	6,400,000	11,830	44,285	3.9302
16			125					Gas MCF ->	1,380	1,000,000	1,380	5,375	4.2931
17													
18	PT EVER2	212	10,397	7.6	95.3	81.2	10,295	Heavy Oil BBLS ->	16,620	6,399,992	106,365	398,164	3.8296
19			1,155					Gas MCF ->	12,565	1,000,000	12,565	48,931	4.2357
20													
21	PT EVER3	392	102,981	40.5	94.8	91.7	9,974	Heavy Oil BBLS ->	158,835	6,400,000	1,016,545	3,805,295	3.6951
22			11,442					Gas MCF ->	124,676	1,000,000	124,676	485,501	4.2430
23													
24	PT EVER4	404	3,096	1.2	94.9	90.8	9,961	Heavy Oil BBLS ->	4,766	6,400,050	30,502	114,180	3.6882
25			344					Gas MCF ->	3,762	1,000,000	3,762	14,650	4.2587
26													
27	RIV 3	280	94,065	51.8	93.3	96.7	9,921	Heavy Oil BBLS ->	144,123	6,399,998	922,385	3,006,533	3.1962

Company: Florida Power & Light

Schedule E4

Nov-2002 Estimated For The Period of : Nov-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
28			10,452					Gas MCF ->	114,486	1,000,000	114,486	445,820	4.2655
30	RIV 4	292	90,967	48.1	92.1	95.4	10,119	Heavy Oil BBLS ->	142,228	6,400,001	910,260	2,967,011	3.2616
31			10,108					Gas MCF ->	112,481	1,000,000	112,481	438,014	4.3336
33	ST LUC 1	853	598,803	97.5	97.5	100.0	10,693	Nuclear Othr ->	6,402,897	1,000,000	6,402,897	1,838,912	0.3071
35	ST LUC 2	726	509,586	97.5	97.5	100.0	10,693	Nuclear Othr ->	5,448,859	1,000,000	5,448,859	1,561,643	0.3065
37	CAP CN 1	398	119,223	46.2	94.4	94.1	9,697	Heavy Oil BBLS ->	178,831	6,400,000	1,144,520	4,222,014	3.5413
38			13,247					Gas MCF ->	139,972	1,000,000	139,972	545,063	4.1146
40	CAP CN 2	398	63,280	24.5	94.5	86.7	10,035	Heavy Oil BBLS ->	98,146	6,400,002	628,137	2,317,133	3.6617
41			7,031					Gas MCF ->	77,430	1,000,000	77,430	301,520	4.2884
43	SANFRD 3	144	42	0.0	48.9	80.4	10,943	Heavy Oil BBLS ->	73	6,401,379	464	1,637	3.8608
45	SANFRD 4	374		0.0	0.0		0						
47	SANFRD 5	384		0.0	0.0		0						
49	PUTNAM 1	250	26,859	14.9	38.1	51.0	10,548	Gas MCF ->	283,308	1,000,000	283,308	1,103,228	4.1074
51	PUTNAM 2	250	60,834	33.8	53.5	93.2	9,385	Gas MCF ->	570,949	1,000,000	570,949	2,223,329	3.6548
53	MANATE 1	805	47,430	8.2	94.9	80.5	10,457	Heavy Oil BBLS ->	77,498	6,399,994	495,989	1,812,506	3.8214

Company: Florida Power & Light

Schedule E4

Nov-2002 Estimated For The Period of : Nov-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
55	MANATE 2	805	213,288	36.8	95.1	81.2	10,365	Heavy Oil BBLS ->	345,441	6,399,999	2,210,820	8,079,053	3.7879
56													
57	FT MY 1	0		0.0	0.0		0						
58													
59	FT MY 2	0		0.0	0.0		0						
60													
61	CUTLER 5	72	48	0.1	97.5	88.5	12,854	Gas MCF ->	611	1,000,000	611	2,378	5.0063
62													
63	CUTLER 6	145	121	0.1	96.5	81.4	11,752	Gas MCF ->	1,423	1,000,000	1,423	5,541	4.5756
64													
65	MARTIN 1	833	1,447	0.3	92.1	45.1	10,622	Heavy Oil BBLS ->	2,366	6,400,135	15,144	56,875	3.9303
66			620					Gas MCF ->	6,815	1,000,000	6,815	26,537	4.2788
67													
68	MARTIN 2	821	99,739	24.1	96.0	81.0	10,335	Heavy Oil BBLS ->	158,368	6,400,000	1,013,555	3,806,488	3.8165
69			42,745					Gas MCF ->	458,990	1,000,000	458,990	1,787,350	4.1814
70													
71	MARTIN 3	470	224,180	66.2	94.1	97.5	7,050	Gas MCF ->	1,580,570	1,000,000	1,580,570	6,154,892	2.7455
72													
73	MARTIN 4	470	243,933	72.1	94.4	97.2	7,010	Gas MCF ->	1,709,961	1,000,000	1,709,961	6,658,753	2.7298
74													
75	FM GT	624	0	0.0	81.0		0	Light Oil BBLS ->	1	6,111,111	6	32	8.0000
76													
77	FL GT	768		0.0	91.6		0						
78													
79	PE GT	384	0	0.0	88.2		0	Gas MCF ->	0	1,000,000	0	1	
80													
81	SJRPP 10	130	86,845	92.8	92.7	100.0	9,817	Coal TONS ->	34,436	24,757,441	852,540	1,303,540	1.5010

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Nov-02

Nov-2002

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
82														
83	SJRPP 2O	130	86,867	92.8	93.3	100.0	9,526	Coal	TONS ->	33,426	24,757,476	827,531	1,265,301	1.4566
84														
85	SCHER #4	648	101,419	21.7	20.0	98.8	10,329	Coal	TONS ->	59,861	17,500,013	1,047,563	1,872,705	1.8465
86														
87	FMREP 1	1,498	1,036,934	96.1	93.3	100.0	6,873	Gas	MCF ->	7,126,650	1,000,000	7,126,650	27,751,859	2.6763
88														
89	SNREP4	986		0.0	0.0		0							
90														
91	SNREP5	986	656,495	92.5	94.8	98.0	7,003	Gas	MCF ->	4,597,353	1,000,000	4,597,353	17,902,535	2.7270
92														
93	MR SC	181	145	0.1	94.1	75.9	10,005	Gas	MCF ->	1,447	1,000,000	1,447	5,635	3.8970
94														
95	FMCT	165		0.0	0.0		0							
96														
97	TOTAL	19,600	6,052,184				8,988					54,394,309	121,541,348	2.0082

Company: Florida Power & Light

Schedule E4

Dec-2002 Estimated For The Period of : Dec-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	398	1,865	0.7	7.8	70.2	9,976	Heavy Oil BBLS ->	2,865	6,399,993	18,338	68,998	3.6992
2			207					Gas MCF ->	2,337	1,000,000	2,337	9,530	4.5994
3													
4	TRKY O 2	398	1,868	0.7	94.5	68.3	10,200	Heavy Oil BBLS ->	2,962	6,400,061	18,959	71,335	3.8190
5			208					Gas MCF ->	2,212	1,000,000	2,212	9,330	4.4964
6													
7	TRKY N 3	717	520,110	97.5	97.5	100.0	10,686	Nuclear Othr ->	5,557,947	1,000,000	5,557,947	1,660,159	0.3192
8													
9	TRKY N 4	717	520,110	97.5	97.5	100.0	10,686	Nuclear Othr ->	5,557,947	1,000,000	5,557,947	1,611,804	0.3099
10													
11	FT LAUD4	440	107,079	32.7	94.7	91.4	7,214	Gas MCF ->	772,442	1,000,000	772,442	3,156,542	2.9479
12													
13	FT LAUD5	440	145,849	44.6	94.7	93.7	7,188	Gas MCF ->	1,048,302	1,000,000	1,048,302	4,283,863	2.9372
14													
15	PT EVER1	212	620	0.4	95.3	79.8	10,551	Heavy Oil BBLS ->	1,017	6,400,315	6,510	22,434	3.6178
16			69					Gas MCF ->	759	1,000,000	759	3,336	4.8488
17													
18	PT EVER2	212	5,528	3.9	95.4	82.7	10,307	Heavy Oil BBLS ->	8,836	6,399,995	56,551	194,865	3.5252
19			614					Gas MCF ->	6,754	1,000,000	6,754	28,797	4.6885
20													
21	PT EVER3	392	63,656	24.3	94.9	89.7	9,996	Heavy Oil BBLS ->	98,247	6,400,001	628,781	2,166,671	3.4037
22			7,073					Gas MCF ->	78,221	1,000,000	78,221	327,328	4.6279
23													
24	PT EVER4	404	68,090	25.2	95.1	87.7	9,978	Heavy Oil BBLS ->	104,949	6,400,001	671,676	2,314,479	3.3991
25			7,566					Gas MCF ->	83,250	1,000,000	83,250	344,573	4.5545
26													
27	RIV 3	280	90,814	48.4	93.5	93.0	9,943	Heavy Oil BBLS ->	139,427	6,400,001	892,330	2,644,041	2.9115

Company: Florida Power & Light

Schedule E4

Dec-2002 Estimated For The Period of : Dec-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
28			10,091					Gas MCF ->	110,979	1,000,000	110,979	460,012	4.5589
29													
30	RIV 4	292	74,940	38.3	92.3	91.3	10,145	Heavy Oil BBLS ->	117,326	6,399,999	750,886	2,224,930	2.9690
31			8,327					Gas MCF ->	93,887	1,000,000	93,887	389,570	4.6786
32													
33	ST LUC 1	853	618,763	97.5	97.5	100.0	10,693	Nuclear Othr ->	6,616,331	1,000,000	6,616,331	1,901,533	0.3073
34													
35	ST LUC 2	726	526,572	97.5	97.5	100.0	10,693	Nuclear Othr ->	5,630,488	1,000,000	5,630,488	1,614,261	0.3066
36													
37	CAP CN 1	398	87,079	32.7	94.6	87.6	9,729	Heavy Oil BBLS ->	130,873	6,399,998	837,586	2,897,941	3.3279
38			9,676					Gas MCF ->	103,734	1,000,000	103,734	425,354	4.3962
39													
40	CAP CN 2	398	41,198	15.5	94.7	84.8	10,035	Heavy Oil BBLS ->	63,892	6,400,003	408,906	1,414,763	3.4340
41			4,578					Gas MCF ->	50,471	1,000,000	50,471	210,737	4.6037
42													
43	SANFRD 3	144	337	0.3	95.7	85.0	10,943	Heavy Oil BBLS ->	576	6,399,792	3,685	12,992	3.8586
44													
45	SANFRD 4	374		0.0	0.0		0						
46													
47	SANFRD 5	384		0.0	0.0		0						
48													
49	PUTNAM 1	250	426	0.2	95.0	77.3	9,323	Gas MCF ->	3,973	1,000,000	3,973	17,432	4.0901
50													
51	PUTNAM 2	250	281	0.2	95.3	76.3	9,319	Gas MCF ->	2,618	1,000,000	2,618	11,511	4.0964
52													
53	MANATE 1	805	100,325	16.8	95.1	80.0	10,481	Heavy Oil BBLS ->	164,299	6,400,003	1,051,512	3,554,745	3.5432
54													

Company: Florida Power & Light

Schedule E4

Dec-2002 Estimated For The Period of : Dec-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
55	MANATE 2	805	192,941	32.2	95.2	81.4	10,383	Heavy Oil BBLS ->	313,016	6,400,001	2,003,304	6,772,381	3.5101
56													
57	FT MY 1	0		0.0	0.0		0						
58													
59	FT MY 2	0		0.0	0.0		0						
60													
61	CUTLER 5	72	21	0.0	97.6	87.9	12,850	Gas MCF ->	269	1,000,000	269	1,095	5.2392
62													
63	CUTLER 6	145	116	0.1	96.7	83.3	11,751	Gas MCF ->	1,364	1,000,000	1,364	5,561	4.7940
64													
65	MARTIN 1	833	30	0.0	53.6	32.3	10,622	Heavy Oil BBLS ->	49	6,400,000	310	1,135	3.8215
66			13					Gas MCF ->	140	1,000,000	140	570	4.4882
67													
68	MARTIN 2	821	52,419	12.3	96.1	83.4	10,325	Heavy Oil BBLS ->	83,121	6,399,998	531,977	1,945,726	3.7119
69			22,465					Gas MCF ->	241,196	1,000,000	241,196	1,021,872	4.5487
70													
71	MARTIN 3	470	194,732	55.7	94.3	96.2	7,052	Gas MCF ->	1,373,344	1,000,000	1,373,344	5,600,785	2.8761
72													
73	MARTIN 4	470	212,069	60.6	94.6	96.7	7,001	Gas MCF ->	1,484,785	1,000,000	1,484,785	6,055,267	2.8553
74													
75	FM GT	624	1	0.0	81.6		0	Light Oil BBLS ->	1	6,000,000	7	41	8.2000
76													
77	FL GT	768		0.0	91.9		0						
78													
79	PE GT	384	0	0.0	88.6		0	Gas MCF ->	0	1,000,000	0	1	
80													
81	SJRPP 10	130	89,740	92.8	92.9	100.0	9,817	Coal TONS ->	35,383	24,897,838	880,958	1,313,905	1.4641

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Dec-02

Dec-2002

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
82														
83	SJRPP 2O	130	89,763	92.8	93.5	100.0	9,526	Coal	TONS ->	34,345	24,897,813	855,115	1,275,363	1.4208
84														
85	SCHER #4	648	96,683	20.1	22.6	98.6	10,329	Coal	TONS ->	57,067	17,500,013	998,672	1,778,894	1.8399
86														
87	FMREP 1	1,498	1,071,498	96.1	93.5	100.0	6,873	Gas	MCF ->	7,364,205	1,000,000	7,364,205	30,032,779	2.8029
88														
89	SNREP4	986	654,835	89.3	95.0	97.8	7,000	Gas	MCF ->	4,583,958	1,000,000	4,583,958	18,694,348	2.8548
90														
91	SNREP5	986	637,807	86.9	95.0	96.2	7,019	Gas	MCF ->	4,476,733	1,000,000	4,476,733	18,257,059	2.8625
92														
93	MR SC	181	178	0.1	94.3	78.5	10,005	Gas	MCF ->	1,782	1,000,000	1,782	7,930	4.4526
94														
95	FMCT	165		0.0	0.0		0							
96														
97	TOTAL	19,600	6,339,224				8,813					55,866,487	126,818,578	2.0005

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jan-02 Thru Dec-02

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Plant Unit	Net Capb (MW)	Net Gen (MWH)	Capac FAC (%)	Equiv Avail FAC (%)	Net Out FAC (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Type	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (C/KWH)
1	TRKY O 1	396	1,597,106	51.2	87.1	95.7	9,898	Heavy Oil BBLS ->	2,448,437	6,400,000	15,669,995	57,538,285	3.6027
2			177,457					Gas MCF ->	1,893,905	1,000,000	1,893,905	7,159,262	4.0344
3													
4	TRKY O 2	396	991,215	31.8	94.4	92.9	10,249	Heavy Oil BBLS ->	1,569,909	6,400,000	10,047,415	36,718,081	3.7044
5			110,135					Gas MCF ->	1,240,123	1,000,000	1,240,123	4,626,594	4.2008
6													
7	TRKY N 3	703	6,003,740	97.5	97.5	100.0	10,883	Nuclear Othr ->	65,337,512	1,000,000	65,337,512	19,536,729	0.3254
8													
9	TRKY N 4	703	5,513,319	89.5	89.5	100.0	10,877	Nuclear Othr ->	59,969,927	1,000,000	59,969,927	17,005,537	0.3084
10													
11	FT LAUD4	430	5,890	76.2	91.9	97.3	7,237	Light Oil BBLS ->	6,977	5,829,946	40,673	222,090	3.7708
12			2,860,412					Gas MCF ->	20,704,002	1,000,000	20,704,002	78,659,194	2.7499
13													
14	FT LAUD5	430	6,069	77.1	91.9	98.5	7,208	Light Oil BBLS ->	7,165	5,829,875	41,773	228,081	3.7583
15			2,894,156					Gas MCF ->	20,862,012	1,000,000	20,862,012	79,589,405	2.7500
16													
17	PT EVER1	211	291,887	17.5	95.2	91.8	10,679	Heavy Oil BBLS ->	481,977	6,400,001	3,084,654	10,995,690	3.7671
18			32,432					Gas MCF ->	378,801	1,000,000	378,801	1,404,036	4.3292
19													
20	PT EVER2	211	527,882	31.7	91.5	93.3	10,401	Heavy Oil BBLS ->	848,439	6,400,000	5,430,010	19,516,025	3.6970
21			58,653					Gas MCF ->	670,801	1,000,000	670,801	2,524,463	4.3040
22													
23	PT EVER3	391	1,759,014	57.1	94.8	96.6	9,986	Heavy Oil BBLS ->	2,720,863	6,400,000	17,413,521	62,511,417	3.5538
24			195,447					Gas MCF ->	2,103,528	1,000,000	2,103,528	7,972,970	4.0794
25													
26	PT EVER4	403	1,862,522	58.6	87.3	96.7	9,975	Heavy Oil BBLS ->	2,879,105	6,400,001	18,426,276	66,074,055	3.5476
27			206,946					Gas MCF ->	2,217,547	1,000,000	2,217,547	8,407,322	4.0626
28													
29	RIV 3	279	1,499,076	68.2	93.4	96.3	9,980	Heavy Oil BBLS ->	2,315,701	6,400,000	14,820,485	46,934,221	3.1309

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jan-02 Thru Dec-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
30			166,564					Gas MCF ->	1,802,093	1,000,000	1,802,093	6,855,770	4.1160
32	RIV 4	291	1,393,029	60.8	92.2	95.8	10,171	Heavy Oil BBLS ->	2,192,174	6,400,000	14,029,916	44,443,053	3.1904
33			154,781					Gas MCF ->	1,712,835	1,000,000	1,712,835	6,523,961	4.2150
35	ST LUC 1	845	6,626,385	89.5	89.5	100.0	10,765	Nuclear Othr ->	71,334,323	1,000,000	71,334,323	20,478,658	0.3090
37	ST LUC 2	719	6,140,275	97.5	97.5	100.0	10,770	Nuclear Othr ->	66,131,557	1,000,000	66,131,557	19,167,436	0.3122
39	CAP CN 1	396	2,070,062	66.4	94.5	96.4	9,720	Heavy Oil BBLS ->	3,118,496	6,400,000	19,958,371	72,009,209	3.4786
40			230,007					Gas MCF ->	2,398,511	1,000,000	2,398,511	9,099,075	3.9560
42	CAP CN 2	396	1,397,725	44.8	90.7	94.5	10,088	Heavy Oil BBLS ->	2,183,153	6,400,000	13,972,182	50,540,337	3.6159
43			155,303					Gas MCF ->	1,694,862	1,000,000	1,694,862	6,437,877	4.1454
45	SANFRD 3	143	164,461	13.1	91.8	93.0	11,148	Heavy Oil BBLS ->	284,321	6,399,998	1,819,653	6,472,219	3.9354
46			0					Gas MCF ->	13,794	1,000,000	13,794	51,200	0.0000
48	SANFRD 4	372	13,668	0.4	97.7	87.4	9,505	Heavy Oil BBLS ->	20,126	6,400,021	128,805	477,390	3.4929
49			0					Gas MCF ->	1,101	1,000,000	1,101	4,515	0.0000
50			0						0		0	0	0.0000
52	SANFRD 5	382	0	0.0	0.0	0.0	0		0		0	0	0.0000
54	PUTNAM 1	244	1,108,017	52.4	89.4	92.3	9,488	Gas MCF ->	10,517,743	1,000,000	10,517,743	39,506,216	3.5655
55			10,543					Light Oil BBLS ->	16,283	5,830,028	94,932	570,754	5.4138
57	PUTNAM 2	244	925,895	44.2	87.5	87.4	9,545	Gas MCF ->	8,846,265	1,000,000	8,846,265	33,485,821	3.6166
58			16,370					Light Oil BBLS ->	25,299	5,829,995	147,494	890,407	5.4394

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jan-02 Thru Dec-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
59													
60	MANATE 1	801	2,482,707	35.4	87.3	90.6	10,547	Heavy Oil BBLS ->	4,091,286	6,400,000	26,184,234	93,667,821	3.7728
61													
62	MANATE 2	801	3,399,287	48.5	87.5	92.7	10,415	Heavy Oil BBLS ->	5,531,820	6,400,000	35,403,647	126,841,805	3.7314
63													
64	FT MY 1	0	0	0.0	0.0	0.0	0		0		0	0	0.0000
65													
66	FT MY 2	0	0	0.0	0.0	0.0	0		0		0	0	0.0000
67													
68	CUTLER 5	71	62,335	10.0	97.5	88.7	13,275	Gas MCF ->	827,469	1,000,000	827,469	3,056,298	4.9030
69													
70	CUTLER 6	144	141,319	11.2	96.6	88.6	12,070	Gas MCF ->	1,705,777	1,000,000	1,705,777	6,301,823	4.4593
71													
72	MARTIN 1	822	1,357,044	26.9	91.6	89.7	10,706	Heavy Oil BBLS ->	2,229,903	6,400,000	14,271,379	51,981,610	3.8305
73			581,591					Gas MCF ->	6,482,846	1,000,000	6,482,846	24,070,814	4.1388
74													
75	MARTIN 2	812	2,175,787	43.7	92.2	93.5	10,409	Heavy Oil BBLS ->	3,476,168	6,400,000	22,247,473	81,546,150	3.7479
76			932,480					Gas MCF ->	10,105,297	1,000,000	10,105,297	38,258,571	4.1029
77													
78	MARTIN 3	457	3,482,292	87.0	94.2	98.9	7,103	Gas MCF ->	24,735,692	1,000,000	24,735,692	94,276,659	2.7073
79													
80	MARTIN 4	457	3,515,967	87.8	90.3	98.2	7,057	Gas MCF ->	24,811,235	1,000,000	24,811,235	94,639,566	2.6917
81													
82	FM GT	582	154,987	3.0	81.3	90.3	13,683	Light Oil BBLS ->	365,623	5,800,001	2,120,612	12,009,603	7.7488
83													
84	FL GT	719	2,919	1.1	91.7	87.8	15,599	Light Oil BBLS ->	8,277	5,829,975	48,255	257,179	8.8117
85			69,087					Gas MCF ->	1,074,976	1,000,000	1,074,976	3,947,328	5.7136
86			0						0		0	0	0.0000
87													

Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jan-02 Thru Dec-02

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
88	PE GT	363	1,303	0.5	88.3	95.4	17,765	Light Oil BBLS ->	4,236	5,829,997	24,698	131,864	10.1239
89			13,240					Gas MCF ->	233,641	1,000,000	233,641	861,313	6.5055
90													
91	SJRPP 1O	128	1,042,314	92.8	92.8	100.0	9,872	Coal TONS ->	414,880	24,801,732	10,289,733	15,441,888	1.4815
92													
93	SJRPP 2O	128	953,821	84.9	85.2	100.0	9,577	Coal TONS ->	368,304	24,802,387	9,134,816	13,709,443	1.4373
94													
95	SCHER #4	645	4,547,055	80.5	81.4	99.9	10,395	Coal TONS ->	2,700,891	17,500,003	47,265,597	83,717,869	1.8411
96													
97	FMREP 1	1,483	7,234,566	55.7	93.4	99.8	6,980	Gas MCF ->	50,500,130	1,000,000	50,500,130	192,069,002	2.6549
98													
99	SNREP4	969	654,835	7.7	95.0	99.5	7,000	Gas MCF ->	4,583,958	1,000,000	4,583,958	18,694,348	2.8548
100													
101	SNREP5	969	3,967,668	46.7	95.0	98.7	7,054	Gas MCF ->	27,987,747	1,000,000	27,987,747	106,815,749	2.6922
102													
103	MR SC	162	15,080	16.8	94.2	100.0	10,445	Light Oil BBLS ->	25,719	5,830,006	149,939	908,819	6.0268
104			224,140					Gas MCF ->	2,348,830	1,000,000	2,348,830	8,721,451	3.8911
105													
106	FMCT	159	17,708	1.3	95.5	100.0	9,686	Gas MCF ->	171,512	1,000,000	171,512	703,391	3.9723
107			0						0		0	0	0.0000
108													
109	TOTAL	19,256	84,195,966				9,474				797,666,886	1,917,267,719	2.2771

Note: E4 schedule excludes gas fixed costs and purchased power tolling fuel. These items are included in the figures shown in Schedule E3.

Company: Florida Power & Light

Schedule: E5
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System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : January 2002 thru December 2002

		January 2002	February 2002	March 2002	April 2002	May 2002	June 2002	Total
Heavy Oil								
1 Purchases:								
2 Units	(BBLS)	2,511,765	2,662,572	3,358,853	3,708,968	3,639,206	3,928,783	19810147
3 Unit Cost	($/BBLS)	23.4473	22.0764	21.1126	21.2560	21.8877	22.7745	22.036989
4 Amount	($)	58,894,000	58,780,000	70,914,000	78,838,000	79,654,000	89,476,000	436556000
5								
6 Burned:								
7 Units	(BBLS)	2,561,765	2,662,572	3,258,853	3,558,968	3,439,206	3,928,783	19410147
8 Unit Cost	($/BBLS)	23.9265	22.9462	21.8385	21.5792	21.8024	22.3922	22.324157
9 Amount	($)	61,294,044	61,095,996	71,168,311	76,799,783	74,982,869	87,974,163	433315166
10								
11 Ending Inventory:								
12 Units	(BBLS)	3,150,001	3,150,001	3,249,997	3,399,982	3,599,981	3,599,979	3599979
13 Unit Cost	($/BBLS)	23.6032	22.8676	22.0855	21.7104	21.8022	22.2195	22.219514
14 Amount	($)	74,350,234	72,033,057	71,777,693	73,814,883	78,487,462	79,989,782	79989782
15								
16 Light Oil								
17								
18								
19 Purchases:								
20 Units	(BBLS)	14,736	689	1,028	83,100	138,688	35,235	273476
21 Unit Cost	($/BBLS)	34.8127	33.3817	32.1012	31.0349	31.0986	30.9635	31.271483
22 Amount	($)	513,000	23,000	33,000	2,579,000	4,313,000	1,091,000	8552000
23								
24 Burned:								
25 Units	(BBLS)	22,718	689	1,028	83,729	139,124	35,235	282523
26 Unit Cost	($/BBLS)	34.8706	36.9898	36.7189	34.0700	32.3373	31.9120	33.028734
27 Amount	($)	792,191	25,486	37,747	2,852,645	4,498,890	1,124,418	9331377
28								
29 Ending Inventory:								
30 Units	(BBLS)	326,066	326,066	326,066	325,437	325,000	325,000	325000
31 Unit Cost	($/BBLS)	34.3930	34.3846	34.3687	33.5957	33.0665	32.9640	32.963994
32 Amount	($)	11,214,383	11,211,659	11,206,455	10,933,286	10,746,618	10,713,298	10713298
33								
34 Coal - SJRPP								
35								
36								
37 Purchases:								
38 Units	(Tons)	70,226	62,876	52,099	50,489	69,037	71,394	376121
39 Unit Cost	($/Tons)	38.4188	36.8662	38.3885	35.6909	36.6036	36.6417	37.118374
40 Amount	($)	2,698,000	2,318,000	2,000,000	1,802,000	2,527,000	2,616,000	13961000
41								
42 Burned:								
43 Units	(Tons)	70,226	62,876	52,099	50,489	69,037	66,872	371599
44 Unit Cost	($/Tons)	37.2301	37.1586	37.7551	36.5781	36.6319	36.6274	36.983447
45 Amount	($)	2,614,524	2,336,384	1,967,004	1,846,791	2,528,959	2,449,350	13743012
46								
47 Ending Inventory:								
48 Units	(Tons)	45,216	45,216	45,216	45,217	45,217	49,739	49739
49 Unit Cost	($/Tons)	37.3570	36.9572	37.6844	36.6838	36.6460	36.6711	36.671083
50 Amount	($)	1,689,132	1,671,059	1,703,938	1,658,730	1,657,020	1,823,983	1823983
51								
52 Coal - SCHERER								
53								
54								
55 Purchases:								
56 Units	(MBTU)	4,606,403	4,160,608	4,606,403	4,466,035	4,614,890	4,756,588	27210925
57 Unit Cost	($/MBTU)	1.7365	1.7608	1.7745	1.7794	1.7795	1.7794	1.7684809
58 Amount	($)	7,999,000	7,326,000	8,174,000	7,947,000	8,212,000	8,464,000	48122000
59								
60 Burned:								
61 Units	(MBTU)	4,606,403	4,160,608	4,606,403	4,466,035	4,614,890	4,466,035	26920373
62 Unit Cost	($/MBTU)	1.7275	1.7471	1.7639	1.7734	1.7771	1.7786	1.7613549
63 Amount	($)	7,957,695	7,268,847	8,125,214	7,919,892	8,201,319	7,943,363	47416330
64								
65 Ending Inventory:								
66 Units	(MBTU)	2,905,578	2,905,578	2,905,578	2,905,543	2,905,543	3,196,095	3196095
67 Unit Cost	($/MBTU)	1.7275	1.7470	1.7639	1.7734	1.7771	1.7786	1.7786192
68 Amount	($)	5,019,417	5,076,159	5,125,083	5,152,584	5,163,563	5,684,636	5684636
69								
70 Gas								
71								
72								
73 Burned:								
74 Units	(MCF)	12,244,431	9,872,160	10,782,436	15,563,708	16,896,918	22,705,876	88065529
75 Unit Cost	($/MCF)	5.2779	5.3520	5.2075	4.6512	4.5788	4.3940	4.8048064
76 Amount	($)	64,624,800	52,835,770	56,149,180	72,389,660	77,368,390	99,770,020	423137820
77								
78 Nuclear								
79								
80								
81 Burned:								
82 Units	(MBTU)	23,362,713	21,101,815	22,107,717	18,417,967	23,281,563	22,530,555	130802330
83 Unit Cost	($/MBTU)	0.2957	0.2952	0.2961	0.2923	0.2902	0.2888	0.2930293
84 Amount	($)	6,908,194	6,228,618	6,545,438	5,382,968	6,756,808	6,506,884	38328910

Company: Florida Power & Light

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : January 2002 thru December 2002

		July 2002	August 2002	September 2002	October 2002	November 2002	December 2002	Total
Heavy Oil								
1 Purchases:								
2 Units	(BBLS)	3,938,846	3,723,154	3,610,751	2,765,153	1,362,253	1,231,456	36,441,760
3 Unit Cost	($/BBLS)	23.3403	23.3651	24.2681	24.1155	22.0752	18.8176	22.5850
4 Amount	($)	91,934,000	86,992,000	87,626,000	66,683,000	30,072,000	23,173,000	823,036,000
5								
6 Burned:								
7 Units	(BBLS)	3,888,846	3,873,154	3,610,751	2,915,153	1,462,253	1,231,456	36,391,760
8 Unit Cost	($/BBLS)	22.9441	23.1958	23.8162	23.9214	23.1465	21.3629	22.7597
9 Amount	($)	89,226,172	89,840,854	85,994,329	69,734,653	33,845,993	26,307,433	828,264,600
10								
11 Ending Inventory:								
12 Units	(BBLS)	3,649,981	3,499,980	3,499,985	3,349,989	3,250,001	3,249,999	3,249,999
13 Unit Cost	($/BBLS)	22.6571	22.8143	23.2807	23.4124	22.9714	22.0073	22.0073
14 Amount	($)	82,698,126	79,849,430	81,481,930	78,431,174	74,657,130	71,523,638	71,523,638
15								
16 Light Oil								
17								
18								
19 Purchases:								
20 Units	(BBLS)	45,482	81,558	38,320	11,694	1	1	450,532
21 Unit Cost	($/BBLS)	31.5509	32.9949	35.4123	34.7187	0.0000	0.0000	32.0532
22 Amount	($)	1,435,000	2,691,000	1,357,000	406,000	0	0	14,441,000
23								
24 Burned:								
25 Units	(BBLS)	45,482	81,558	38,320	11,694	1	1	459,579
26 Unit Cost	($/BBLS)	32.7908	33.3224	33.5254	33.6536	32.0000	41.0000	33.1146
27 Amount	($)	1,491,393	2,717,712	1,284,695	393,545	32	41	15,218,795
28								
29 Ending Inventory:								
30 Units	(BBLS)	325,000	325,000	325,000	325,000	325,000	325,000	325,000
31 Unit Cost	($/BBLS)	32.7894	32.7079	32.9306	32.9675	32.9675	32.9675	32.9675
32 Amount	($)	10,656,552	10,630,077	10,702,455	10,714,453	10,714,453	10,714,450	10,714,450
33								
34 Coal - SJRPP								
35								
36								
37 Purchases:								
38 Units	(Tons)	68,789	69,112	66,852	64,717	67,860	69,727	783,178
39 Unit Cost	($/Tons)	36.2849	38.6329	38.0393	37.4554	37.9900	36.5282	37.3082
40 Amount	($)	2,496,000	2,670,000	2,543,000	2,424,000	2,578,000	2,547,000	29,219,000
41								
42 Burned:								
43 Units	(Tons)	68,789	69,112	66,852	69,239	67,860	69,727	783,178
44 Unit Cost	($/Tons)	36.4997	37.6649	37.8837	37.6035	37.8543	37.1336	37.2216
45 Amount	($)	2,510,777	2,603,094	2,532,599	2,603,627	2,568,793	2,589,217	29,151,119
46								
47 Ending Inventory:								
48 Units	(Tons)	49,739	49,739	49,739	45,217	45,216	45,216	45,216
49 Unit Cost	($/Tons)	36.3771	37.7129	37.9145	37.7328	37.9336	36.9985	36.9985
50 Amount	($)	1,809,363	1,875,802	1,885,829	1,706,165	1,715,204	1,672,922	1,672,922
51								
52 Coal - SCHERER								
53								
54								
55 Purchases:								
56 Units	(MBTU)	4,614,890	4,614,890	4,466,035	4,312,648	1,047,568	998,673	47,265,628
57 Unit Cost	($/MBTU)	1.7847	1.7847	1.7846	1.7894	1.7889	1.7623	1.7754
58 Amount	($)	8,236,000	8,236,000	7,970,000	7,717,000	1,874,000	1,760,000	83,915,000
59								
60 Burned:								
61 Units	(MBTU)	4,614,890	4,614,890	4,466,035	4,603,200	1,047,568	998,673	47,265,628
62 Unit Cost	($/MBTU)	1.7821	1.7836	1.7842	1.7871	1.7877	1.7813	1.7712
63 Amount	($)	8,224,393	8,231,046	7,968,134	8,226,368	1,872,705	1,778,894	83,717,870
64								
65 Ending Inventory:								
66 Units	(MBTU)	3,196,095	3,196,095	3,196,095	2,905,543	2,905,543	2,905,543	2,905,543
67 Unit Cost	($/MBTU)	1.7821	1.7836	1.7842	1.7871	1.7877	1.7813	1.7813
68 Amount	($)	5,695,896	5,700,504	5,702,364	5,192,501	5,194,176	5,175,531	5,175,531
69								
70 Gas								
71								
72								
73 Burned:								
74 Units	(MCF)	28,122,502	28,442,168	26,657,545	22,694,868	19,699,988	21,888,626	235,571,227
75 Unit Cost	($/MCF)	4.2637	4.3679	4.3294	4.5000	4.6310	4.7698	4.5865
76 Amount	($)	119,907,040	124,232,460	115,410,110	102,126,790	91,230,080	104,403,640	1,080,447,940
77								
78 Nuclear								
79								
80								
81 Burned:								
82 Units	(MBTU)	23,281,563	23,281,563	22,318,024	17,118,060	22,609,080	23,362,713	262,773,333
83 Unit Cost	($/MBTU)	0.2847	0.2847	0.2849	0.2871	0.2894	0.2905	0.2899
84 Amount	($)	6,628,649	6,628,317	6,357,370	4,914,050	6,543,307	6,787,757	76,188,360

Company: Florida Power & Light

Schedule: E6
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POWER SOLD

Estimated For the Period of : January 2002 Through December 2002

	(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWh Sold	(5) MWh Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWh	(7B) Total Cost Cents / KWh	(8) Total $ For Fuel Adjustmen (6) * (7A)	(9) Total Cost $ (6) * (7B)	(10) $ Gain From Off System Sales
1	January		OS	225,000		225,000	3.904	5.258	8,784,000	11,831,250	2,128,787
2	2002	St. Lucie Reliability		46,083		46,083	0.315	0.315	145,020	145,020	0
3											
4	Total			271,083	0	271,083	3.294	4.418	8,929,020	11,976,270	2,128,787
5											
6	February		OS	150,000		150,000	3.651	4.888	5,476,500	7,331,250	1,209,425
7	2002	St. Lucie Reliability		41,624		41,624	0.315	0.315	130,990	130,990	0
8											
9	Total			191,624	0	191,624	2.926	3.894	5,607,490	7,462,240	1,209,425
10											
11	March		OS	125,000		125,000	3.552	4.605	4,440,000	5,756,250	757,677
12	2002	St. Lucie Reliability		46,083		46,083	0.315	0.315	145,070	145,070	0
13											
14	Total			171,083	0	171,083	2.680	3.449	4,585,070	5,901,320	757,677
15											
16	April		OS	115,000		115,000	4.344	4.914	4,995,600	5,651,250	129,202
17	2002	St. Lucie Reliability		43,864		43,864	0.309	0.309	135,580	135,580	0
18											
19	Total			158,864	0	158,864	3.230	3.643	5,131,180	5,786,830	129,202
20											
21	May		OS	150,000		150,000	4.293	5.000	6,439,500	7,500,000	546,425
22	2002	St. Lucie Reliability		45,326		45,326	0.309	0.309	140,050	140,050	0
23											
24	Total			195,326	0	195,326	3.368	3.911	6,579,550	7,640,050	546,425
25											
26	June		OS	175,000		175,000	4.130	6.000	7,227,500	10,500,000	2,645,912
27	2002	St. Lucie Reliability		43,864		43,864	0.309	0.309	135,620	135,620	0
28											
29	Total			218,864	0	218,864	3.364	4.859	7,363,120	10,635,620	2,645,912
30											

Company: Florida Power & Light

Schedule: E6
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POWER SOLD

Estimated For the Period of : January 2002 Through December 2002

	(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWh Sold	(5) MWh Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWh	(7B) Total Cost Cents / KWh	(8) Total $ For Fuel Adjustmen (6) * (7A)	(9) Total Cost $ (6) * (7B)	(10) $ Gain From Off System Sales
1	July		OS	200,000		200,000	4.064	6.450	8,128,000	12,900,000	4,049,000
2	2002	St. Lucie Reliability		45,326		45,326	0.305	0.305	138,030	138,030	0
3											
4	Total			245,326	0	245,326	3.369	5.315	8,266,030	13,038,030	4,049,000
5											
6	August		OS	200,000		200,000	4.217	6.450	8,434,000	12,900,000	3,743,000
7	2002	St. Lucie Reliability		45,326		45,326	0.305	0.305	138,130	138,130	0
8											
9	Total			245,326	0	245,326	3.494	5.315	8,572,130	13,038,130	3,743,000
10											
11	September		OS	150,000		150,000	4.311	5.500	6,466,500	8,250,000	1,237,225
12	2002	St. Lucie Reliability		42,402		42,402	0.305	0.305	129,220	129,220	0
13											
14	Total			192,402	0	192,402	3.428	4.355	6,595,720	8,379,220	1,237,225
15											
16	October		OS	100,000		100,000	4.008	4.500	4,008,000	4,500,000	144,990
17	2002	St. Lucie Reliability		2,924		2,924	0.305	0.305	8,910	8,910	0
18											
19	Total			102,924	0	102,924	3.903	4.381	4,016,910	4,508,910	144,990
20											
21	November		OS	100,000		100,000	3.420	4.000	3,420,000	4,000,000	239,430
22	2002	St. Lucie Reliability		44,597		44,597	0.307	0.307	136,960	136,960	0
23											
24	Total			144,597	0	144,597	2.460	2.861	3,556,960	4,136,960	239,430
25											
26	December		OS	125,000		125,000	2.942	4.100	3,677,500	5,125,000	1,007,297
27	2002	St. Lucie Reliability		46,083		46,083	0.307	0.307	141,620	141,620	0
28											
29	Total			171,083	0	171,083	2.232	3.078	3,819,120	5,266,620	1,007,297
30											
31	Period		OS	1,815,000		1,815,000	3.939	5.303	71,497,100	96,245,000	17,838,370
32	Total	St. Lucie Reliability		493,502		493,502	0.309	0.309	1,525,200	1,525,200	0
33											
34	Total			2,308,502	0	2,308,502	3.163	4.235	73,022,300	97,770,200	17,838,370
35											

Company: Florida Power & Light

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Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : January 2002 thru December 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2002 January	Sou. Co. (UPS + R)		690,431			690,431	1.621		11,191,930
	St. Lucie Rel.		46,083			46,083	0.319		147,100
	SJRPP		269,250			269,250	1.503		4,047,050
Total			1,005,764			1,005,764	1.530		15,386,080
2002 February	Sou. Co. (UPS + R)		623,616			623,616	1.621		10,108,850
	St. Lucie Rel.		41,624			41,624	0.319		132,900
	SJRPP		243,195			243,195	1.430		3,477,500
Total			908,435			908,435	1.510		13,719,250
2002 March	Sou. Co. (UPS + R)		690,431			690,431	1.621		11,191,930
	St. Lucie Rel.		46,083			46,083	0.320		147,300
	SJRPP		199,758			199,758	1.502		2,999,840
Total			936,272			936,272	1.532		14,339,070
2002 April	Sou. Co. (UPS + R)		668,159			668,159	1.621		10,830,900
	St. Lucie Rel.		43,864			43,864	0.314		137,600
	SJRPP		190,907			190,907	1.416		2,702,380
Total			902,930			902,930	1.514		13,670,880
2002 May	Sou. Co. (UPS + R)		690,431			690,431	1.621		11,191,930
	St. Lucie Rel.		45,326			45,326	0.314		142,200
	SJRPP		263,038			263,038	1.441		3,790,900
Total			998,795			998,795	1.514		15,125,030
2002 June	Sou. Co. (UPS + R)		668,159			668,159	1.621		10,830,900
	St. Lucie Rel.		43,864			43,864	0.314		137,800
	SJRPP		254,553			254,553	1.444		3,675,920
Total			966,576			966,576	1.515		14,644,620
Period Total	Sou. Co. (UPS + R)		4,031,227			4,031,227	1.621		65,346,440
	St. Lucie Rel.		266,844			266,844	0.317		844,900
	SJRPP		1,420,701			1,420,701	1.457		20,693,590
Total			5,718,772			5,718,772	1.519		86,884,930

Company: Florida Power & Light

Schedule: E7
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Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : January 2002 thru December 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2002	Sou. Co. (UPS + R)		690,431			690,431	1.621		11,191,930
July	St. Lucie Rel.		45,326			45,326	0.309		140,200
	SJRPP		263,038			263,038	1.423		3,744,260
Total			998,795			998,795	1.509		15,076,390
2002	Sou. Co. (UPS + R)		690,431			690,431	1.621		11,191,930
August	St. Lucie Rel.		45,326			45,326	0.310		140,300
	SJRPP		263,038			263,038	1.522		4,004,320
Total			998,795			998,795	1.536		15,336,550
2002	Sou. Co. (UPS + R)		668,159			668,159	1.621		10,830,900
September	St. Lucie Rel.		43,864			43,864	0.310		135,900
	SJRPP		254,553			254,553	1.498		3,813,960
Total			966,576			966,576	1.529		14,780,760
2002	Sou. Co. (UPS + R)		688,781			688,781	1.621		11,165,190
October	St. Lucie Rel.		45,326			45,326	0.305		138,300
	SJRPP		263,038			263,038	1.479		3,890,020
Total			997,145			997,145	1.524		15,193,510
2002	Sou. Co. (UPS + R)		631,193			631,193	1.621		10,231,670
November	St. Lucie Rel.		44,597			44,597	0.307		136,700
	SJRPP		260,565			260,565	1.484		3,866,800
Total			936,355			936,355	1.520		14,235,170
2002	Sou. Co. (UPS + R)		644,504			644,504	1.621		10,447,450
December	St. Lucie Rel.		46,083			46,083	0.307		141,300
	SJRPP		269,250			269,250	1.419		3,820,450
Total			959,837			959,837	1.501		14,409,200
	Sou. Co. (UPS + R)		8,044,726			8,044,726	1.621		130,405,510
Period	St. Lucie Rel.		537,366			537,366	0.312		1,677,600
Total	SJRPP		2,994,183			2,994,183	1.464		43,833,400
Total			11,576,275			11,576,275	1.520		175,916,510

Company: Florida Power & Light

Schedule: E8
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Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2002 thru December 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2002 January	Qual. Facilities		588,426			588,426	2.177	2.177	12,810,300
Total			588,426			588,426	2.177	2.177	12,810,300
2002 February	Qual. Facilities		547,248			547,248	2.177	2.177	11,912,760
Total			547,248			547,248	2.177	2.177	11,912,760
2002 March	Qual. Facilities		596,337			596,337	2.165	2.165	12,909,160
Total			596,337			596,337	2.165	2.165	12,909,160
2002 April	Qual. Facilities		520,091			520,091	2.249	2.249	11,696,060
Total			520,091			520,091	2.249	2.249	11,696,060
2002 May	Qual. Facilities		615,521			615,521	2.192	2.192	13,494,290
Total			615,521			615,521	2.192	2.192	13,494,290
2002 June	Qual. Facilities		599,867			599,867	2.185	2.185	13,105,070
Total			599,867			599,867	2.185	2.185	13,105,070
Period Total	Qual. Facilities		3,467,490			3,467,490	2.190	2.190	75,927,640
Total			3,467,490			3,467,490	2.190	2.190	75,927,640

Company: Florida Power & Light

Schedule: E8
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Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2002 thru December 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2002 July	Qual. Facilities		614,333			614,333	2.185	2.185	13,425,790
Total			614,333			614,333	2.185	2.185	13,425,790
2002 August	Qual. Facilities		608,111			608,111	2.193	2.193	13,336,590
Total			608,111			608,111	2.193	2.193	13,336,590
2002 September	Qual. Facilities		594,532			594,532	2.194	2.194	13,044,160
Total			594,532			594,532	2.194	2.194	13,044,160
2002 October	Qual. Facilities		594,340			594,340	2.183	2.183	12,975,790
Total			594,340			594,340	2.183	2.183	12,975,790
2002 November	Qual. Facilities		415,491			415,491	2.246	2.246	9,330,950
Total			415,491			415,491	2.246	2.246	9,330,950
2002 December	Qual. Facilities		499,740			499,740	2.142	2.142	10,704,600
Total			499,740			499,740	2.142	2.142	10,704,600
Period Total	Qual. Facilities		6,794,037			6,794,037	2.189	2.189	148,745,520
Total			6,794,037			6,794,037	2.189	2.189	148,745,520

Company: Florida Power & Light

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Economy Energy Purchases

Estimated For the Period of : January 2002 Through December 2002

	(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWh Purchased	(5) Transaction Cost (Cents/KWh)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWh)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
1	January	Florida	OS	127,200	3.042	3,869,415	3.904	4,965,877	1,096,462
2	2002	Non-Florida	OS	49,848	3.700	1,844,380	3.904	1,946,066	101,686
3									
4	Total			177,048	3.227	5,713,795	3.904	6,911,943	1,198,148
5									
6									
7	February	Florida	OS	133,600	3.111	4,156,289	3.651	4,877,728	721,439
8	2002	Non-Florida	OS	49,728	3.600	1,790,210	3.651	1,815,569	25,359
9									
10	Total			183,328	3.244	5,946,499	3.651	6,693,297	746,798
11									
12									
13	March	Florida	OS	112,200	2.797	3,138,226	3.552	3,985,334	847,108
14	2002	Non-Florida	OS	99,696	3.400	3,389,660	3.552	3,541,202	151,542
15									
16	Total			211,896	3.081	6,527,886	3.552	7,526,536	998,650
17									
18									
19	April	Florida	OS	95,760	2.743	2,626,690	4.344	4,159,803	1,533,113
20	2002	Non-Florida	OS	139,680	3.750	5,238,000	4.344	6,067,699	829,699
21									
22	Total			235,440	3.340	7,864,690	4.344	10,227,502	2,362,813
23									
24									
25	May	Florida	OS	112,200	3.148	3,532,047	4.293	4,816,734	1,284,687
26	2002	Non-Florida	OS	99,696	3.825	3,813,370	4.293	4,279,949	466,579
27									
28	Total			211,896	3.467	7,345,417	4.293	9,096,683	1,751,266
29									
30									
31	June	Florida	OS	85,680	3.138	2,688,630	4.130	3,538,573	849,943
32	2002	Non-Florida	OS	100,000	3.900	3,900,000	4.130	4,130,000	230,000
33									
34	Total			185,680	3.548	6,588,630	4.130	7,668,573	1,079,943
35									

Company: Florida Power & Light

Schedule: E9
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Economy Energy Purchases

Estimated For the Period of : January 2002 Through December 2002

	(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWH Purchased	(5) Transaction Cost (Cents/KWH)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWH)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
1	July	Florida	OS	92,200	3.137	2,892,305	4.064	3,746,997	854,691
2	2002	Non-Florida	OS	69,936	3.950	2,762,470	4.064	2,842,199	79,729
3									
4	Total			162,136	3.488	5,654,775	4.064	6,589,196	934,420
5									
6									
7	August	Florida	OS	77,200	3.083	2,380,067	4.217	3,255,512	875,445
8	2002	Non-Florida	OS	84,816	4.000	3,392,640	4.217	3,576,691	184,051
9									
10	Total			162,016	3.563	5,772,707	4.217	6,832,203	1,059,496
11									
12									
13	September	Florida	OS	85,680	2.905	2,488,996	4.311	3,693,654	1,204,657
14	2002	Non-Florida	OS	149,760	4.000	5,990,400	4.311	6,456,154	465,754
15									
16	Total			235,440	3.602	8,479,396	4.311	10,149,807	1,670,411
17									
18									
19	October	Florida	OS	87,048	2.833	2,466,062	4.008	3,488,873	1,022,811
20	2002	Non-Florida	OS	124,992	3.500	4,374,720	4.008	5,009,679	634,959
21									
22	Total			212,040	3.226	6,840,782	4.008	8,498,552	1,657,770
23									
24									
25	November	Florida	OS	136,000	2.860	3,889,010	3.420	4,651,191	762,181
26	2002	Non-Florida	OS	49,680	3.100	1,540,080	3.420	1,699,056	158,976
27									
28	Total			185,680	2.924	5,429,090	3.420	6,350,247	921,157
29									
30									
31	December	Florida	OS	156,916	2.634	4,132,840	2.942	4,616,460	483,620
32	2002	Non-Florida	OS	29,760	2.850	848,160	2.942	875,539	27,379
33									
34	Total			186,676	2.668	4,981,000	2.942	5,492,000	511,000
35									
36									
37	Period	Florida	OS	1,301,681	2.939	38,260,579	3.826	49,796,736	11,536,157
38	Total	Non-Florida	OS	1,047,592	3.712	38,884,090	4.032	42,239,804	3,355,714
39									
40	Total			2,349,273	3.284	77,144,669	3.918	92,036,539	14,891,871
41									

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	OCT 01 - DEC 01	JAN 02 - DEC 02	DIFFERENCE $	DIFFERENCE %
BASE	$43.26	$43.26	$0.00	0.00%
FUEL	$30.41	$28.96	-$1.45	-4.77%
CONSERVATION	$1.81	$1.81	$0.00	0.00%
CAPACITY PAYMENT	$5.27	$6.80	$1.53	29.03%
ENVIRONMENTAL	$0.08	$0.00	-$0.08	-100.00%
SUBTOTAL	$80.83	$80.83	0.00	0.00%
GROSS RECEIPTS TAX	$0.83	$0.83	$0.00	0.00%
TOTAL	**$81.66**	**$81.66**	**$0.00**	**0.00%**

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

		PERIOD				DIFFERENCE (%) FROM PRIOR PERIOD		
		ACTUAL	ACTUAL	ESTIMATED/ACTUAL	PROJECTED			
		JAN - DEC	JAN - DEC	JAN - DEC	JAN - DEC	(COLUMN 2)	(COLUMN 3)	(COLUMN 4)
		1999 - 1999	2000 - 2000	2001 - 2001	2002 - 2002			
		(COLUMN 1)	(COLUMN 2)	(COLUMN 3)	(COLUMN 4)	(COLUMN 1)	(COLUMN 2)	(COLUMN 3)
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL	541,742,247	910,227,585	1,026,235,942	828,267,350	68.0	12.7	(19.3)
2	LIGHT OIL	8,627,808	36,040,961	17,279,154	15,272,710	317.7	(52.1)	(11.6)
3	COAL	98,548,734	115,539,152	110,132,995	112,869,190	17.2	(4.7)	2.5
4	GAS	609,432,220	868,918,201	1,095,520,822	1,083,894,070	42.6	26.1	(1.1)
5	NUCLEAR	83,604,614	79,212,105	73,071,636	76,188,380	(5.3)	(7.8)	4.3
6	OTHER (ORIMULSION)	0	0	0	0	0.0	0.0	0.0
7	TOTAL ($)	1,341,955,624	2,009,938,004	2,322,240,249	2,116,491,700	49.8	15.5	(8.9)
	SYSTEM NET GENERATION							
8	HEAVY OIL	22,892,680	22,644,991	25,954,163	22,982,473	(1.1)	14.6	(11.5)
9	LIGHT OIL	177,313	455,227	208,679	214,076	156.7	(54.2)	2.6
10	COAL	6,145,706	7,086,367	6,497,671	6,543,190	15.3	(8.3)	0.7
11	GAS	23,097,966	24,103,109	23,994,841	30,443,928	4.4	(0.5)	26.9
12	NUCLEAR	24,614,479	24,316,923	23,997,759	24,283,716	(1.2)	(1.3)	1.2
13	OTHER	0	0	0	0	0.0	0.0	0.0
14	TOTAL (MWH)	76,928,144	78,606,617	80,653,113	84,467,385	2.2	2.6	4.7
	UNITS OF FUEL BURNED							
15	HEAVY OIL (Bbl)	36,475,060	35,766,850	41,111,366	36,391,878	(1.9)	14.9	(11.5)
16	LIGHT OIL (Bbl)	467,176	1,083,983	462,311	461,181	122.5	(57.4)	(0.2)
17	COAL (TON)	708,742	690,985	779,214	3,484,074	(2.5)	12.8	347.1
18	GAS (MCF)	193,723,441	201,564,340	209,117,384	235,570,629	4.1	3.8	12.7
19	NUCLEAR (MMBTU)	267,914,380	257,902,609	260,921,540	262,773,320	(3.7)	1.2	0.7
20	OTHER (TONS)	0	0	0	0	0.0	0.0	0.0
	BTU'S BURNED (MMBTU)							
21	HEAVY OIL	231,976,594	228,572,995	262,192,748	232,908,021	(1.5)	14.7	(11.2)
22	LIGHT OIL	2,832,412	6,310,701	2,677,548	2,677,715	122.8	(57.6)	0.0
23	COAL	59,283,652	70,095,286	64,954,934	66,690,146	18.2	(7.3)	2.7
24	GAS	201,980,118	207,356,808	214,250,654	235,570,629	2.7	3.3	10.0
25	NUCLEAR	267,914,384	257,902,607	260,921,539	262,773,320	(3.7)	1.2	0.7
26	OTHER	0	0	0	0	0.0	0.0	0.0
27	TOTAL (MMBTU)	763,987,160	770,238,396	804,997,423	800,619,831	0.8	4.5	(0.5)
	GENERATION MIX (%MWH)							
28	HEAVY OIL	29.76	28.81	32.18	27.21	-	-	-
29	LIGHT OIL	0.23	0.58	0.26	0.25	-	-	-
30	COAL	7.99	9.01	8.06	7.75			
31	GAS	30.03	30.66	29.75	36.04	-	-	-
32	NUCLEAR	32.00	30.93	29.75	28.75	-	-	-
33	OTHER	0.00	0.00	0.00	0.00	-	-	-
34	TOTAL (%)	100.00	100.00	100.00	100.00	-	-	-
	FUEL COST PER UNIT							
35	HEAVY OIL ($/Bbl)	14.8524	25.4489	24.9623	22.7597	71.4	(1.9)	(8.8)
36	LIGHT OIL ($/Bbl)	17.7098	33.2486	37.3756	33.1165	87.7	12.4	(11.4)
37	COAL ($/TON)	37.3610	40.1472	36.3263	32.3957	7.5	(9.5)	(10.8)
38	GAS ($/MCF)	3.1459	4.3109	5.2388	4.6011	37.0	21.5	(12.2)
39	NUCLEAR ($/MMBTU)	0.3121	0.3071	0.2801	0.2899	(1.6)	(8.8)	3.5
40	OTHER ($/TON)	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
	FUEL COST PER MMBTU ($/MMBTU)							
41	HEAVY OIL	2.3353	3.9822	3.9141	3.5562	70.5	(1.7)	(9.1)
42	LIGHT OIL	3.0461	5.7111	6.4533	5.7036	87.5	13.0	(11.6)
43	COAL	1.6623	1.6483	1.6955	1.6924	(0.8)	2.9	(0.2)
44	GAS	3.0173	4.1904	5.1133	4.6011	38.9	22.0	(10.0)
45	NUCLEAR	0.3121	0.3071	0.2801	0.2899	(1.6)	(8.8)	3.5
46	OTHER	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
47	TOTAL ($/MMBTU)	1.7565	2.6095	2.8848	2.6436	48.6	10.6	(8.4)
	BTU BURNED PER KWH (BTU/KWH)							
48	HEAVY OIL	10,133	10,094	10,102	10,134	(0.4)	0.1	0.3
49	LIGHT OIL	15,974	13,863	12,831	12,508	(13.2)	(7.4)	(2.5)
50	COAL	9,646	9,892	9,997	10,192	2.6	1.1	2.0
51	GAS	8,744	8,603	8,929	7,738	(1.6)	3.8	(13.3)
52	NUCLEAR	10,884	10,606	10,873	10,821	(2.6)	2.5	(0.5)
53	OTHER	0	0	0	0	0.0	0.0	0.0
54	TOTAL (BTU/KWH)	9,931	9,799	9,981	9,478	(1.3)	1.9	(5.0)
	GENERATED FUEL COST PER KWH (c/KWH)							
55	HEAVY OIL	2.3664	4.0196	3.9540	3.6039	69.9	(1.6)	(8.9)
56	LIGHT OIL	4.8659	7.9171	8.2803	7.1342	62.7	4.6	(13.8)
57	COAL	1.6035	1.6304	1.6950	1.7250	1.7	4.0	1.8
58	GAS	2.6385	3.6050	4.5667	3.5603	36.6	26.7	(22.0)
59	NUCLEAR	0.3397	0.3257	0.3045	0.3137	(4.1)	(6.5)	3.0
60	OTHER	0.0000	0.0000	0.0000	2.5057	0.0	0.0	0.0
61	TOTAL (c/KWH)	1.7444	2.5570	2.8793	2.5057	46.6	12.6	(13.0)

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

(Continued from Sheet No. 10.100)

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

For informational purposes only, the estimated incremental As-Available Energy costs for the next five periods are as follows. In addition, As-Available Energy cost payments will include .0014¢/kWh for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
January 1, 2002 - March 31, 2002	3.74	3.41	3.51
April 1, 2002 - September 30, 2002	4.58	3.55	3.86
October 1, 2002 - March 31, 2003	3.25	2.94	3.04
April 1, 2003 - September 30, 2003	3.99	3.22	3.45
October 1, 2003 - December 31, 2003	3.72	3.24	3.39

A MW block size ranging from 37 MW to 42 MW has been used to calculate the estimated As-Available Energy cost.

DELIVERY VOLTAGE ADJUSTMENT

The Company's actual hourly As-Available Energy costs shall be adjusted according to the delivery voltage by the following multipliers:

Delivery Voltage	Adjustment Factor
Transmission Voltage Delivery	1.0000
Primary Voltage Delivery	1.0306
Secondary Voltage Delivery	1.0679

For informational purposes the Company's projected annual generation mix and fuel prices are as follows:

PROJECTED ANNUAL GENERATION MIX AND FUEL PRICES

	Generation by Fuel Type (%)					Price by Fuel Type ($/MMBTU)			
Year	Nuclear	Oil	Gas	Coal	Purchased Power	Nuclear	Oil	Gas	Coal
2002	24	23	30	7	16	.30	3.58	4.60	1.69
2003	23	17	39	7	14	.31	3.48	4.48	1.81
2004	22	20	38	6	14	.31	3.46	4.54	1.62
2005	22	16	43	6	14	.33	3.29	4.55	1.63
2006	20	12	48	6	13	.33	3.38	4.48	1.65
2007	20	10	51	6	13	.34	3.52	4.51	1.67
2008	20	11	50	6	13	.34	3.62	4.62	1.68
2009	19	10	52	6	13	.34	3.68	4.71	1.69
2010	19	7	56	6	12	.34	3.70	4.81	1.72
2011	19	5	58	6	12	.34	3.88	4.91	1.75

NOTE: The Company's forecasts are for illustrative purposes, and are subject to frequent revision. Amounts may not add to 100% due to rounding.

(Continued on Sheet No. 10.102)

(Continued from Sheet No. 10.102)

Customer Rate Schedule	Charge($)	Customer Rate Schedule	Charge($)
GS-1	9.00	CST-1	110.00
GST-1	12.30	GSLD-2	170.00
GSD-1	35.00	GSLDT-2	170.00
GSDT-1	41.50	CS-2	170.00
RS-1	5.65	CST-2	170.00
RST-1	8.95	GSLD-3	400.00
GSLD-1	41.00	CS-3	400.00
GSLDT-1	41.00	CST-3	400.00
CS-1	110.00	GSLDT-3	400.00

B. **Interconnection Charge for Non-Variable Utility Expenses:**

The Qualifying Facility shall bear the cost required for interconnection, including the metering. The Qualifying Facility shall have the option of (i) payment in full for the interconnection costs upon completion of the interconnection facilities (including the time value of money during the construction) and providing a surety bond, letter of credit or comparable assurance of payment acceptable to the Company adequate to cover the interconnection costs, (ii) payment of monthly invoices from the Company for actual costs progressively incurred by the Company in installing the interconnection facilities, or (iii) upon a showing of credit worthiness, making equal monthly installment payments over a period no longer than thirty-six (36) months toward the full cost of interconnection. In the latter case, the Company shall assess interest at the rate then prevailing for the thirty (30) days highest grade commercial paper rate, such rate to be specified by the Company thirty (30) days prior to the date of each installment payment by the Qualifying Facility.

C. **Interconnection Charge for Variable Utility Expenses:**

The Qualifying Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection facilities. These include (a) the Company's inspections of the interconnection facilities and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility if no sales to the Company were involved.

In lieu of payments for actual charges, the Qualifying Facility may pay a monthly charge equal to a percentage of the installed cost of the interconnection facilities necessary for the sale of energy to the Company. The applicable percentages are as follows:

Equipment Type	Charge
Metering Equipment	0.230%
Distribution Equipment	0.304%
Transmission Equipment	0.119%

D. **Taxes and Assessments**

The Qualifying Facility shall be billed monthly an amount equal to any taxes, assessments or other impositions, for which the Company is liable as a result of its purchases of As-Available Energy produced by the Qualifying Facility. In the event the Company receives a tax benefit as a result of its purchases of As-Available Energy produced by the Qualifying Facility, the Qualifying Facility shall be entitled to a refund in an amount equal to such benefit.

TERMS OF SERVICE

(1) It shall be the Qualifying Facility's responsibility to inform the Company of any change in the Qualifying Facility's electric generation capability.

(Continue on Sheet No. 10.104)

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AD KMD-1,2,3,4

APPENDIX III

CAPACITY COST RECOVERY

KMD-6
DOCKET NO. 010001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT_____
PAGES 1-7
AUGUST 31, 2001

APPENDIX III
CAPACITY COST RECOVERY

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6-7	Calculation of Estimated/Actual True-Up Amount	K. M. Dubin

FLORIDA POWER & LIGHT COMPANY
PROJECTED CAPACITY PAYMENTS
JANUARY 2002 THROUGH DECEMBER 2002

	PROJECTED												
	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1. CAPACITY PAYMENTS TO NON-COGENERATORS	$16,857,268	$17,472,867	$16,227,803	$18,595,017	$20,018,375	$31,705,723	$31,729,147	$31,714,369	$25,648,299	$19,525,408	$19,746,575	$22,376,447	$273,617,298
2. CAPACITY PAYMENTS TO COGENERATORS	$28,415,860	$28,415,860	$28,415,860	$28,080,250	$28,080,250	$28,080,250	$28,080,250	$28,080,250	$28,080,250	$28,080,250	$28,080,250	$28,080,250	$337,969,830
3. CAPACITY PAYMENTS FOR MISSION SETTLEMENT	$0	$121,674	$0	$1,530,589	$0	$0	$0	$0	$0	$1,530,589	$170,349	$0	$3,353,202
4. CAPACITY PAYMENTS FOR OKEELANTA/OSCEOLA SETTLEMENT	$3,481,566	$3,472,289	$3,463,012	$3,453,735	$3,444,458	$3,435,181	$3,425,904	$3,416,627	$3,407,350	$3,398,073	$3,388,796	$3,379,519	$41,166,505
5. TRANSMISSION REVENUES FROM CAPACITY SALES	$918,463	$645,325	$558,573	$526,448	$514,075	$626,568	$723,000	$723,000	$546,275	$347,010	$340,570	$440,203	$6,909,530
6. SJRPP SUSPENSION ACCRUAL	$301,945	$301,945	$301,945	$301,945	$301,945	$301,945	$301,945	$301,945	$301,945	$301,945	$301,945	$301,945	$3,623,340
7. RETURN REQUIREMENT ON SUSPENSION PAYMENT	$192,580	$195,552	$198,525	$201,497	$204,470	$207,443	$210,415	$213,388	$216,361	$219,333	$222,306	$225,278	$2,507,148
8. SYSTEM TOTAL (Lines 1+2+3+4-5+6-7)	$44,464,030	$45,471,469	$46,188,510	$47,779,856	$47,682,025	$59,253,887	$59,177,927	$59,160,176	$53,267,858	$48,871,849	$47,736,243	$50,093,161	$650,313,497
9. JURISDICTIONAL % *													99.03598%
10. JURISDICTIONALIZED CAPACITY PAYMENTS													$644,044,345
11. SJRPP CAPACITY PAYMENTS INCLUDED IN THE 1988 TAX SAVINGS REFUND DOCKET													($56,945,592)
12. FINAL TRUE-UP -- overrecovery/(underrecovery) JANUARY 2000 - DECEMBER 2000 ($2,850,420)			EST \ ACT TRUE-UP -- overrecovery/(underrecovery) JANUARY 2001 - DECEMBER 2001 $25,003,277										$22,152,857
13. TOTAL (Lines 10+11+12)													$564,945,896
14. REVENUE TAX MULTIPLIER													1.01597
15. TOTAL RECOVERABLE CAPACITY PAYMENTS													$573,968,082

*CALCULATION OF JURISDICTIONAL %

	AVG. 12 CP AT GEN.(MW)	%
FPSC	15,948	99.03598%
FERC	155	0.96402%
TOTAL	16,103	100.00000%

* BASED ON 2000 ACTUAL DATA

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2002 THROUGH DECEMBER 2002

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	60.938%	49,852,758,388	9,338,925	1.096656115	1.075433109	53,613,306,945	10,241,589	52.70839%	59.62713%
GS1	71.059%	5,875,092,080	943,825	1.096656115	1.075433109	6,318,268,541	1,035,051	6.21162%	6.02613%
GSD1	78.573%	21,701,895,013	3,152,973	1.096544563	1.075351927	23,337,174,622	3,457,375	22.94327%	20.12904%
OS2	149.531%	21,518,662	1,643	1.080484913	1.063082399	22,876,111	1,775	0.02249%	0.01033%
GSLD1/CS1	81.969%	9,726,195,726	1,354,532	1.094747540	1.074025051	10,446,177,861	1,482,871	10.26986%	8.63336%
GSLD2/CS2	90.955%	1,518,584,200	190,594	1.087891242	1.068548693	1,622,681,162	207,346	1.59529%	1.20718%
GSLD3/CS3	84.688%	513,062,638	69,158	1.026933481	1.022023682	524,362,166	71,021	0.51551%	0.41349%
ISST1D	0.000%	0	0	1.096656115	1.075433109	0	0	0.00000%	0.00000%
SST1T	95.114%	90,903,238	10,910	1.026933481	1.022023682	92,905,262	11,204	0.09134%	0.06523%
SST1D	81.410%	66,451,536	9,318	1.058919085	1.046606781	69,548,628	9,867	0.06837%	0.05745%
CILC D/CILC G	93.492%	3,432,793,959	419,150	1.084866212	1.066720945	3,661,833,216	454,722	3.60003%	2.64742%
CILC T	93.120%	1,223,946,682	150,043	1.026933481	1.022023682	1,250,902,495	154,084	1.22979%	0.89709%
MET	66.484%	87,750,948	15,067	1.058368342	1.046190930	91,804,246	15,946	0.09025%	0.09284%
OL1/SL1/PL1	297.393%	531,720,880	20,410	1.096656115	1.075433109	571,830,239	22,383	0.56218%	0.13032%
SL2	100.229%	86,637,051	9,867	1.096656115	1.075433109	93,172,353	10,821	0.09160%	0.06300%
TOTAL		94,729,311,000	15,686,415			101,716,843,847	17,176,055	100.00%	100.00%

(1) AVG 12 CP load factor based on actual calendar data.
(2) Projected kwh sales for the period January 2002 through December 2002.
(3) Calculated: Col(2)/(8760 hours * Col(1))
(4) Based on 2000 demand losses.
(5) Based on 2000 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
JANUARY 2002 THROUGH DECEMBER 2002

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	52.70839%	59.62713%	$23,271,486	$315,914,498	$339,185,984	49,852,758,388	-	-	-	0.00680
GS1	6.21162%	6.02613%	$2,742,519	$31,927,430	$34,669,949	5,875,092,080	-	-	-	0.00590
GSD1	22.94327%	20.12904%	$10,129,775	$106,647,014	$116,776,789	21,701,895,013	48.23371%	51,319,996	2.28	-
OS2	0.02249%	0.01033%	$9,930	$54,752	$64,682	21,518,662	-	-	-	0.00301
GSLD1/CS1	10.26986%	8.63336%	$4,534,286	$45,740,993	$50,275,279	9,726,195,726	61.70922%	21,590,867	2.33	-
GSLD2/CS2	1.59529%	1.20718%	$704,344	$6,395,844	$7,100,188	1,518,584,200	67.56448%	3,078,914	2.31	-
GSLD3/CS3	0.51551%	0.41349%	$227,606	$2,190,731	$2,418,337	513,062,638	70.23956%	1,000,612	2.42	-
ISST1D	0.00000%	0.00000%	$0	$0	$0	0	0.00000%	0	**	-
SST1T	0.09134%	0.06523%	$40,327	$345,601	$385,928	90,903,238	10.45089%	1,191,525	**	-
SST1D	0.06837%	0.05745%	$30,188	$304,360	$334,548	66,451,536	62.93622%	144,638	**	-
CILC D/CILC G	3.60003%	2.64742%	$1,589,462	$14,026,463	$15,615,925	3,432,793,959	73.24678%	6,420,019	2.43	-
CILC T	1.22979%	0.89709%	$542,969	$4,752,912	$5,295,881	1,223,946,682	77.61662%	2,160,155	2.45	-
MET	0.09025%	0.09284%	$39,849	$491,874	$531,723	87,750,948	55.94088%	214,882	2.47	-
OL1/SL1/PL1	0.56218%	0.13032%	$248,210	$690,431	$938,641	531,720,880	-	-	-	0.00177
SL2	0.09160%	0.06300%	$40,443	$333,787	$374,230	86,637,051	-	-	-	0.00432
TOTAL			$44,151,394	$529,816,688	$573,968,082	94,729,311,000		87,121,608		

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

(1) Obtained from Page 2, Col(8)
(2) Obtained from Page 2, Col(9)
(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 January 2001 through December 2001
(7) (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)

Totals may not add due to rounding.

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)	$0.31	$0.15
SST1 (T)	$0.29	$0.14
SST1 (D)	$0.29	$0.14

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2001

LINE NO.		(1) JAN 2001	(2) FEB 2001	(3) MAR 2001	(4) APR 2001	(5) MAY 2001	(6) JUN 2001
1.	UPS Capacity Charges	$ 9,405,570.00	$ 9,350,830.00	$ 8,534,569.00	$ 9,020,204.00	$ 8,329,952.00	$ 8,976,256.00
2.	Short Term Capacity Purchases CCR	0.00	0.00	0.00	961,500.00	3,619,100.00	4,899,588.00
3.	QF Capacity Charges	24,590,700.21	26,704,892.68	26,008,146.70	26,466,192.76	26,226,248.57	26,341,889.09
4.	SJRPP Capacity Charges	7,367,204.48	7,666,884.36	7,840,198.21	7,668,625.57	7,316,990.34	7,232,505.30
4a.	SJRPP Suspension Accrual	364,775.00	364,775.00	364,775.00	364,775.00	364,775.00	364,775.00
4b.	Return on SJRPP Suspension Liability	(149,794.52)	(153,385.72)	(156,976.90)	(160,568.09)	(164,159.28)	(167,750.47)
5.	SJRPP Deferred Interest Payment	(310,545.87)	(310,545.87)	(310,545.87)	(310,545.87)	(310,545.87)	(310,545.87)
6.	Cypress Settlement (Capacity)	0.00	0.00	0.00	1,530,589.14	0.00	0.00
7.	Trans. of Electricity by Others - FPL Sales	4,227.67	(4,452.00)	350.00	234,914.00	502,599.96	521,443.00
8.	Revenues from Capacity Sales	(1,526,403.55)	(991,620.28)	(977,935.98)	(444,461.99)	(753,189.28)	(281,737.40)
9.	Total (Lines 1 through 8)	$ 39,745,733.42	$ 42,627,378.17	$ 41,302,580.16	$ 45,331,224.52	$ 45,131,771.44	$ 47,576,422.65
10.	Jurisdictional Separation Factor (a)	*99.01014%*	*99.01014%*	*99.01014%*	99.01014%	99.01014%	99.01014%
11.	Jurisdictional Capacity Charges	39,352,306.30	42,205,426.80	40,893,742.44	44,882,508.86	44,685,030.09	47,105,482.67
12.	Capacity related amounts included in Base Rates *(FPSC Portion Only)* (b)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)
13.	Jurisdictional Capacity Charges Authorized	$ 34,606,840.30	$ 37,459,960.80	$ 36,148,276.44	$ 40,137,042.86	$ 39,939,564.09	$ 42,360,016.67
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 36,914,301.34	$ 32,808,068.94	$ 31,384,613.55	$ 31,848,137.61	$ 32,228,720.86	$ 38,069,850.96
15.	Prior Period True-up Provision	4,905,797.00	4,905,797.00	4,905,797.00	4,905,797.00	4,905,797.00	4,905,797.00
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 41,820,098.34	$ 37,713,865.94	$ 36,290,410.55	$ 36,753,934.61	$ 37,134,517.86	$ 42,975,647.96
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	7,213,258.04	253,905.14	142,134.11	(3,383,108.25)	(2,805,046.23)	615,631.29
18.	Interest Provision for Month	287,055.45	250,949.37	219,201.44	177,732.50	130,541.99	102,657.22
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	58,869,559.25	61,464,075.74	57,063,133.25	52,518,671.80	44,407,499.05	36,827,197.81
20.	Deferred True-up - Over/(Under) Recovery	(2,850,420.00)	(2,850,420.00)	(2,850,420.00)	(2,850,420.00)	(2,850,420.00)	(2,850,420.00)
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(4,905,797.00)	(4,905,797.00)	(4,905,797.00)	(4,905,797.00)	(4,905,797.00)	(4,905,797.00)
22.	End of Period True-up - Over/(Under) Recovery *(Sum of Lines 17 through 21)*	$ 58,613,655.74	$ 54,212,713.25	$ 49,668,251.80	$ 41,557,079.05	$ 33,976,777.81	$ 29,789,269.31

Notes:
(a) Per K. M. Dubin's Testimony Appendix III Page 3, Docket No. 000001-EI, filed September 21, 2000.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, 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.

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2001

LINE NO.		(7) JUL 2001	(8) AUG 2001	(9) SEP 2001	(10) OCT 2001	(11) NOV 2001	(12) DEC 2001	(13) TOTAL	LINE NO.
1.	UPS Capacity Charges	$ 8,949,781.00	$ 8,704,640.00	$ 8,704,640.00	$ 8,704,640.00	$ 8,704,640.00	$ 8,704,640.00	$106,090,362.00	1.
2.	Short Term Capacity Purchases CCR	4,899,588.00	5,277,344.00	3,256,700.00	961,500.00	961,500.00	961,500.00	25,798,320.00	2.
3.	QF Capacity Charges	26,541,038.20	26,469,351.44	26,469,351.44	26,469,351.44	26,469,351.44	26,469,351.44	315,225,865.43	3.
4.	SJRPP Capacity Charges	7,665,338.96	7,097,148.33	7,097,148.33	7,097,148.33	7,097,148.33	7,097,148.33	88,243,488.89	4.
4a.	SJRPP Suspension Accrual	364,775.00	364,775.00	364,775.00	364,775.00	364,775.00	364,775.00	4,377,300.00	4a.
4b.	Return on SJRPP Suspension Liability	(171,341.67)	(174,932.86)	(178,524.05)	(182,115.25)	(185,706.42)	(189,297.61)	(2,034,552.84)	4b.
5.	SJRPP Deferred Interest Payment	(310,545.87)	(310,545.87)	(310,545.87)	(310,545.87)	(310,545.87)	(310,545.87)	(3,726,550.44)	5.
6.	Cypress Settlement (Capacity)	0.00			1,530,589.14	164,588.85		3,225,767.13	6.
7.	Trans. of Electricity by Others - FPL Sales	735,452.00	80,500.00	38,640.00	9,660.00	9,660.00	48,300.00	2,181,294.63	7.
8.	Revenues from Capacity Sales	(361,780.29)	(642,688.00)	(488,390.00)	(462,160.00)	(381,848.00)	(581,113.00)	(7,893,327.77)	8.
9.	Total (Lines 1 through 8)	$ 48,312,305.33	$ 46,865,592.05	$ 44,953,794.86	$ 44,182,842.80	$ 42,893,563.34	$ 42,564,758.30	$531,487,967.03	9.
10.	Jurisdictional Separation Factor (a)	99.01014%	99.01014%	99.01014%	99.01014%	99.01014%	99.01014%	N/A	10.
11.	Jurisdictional Capacity Charges	47,834,081.14	46,401,688.30	44,508,815.22	43,745,494.51	42,468,977.11	42,143,426.78	526,226,980.24	11.
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(56,945,592.00)	12.
13.	Jurisdictional Capacity Charges Authorized	$ 43,088,615.14	$ 41,656,222.30	$ 39,763,349.22	$ 39,000,028.51	$ 37,723,511.11	$ 37,397,960.78	$469,281,388.24	13.
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 40,201,822.73	$ 41,901,322.29	$ 42,485,577.49	$ 39,236,356.30	$ 33,004,619.84	$ 33,642,815.94	$433,726,207.85	14.
15.	Prior Period True-up Provision	4,905,797.00	4,905,797.00	4,905,797.00	4,905,797.00	4,905,797.00	4,905,797.00	58,869,559.00	15.
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 45,107,619.73	$ 46,807,119.29	$ 47,391,374.49	$ 44,142,153.30	$ 37,910,416.84	$ 38,548,612.94	$492,595,766.85	16.
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	2,019,004.59	5,150,896.99	7,628,025.27	5,142,124.79	186,905.72	1,150,652.15	23,314,378.61	17.
18.	Interest Provision for Month	89,171.39	84,731.87	89,633.11	94,535.95	87,827.37	74,861.15	1,688,898.82	18.
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	32,639,689.31	29,842,068.29	30,171,900.15	32,983,761.53	33,314,625.27	28,683,561.37	58,869,559.25	19.
20.	Deferred True-up - Over/(Under) Recovery	(2,850,420.00)	(2,850,420.00)	(2,850,420.00)	(2,850,420.00)	(2,850,420.00)	(2,850,420.00)	(2,850,420.00)	20.
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(4,905,797.00)	(4,905,797.00)	(4,905,797.00)	(4,905,797.00)	(4,905,797.00)	(4,905,797.00)	(58,869,559.00)	21.
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ 26,991,648.29	$ 27,321,480.15	$ 30,133,341.53	$ 30,464,205.27	$ 25,833,141.37	$ 22,152,857.68	$ 22,152,857.68	22.

Notes:

(a) Per K. M. Dubin's Testimony Appendix III Page 3, Docket No. 000001-EI, filed September 21, 2000.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, 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.

APPENDIX II
FUEL COST RECOVERY
E SCHEDULES

KMD-7
DOCKET NO. 010001-EI
EXHIBIT _____
PAGES 1-14
NOVEMBER 5, 2001

SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2002 - DECEMBER 2002

		(a)		(b)	(c)
		DOLLARS		MWH	¢/KWH
1	Fuel Cost of System Net Generation (E3)	$2,015,046,641		81,717,455	2.4659
2	Nuclear Fuel Disposal Costs (E2)	22,562,002		24,283,718	0.0929
3	Fuel Related Transactions (E2)	12,061,527		0	0.0000
3a	Security Costs (E3)	1,860,000			
4	Fuel Cost of Sales to FKEC / CKW (E2)	(30,745,716)		(1,022,607)	3.0066
5	TOTAL COST OF GENERATED POWER	$2,020,784,454		80,694,848	2.5042
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	175,916,510		11,576,275	1.5196
7	Energy Cost of Sched C & X Econ Purch (Florida) (E9)	28,557,741		1,008,000	2.8331
8	Energy Cost of Other Econ Purch (Non-Florida) (E9)	37,012,500		1,020,000	3.6287
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 (E2)	2,428,182		0	0.0000
11a	Okeelanta/Osceola Settlement (E2)	$10,942,995		0	0.0000
12	Payments to Qualifying Facilities (E8)	148,745,520		6,794,037	2.1894
13	TOTAL COST OF PURCHASED POWER	$403,603,448		20,398,312	1.9786
14	TOTAL AVAILABLE KWH (LINE 5 + LINE 13)			101,093,160	
15	Fuel Cost of Economy Sales (E6)	(70,301,000)		(1,840,000)	3.8207
16	Gain on Economy Sales (E6A)	0		0	0.0000
17	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(1,525,200)		(493,502)	0.3091
18	Fuel Cost of Other Power Sales (E6)	0		0	0.0000
18a	Revenues from Off-System Sales	(15,113,296)		(2,333,502)	0.6477
19	TOTAL FUEL COST AND GAINS OF POWER SALES	($86,939,496)		(2,333,502)	3.7257
19a	Net Inadvertent Interchange	0		0	
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 13 + 19 + 19a)	$2,337,448,406		98,759,658	2.3668
21	Net Unbilled Sales	(2,237,461)	**	(94,535)	(0.0024)
22	Company Use	7,012,345	**	296,279	0.0076
23	T & D Losses	151,934,146	**	6,419,378	0.1649
24	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$2,337,448,406		92,138,536	2.5369
25	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$5,298,061		208,845	2.5369
26	Jurisdictional MWH Sales	$2,332,150,345		91,929,691	2.5369
27	Jurisdictional Loss Multiplier	-		-	1.00052
28	Jurisdictional MWH Sales Adjusted for Line Losses	$2,333,363,063		91,929,691	2.5382
29	FINAL TRUE-UP JAN 00 - DEC 00 $259,002,688 underrecovery / EST/ACT TRUE-UP JAN 01 - DEC 01 $13,794,067 overrecovery	245,208,621		91,929,691	0.2667
30	TOTAL JURISDICTIONAL FUEL COST	$2,578,571,684		91,929,691	2.8049
31	Revenue Tax Factor				1.01597
32	Fuel Factor Adjusted for Taxes				2.8497
33	GPIF ***	$9,004,713		91,929,691	0.0098
34	Fuel Factor including GPIF (Line 32 + Line 33)				2.8595
35	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH				2.860

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

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1D

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

JANUARY 2002 - DECEMBER 2002

NET ENERGY FOR LOAD (%)		FUEL COST (%)
ON PEAK	30.93	34.27
OFF PEAK	69.07	65.73
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$2,337,448,406	$801,043,569	$1,536,404,837
2	MWH SALES	92,138,537	28,498,449	63,640,088
3	COST PER KWH SOLD	2.5369	2.8108	2.4142
4	JURISDICTIONAL LOSS FACTOR	1.00052	1.00052	1.00052
5	JURISDICTIONAL FUEL FACTOR	2.5382	2.8123	2.4155
6	TRUE-UP	0.2667	0.2667	0.2667
7				
8	TOTAL	2.8049	3.0790	2.6822
9	REVENUE TAX FACTOR	1.01597	1.01597	1.01597
10	RECOVERY FACTOR	2.8497	3.1282	2.7250
11	GPIF	0.0098	0.0098	0.0098
12	RECOVERY FACTOR including GPIF	2.8595	3.1380	2.7348
13	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	2.860	3.138	2.735

HOURS:		
	ON-PEAK	24.73 %
	OFF-PEAK	75.27 %

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1E

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

JANUARY 2002 - DECEMBER 2002

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1, GS-1, SL-2		2.860	1.00210	2.866
A-1*	SL-1, OL-1, PL-1		2.799	1.00210	2.805
B	GSD-1		2.860	1.00202	2.865
C	GSLD-1 & CS-1		2.860	1.00078	2.862
D	GSLD-2, CS-2, OS-2 & MET		2.860	0.99429	2.843
E	GSLD-3 & CS-3		2.860	0.95233	2.723
A	RST-1, GST-1	ON-PEAK	3.138	1.00210	3.145
		OFF-PEAK	2.735	1.00210	2.741
B	GSDT-1	ON-PEAK	3.138	1.00202	3.144
	CILC-1(G)	OFF-PEAK	2.735	1.00202	2.740
C	GSLDT-1 &	ON-PEAK	3.138	1.00078	3.140
	CST-1	OFF-PEAK	2.735	1.00078	2.737
D	GSLDT-2 &	ON-PEAK	3.138	0.99429	3.120
	CST-2	OFF-PEAK	2.735	0.99429	2.719
E	GSLDT-3,CST-3,	ON-PEAK	3.138	0.95233	2.988
	CILC -1(T) & ISST-1(T)	OFF-PEAK	2.735	0.95233	2.604
F	CILC -1(D) &	ON-PEAK	3.138	0.99331	3.117
	ISST-1(D)	OFF-PEAK	2.735	0.99331	2.717

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

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2002 - DECEMBER 2002

SCHEDULE E2
Page 1 of 2

LINE NO.		(a) JANUARY	(b) FEBRUARY	(c) ESTIMATED MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) 6 MONTH SUB-TOTAL	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$140,838,890	$125,884,800	$132,132,160	$154,609,473	$181,113,173	$188,403,511	$922,982,007	A1
1a	NUCLEAR FUEL DISPOSAL	2,030,598	1,834,089	1,921,482	1,570,368	1,980,798	1,916,901	11,254,236	1a
1b	COAL CAR INVESTMENT	301,618	299,886	298,153	296,420	294,688	292,955	1,783,720	1b
1c	NUCLEAR THERMAL UPRATE	0	0	0	0	0	0	0	1c
1d	GAS LATERAL ENHANCEMENTS	197,127	195,672	194,216	192,761	191,305	189,849	1,160,930	1d
1e	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	0	0	0	1e
1f	SECURITY COSTS	155,000	155,000	155,000	155,000	155,000	155,000	930,000	1f
2	FUEL COST OF POWER SOLD	(7,891,020)	(6,462,490)	(5,320,070)	(4,689,580)	(6,518,050)	(6,119,120)	(37,000,330)	2
2a	REVENUES FROM OFF-SYSTEM SALES	(753,140)	(948,500)	(770,042)	(580,566)	(612,092)	(1,575,882)	(5,240,222)	2a
3	FUEL COST OF PURCHASED POWER	15,386,080	13,719,250	14,339,070	13,670,880	15,125,030	14,644,620	86,884,930	3
3a	MISSION SETTLEMENT	0	88,109	0	1,108,358	0	0	1,196,467	3a
3b	OKEELANTA/OSCEOLA SETTLEMENT	925,479	923,013	920,547	918,081	915,615	913,149	5,515,886	3b
3c	QUALIFYING FACILITIES	12,810,300	11,912,760	12,909,160	11,696,060	13,494,290	13,105,070	75,927,640	3c
4	ENERGY COST OF ECONOMY PURCHASES	4,249,945	4,961,046	6,407,445	8,148,645	8,444,945	3,636,145	35,848,171	4
4a	FUEL COST OF SALES TO FKEC / CKW	(2,248,087)	(2,168,424)	(2,215,322)	(2,371,169)	(2,508,016)	(2,655,147)	(14,166,165)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$166,002,791	$150,394,212	$160,971,799	$184,724,732	$212,076,687	$212,907,051	$1,087,077,271	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	7,230,250	6,975,646	6,393,448	6,673,565	7,078,079	8,193,682	42,544,670	6
7	COST PER KWH SOLD (¢/KWH)	2.2959	2.1560	2.5178	2.7680	2.9962	2.5984	2.5551	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052	7a
7b	JURISDICTIONAL COST (¢/KWH)	2.2971	2.1571	2.5191	2.7694	2.9978	2.5998	2.5565	7b
9	TRUE-UP (¢/KWH)	0.2826	0.2930	0.3196	0.3062	0.2887	0.2494	0.2882	9
10	TOTAL	2.5797	2.4501	2.8387	3.0756	3.2865	2.8492	2.8447	10
11	REVENUE TAX FACTOR 0.01597	0.0412	0.0391	0.0453	0.0491	0.0525	0.0455	0.0454	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	2.6209	2.4892	2.8840	3.1247	3.3390	2.8947	2.8901	12
13	GPIF (¢/KWH)	0.0104	0.0108	0.0117	0.0112	0.0106	0.0092	0.0106	13
14	RECOVERY FACTOR Including GPIF	2.6313	2.5000	2.8957	3.1359	3.3496	2.9039	2.9007	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	2.631	2.500	2.896	3.136	3.350	2.904	2.901	15

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2002 - DECEMBER 2002

LINE NO.	(h) JULY	(i) AUGUST	(j) ESTIMATED SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) 12 MONTH PERIOD	LINE NO.
A1 FUEL COST OF SYSTEM GENERATION	$215,721,064	$212,332,717	$191,826,970	$189,830,473	$137,567,140	$144,786,270	$2,015,046,641	A1
1a NUCLEAR FUEL DISPOSAL	1,980,798	1,980,798	1,898,660	1,451,817	1,965,095	2,030,598	$22,562,002	1a
1b COAL CAR INVESTMENT	291,223	289,490	287,757	286,025	284,292	282,560	$3,505,067	1b
1c NUCLEAR THERMAL UPRATE	0	0	0	0	0	0	$0	1c
1d GAS LATERAL ENHANCEMENTS	188,394	186,938	185,483	184,027	182,572	181,116	$2,269,460	1d
1e DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	6,287,000	0	$6,287,000	1e
1f SECURITY COSTS	155,000	155,000	155,000	155,000	155,000	155,000	$1,860,000	1f
2 FUEL COST OF POWER SOLD	(8,204,030)	(8,294,130)	(7,179,970)	(3,026,160)	(3,530,960)	(4,590,620)	($71,826,200)	2
2a REVENUES FROM OFF-SYSTEM SALES	(3,602,872)	(3,537,504)	(1,473,871)	(114,012)	(263,580)	(881,235)	($15,113,296)	2a
3 FUEL COST OF PURCHASED POWER	15,076,390	15,336,550	14,780,760	15,193,510	14,235,170	14,409,200	$175,916,510	3
3a MISSION SETTLEMENT	0	0	0	1,108,358	123,357	0	$2,428,182	3a
3b OKEELANTA/OSCEOLA SETTLEMENT	910,683	908,217	905,751	903,285	900,819	898,353	$10,942,995	3b
3c QUALIFYING FACILITIES	13,425,790	13,336,590	13,044,160	12,975,790	9,330,950	10,704,600	$148,745,520	3c
4 ENERGY COST OF ECONOMY PURCHASES	3,689,945	4,244,945	8,198,645	6,019,945	4,698,645	2,869,945	$65,570,241	4
4a FUEL COST OF SALES TO FKEC / CKW	(2,814,935)	(2,930,042)	(2,936,047)	(2,856,568)	(2,657,303)	(2,384,656)	($30,745,716)	4a
5 TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$236,817,450	$234,009,569	$219,693,299	$222,111,490	$169,278,197	$168,461,131	$2,337,448,406	5
6 SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	8,566,039	9,049,187	8,868,138	8,356,356	7,499,560	7,254,587	92,138,537	6
7 COST PER KWH SOLD (¢/KWH)	2.7646	2.5860	2.4773	2.6580	2.2572	2.3221	2.5369	7
7a JURISDICTIONAL LOSS MULTIPLIER	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052	7a
7b JURISDICTIONAL COST (¢/KWH)	2.7660	2.5873	2.4786	2.6594	2.2583	2.3233	2.5382	7b
9 TRUE-UP (¢/KWH)	0.2395	0.2267	0.2313	0.2455	0.2737	0.2830	0.2667	9
10 TOTAL	3.0055	2.8140	2.7099	2.9049	2.5320	2.6063	2.8049	10
11 REVENUE TAX FACTOR 0.01597	0.0480	0.0449	0.0433	0.0464	0.0404	0.0416	0.0448	11
12 RECOVERY FACTOR ADJUSTED FOR TAXES	3.0535	2.8589	2.7532	2.9513	2.5724	2.6479	2.8497	12
13 GPIF (¢/KWH)	0.0088	0.0083	0.0085	0.0090	0.0101	0.0104	0.0098	13
14 RECOVERY FACTOR including GPIF	3.0623	2.8672	2.7617	2.9603	2.5825	2.6583	2.8595	14
15 RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	3.062	2.867	2.762	2.960	2.583	2.658	2.860	15

Generating System Comparative Data by Fuel Type

		Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02
	Fuel Cost of System Net Generation ($)						
1	Heavy Oil	$58,808,150	$58,373,170	$61,894,110	$67,018,680	$76,255,360	$75,073,380
2	Light Oil	$776,720	$8,540	$19,590	$3,168,950	$7,254,990	$974,880
3	Coal	$10,572,270	$9,605,270	$10,092,230	$9,766,680	$10,730,280	$10,392,710
4	Gas	$63,773,560	$51,669,200	$53,580,790	$69,272,193	$80,115,733	$95,455,651
5	Nuclear	$6,908,190	$6,228,620	$6,545,440	$5,382,970	$6,756,810	$6,506,890
6	***Total***	$140,838,890	$125,884,800	$132,132,160	$154,609,473	$181,113,173	$188,403,511
	System Net Generation (MWH)						
7	Heavy Oil	1,565,919	1,620,692	1,804,556	1,960,451	2,205,787	2,115,639
8	Light Oil	9,341	102	233	41,878	100,784	13,988
9	Coal	625,612	565,068	579,282	555,534	617,898	597,965
10	Gas	1,536,538	1,239,808	1,314,343	1,751,329	2,038,380	2,729,605
11	Nuclear	2,185,554	1,974,049	2,068,111	1,690,203	2,131,954	2,063,180
12	***Total***	5,922,964	5,399,719	5,766,525	5,999,395	7,094,803	7,520,377
	Units of Fuel Burned						
13	Heavy Oil (BBLS)	2,459,110	2,543,709	2,829,660	3,104,961	3,493,220	3,362,394
14	Light Oil (BBLS)	21,979	230	527	93,202	226,162	30,116
15	Coal (TONS)	333,450	300,626	315,322	305,691	332,746	322,073
16	Gas (MCF)	11,964,508	9,518,435	10,057,992	14,617,198	17,561,844	21,455,482
17	Nuclear (MBTU)	23,362,712	21,101,814	22,107,716	18,417,964	23,281,562	22,530,554
	BTU Burned (MMBTU)						
18	Heavy Oil	15,738,298	16,279,735	18,109,822	19,871,750	22,356,602	21,519,322
19	Light Oil	127,824	1,332	3,057	541,333	1,313,587	174,811
20	Coal	6,342,469	5,728,681	5,901,118	5,714,840	6,326,755	6,122,670
21	Gas	11,964,508	9,518,435	10,057,992	14,617,198	17,561,844	21,455,482
22	Nuclear	23,362,712	21,101,814	22,107,716	18,417,964	23,281,562	22,530,554
23	***Total***	57,535,811	52,629,997	56,179,705	59,163,085	70,840,350	71,802,839

Generating System Comparative Data by Fuel Type

		Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02
	Generation Mix (%MWH)						
24	Heavy Oil	26.44%	30.01%	31.29%	32.68%	31.09%	28.13%
25	Light Oil	0.16%	0.00%	0.00%	0.70%	1.42%	0.19%
26	Coal	10.56%	10.46%	10.05%	9.26%	8.71%	7.95%
27	Gas	25.94%	22.96%	22.79%	29.19%	28.73%	36.30%
28	Nuclear	36.90%	36.56%	35.86%	28.17%	30.05%	27.43%
29	***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Fuel Cost per Unit						
30	Heavy Oil ($/BBL)	23.9144	22.9481	21.8733	21.5844	21.8295	22.3274
31	Light Oil ($/BBL)	35.3392	37.1304	37.1727	34.0009	32.0787	32.3708
32	Coal ($/ton)	31.7057	31.9509	32.0061	31.9495	32.2477	32.2682
33	Gas ($/MCF)	5.3302	5.4283	5.3272	4.7391	4.5619	4.4490
34	Nuclear ($/MBTU)	0.2957	0.2952	0.2961	0.2923	0.2902	0.2888
	Fuel Cost per MMBTU ($/MMBTU)						
35	Heavy Oil	3.7366	3.5856	3.4177	3.3726	3.4109	3.4886
36	Light Oil	6.0765	6.4114	6.4082	5.8540	5.5230	5.5768
37	Coal	1.6669	1.6767	1.7102	1.7090	1.6960	1.6974
38	Gas	5.3302	5.4283	5.3272	4.7391	4.5619	4.4490
39	Nuclear	0.2957	0.2952	0.2961	0.2923	0.2902	0.2888
	BTU burned per KWH (BTU/KWH)						
40	Heavy Oil	10,051	10,045	10,036	10,136	10,135	10,172
41	Light Oil	13,684	13,059	13,120	12,926	13,034	12,497
42	Coal	10,138	10,138	10,187	10,287	10,239	10,239
43	Gas	7,787	7,677	7,652	8,346	8,616	7,860
44	Nuclear	10,690	10,690	10,690	10,897	10,920	10,920
	***Generated* Fuel Cost per KWH (cents/KWH)**						
45	Heavy Oil	3.7555	3.6017	3.4299	3.4185	3.4571	3.5485
46	Light Oil	8.3152	8.3725	8.4077	7.5671	7.1986	6.9694
47	Coal	1.6899	1.6998	1.7422	1.7581	1.7366	1.7380
48	Gas	4.1505	4.1675	4.0766	3.9554	3.9304	3.4970
49	Nuclear	0.3161	0.3155	0.3165	0.3185	0.3169	0.3154
50	***Total***	2.3778	2.3313	2.2914	2.5771	2.5528	2.5052

Generating System Comparative Data by Fuel Type

		Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Total
	Fuel Cost of System Net Generation ($)							
1	Heavy Oil	$79,835,450	$74,151,020	$67,306,520	$70,740,330	$35,551,350	$29,942,680	$754,950,200
2	Light Oil	$1,283,170	$2,152,930	$634,370	$533,050	$230	$23,350	$16,830,770
3	Coal	$10,735,170	$10,834,140	$10,500,730	$10,840,820	$4,517,810	$4,564,620	$113,152,730
4	Gas	$117,238,624	$118,566,307	$107,027,980	$102,802,223	$90,954,440	$103,467,860	$1,053,924,561
5	Nuclear	$6,628,650	$6,628,320	$6,357,370	$4,914,050	$6,543,310	$6,787,760	$76,188,380
6	***Total***	$215,721,064	$212,332,717	$191,826,970	$189,830,473	$137,567,140	$144,786,270	$2,015,046,641
	System Net Generation (MWH)							
7	Heavy Oil	2,190,198	2,015,813	1,784,044	1,866,604	977,005	889,846	20,996,554
8	Light Oil	20,171	35,033	9,692	7,763	3	488	239,476
9	Coal	617,898	617,898	597,965	617,350	279,276	286,919	6,558,665
10	Gas	3,553,674	3,513,689	3,203,586	2,995,753	2,708,266	3,054,071	29,639,042
11	Nuclear	2,131,954	2,131,954	2,043,547	1,562,606	2,115,052	2,185,554	24,283,718
12	***Total***	8,513,895	8,314,387	7,638,834	7,050,076	6,079,602	6,416,878	81,717,455
	Units of Fuel Burned							
13	Heavy Oil (BBLS)	3,486,046	3,204,726	2,837,850	2,961,353	1,535,262	1,406,201	33,224,492
14	Light Oil (BBLS)	39,005	64,895	19,110	15,979	7	695	511,907
15	Coal (TONS)	332,497	332,820	322,054	332,624	130,159	133,115	3,493,177
16	Gas (MCF)	27,368,598	26,995,546	24,399,396	22,792,150	19,573,850	21,612,500	227,917,499
17	Nuclear (MBTU)	23,281,562	23,281,562	22,318,024	17,118,058	22,609,080	23,362,712	262,773,320
	BTU Burned (MMBTU)							
18	Heavy Oil	22,310,692	20,510,244	18,162,240	18,952,658	9,825,676	8,999,687	212,636,726
19	Light Oil	226,682	377,396	111,035	92,820	40	4,050	2,973,967
20	Coal	6,326,755	6,326,755	6,122,670	6,321,108	2,770,284	2,845,347	66,849,452
21	Gas	27,368,598	26,995,546	24,399,396	22,792,150	19,573,850	21,612,500	227,917,499
22	Nuclear	23,281,562	23,281,562	22,318,024	17,118,058	22,609,080	23,362,712	262,773,320
23	***Total***	79,514,289	77,491,503	71,113,365	65,276,794	54,778,930	56,824,296	773,150,964

Florida Power & Light Company

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Generating System Comparative Data by Fuel Type

		Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Total
	Generation Mix (%MWH)							
24	Heavy Oil	25.72%	24.24%	23.35%	26.48%	16.07%	13.87%	25.69%
25	Light Oil	0.24%	0.42%	0.13%	0.11%	0.00%	0.01%	0.29%
26	Coal	7.26%	7.43%	7.83%	8.76%	4.59%	4.47%	8.03%
27	Gas	41.74%	42.26%	41.94%	42.49%	44.55%	47.59%	36.27%
28	Nuclear	25.04%	25.64%	26.75%	22.16%	34.79%	34.06%	29.72%
29	***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Fuel Cost per Unit							
30	Heavy Oil ($/BBL)	22.9014	23.1380	23.7174	23.8878	23.1565	21.2933	22.7227
31	Light Oil ($/BBL)	32.8976	33.1756	33.1957	33.3594	32.8571	33.5971	32.8786
32	Coal ($/ton)	32.2865	32.5526	32.6055	32.5918	34.7099	34.2908	32.3925
33	Gas ($/MCF)	4.2837	4.3921	4.3865	4.5104	4.6467	4.7874	4.6241
34	Nuclear ($/MBTU)	0.2847	0.2847	0.2849	0.2871	0.2894	0.2905	0.2899
	Fuel Cost per MMBTU ($/MMBTU)							
35	Heavy Oil	3.5783	3.6153	3.7058	3.7325	3.6182	3.3271	3.5504
36	Light Oil	5.6607	5.7047	5.7132	5.7428	5.7500	5.7654	5.6594
37	Coal	1.6968	1.7124	1.7151	1.7150	1.6308	1.6042	1.6927
38	Gas	4.2837	4.3921	4.3865	4.5104	4.6467	4.7874	4.6241
39	Nuclear	0.2847	0.2847	0.2849	0.2871	0.2894	0.2905	0.2899
	BTU burned per KWH (BTU/KWH)							
40	Heavy Oil	10,187	10,175	10,180	10,154	10,057	10,114	10,127
41	Light Oil	11,238	10,773	11,456	11,957	13,333	8,299	12,419
42	Coal	10,239	10,239	10,239	10,239	9,920	9,917	10,193
43	Gas	7,701	7,683	7,616	7,608	7,227	7,077	7,690
44	Nuclear	10,920	10,920	10,921	10,955	10,690	10,690	10,821
	Generated Fuel Cost per KWH (cents/KWH)							
45	Heavy Oil	3.6451	3.6785	3.7727	3.7898	3.6388	3.3649	3.5956
46	Light Oil	6.3615	6.1454	6.5453	6.8665	7.6667	4.7848	7.0282
47	Coal	1.7374	1.7534	1.7561	1.7560	1.6177	1.5909	1.7252
48	Gas	3.2991	3.3744	3.3409	3.4316	3.3584	3.3879	3.5559
49	Nuclear	0.3109	0.3109	0.3111	0.3145	0.3094	0.3106	0.3137
50	***Total***	2.5338	2.5538	2.5112	2.6926	2.2628	2.2563	2.4659

Company: Florida Power & Light

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POWER SOLD

Estimated For the Period of : January 2002 Through December 2002

	(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWh Sold	(5) MWh Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWh)	(7B) Total Cost (Cents / KWh)	(8) Total $ For Fuel Adjustment (6) * (7A)	(9) Total Cost $ (6) * (7B)	(10) $ Gain From Off System Sales
1	January		OS	200,000		200,000	3.873	4.666	7,746,000	9,331,250	753,140
2	2002	St. Lucie Reliability		46,083		46,083	0.315	0.315	145,020	145,020	0
3											
4	Total			246,083	0	246,083	3.207	3.851	7,891,020	9,476,270	753,140
5											
6	February		OS	175,000		175,000	3.618	4.575	6,331,500	8,006,250	948,500
7	2002	St. Lucie Reliability		41,624		41,624	0.315	0.315	130,990	130,990	0
8											
9	Total			216,624	0	216,624	2.983	3.756	6,462,490	8,137,240	948,500
10											
11	March		OS	150,000		150,000	3.450	4.388	5,175,000	6,581,250	770,042
12	2002	St. Lucie Reliability		46,083		46,083	0.315	0.315	145,070	145,070	0
13											
14	Total			196,083	0	196,083	2.713	3.430	5,320,070	6,726,320	770,042
15											
16	April		OS	115,000		115,000	3.960	4.914	4,554,000	5,651,250	580,566
17	2002	St. Lucie Reliability		43,864		43,864	0.309	0.309	135,580	135,580	0
18											
19	Total			158,864	0	158,864	2.952	3.643	4,689,580	5,786,830	580,566
20											
21	May		OS	150,000		150,000	4.252	5.000	6,378,000	7,500,000	612,092
22	2002	St. Lucie Reliability		45,326		45,326	0.309	0.309	140,050	140,050	0
23											
24	Total			195,326	0	195,326	3.337	3.911	6,518,050	7,640,050	612,092
25											
26	June		OS	150,000		150,000	3.989	5.400	5,983,500	8,100,000	1,575,882
27	2002	St. Lucie Reliability		43,864		43,864	0.309	0.309	135,620	135,620	0
28											
29	Total			193,864	0	193,864	3.156	4.248	6,119,120	8,235,620	1,575,882
30											

Company: Florida Power & Light

POWER SOLD

Estimated For the Period of : January 2002 Through December 2002

	(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWh Sold	(5) MWh Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWh	(7B) Total Cost (Cents / KWh)	(8) Total $ For Fuel Adjustment (6) * (7A)	(9) Total Cost $ (6) * (7B)	(10) $ Gain From Off System Sales
1	July		OS	200,000		200,000	4.033	6.200	8,066,000	12,400,000	3,602,872
2	2002	St. Lucie Reliability		45,326		45,326	0.305	0.305	138,030	138,030	0
3											
4	Total			245,326	0	245,326	3.344	5.111	8,204,030	12,538,030	3,602,872
5											
6	August		OS	200,000		200,000	4.078	6.200	8,156,000	12,400,000	3,537,504
7	2002	St. Lucie Reliability		45,326		45,326	0.305	0.305	138,130	138,130	0
8											
9	Total			245,326	0	245,326	3.381	5.111	8,294,130	12,538,130	3,537,504
10											
11	September		OS	175,000		175,000	4.029	5.200	7,050,750	9,100,000	1,473,871
12	2002	St. Lucie Reliability		42,402		42,402	0.305	0.305	129,220	129,220	0
13											
14	Total			217,402	0	217,402	3.303	4.245	7,179,970	9,229,220	1,473,871
15											
16	October		OS	75,000		75,000	4.023	4.500	3,017,250	3,375,000	114,012
17	2002	St. Lucie Reliability		2,924		2,924	0.305	0.305	8,910	8,910	0
18											
19	Total			77,924	0	77,924	3.883	4.343	3,026,160	3,383,910	114,012
20											
21	November		OS	100,000		100,000	3.394	4.000	3,394,000	4,000,000	263,580
22	2002	St. Lucie Reliability		44,597		44,597	0.307	0.307	136,960	136,960	0
23											
24	Total			144,597	0	144,597	2.442	2.861	3,530,960	4,136,960	263,580
25											
26	December		OS	150,000		150,000	2.966	3.900	4,449,000	5,850,000	881,235
27	2002	St. Lucie Reliability		46,083		46,083	0.307	0.307	141,620	141,620	0
28											
29	Total			196,083	0	196,083	2.341	3.056	4,590,620	5,991,620	881,235
30											
31	Period		OS	1,840,000		1,840,000	3.821	5.016	70,301,000	92,295,000	15,113,296
32	Total	St. Lucie Reliability		493,502		493,502	0.309	0.309	1,525,200	1,525,200	0
33											
34	Total			2,333,502	0	2,333,502	3.078	4.021	71,826,200	93,820,200	15,113,296
35											

Company: Florida Power & Light

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Economy Energy Purchases

Estimated For the Period of : January 2002 Thru December 2002

	(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWH Purchased	(5) Transaction Cost (Cents/KWH)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWH)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
1	January	Florida	OS	107,200	2.957	3,169,945	3.873	4,151,845	981,900
2	2002	Non-Florida	OS	30,000	3.600	1,080,000	3.873	1,161,900	81,900
3									
4	Total			137,200	3.098	4,249,945	3.873	5,313,745	1,063,800
5									
6									
7	February	Florida	OS	103,600	2.931	3,036,046	3.618	3,748,240	712,194
8	2002	Non-Florida	OS	55,000	3.500	1,925,000	3.618	1,989,900	64,900
9									
10	Total			158,600	3.128	4,961,046	3.618	5,738,140	777,094
11									
12									
13	March	Florida	OS	87,200	2.689	2,344,945	3.450	3,008,390	663,445
14	2002	Non-Florida	OS	125,000	3.250	4,062,500	3.450	4,312,500	250,000
15									
16	Total			212,200	3.020	6,407,445	3.450	7,320,890	913,445
17									
18									
19	April	Florida	OS	86,000	3.022	2,598,645	3.960	3,405,590	806,945
20	2002	Non-Florida	OS	150,000	3.700	5,550,000	3.960	5,940,000	390,000
21									
22	Total			236,000	3.453	8,148,645	3.960	9,345,590	1,196,945
23									
24									
25	May	Florida	OS	87,200	3.062	2,669,945	4.252	3,707,732	1,037,787
26	2002	Non-Florida	OS	150,000	3.850	5,775,000	4.252	6,378,000	603,000
27									
28	Total			237,200	3.560	8,444,945	4.252	10,085,732	1,640,787
29									
30									
31	June	Florida	OS	61,000	2.764	1,686,145	3.989	2,433,280	747,135
32	2002	Non-Florida	OS	50,000	3.900	1,950,000	3.989	1,994,500	44,500
33									
34	Total			111,000	3.276	3,636,145	3.989	4,427,780	791,635
35									
36									
37	Period	Florida	OS	532,200	2.914	15,505,671	3.843	20,455,077	4,949,406
38	Total	Non-Florida	OS	560,000	3.633	20,342,500	3.889	21,776,800	1,434,300
39									
40	Total			1,092,200	3.282	35,848,171	3.867	42,231,877	6,383,706
41									

Company: Florida Power & Light

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Economy Energy Purchases

Estimated For the Period of : January 2002 Thru December 2002

	(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWH Purchased	(5) Transaction Cost (Cents/KWH)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWH)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
1	July	Florida	OS	52,200	2.529	1,319,945	4.033	2,105,215	785,270
2	2002	Non-Florida	OS	60,000	3.950	2,370,000	4.033	2,419,800	49,800
3									
4	Total			112,200	3.289	3,689,945	4.033	4,525,015	835,070
5									
6									
7	August	Florida	OS	52,200	2.529	1,319,945	4.078	2,128,705	808,760
8	2002	Non-Florida	OS	75,000	3.900	2,925,000	4.078	3,058,500	133,500
9									
10	Total			127,200	3.337	4,244,945	4.078	5,187,205	942,260
11									
12									
13	September	Florida	OS	86,000	3.080	2,648,645	4.029	3,464,930	816,285
14	2002	Non-Florida	OS	150,000	3.700	5,550,000	4.029	6,043,500	493,500
15									
16	Total			236,000	3.474	8,198,645	4.029	9,508,430	1,309,785
17									
18									
19	October	Florida	OS	87,200	2.890	2,519,945	4.023	3,508,045	988,100
20	2002	Non-Florida	OS	100,000	3.500	3,500,000	4.023	4,023,000	523,000
21									
22	Total			187,200	3.216	6,019,945	4.023	7,531,045	1,511,100
23									
24									
25	November	Florida	OS	111,000	2.792	3,098,645	3.394	3,767,331	668,686
26	2002	Non-Florida	OS	50,000	3.200	1,600,000	3.394	1,697,000	97,000
27									
28	Total			161,000	2.918	4,698,645	3.394	5,464,331	765,686
29									
30									
31	December	Florida	OS	87,200	2.460	2,144,945	2.966	2,586,344	441,399
32	2002	Non-Florida	OS	25,000	2.900	725,000	2.966	741,500	16,500
33									
34	Total			112,200	2.558	2,869,945	2.966	3,327,844	457,899
35									
36									
37	Period	Florida	OS	1,008,000	2.833	28,557,741	3.771	38,015,647	9,457,906
38	Total	Non-Florida	OS	1,020,000	3.629	37,012,500	3.898	39,760,100	2,747,600
39									
40	Total			2,028,000	3.233	65,570,241	3.835	77,775,747	12,205,506
41									

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	CURRENT OCT 01 - DEC 01	AS FILED JAN 02 - DEC 02	REVISED JAN 02 - DEC 02	DIFFERENCE FROM CURRENT $	DIFFERENCE FROM CURRENT %	DIFFERENCE FROM AS FILED $	DIFFERENCE FROM AS FILED %
BASE	$43.26	$43.26	$43.26	$0.00	0.00%	$0.00	0.00%
FUEL	$30.41	$28.96	$28.66	($1.75)	-5.75%	($0.30)	-1.04%
CONSERVATION	$1.81	$1.81	$1.87	$0.06	3.31%	$0.06	3.31%
CAPACITY PAYMENT	$5.27	$6.80	$7.01	$1.74	33.02%	$0.21	3.09%
ENVIRONMENTAL	$0.08	$0.00	$0.00	($0.08)	-100.00%	$0.00	0.00%
SUBTOTAL	$80.83	$80.83	$80.80	($0.03)	-0.04%	($0.03)	-0.04%
GROSS RECEIPTS TAX	$0.83	$0.83	$0.83	$0.00	0.00%	$0.00	0.00%
TOTAL	**$81.66**	**$81.66**	**$81.63**	**-$0.03**	**-0.04%**	**($0.03)**	**-0.04%**

APPENDIX III

CAPACITY COST RECOVERY

KMD-8
DOCKET NO. 010001-EI
EXHIBIT _____
PAGES 1-3
NOVEMBER 5, 2001

FLORIDA POWER & LIGHT COMPANY
PROJECTED CAPACITY PAYMENTS
JANUARY 2002 THROUGH DECEMBER 2002

	PROJECTED												
	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1. CAPACITY PAYMENTS TO NON-COGENERATORS	$16,857,268	$17,472,867	$18,227,803	$18,595,017	$20,018,375	$31,705,723	$31,729,147	$31,714,369	$25,648,299	$19,525,408	$19,746,575	$22,376,447	$273,617,298
2. CAPACITY PAYMENTS TO COGENERATORS	$28,415,860	$28,415,860	$28,415,860	$28,080,250	$28,080,250	$28,080,250	$28,080,250	$28,080,250	$28,080,250	$28,080,250	$28,080,250	$28,080,250	$337,969,830
3. CAPACITY PAYMENTS FOR MISSION SETTLEMENT	$0	$121,674	$0	$1,530,589	$0	$0	$0	$0	$0	$1,530,589	$170,349	$0	$3,353,202
4. CAPACITY PAYMENTS FOR OKEELANTA/OSCEOLA SETTLEMENT	$3,481,566	$3,472,289	$3,463,012	$3,453,735	$3,444,458	$3,435,181	$3,425,904	$3,416,627	$3,407,350	$3,398,073	$3,388,796	$3,379,519	$41,166,505
5. TRANSMISSION REVENUES FROM CAPACITY SALES	$918,463	$645,325	$558,573	$526,448	$514,075	$626,588	$723,000	$723,000	$546,275	$347,010	$340,570	$440,203	$6,909,530
6. SJRPP SUSPENSION ACCRUAL	$301,945	$301,945	$301,945	$301,945	$301,945	$301,945	$301,945	$301,945	$301,945	$301,945	$301,945	$301,945	$3,623,340
7. RETURN REQUIREMENT ON SUSPENSION PAYMENT	$192,580	$195,552	$198,525	$201,497	$204,470	$207,443	$210,415	$213,388	$216,361	$219,333	$222,306	$225,278	$2,507,148
8. SYSTEM TOTAL (Lines 1+2+3+4-5+6-7)	$44,464,030	$45,471,469	$46,188,510	$47,779,856	$47,682,025	$59,253,887	$59,177,927	$59,160,176	$53,267,858	$48,871,849	$47,736,243	$50,093,161	$650,313,497
9. JURISDICTIONAL % *													*99.03598%*
10. JURISDICTIONALIZED CAPACITY PAYMENTS													$644,044,345
11. SJRPP CAPACITY PAYMENTS INCLUDED IN THE 1988 TAX SAVINGS REFUND DOCKET													($56,945,592)
12. FINAL TRUE-UP -- overrecovery/(underrecovery) JANUARY 2000 - DECEMBER 2000 ($2,850,420)				EST \ ACT TRUE-UP -- overrecovery/(underrecovery) JANUARY 2001 - DECEMBER 2001 $25,003,277									$22,152,857
13. TOTAL (Lines 10+11+12)													$564,945,896
14. REVENUE TAX MULTIPLIER													1.01597
15. TOTAL RECOVERABLE CAPACITY PAYMENTS													$573,968,082

*CALCULATION OF JURISDICTIONAL %

	AVG. 12 CP AT GEN.(MW)	%
FPSC	15,948	99.03598%
FERC	155	0.96402%
TOTAL	16,103	100.00000%

* BASED ON 2000 ACTUAL DATA

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2002 THROUGH DECEMBER 2002

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	60.938%	48,379,415,259	9,062,923	1.096656115	1.075433109	52,028,824,964	9,938,910	52.70839%	59.62714%
GS1	71.059%	5,701,460,232	915,931	1.096656115	1.075433109	6,131,539,103	1,004,461	6.21162%	6.02613%
GSD1	78.573%	21,060,519,512	3,059,790	1.096544563	1.075351927	22,647,470,241	3,355,196	22.94327%	20.12904%
OS2	149.531%	20,882,701	1,594	1.080484913	1.063082399	22,200,032	1,722	0.02249%	0.01033%
GSLD1/CS1	81.969%	9,438,748,770	1,314,500	1.094747540	1.074025051	10,137,452,629	1,439,046	10.26986%	8.63336%
GSLD2/CS2	90.955%	1,473,704,124	184,961	1.087891242	1.068548693	1,574,724,616	201,217	1.59529%	1.20717%
GSLD3/CS3	84.688%	497,899,639	67,114	1.026933481	1.022023682	508,865,222	68,922	0.51551%	0.41349%
ISST1D	0.000%	0	0	1.096656115	1.075433109	0	0	0.00000%	0.00000%
SST1T	95.114%	88,216,694	10,588	1.026933481	1.022023682	90,159,550	10,873	0.09134%	0.06523%
SST1D	81.410%	64,487,635	9,043	1.058919085	1.046606781	67,493,196	9,576	0.06837%	0.05745%
CILC D/CILC G	93.492%	3,331,341,530	406,762	1.084866212	1.066720945	3,553,611,785	441,282	3.60003%	2.64741%
CILC T	93.120%	1,187,774,292	145,609	1.026933481	1.022023682	1,213,933,455	149,531	1.22979%	0.89709%
MET	66.484%	85,157,566	14,622	1.058368342	1.046190930	89,091,073	15,475	0.09025%	0.09284%
OL1/SL1/PL1	297.393%	516,006,457	19,807	1.096656115	1.075433109	554,930,428	21,721	0.56218%	0.13031%
SL2	100.229%	84,076,588	9,576	1.096656115	1.075433109	90,418,746	10,502	0.09160%	0.06301%
TOTAL		91,929,691,000	15,222,820			98,710,715,040	16,668,434	100.00%	100.00%

(1) AVG 12 CP load factor based on actual calendar data.
(2) Projected kwh sales for the period January 2002 through December 2002.
(3) Calculated: Col(2)/(8760 hours * Col(1))
(4) Based on 2000 demand losses.
(5) Based on 2000 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
JANUARY 2002 THROUGH DECEMBER 2002

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	52.70839%	59.62714%	$23,271,486	$315,914,525	$339,186,011	48,379,415,259	-	-	-	0.00701
GS1	6.21162%	6.02613%	$2,742,519	$31,927,427	$34,669,946	5,701,460,232	-	-	-	0.00608
GSD1	22.94327%	20.12904%	$10,129,775	$106,647,022	$116,776,797	21,060,519,512	48.23371%	49,803,291	2.34	-
OS2	0.02249%	0.01033%	$9,930	$54,735	$64,665	20,882,701	-	-	-	0.00310
GSLD1/CS1	10.26986%	8.63336%	$4,534,286	$45,740,985	$50,275,271	9,438,748,770	61.70922%	20,952,773	2.40	-
GSLD2/CS2	1.59529%	1.20717%	$704,344	$6,395,809	$7,100,153	1,473,704,124	67.56448%	2,987,920	2.38	-
GSLD3/CS3	0.51551%	0.41349%	$227,606	$2,190,729	$2,418,335	497,899,639	70.23956%	971,040	2.49	-
ISST1D	0.00000%	0.00000%	$0	$0	$0	0	0.00000%	0	**	-
SST1T	0.09134%	0.06523%	$40,327	$345,605	$385,932	88,216,694	10.45089%	1,156,311	**	-
SST1D	0.06837%	0.05745%	$30,188	$304,379	$334,567	64,487,635	62.93622%	140,363	**	-
CILC D/CILC G	3.60003%	2.64741%	$1,589,462	$14,026,427	$15,615,889	3,331,341,530	73.24678%	6,230,283	2.51	-
CILC T	1.22979%	0.89709%	$542,969	$4,752,937	$5,295,906	1,187,774,292	77.61662%	2,096,314	2.53	-
MET	0.09025%	0.09284%	$39,849	$491,883	$531,732	85,157,566	55.94088%	208,531	2.55	-
OL1/SL1/PL1	0.56218%	0.13031%	$248,210	$690,416	$938,626	516,006,457	-	-	-	0.00182
SL2	0.09160%	0.06301%	$40,443	$333,813	$374,256	84,076,588	-	-	-	0.00445
TOTAL			$44,151,394	$529,816,690	$573,968,082	91,929,691,000		84,546,826		

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

(1) Obtained from Page 2, Col(8)
(2) Obtained from Page 2, Col(9)
(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 January 2001 through December 2001
(7) (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)

Totals may not add due to rounding.

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)	$0.31	$0.15
SST1 (T)	$0.29	$0.14
SST1 (D)	$0.30	$0.14

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APPENDIX I
FUEL COST RECOVERY
FORECAST ASSUMPTIONS

LEG-1
DOCKET NO. 010001-EI
EXHIBIT _____
PAGES 1-4
NOVEMBER 5, 2001

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 26
COMPANY/ WITNESS: Green
DATE: 11-20 & 21-01

Unemployment Rates

State of Florida and Selected Florida Counties

		County										
Year	Florida	Brevard	Broward	Collier	Duval	Hills-borough	Lee	Miami-Dade	Orange	Palm Beach	Pinellas	Volusia
1980	5.9	5.4	4.1	6.3	4.7	5.0	4.7	8.0	5.4	4.9	4.7	5.6
1981	6.8	6.5	4.8	8.4	5.8	5.8	5.3	9.4	6.3	5.8	5.0	6.2
1982	8.2	7.0	6.7	12.0	6.8	7.9	7.9	10.0	6.8	7.6	6.3	7.0
1983	8.6	7.6	7.3	12.2	7.8	8.3	8.1	9.8	7.3	8.5	6.6	7.4
1984	6.3	5.1	5.0	8.4	5.6	5.3	5.3	7.8	5.4	6.3	4.4	5.2
1985	6.0	4.7	4.9	7.3	5.1	5.3	4.8	7.5	4.9	6.2	4.2	4.8
1986	5.7	6.0	4.5	5.9	5.4	5.7	4.2	6.7	4.7	5.9	4.2	5.0
1987	5.3	5.5	4.2	4.9	5.4	5.1	3.8	5.8	4.7	5.4	4.2	4.7
1988	5.0	4.7	4.1	4.3	5.4	4.5	3.6	5.4	4.6	5.0	4.4	4.5
1989	5.6	5.2	5.1	4.6	5.8	4.9	3.9	6.4	5.0	6.0	4.7	5.4
1990	6.0	5.3	5.6	5.4	5.2	4.7	3.8	7.8	5.4	7.0	4.5	5.0
1991	7.4	7.0	7.7	7.8	6.3	6.1	6.0	9.4	6.8	8.9	6.0	6.5
1992	8.3	7.9	8.5	9.5	6.8	7.1	7.4	10.5	7.4	10.3	6.6	7.6
1993	7.0	7.6	6.9	8.4	5.5	6.4	5.7	8.2	6.2	9.0	6.0	6.7
1994	6.6	7.4	6.5	8.2	4.9	5.2	4.9	8.4	5.7	8.8	5.0	6.2
1995	5.5	6.5	5.7	7.0	3.8	4.3	4.2	7.4	4.5	7.2	4.1	4.8
1996	5.1	5.4	5.1	5.8	3.8	3.8	3.8	7.3	3.8	6.6	3.7	4.3
1997	4.8	4.6	4.9	5.0	3.8	3.3	3.4	7.1	3.3	6.3	3.4	3.9
1998	4.3	4.3	4.5	4.2	3.2	2.8	3.0	6.4	3.0	5.6	3.1	3.4
1999	3.9	3.9	4.1	3.7	3.1	2.6	2.6	5.8	2.7	5.0	2.7	3.1
2000	3.6	3.4	3.7	3.5	3.3	2.6	2.6	5.3	2.5	4.4	2.5	2.9

☐ County's unemployment rate is greater than state

GROWTH IN PER CAPITA INCOME

		County										
Year	Florida	Brevard	Broward	Collier	Duval	Hills-borough	Lee	Miami-Dade	Orange	Palm Beach	Pinellas	Volusia
1981	2.5%	3.9%	0.7%	3.8%	3.4%	3.3%	1.8%	1.0%	4.1%	6.5%	4.7%	1.5%
1982	-0.4%	-2.1%	-0.4%	-3.9%	1.5%	1.1%	-4.1%	-0.8%	2.1%	-0.7%	0.0%	-0.8%
1983	2.8%	2.1%	2.8%	4.5%	2.3%	3.3%	3.0%	1.4%	3.0%	5.6%	2.1%	3.5%
1984	5.0%	5.2%	6.2%	5.2%	7.6%	6.0%	4.4%	3.6%	5.6%	5.1%	5.2%	4.7%
1985	3.3%	2.5%	3.1%	3.0%	3.6%	3.4%	5.1%	2.2%	3.9%	5.2%	2.3%	3.5%
1986	2.4%	2.3%	0.1%	4.6%	2.1%	1.5%	3.0%	1.1%	2.3%	2.4%	3.1%	2.4%
1987	2.6%	2.7%	2.0%	7.6%	2.0%	2.8%	2.9%	2.9%	2.0%	4.8%	0.7%	1.3%
1988	3.1%	1.8%	3.0%	12.7%	1.1%	2.5%	4.1%	1.0%	3.0%	4.8%	2.0%	1.8%
1989	3.5%	4.0%	3.7%	1.5%	3.6%	3.2%	6.1%	2.0%	1.0%	4.3%	5.7%	1.7%
1990	-0.4%	-0.8%	-2.3%	-2.0%	0.3%	1.8%	-2.0%	-0.9%	-0.8%	2.9%	-2.9%	-1.9%
1991	-1.7%	-3.4%	-2.2%	-1.9%	-1.7%	0.2%	-3.7%	-2.2%	-1.3%	2.0%	-2.4%	-3.4%
1992	-0.7%	-1.3%	0.7%	6.3%	0.8%	1.4%	0.8%	-8.3%	0.5%	-0.4%	0.9%	-0.6%
1993	2.3%	0.4%	-1.2%	3.3%	2.3%	1.4%	0.3%	11.8%	1.4%	-0.4%	3.7%	0.2%
1994	1.2%	-0.1%	0.1%	4.5%	2.3%	3.1%	1.8%	0.1%	0.6%	0.5%	0.0%	1.7%
1995	2.9%	2.4%	1.0%	1.1%	3.2%	4.3%	4.0%	1.8%	3.0%	3.4%	3.8%	3.3%
1996	2.5%	1.2%	1.3%	3.7%	2.2%	3.4%	1.0%	1.3%	2.7%	3.3%	2.9%	3.1%
1997	2.5%	0.3%	4.0%	6.2%	2.2%	3.5%	4.0%	0.9%	3.3%	-1.0%	4.7%	2.9%
1998	3.6%	2.7%	2.5%	1.1%	4.4%	4.6%	3.0%	3.6%	5.1%	3.6%	4.0%	2.2%
1999	1.3%	1.0%	0.2%	1.6%	2.0%	3.1%	0.3%	1.0%	4.7%	1.4%	3.2%	0.7%
2000	3.1%	1.4%	1.1%	2.4%	2.4%	2.5%	1.1%	1.6%	0.7%	1.6%	1.8%	1.0%

☐ County's Growth in Per Capita Income is less than state

FLORIDA POWER & LIGHT COMPANY
IMPACT OF ECONOMIC RECESSIONS ON DEMAND FOR ELECTRICITY
(INCOME, CUSTOMERS GROWTH AND USE OF ELECTRICITY PER CUSTOMER)

Year	Florida Real Per Capita Income (Chained $1996)	% Change	Customers	Absolute Change	% Change	Use Per Customer (KWH)	% Change
1972	15,440		1,446,114			21,782	
1973	16,323	5.7%	1,567,638	121,524	8.4%	22,445	3.0%
1974	15,957	-2.2%	1,676,022	108,384	6.9%	21,160	-5.7%
1975	15,482	-3.0%	1,738,071	62,050	3.7%	21,375	1.0%
1976	15,858	2.4%	1,795,793	57,721	3.3%	21,225	-0.7%
1977	16,336	3.0%	1,875,821	80,028	4.5%	21,704	2.3%
1978	17,201	5.3%	1,967,352	91,531	4.9%	22,215	2.4%
1979	17,720	3.0%	2,074,327	106,975	5.4%	21,859	-1.6%
1980	18,119	2.3%	2,184,974	110,646	5.3%	22,174	1.4%
1981	18,574	2.5%	2,285,187	100,214	4.6%	21,890	-1.3%
1982	18,509	-0.4%	2,358,167	72,980	3.2%	21,429	-2.1%
1983	19,021	2.8%	2,429,688	71,521	3.0%	21,608	0.8%
1984	19,977	5.0%	2,520,523	90,835	3.7%	21,086	-2.4%
1985	20,638	3.3%	2,617,556	97,033	3.8%	21,393	1.5%
1986	21,130	2.4%	2,723,555	105,999	4.0%	21,394	0.0%
1987	21,670	2.6%	2,840,207	116,651	4.3%	21,694	1.4%
1988	22,346	3.1%	2,953,663	113,457	4.0%	21,910	1.0%
1989	23,127	3.5%	3,064,436	110,773	3.8%	22,828	4.2%
1990	23,044	-0.4%	3,158,817	94,381	3.1%	22,486	-1.5%
1991	22,662	-1.7%	3,226,455	67,638	2.1%	22,675	0.8%
1992	22,505	-0.7%	3,281,238	54,783	1.7%	22,277	-1.8%
1993	23,024	2.3%	3,355,794	74,556	2.3%	22,580	1.4%
1994	23,296	1.2%	3,422,187	66,393	2.0%	23,487	4.0%
1995	23,963	2.9%	3,488,796	66,609	1.9%	24,066	2.5%
1996	24,558	2.5%	3,550,747	61,951	1.8%	23,937	-0.5%
1997	25,184	2.5%	3,615,485	64,738	1.8%	24,022	0.4%
1998	26,095	3.6%	3,680,470	64,985	1.8%	25,177	4.8%
1999	26,442	1.3%	3,756,009	75,539	2.1%	24,350	-3.3%
2000	27,260	3.1%	3,848,350	92,341	2.5%	24,943	2.4%

Note: Shaded areas represent recession years.

Revised Load Forecast
(Net Energy For Load & Customers)

Year	Net Energy for Load (NEL) (gWh)	% Change	Revised NEL (gWh)	% Change	Difference	Absolute Customer Growth	Revised Absolute Customer Growth	Difference	NEL/ Customer kWh	% Change	Revised NEL/ Customer kWh	% Change	Difference
2001	99,704	3.9%	98,503	2.6%	-1.2%	86,760	86,606	-0.2%	25,337	1.6%	25,032	0.4%	-1.2%
2002	103,223	3.5%	100,158	1.7%	-3.0%	85,643	65,000	-24.1%	25,672	1.3%	25,039	0.0%	-2.5%

NOTE: Exhibit 27 was marked for identification and received into evidence as Mr. Hartzog's exhibit. However, Mr. Hartzog did not have an exhibit, so Exhibit 27 does not exist.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 27
COMPANY/ WITNESS: Hartzog
DATE: 11-20-01

DOCUMENT NO. 1

WITNESS: R. SILVA

DOCKET NO. 010001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2000

RS - 1
DOCKET NO. 010001-EI
FPL Witness: R. Silva
Exhibit No.:
Pages 1 - 26
April 2, 2001

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 28
COMPANY/ WITNESS: Silva
DATE: 10-30 & 31-01

DOCUMENT NUMBER 1 INDEX

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2000

DOCUMENT	INDEX OF MANUAL PAGES	TITLES
1	6.203.001	Index of Manual Pages
	6.203.002	GPIF Reward/(Penalty) Table (Actual)
	6.203.003	GPIF Calculation of Maximum Allowed Incentive Dollars (Actual)
	6.203.004	Derivation of System Actual GPIF Points
	6.203.005	Actual Equivalent Availability and Adjustments Summary
	6.203.006	EAF Adjustment Documentation
	6.203.007	Adjustments to Average Net Operating Heat Rates and Adjustments Summary
	6.203.008 - 6.203.025	GPIF Units Points Tables
	6.203.026	Planned Outages Schedules (Actual)

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ACTUAL)

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2000

GENERATNG PERFORMANCE INCENTIVE POINTS (GPIF)		FUEL SAVINGS/(LOSS) ($000)		GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+ 10		39,556.00		20,101.63
+ 9		35,600.40		18,091.47
+ 8		31,644.80		16,081.31
+ 7		27,689.20		14,071.14
+ 6		23,733.60		12,060.98
+ 5		19,778.00		10,050.82
+ 4	<---------- 4.48	15,822.40	9,004.713 ---------->	8,040.65
+ 3		11,866.80		6,030.49
+ 2		7,911.20		4,020.33
+ 1		3,955.60		2,010.16
0		0.00		0.00
- 1		(4,077.30)		(2,010.16)
- 2		(8,154.60)		(4,020.33)
- 3		(12,231.90)		(6,030.49)
- 4		(16,309.20)		(8,040.65)
- 5		(20,386.50)		(10,050.82)
- 6		(24,463.80)		(12,060.98)
- 7		(28,541.10)		(14,071.14)
- 8		(32,618.40)		(16,081.31)
- 9		(36,695.70)		(18,091.47)
- 10		(40,773.00)		(20,101.63)

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ACTUAL

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2000

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY		$ 4,792,763,414
	END OF MONTH BALANCE OF COMMON EQUITY		
LINE 2	MONTH OF January	2000	$ 4,727,179,660
LINE 3	MONTH OF February	2000	$ 4,726,828,335
LINE 4	MONTH OF March	2000	$ 4,700,566,178
LINE 5	MONTH OF April	2000	$ 4,726,080,486
LINE 6	MONTH OF May	2000	$ 4,841,034,904
LINE 7	MONTH OF June	2000	$ 4,853,418,637
LINE 8	MONTH OF July	2000	$ 4,867,883,837
LINE 9	MONTH OF August	2000	$ 5,186,617,889
LINE 10	MONTH OF September	2000	$ 5,169,337,736
LINE 11	MONTH OF October	2000	$ 5,142,205,512
LINE 12	MONTH OF November	2000	$ 5,128,151,746
LINE 13	MONTH OF December	2000	$ 5,032,429,690
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 4,914,961,386
LINE 15	25 BASIS POINTS		0.0025
LINE 16	REVENUE EXPANSION FACTOR		60.4594%
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 20,323,397
LINE 18	JURISDICTIONAL SALES		87,959,341,000 KWH
LINE 19	TOTAL SALES		88,929,719,000 KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		98.91%
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS		$ 20,101,633

JANUARY THROUGH DECEMBER, 2000

DERIVATION OF SYSTEM ACTUAL GPIF POINTS

PILANT/UNIT	PERFORMANCE INDICATOR	WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
Cape Canaveral 1	EAF	0.12	-6.42	-.0079
	ANHR	1.29	0.00	.0000
Cape Canaveral 2	EAF	0.15	-3.77	-.0057
	ANHR	0.90	0.00	.0000
Lauderdale 4	EAF	0.68	-10.00	-.0681
	ANHR	1.14	0.00	.0000
Lauderdale 5	EAF	0.66	-10.00	-.0659
	ANHR	1.12	0.00	.0000
Fort Myers 2	EAF	0.39	-10.00	-.0390
	ANHR	2.20	-3.73	-.0820
Manatee 2	EAF	0.35	10.00	.0351
	ANHR	4.82	0.00	.0000
Martin 3	EAF	0.92	5.28	.0485
	ANHR	6.00	6.75	.4050
Martin 4	EAF	1.18	10.00	.1181
	ANHR	5.38	7.21	.3878
Port Everglades 3	EAF	0.13	-6.18	-.0082
	ANHR	3.40	1.73	.0587
Port Everglades 4	EAF	0.11	-10.00	-.0109
	ANHR	2.80	0.00	.0000
Putnam 1	EAF	0.29	8.51	.0249
	ANHR	0.75	0.00	.0000
Sanford 4	EAF	0.15	-5.94	-.0087
	ANHR	3.93	-10.00	-.3932
Sanford 5	EAF	0.21	7.17	.0150
	ANHR	3.27	0.00	.0000
Turkey Point 3	EAF	8.89	10.00	.8889
	ANHR	4.84	0.00	.0000
Turkey Point 4	EAF	8.86	10.00	.8855
	ANHR	5.56	0.00	.0000
St.Lucie 1	EAF	11.62	10.00	1.1622
	ANHR	2.94	0.00	.0000
St.Lucie 2	EAF	8.84	10.00	.8841
	ANHR	1.93	0.00	.0000
Scherer 4	EAF	2.55	10.00	.2554
	ANHR	1.64	0.00	.0000
GPIF System Total:		100.00		4.48

ACTUAL EQUIVALENT AVAILABILITY AND ADJUSTMENTS

JANUARY THROUGH DECEMBER, 2000

1	2	3	4	5	6	7	8	9			
	ACTUAL				PLANNED						ACTUAL
UNIT	FOF	MOF	POF	EA	OUTAGE ADJ TO EA (1)	ADJUSTED ACTUAL EA	TARGET EA	POINTS FROM TABLES	ORIGINAL PLANNED DATES	ACTUAL DATES	FUEL SAVINGS/ (LOSS) ($000)
Cape Canaveral 1	0.1	9.1	0.0	90.8	-1.6	90.8	92.4	-6.42	NONE	NONE	(31.3)
Cape Canaveral 2	0.7	6.2	16.1	77.0	-0.9	77.2	78.2	-3.77	03/11/00 - 05/07/00	10/20/2000 - 12/18/200	(17.1)
Lauderdale 4	1.8	4.1	3.0	91.1	-2.1	91.3	93.5	-10.00	03/11/00 - 03/20/00	2/27/2000 - 3/09/2000	(269.1)
Lauderdale 5	1.8	5.5	2.9	89.8	-3.5	89.9	93.5	-10.00	03/11/00 - 03/20/00	3/11/2000 - 03/20/2000	(260.1)
Fort Myers 2	1.8	9.2	0.0	88.9	-3.8	88.9	92.7	-10.00	NONE	NONE	(153.3)
Manatee 2	0.8	4.2	14.6	80.4	9.4	81.1	71.7	10.00	09/30/00 - (11/19/00)	2/18/2000 - 4/11/2000	138.9
Martin 3	0.2	2.8	4.2	92.8	1.1	95.3	94.2	5.28	04/01/00 - 04/06/00	3/12/2000 - 4/05/2000	191.7
Martin 4	0.0	1.9	1.2	96.9	3.6	95.3	91.6	10.00	04/15/00 - 05/05/00	11/13/2000 - 11/22/200	467.0
Port Everglades 3	0.2	5.2	0.0	94.6	-1.2	94.6	95.8	-6.18	NONE	NONE	(32.7)
Port Everglades 4	0.8	7.3	8.4	83.5	-4.5	83.7	88.2	-10.00	10/14/00 - 11/12/00	3/07/2000 - 3/14/2000	(43.2)
Putnam 1	0.6	1.7	1.2	96.4	1.7	92.9	91.2	8.51	11/11/00 - 12/16/00	12/05/2000 - 12/13/200	98.5
Sanford 4	2.2	7.0	0.0	90.8	-1.5	90.8	92.3	-5.94	NONE	NONE	(34.5)
Sanford 5	2.4	5.8	0.0	91.8	2.5	91.8	89.3	7.17	NONE	NONE	59.3
Turkey Point 3	0.0	0.3	8.5	91.2	5.5	90.1	84.6	10.00	02/28/00 - 04/02/00	2/28/2000 - 3/27/2000	3516.3
Turkey Point 4	1.0	0.2	8.9	89.9	4.6	89.2	84.6	10.00	10/02/00 - 11/05/00	9/25/2000 - 10/24/2000	3502.8
St.Lucie 1	0.0	0.0	0.0	100.0	6.4	100.0	93.6	10.00	NONE	NONE	4597.4
St.Lucie 2	0.1	0.0	8.8	91.1	5.6	90.3	84.6	10.00	04/17/00 - 05/21/00	4/17/2000 - 5/20/2000	3497.1
Scherer 4	1.1	0.9	0.0	98.0	3.8	98.0	94.2	10.00	NONE	NONE	1010.2
											16238.0

(1) EQUIVALENT AVAILABILITY ADJUSTMENT DUE TO PLANNED OUTAGE ACTUAL DURATION VERSUS TARGETED DURATION
SEE 6.203.006 FOR FORMULAS AND CALCULATION DATA

EQUIVALENT AVAILABILITY ADJUSTMENTS
JANUARY THROUGH DECEMBER, 2000

	ACTUAL				TARGETS		ADJUSTED ACTUAL
PLANT / UNIT	PH	EFOH	EMOH	EPOH	POF%	POH	EAF%
Cape Canaveral 1	8784	7.4	801.2	0.0	0.0	0.0	90.8
Cape Canaveral 2	8784	64.3	546.9	1413.5	15.8	1384.1	77.2
Lauderdale 4	8784	158.5	363.6	261.3	2.7	236.5	91.3
Lauderdale 5	8784	161.5	485.0	252.9	2.7	236.5	89.9
Fort Myers 2	8784	158.8	811.9	0.0	0.0	0.0	88.9
Manatee 2	8784	71.4	365.2	1284.0	13.9	1217.6	81.1
Martin 3	8784	13.9	247.4	367.1	1.8	157.7	95.3
Martin 4	8784	1.7	164.3	105.3	2.9	254.0	95.3
Port Everglades 3	8784	20.4	457.1	0.0	0.0	0.0	94.6
Port Everglades 4	8784	68.4	639.5	737.2	8.2	718.3	83.7
Putnam 1	8784	55.8	151.6	104.9	4.9	429.2	92.9
Sanford 4	8784	192.1	614.8	0.0	0.0	0.0	90.8
Sanford 5	8784	209.9	509.6	0.0	0.0	0.0	91.8
Turkey Point 3	8784	3.7	22.6	743.9	9.6	841.0	90.1
Turkey Point 4	8784	90.2	17.0	782.9	9.6	841.0	89.2
St.Lucie 1	8784	2.6	0.0	0.6	0.0	0.0	100.0
St.Lucie 2	8784	12.7	0.0	771.1	9.6	841.0	90.3
Scherer 4	8784	96.4	75.3	0.0	0.0	0.0	98.0

$$\text{ADJ. ACTUAL EAF\%} = 100\% - POF_T - \frac{(EFOH_A + EMOH_A) \times \frac{PH - POH_T}{PH - POH_A}}{PH} \times 100\%$$

ADJUSTMENTS TO AVERAGE NET OPERATING HEAT RATES & ADJUSTMENTS SUMMARY

JANUARY THROUGH DECEMBER, 2000

1	2					3	4	5	6	7	8	9	
						ACTUAL		TARGET (2)	ADJUST.(3)		ADJUST.(5)		ACTUAL
UNIT	HEAT RATE (1) FORMULA					NOF %	ANOHR BTU/KWH	ANOHR AT ACTUAL NOF BTU/KWH	TO ANOHR BTU/KWH	TARGET (4) ANOHR BTU/KWH	ACTUAL ANOHR BTU/KWH	GPIF(6) FROM TABLE	FUEL SAV./(LOSS) $000
Cape Canaveral 1	ANOHR=	-7.68	NOF	+	10099	68.1	9605	9576	29	9511	9541	0.00	0.0
Cape Canaveral 2	ANOHR=	-3.71	NOF	+	9972	63.4	9811	9737	74	9690	9764	0.00	0.0
Lauderdale 4	ANOHR=	-8.00	NOF	+	8135	87.4	7421	7436	-15	7349	7334	0.00	0.0
Lauderdale 5	ANOHR=	-8.64	NOF	+	8205	85.8	7409	7464	-55	7358	7303	0.00	0.0
Fort Myers 2	ANOHR=	-8.34	NOF	+	10086	75.8	9575	9454	121	9321	9442	-3.73	(324.5)
Manatee 2	ANOHR=	-12.47	NOF	+	11026	54.7	10313	10344	-31	10162	10131	0.00	0.0
Martin 3	ANOHR=	-1.63	NOF	+	7156	89.9	6783	7009	-226	6996	6770	6.75	1602.2
Martin 4	ANOHR=	-4.65	NOF	+	7357	93.2	6702	6923	-221	6906	6685	7.21	1534.1
Port Everglades 3	ANOHR=	-22.09	NOF	+	11475	66.0	9900	10017	-117	9748	9631	1.73	232.2
Port Everglades 4	ANOHR=	-24.40	NOF	+	11576	66.5	9937	9954	-17	9664	9647	0.00	0.0
Putnam 1	ANOHR=	-7.86	NOF	+	9658	82.6	9005	9008	-3	8937	8934	0.00	0.0
Sanford 4	ANOHR=	-0.81	NOF	+	10078	58.4	10537	10031	506	10016	10522	-10.00	(1555.4)
Sanford 5	ANOHR=	-2.97	NOF	+	10514	59.9	10293	10336	-43	10290	10247	0.00	0.0
Turkey Point 3	ANOHR=	-34.37	NOF	+	14496	101.1	11051	11021	30	11066	11095	0.00	0.0
Turkey Point 4	ANOHR=	-35.64	NOF	+	14661	100.6	11070	11075	-6	11093	11088	0.00	0.0
St.Lucie 1	ANOHR=	-20.62	NOF	+	12916	102.0	10763	10812	-49	10854	10805	0.00	0.0
St.Lucie 2	ANOHR=	-15.09	NOF	+	12382	100.9	10824	10859	-35	10872	10837	0.00	0.0
Scherer 4	ANOHR=	-13.98	NOF	+	11351	89.1	10152	10105	47	9989	10036	0.00	0.0
													1488.6

1) THESE FORMULAS ARE AS APPROVED BY THE COMMSION IN THE PROJECTED DATA AND REFLECT ON MONTHLY ACTUAL DATA
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 COMMISION 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 COMMISION IN PROJECTED TARGETS.

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2000

UNIT: Cape Canaveral 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	48.42	94.90		+10	509.02	9347	
+9	43.58	94.65		+9	458.12	9356	
+8	38.74	94.40		+8	407.22	9365	
+7	33.89	94.15		+7	356.32	9374	
+6	29.05	93.90		+6	305.41	9383	
+5	24.21	93.65		+5	254.51	9392	
+4	19.37	93.40		+4	203.61	9401	
+3	14.53	93.15		+3	152.71	9410	
+2	9.68	92.90		+2	101.80	9419	
+1	4.84	92.65		+1	50.90	9428	
					0.00	9436	
0	0.00	92.40		0	0.00	9511	<- Adj. Act. HR=9541
					(0.00)	9586	
-1	(-4.88)	92.15		-1	(50.90)	9595	
-2	(-9.76)	91.90		-2	(101.80)	9604	
-3	(-14.63)	91.65		-3	(152.71)	9613	
-4	(-19.51)	91.40		-4	(203.61)	9622	
-5	(-24.39)	91.15		-5	(254.51)	9631	
-6	(-29.27)	90.90		-6	(305.41)	9640	
-7	(-34.15)	90.65	<- Adj. Act. EAF= 90.79	-7	(356.32)	9649	
-8	(-39.02)	90.40		-8	(407.22)	9658	
-9	(-43.90)	90.15		-9	(458.12)	9667	
-10	(-48.78)	89.90		-10	(509.02)	9676	
	WEIGHTING FACTOR =	0.12			WEIGHTING FACTOR =	1.29	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2000

UNIT: Cape Canaveral 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	59.76	80.66		+10	356.40	9531	
+9	53.78	80.41		+9	320.76	9539	
+8	47.81	80.16		+8	285.12	9548	
+7	41.83	79.91		+7	249.48	9556	
+6	35.86	79.66		+6	213.84	9564	
+5	29.88	79.41		+5	178.20	9573	
+4	23.90	79.16		+4	142.56	9581	
+3	17.93	78.91		+3	106.92	9590	
+2	11.95	78.66		+2	71.28	9598	
+1	5.98	78.41		+1	35.64	9606	
					0.00	9615	
0	0.00	78.16		0	0.00	9690	<- Adj. Act. HR=9764
					(0.00)	9765	
-1	(-4.54)	77.91		-1	(35.64)	9773	
-2	(-9.07)	77.66		-2	(71.28)	9781	
-3	(-13.61)	77.41		-3	(106.92)	9790	
-4	(-18.14)	77.16	<- Adj. Act. EAF= 77.21	-4	(142.56)	9798	
-5	(-22.68)	76.91		-5	(178.20)	9807	
-6	(-27.21)	76.66		-6	(213.84)	9815	
-7	(-31.75)	76.41		-7	(249.48)	9823	
-8	(-36.28)	76.16		-8	(285.12)	9832	
-9	(-40.82)	75.91		-9	(320.76)	9840	
-10	(-45.35)	75.66		-10	(356.40)	9848	
	WEIGHTING FACTOR =	0.15			WEIGHTING FACTOR =	0.90	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2000

UNIT: Lauderdale 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	269.54	95.47		+10	450.60	7228	
+9	242.59	95.27		+9	405.54	7233	
+8	215.63	95.07		+8	360.48	7237	
+7	188.68	94.87		+7	315.42	7242	
+6	161.72	94.67		+6	270.36	7247	
+5	134.77	94.47		+5	225.30	7251	
+4	107.82	94.27		+4	180.24	7256	
+3	80.86	94.07		+3	135.18	7261	
+2	53.91	93.87		+2	90.12	7265	
+1	26.95	93.67		+1	45.06	7270	
					0.00	7274	<- Adj. Act. HR=7334
0	0.00	93.47		0	0.00	7349	
					(0.00)	7424	
-1	(-26.91)	93.27		-1	(45.06)	7429	
-2	(-53.82)	93.07		-2	(90.12)	7434	
-3	(-80.73)	92.87		-3	(135.18)	7438	
-4	(-107.64)	92.67		-4	(180.24)	7443	
-5	(-134.55)	92.47		-5	(225.30)	7447	
-6	(-161.45)	92.27		-6	(270.36)	7452	
-7	(-188.36)	92.07		-7	(315.42)	7457	
-8	(-215.27)	91.87		-8	(360.48)	7461	
-9	(-242.18)	91.67		-9	(405.54)	7466	
-10	(-269.09)	91.47	<- Adj. Act. EAF= 91.34	-10	(450.60)	7471	
	WEIGHTING FACTOR =	0.68			WEIGHTING FACTOR =	1.14	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2000

UNIT: Lauderdale 5

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	260.62	95.47		+10	444.16	7237	
+9	234.56	95.27		+9	399.74	7242	
+8	208.50	95.07		+8	355.33	7246	
+7	182.43	94.87		+7	310.91	7251	
+6	156.37	94.67		+6	266.50	7256	
+5	130.31	94.47		+5	222.08	7260	
+4	104.25	94.27		+4	177.66	7265	
+3	78.19	94.07		+3	133.25	7269	
+2	52.12	93.87		+2	88.83	7274	
+1	26.06	93.67		+1	44.42	7278	
					0.00	7283	<- Adj. Act. HR=7303
0	0.00	93.47		0	0.00	7358	
					(0.00)	7433	
-1	(-26.01)	93.27		-1	(44.42)	7438	
-2	(-52.02)	93.07		-2	(88.83)	7442	
-3	(-78.03)	92.87		-3	(133.25)	7447	
-4	(-104.04)	92.67		-4	(177.66)	7451	
-5	(-130.05)	92.47		-5	(222.08)	7456	
-6	(-156.05)	92.27		-6	(266.50)	7460	
-7	(-182.06)	92.07		-7	(310.91)	7465	
-8	(-208.07)	91.87		-8	(355.33)	7469	
-9	(-234.08)	91.67		-9	(399.74)	7474	
-10	(-260.09)	91.47	<- Adj. Act. EAF= 89.94	-10	(444.16)	7479	
	WEIGHTING FACTOR =	0.66			WEIGHTING FACTOR =	1.12	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2000

UNIT: Fort Myers 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	154.40	95.20		+10	869.56	9123	
+9	138.96	94.95		+9	782.61	9135	
+8	123.52	94.70		+8	695.65	9148	
+7	108.08	94.45		+7	608.69	9160	
+6	92.64	94.20		+6	521.74	9172	
+5	77.20	93.95		+5	434.78	9184	
+4	61.76	93.70		+4	347.83	9197	
+3	46.32	93.45		+3	260.87	9209	
+2	30.88	93.20		+2	173.91	9221	
+1	15.44	92.95		+1	86.96	9234	
					0.00	9246	
0	0.00	92.70		0	0.00	9321	
					(0.00)	9396	
-1	(-15.33)	92.45		-1	(86.96)	9408	
-2	(-30.67)	92.20		-2	(173.91)	9420	
-3	(-46.00)	91.95		-3	(260.87)	9433	<- Adj. Act. HR=9442
-4	(-61.33)	91.70		-4	(347.83)	9445	
-5	(-76.67)	91.45		-5	(434.78)	9457	
-6	(-92.00)	91.20		-6	(521.74)	9470	
-7	(-107.33)	90.95		-7	(608.69)	9482	
-8	(-122.66)	90.70		-8	(695.65)	9494	
-9	(-138.00)	90.45		-9	(782.61)	9506	
-10	(-153.33)	90.20	<- Adj. Act. EAF= 88.95	-10	(869.56)	9519	
	WEIGHTING FACTOR =	0.39			WEIGHTING FACTOR =	2.20	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2000

UNIT: Manatee 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	138.93	75.67	<- Adj. Act. EAF= 81.09	+10	1905.64	9729	
+9	125.04	75.27		+9	1715.08	9765	
+8	111.14	74.87		+8	1524.51	9801	
+7	97.25	74.47		+7	1333.95	9837	
+6	83.36	74.07		+6	1143.39	9873	
+5	69.47	73.67		+5	952.82	9908	
+4	55.57	73.27		+4	762.26	9944	
+3	41.68	72.87		+3	571.69	9980	
+2	27.79	72.47		+2	381.13	10016	
+1	13.89	72.07		+1	190.56	10051	
					0.00	10087	<- Adj. Act. HR=10131
0	0.00	71.67		0	0.00	10162	
					(0.00)	10237	
-1	(-13.87)	71.27		-1	(190.56)	10273	
-2	(-27.75)	70.87		-2	(381.13)	10309	
-3	(-41.62)	70.47		-3	(571.69)	10345	
-4	(-55.49)	70.07		-4	(762.26)	10380	
-5	(-69.37)	69.67		-5	(952.82)	10416	
-6	(-83.24)	69.27		-6	(1143.39)	10452	
-7	(-97.11)	68.87		-7	(1333.95)	10488	
-8	(-110.98)	68.47		-8	(1524.51)	10524	
-9	(-124.86)	68.07		-9	(1715.08)	10559	
-10	(-138.73)	67.67		-10	(1905.64)	10595	
	WEIGHTING FACTOR =	0.35			WEIGHTING FACTOR =	4.82	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2000

UNIT: Martin 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	363.06	96.22		+10	2372.12	6697	
+9	326.75	96.02		+9	2134.91	6720	
+8	290.45	95.82		+8	1897.70	6742	
+7	254.14	95.62		+7	1660.49	6764	<- Adj. Act. HR=6770
+6	217.84	95.42		+6	1423.27	6787	
+5	181.53	95.22	<- Adj. Act. EAF= 95.28	+5	1186.06	6809	
+4	145.22	95.02		+4	948.85	6832	
+3	108.92	94.82		+3	711.64	6854	
+2	72.61	94.62		+2	474.42	6876	
+1	36.31	94.42		+1	237.21	6899	
					0.00	6921	
0	0.00	94.22		0	0.00	6996	
					(0.00)	7071	
-1	(-36.27)	94.02		-1	(237.21)	7094	
-2	(-72.54)	93.82		-2	(474.42)	7116	
-3	(-108.80)	93.62		-3	(711.64)	7138	
-4	(-145.07)	93.42		-4	(948.85)	7161	
-5	(-181.34)	93.22		-5	(1186.06)	7183	
-6	(-217.61)	93.02		-6	(1423.27)	7205	
-7	(-253.88)	92.82		-7	(1660.49)	7228	
-8	(-290.14)	92.62		-8	(1897.70)	7250	
-9	(-326.41)	92.42		-9	(2134.91)	7273	
-10	(-362.68)	92.22		-10	(2372.12)	7295	
	WEIGHTING FACTOR =	0.92			WEIGHTING FACTOR =	6.00	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2000

UNIT: Martin 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	467.01	94.13	<- Adj. Act. EAF= 95.26	+10	2126.99	6629	
+9	420.31	93.88		+9	1914.29	6649	
+8	373.61	93.63		+8	1701.59	6669	<- Adj. Act. HR=6685
+7	326.91	93.38		+7	1488.90	6689	
+6	280.21	93.13		+6	1276.20	6709	
+5	233.51	92.88		+5	1063.50	6730	
+4	186.80	92.63		+4	850.80	6750	
+3	140.10	92.38		+3	638.10	6770	
+2	93.40	92.13		+2	425.40	6790	
+1	46.70	91.88		+1	212.70	6810	
					0.00	6831	
0	0.00	91.63		0	0.00	6906	
					(0.00)	6981	
-1	(-46.72)	91.38		-1	(212.70)	7001	
-2	(-93.45)	91.13		-2	(425.40)	7021	
-3	(-140.17)	90.88		-3	(638.10)	7041	
-4	(-186.89)	90.63		-4	(850.80)	7061	
-5	(-233.62)	90.38		-5	(1063.50)	7082	
-6	(-280.34)	90.13		-6	(1276.20)	7102	
-7	(-327.06)	89.88		-7	(1488.90)	7122	
-8	(-373.78)	89.63		-8	(1701.59)	7142	
-9	(-420.51)	89.38		-9	(1914.29)	7162	
-10	(-467.23)	89.13		-10	(2126.99)	7183	
	WEIGHTING FACTOR =	1.18			WEIGHTING FACTOR =	5.38	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2000

UNIT: Port Everglades 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	52.56	97.80		+10	1344.93	9432	
+9	47.30	97.60		+9	1210.44	9456	
+8	42.05	97.40		+8	1075.95	9480	
+7	36.79	97.20		+7	941.45	9504	
+6	31.54	97.00		+6	806.96	9528	
+5	26.28	96.80		+5	672.47	9552	
+4	21.02	96.60		+4	537.97	9577	
+3	15.77	96.40		+3	403.48	9601	
+2	10.51	96.20		+2	268.99	9625	<- Adj. Act. HR=9631
+1	5.26	96.00		+1	134.49	9649	
					0.00	9673	
0	0.00	95.80		0	0.00	9748	
					(0.00)	9823	
-1	(-5.29)	95.60		-1	(134.49)	9847	
-2	(-10.57)	95.40		-2	(268.99)	9871	
-3	(-15.86)	95.20		-3	(403.48)	9895	
-4	(-21.14)	95.00		-4	(537.97)	9919	
-5	(-26.43)	94.80		-5	(672.47)	9944	
-6	(-31.72)	94.60		-6	(806.96)	9968	
-7	(-37.00)	94.40	<- Adj. Act. EAF= 94.56	-7	(941.45)	9992	
-8	(-42.29)	94.20		-8	(1075.95)	10016	
-9	(-47.57)	94.00		-9	(1210.44)	10040	
-10	(-52.86)	93.80		-10	(1344.93)	10064	
	WEIGHTING FACTOR =	0.13			WEIGHTING FACTOR =	3.40	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2000

UNIT: Port Everglades 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	43.09	90.20		+10	1107.53	9350	
+9	38.78	90.00		+9	996.78	9374	
+8	34.47	89.80		+8	886.03	9398	
+7	30.16	89.60		+7	775.27	9422	
+6	25.85	89.40		+6	664.52	9446	
+5	21.55	89.20		+5	553.77	9470	
+4	17.24	89.00		+4	443.01	9494	
+3	12.93	88.80		+3	332.26	9518	
+2	8.62	88.60		+2	221.51	9541	
+1	4.31	88.40		+1	110.75	9565	
					0.00	9589	<- Adj. Act. HR=9647
0	0.00	88.20		0	0.00	9664	
					(0.00)	9739	
-1	(-4.32)	88.00		-1	(110.75)	9763	
-2	(-8.64)	87.80		-2	(221.51)	9787	
-3	(-12.95)	87.60		-3	(332.26)	9811	
-4	(-17.27)	87.40		-4	(443.01)	9835	
-5	(-21.59)	87.20		-5	(553.77)	9859	
-6	(-25.91)	87.00		-6	(664.52)	9883	
-7	(-30.23)	86.80		-7	(775.27)	9907	
-8	(-34.54)	86.60		-8	(886.03)	9930	
-9	(-38.86)	86.40		-9	(996.78)	9954	
-10	(-43.18)	86.20	<- Adj. Act. EAF= 83.72	-10	(1107.53)	9978	
	WEIGHTING FACTOR =	0.11			WEIGHTING FACTOR =	2.80	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2000

UNIT: Putnam 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	115.72	93.15		+10	296.95	8789	
+9	104.15	92.95		+9	267.25	8796	
+8	92.58	92.75	<- Adj. Act. EAF= 92.85	+8	237.56	8804	
+7	81.00	92.55		+7	207.86	8811	
+6	69.43	92.35		+6	178.17	8818	
+5	57.86	92.15		+5	148.47	8826	
+4	46.29	91.95		+4	118.78	8833	
+3	34.72	91.75		+3	89.08	8840	
+2	23.14	91.55		+2	59.39	8848	
+1	11.57	91.35		+1	29.69	8855	
					0.00	8862	<- Adj. Act. HR=8934
0	0.00	91.15		0	0.00	8937	
					(0.00)	9012	
-1	(-11.60)	90.95		-1	(29.69)	9020	
-2	(-23.19)	90.75		-2	(59.39)	9027	
-3	(-34.79)	90.55		-3	(89.08)	9034	
-4	(-46.38)	90.35		-4	(118.78)	9041	
-5	(-57.98)	90.15		-5	(148.47)	9049	
-6	(-69.58)	89.95		-6	(178.17)	9056	
-7	(-81.17)	89.75		-7	(207.86)	9063	
-8	(-92.77)	89.55		-8	(237.56)	9071	
-9	(-104.36)	89.35		-9	(267.25)	9078	
-10	(-115.96)	89.15		-10	(296.95)	9085	
	WEIGHTING FACTOR =	0.29			WEIGHTING FACTOR =	0.75	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2000

UNIT: Sanford 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	57.88	94.80		+10	1555.45	9617	
+9	52.09	94.55		+9	1399.90	9650	
+8	46.30	94.30		+8	1244.36	9682	
+7	40.52	94.05		+7	1088.81	9714	
+6	34.73	93.80		+6	933.27	9747	
+5	28.94	93.55		+5	777.72	9779	
+4	23.15	93.30		+4	622.18	9812	
+3	17.36	93.05		+3	466.63	9844	
+2	11.58	92.80		+2	311.09	9876	
+1	5.79	92.55		+1	155.54	9909	
					0.00	9941	
0	0.00	92.30		0	0.00	10016	
					(0.00)	10091	
-1	(-5.81)	92.05		-1	(155.54)	10124	
-2	(-11.62)	91.80		-2	(311.09)	10156	
-3	(-17.43)	91.55		-3	(466.63)	10189	
-4	(-23.24)	91.30		-4	(622.18)	10221	
-5	(-29.05)	91.05		-5	(777.72)	10253	
-6	(-34.85)	90.80	<- Adj. Act. EAF= 90.81	-6	(933.27)	10286	
-7	(-40.66)	90.55		-7	(1088.81)	10318	
-8	(-46.47)	90.30		-8	(1244.36)	10351	
-9	(-52.28)	90.05		-9	(1399.90)	10383	
-10	(-58.09)	89.80		-10	(1555.45)	10415	<- Adj. Act. HR=10522
	WEIGHTING FACTOR =	0.15			WEIGHTING FACTOR =	3.93	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2000

UNIT: Sanford 5

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	82.82	92.80		+10	1292.84	9883	
+9	74.54	92.45		+9	1163.55	9916	
+8	66.26	92.10		+8	1034.27	9949	
+7	57.97	91.75	<- Adj. Act. EAF= 91.81	+7	904.99	9982	
+6	49.69	91.40		+6	775.70	10016	
+5	41.41	91.05		+5	646.42	10049	
+4	33.13	90.70		+4	517.13	10082	
+3	24.85	90.35		+3	387.85	10115	
+2	16.56	90.00		+2	258.57	10148	
+1	8.28	89.65		+1	129.28	10181	
					0.00	10215	<- Adj. Act. HR=10247
0	0.00	89.30		0	0.00	10290	
					(0.00)	10365	
-1	(-8.30)	88.95		-1	(129.28)	10398	
-2	(-16.61)	88.60		-2	(258.57)	10431	
-3	(-24.91)	88.25		-3	(387.85)	10464	
-4	(-33.21)	87.90		-4	(517.13)	10497	
-5	(-41.52)	87.55		-5	(646.42)	10531	
-6	(-49.82)	87.20		-6	(775.70)	10564	
-7	(-58.12)	86.85		-7	(904.99)	10597	
-8	(-66.42)	86.50		-8	(1034.27)	10630	
-9	(-74.73)	86.15		-9	(1163.55)	10663	
-10	(-83.03)	85.80		-10	(1292.84)	10696	
	WEIGHTING FACTOR =	0.21			WEIGHTING FACTOR =	3.27	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2000

UNIT: Turkey Point 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	3,516.26	87.63	<- Adj. Act. EAF= 90.11	+10	1914.75	10834	
+9	3,164.63	87.33		+9	1723.28	10850	
+8	2,813.01	87.03		+8	1531.80	10865	
+7	2,461.38	86.73		+7	1340.33	10881	
+6	2,109.76	86.43		+6	1148.85	10897	
+5	1,758.13	86.13		+5	957.38	10912	
+4	1,406.50	85.83		+4	765.90	10928	
+3	1,054.88	85.53		+3	574.43	10944	
+2	703.25	85.23		+2	382.95	10959	
+1	351.63	84.93		+1	191.48	10975	
					0.00	10991	
0	0.00	84.63		0	0.00	11066	<- Adj. Act. HR=11095
					(0.00)	11141	
-1	(-351.31)	84.33		-1	(183.91)	11156	
-2	(-702.62)	84.03		-2	(367.82)	11172	
-3	(-1,053.92)	83.73		-3	(551.73)	11188	
-4	(-1,405.23)	83.43		-4	(735.64)	11203	
-5	(-1,756.54)	83.13		-5	(919.55)	11219	
-6	(-2,107.85)	82.83		-6	(1103.45)	11235	
-7	(-2,459.16)	82.53		-7	(1287.36)	11250	
-8	(-2,810.46)	82.23		-8	(1471.27)	11266	
-9	(-3,161.77)	81.93		-9	(1655.18)	11281	
-10	(-3,513.08)	81.63		-10	(1839.09)	11297	
	WEIGHTING FACTOR =	8.89			WEIGHTING FACTOR =	4.84	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2000

UNIT: Turkey Point 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	3,502.79	87.63	<- Adj. Act. EAF= 89.20	+10	2197.72	10837	
+9	3,152.51	87.33		+9	1977.95	10855	
+8	2,802.23	87.03		+8	1758.18	10873	
+7	2,451.95	86.73		+7	1538.40	10891	
+6	2,101.67	86.43		+6	1318.63	10909	
+5	1,751.40	86.13		+5	1098.86	10928	
+4	1,401.12	85.83		+4	879.09	10946	
+3	1,050.84	85.53		+3	659.32	10964	
+2	700.56	85.23		+2	439.54	10982	
+1	350.28	84.93		+1	219.77	11000	
					0.00	11018	<- Adj. Act. HR=11088
0	0.00	84.63		0	0.00	11093	
					(0.00)	11168	
-1	(-350.02)	84.33		-1	(263.05)	11186	
-2	(-700.05)	84.03		-2	(526.10)	11204	
-3	(-1,050.07)	83.73		-3	(789.15)	11223	
-4	(-1,400.09)	83.43		-4	(1052.20)	11241	
-5	(-1,750.12)	83.13		-5	(1315.25)	11259	
-6	(-2,100.14)	82.83		-6	(1578.29)	11277	
-7	(-2,450.16)	82.53		-7	(1841.34)	11295	
-8	(-2,800.18)	82.23		-8	(2104.39)	11313	
-9	(-3,150.21)	81.93		-9	(2367.44)	11331	
-10	(-3,500.23)	81.63		-10	(2630.49)	11349	
	WEIGHTING FACTOR =	8.86			WEIGHTING FACTOR =	5.56	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2000

UNIT: St.Lucie 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	4,597.41	96.60	<- Adj. Act. EAF= 99.97	+10	1163.21	10699	
+9	4,137.67	96.30		+9	1046.89	10707	
+8	3,677.93	96.00		+8	930.57	10715	
+7	3,218.19	95.70		+7	814.25	10723	
+6	2,758.45	95.40		+6	697.93	10731	
+5	2,298.71	95.10		+5	581.61	10739	
+4	1,838.96	94.80		+4	465.28	10747	
+3	1,379.22	94.50		+3	348.96	10755	
+2	919.48	94.20		+2	232.64	10763	
+1	459.74	93.90		+1	116.32	10771	
					0.00	10779	<- Adj. Act. HR=10805
0	0.00	93.60		0	0.00	10854	
					(0.00)	10929	
-1	(-458.90)	93.30		-1	(120.55)	10937	
-2	(-917.80)	93.00		-2	(241.10)	10945	
-3	(-1,376.71)	92.70		-3	(361.64)	10953	
-4	(-1,835.61)	92.40		-4	(482.19)	10961	
-5	(-2,294.51)	92.10		-5	(602.74)	10969	
-6	(-2,753.41)	91.80		-6	(723.29)	10977	
-7	(-3,212.31)	91.50		-7	(843.84)	10985	
-8	(-3,671.22)	91.20		-8	(964.38)	10993	
-9	(-4,130.12)	90.90		-9	(1084.93)	11001	
-10	(-4,589.02)	90.60		-10	(1205.48)	11009	
	WEIGHTING FACTOR =	11.62			WEIGHTING FACTOR =	2.94	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2000

UNIT: St.Lucie 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	3,497.10	87.63	<- Adj. Act. EAF= 90.26	+10	763.55	10743	
+9	3,147.39	87.33		+9	687.20	10749	
+8	2,797.68	87.03		+8	610.84	10754	
+7	2,447.97	86.73		+7	534.49	10759	
+6	2,098.26	86.43		+6	458.13	10765	
+5	1,748.55	86.13		+5	381.78	10770	
+4	1,398.84	85.83		+4	305.42	10776	
+3	1,049.13	85.53		+3	229.07	10781	
+2	699.42	85.23		+2	152.71	10786	
+1	349.71	84.93		+1	76.35	10792	
					0.00	10797	<- Adj. Act. HR=10837
0	0.00	84.63		0	0.00	10872	
					(0.00)	10947	
-1	(-349.43)	84.33		-1	(116.32)	10952	
-2	(-698.85)	84.03		-2	(232.64)	10958	
-3	(-1,048.28)	83.73		-3	(348.96)	10963	
-4	(-1,397.70)	83.43		-4	(465.28)	10969	
-5	(-1,747.13)	83.13		-5	(581.61)	10974	
-6	(-2,096.56)	82.83		-6	(697.93)	10979	
-7	(-2,445.98)	82.53		-7	(814.25)	10985	
-8	(-2,795.41)	82.23		-8	(930.57)	10990	
-9	(-3,144.83)	81.93		-9	(1046.89)	10995	
-10	(-3,494.26)	81.63		-10	(1163.21)	11001	
	WEIGHTING FACTOR =	8.84			WEIGHTING FACTOR =	1.93	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2000

UNIT: Scherer 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	1,010.21	96.70	<- Adj. Act. EAF= 98.04	+10	647.47	9838	
+9	909.19	96.45		+9	582.73	9846	
+8	808.17	96.20		+8	517.98	9854	
+7	707.15	95.95		+7	453.23	9861	
+6	606.13	95.70		+6	388.48	9869	
+5	505.11	95.45		+5	323.74	9876	
+4	404.08	95.20		+4	258.99	9884	
+3	303.06	94.95		+3	194.24	9892	
+2	202.04	94.70		+2	129.49	9899	
+1	101.02	94.45		+1	64.75	9907	
					0.00	9914	
0	0.00	94.20		0	0.00	9989	<- Adj. Act. HR=10036
					(0.00)	10064	
-1	(-146.03)	93.95		-1	(64.75)	10072	
-2	(-292.06)	93.70		-2	(129.49)	10080	
-3	(-438.10)	93.45		-3	(194.24)	10087	
-4	(-584.13)	93.20		-4	(258.99)	10095	
-5	(-730.16)	92.95		-5	(323.74)	10103	
-6	(-876.19)	92.70		-6	(388.48)	10110	
-7	(-1,022.22)	92.45		-7	(453.23)	10118	
-8	(-1,168.26)	92.20		-8	(517.98)	10125	
-9	(-1,314.29)	91.95		-9	(582.73)	10133	
-10	(-1,460.32)	91.70		-10	(647.47)	10141	
	WEIGHTING FACTOR =	2.55			WEIGHTING FACTOR =	1.63	

ACTUAL OUTAGE SCHEDULE

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2000

PLANT/UNIT	ACTUAL OUTAGES	REASON FOR OUTAGE
Cape Canaveral 1	NONE	
Cape Canaveral 2	10/20/2000 - 12/18/2000	Turbine Upgrade
Lauderdale 4	2/27/2000 - 3/09/2000	Combustion Turbine Overhaul
Lauderdale 5	3/11/2000 - 03/20/2000	Combustion Turbine Overhaul
Fort Myers 2	NONE	
Manatee 2	2/18/2000 - 4/11/2000	Turbine/Gen. Overhaul
Martin 3	3/12/2000 - 4/05/2000	Combustion Turbine Overhaul
Martin 4	11/13/2000 - 11/22/2000	Combustion Turbine Overhaul
Port Everglades 3	NONE	
Port Everglades 4	3/07/2000 - 3/14/2000	Generator Overhaul
Putnam 1	12/05/2000 - 12/13/2000	Combustion Turbine Overhaul
Sanford 4	NONE	
Sanford 5	NONE	
Turkey Point 3	2/28/2000 - 3/27/2000	Refueling
Turkey Point 4	9/25/2000 - 10/24/2000	Refueling
St.Lucie 1	NONE	
St.Lucie 2	4/17/2000 - 5/20/2000	Refueling
Scherer 4	NONE	

DOCUMENT NO. 1

WITNESS: R. SILVA

DOCKET NO. 010001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2002

DOCUMENT NUMBER 1 INDEX

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2002

DOCUMENT	INDEX OF MANUAL PAGES	TITLES
1	7.201.001	Index of Manual Pages
	7.201.002 to 7.201.003	Generating Unit Selection Criteria
	7.201.004	GPIF Reward/(Penalty) Table (Estimated)
	7.201.005	GPIF calculation of Maximum Allowed Dollars (Estimated)
	7.201.006 and 7.201.007	GPIF Target and Range Summary
	7.201.008	GPIF Predicted Unit Heat Rates
	7.201.009	Derivation of Weighting Factors
	7.201.010	Estimated Unit Performance Data
	7.201.011 - 7.201.032	Unit MOF and FOF Versus Time Graphs
	7.201.033	Planned Outages Schedules (Estimated)

Table 2.0
POWRSYM Projected System Generation
Period Of: January Through December 2002

Name	Capacity* (MW)	Service Hours	Net Output MWH	NOF %	% of Total Output	Cumulative % of Total Output	Production Cost ($000)
Ft. Myers Repowering	1,483	4,889	7,234,567	100%	8.6	8.6	192,069
St. Lucie 1	845	7,837	6,626,386	100%	7.9	16.5	21,587
St. Lucie 2	719	8,538	6,140,276	100%	7.3	23.8	19,940
Turkey Point 3	703	8,538	6,003,740	100%	7.1	30.9	19,526
Turkey Point 4	703	7,837	5,513,318	100%	6.5	37.4	16,994
Scherer 4	645	7,057	4,547,052	100%	5.4	42.8	83,718
Sanford Repowering 5	969	4,148	3,967,667	99%	4.7	47.5	106,816
Martin 4	457	7,835	3,515,966	98%	4.2	51.7	94,640
Martin 3	457	7,702	3,482,294	99%	4.1	55.9	94,277
Manatee 2	801	4,577	3,399,288	93%	4.0	59.9	126,842
Martin 2	812	4,091	3,108,268	94%	3.7	63.6	119,805
Lauderdale 5	430	6,858	2,900,226	98%	3.4	67.0	79,817
Lauderdale 4	430	6,861	2,866,302	97%	3.4	70.4	78,881
Manatee 1	801	3,420	2,482,706	91%	2.9	73.4	93,668
Cape Canaveral 1	396	6,031	2,300,068	96%	2.7	76.1	81,108
Port Everglades 4	403	5,314	2,069,470	97%	2.5	78.6	74,481
Port Everglades 3	391	5,176	1,954,462	97%	2.3	80.9	70,484
Martin 1	822	2,630	1,938,634	90%	2.3	83.2	76,052
Turkey Point 1	396	4,687	1,774,562	96%	2.1	85.3	64,698
Riviera 3	279	6,200	1,665,641	96%	2.0	87.3	53,790
Cape Canaveral 2	396	4,154	1,553,029	94%	1.8	89.1	56,978
Riviera 4	291	5,558	1,547,810	96%	1.8	91.0	50,967
Putnam 1	244	4,976	1,118,558	92%	1.3	92.3	40,077
Turkey Point 2	396	2,996	1,101,349	93%	1.3	93.6	41,345
St. Johns River 1	128	8,126	1,042,312	100%	1.2	94.8	15,442
St. Johns River 2	128	7,436	953,821	100%	1.1	96.0	13,709
Putnam 2	244	4,427	942,264	87%	1.1	97.1	34,376
Sanford Repower 4	969	679	654,835	100%	0.8	97.9	18,694
Port Everglades 2	211	2,972	586,535	93%	0.7	98.6	22,040
Port Everglades 1	211	1,671	324,319	92%	0.4	99.0	12,400
Martin SC 8	325	870	239,221	85%	0.3	99.2	9,630
Sanford 3	582	1,238	164,461	23%	0.2	99.4	6,523
Ft. Myers GT 1-12	582	295	154,987	90%	0.2	99.6	12,010
Cutler 6	144	1,104	141,318	89%	0.2	99.8	6,302
Ft. lauderdale GT 1-24	719	114	72,006	88%	0.1	99.9	4,205
Cutler 5	71	984	62,335	89%	0.1	99.9	3,056
Ft. Myers CT 1-6	990	19	17,707	94%	0.0	100.0	703
Port Everglades GT 1-1	363	42	14,543	95%	0.0	100.0	993
Sanford 4	374	42	13,668	87%	0.0	100.0	482
Total	20,309	167,929	84,195,971		100.0	100.0	1,919,126

*From E4 Schedule (simple avg 5 month of winter + 7 month of summer)

FLORIDA POWER & LIGHT COMPANY
UNITS TO BE USED TO DETERMINE THE
GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2002

Cape Canaveral Unit No. 1
Cape Canaveral Unit No.2

Lauderdale Unit No.4
Lauderdale Unit No.5

Manatee Unit No.1
Manatee Unit No.2

Martin Unit No.1
Martin Unit No.2

Martin Unit No.3
Martin Unit No.4

Port Everglades Unit No.3
Port Everglades Unit No.4

Putnam Unit No. 1

Riviera Unit No. 3
Riviera Unit No. 4

Scherer Unit No.4

St.Lucie Unit No.1
St.Lucie Unit No.2

Turkey Point Unit No.1
Turkey Point Unit No.2

Turkey Point Unit No.3
Turkey Point Unit No.4

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2002

Generating Performance Incentive Points (GPIF)	Fuel Savings/(Loss) ($000)	Generating Performance Incentive Factor ($000)
+ 10	62,576	22,268
+ 9	56,318	20,041
+ 8	50,061	17,814
+ 7	43,803	15,588
+ 6	37,546	13,361
+ 5	31,288	11,134
+ 4	25,030	8,907
+ 3	18,773	6,680
+ 2	12,515	4,454
+ 1	6,258	2,227
0	0	0
- 1	(6,703)	(2,227)
- 2	(13,405)	(4,454)
- 3	(20,108)	(6,680)
- 4	(26,810)	(8,907)
- 5	(33,513)	(11,134)
- 6	(40,216)	(13,361)
- 7	(46,918)	(15,588)
- 8	(53,621)	(17,814)
- 9	(60,323)	(20,041)
- 10	(67,026)	(22,268)

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ESTIMATED

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2002

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$	5,361,894,538
LINE 2	MONTH OF JANUARY	2002	$	5,374,905,335
LINE 3	MONTH OF FEBRUARY	2002	$	5,430,754,397
LINE 4	MONTH OF MARCH	2002	$	5,444,356,294
LINE 5	MONTH OF APRIL	2002	$	5,453,506,251
LINE 6	MONTH OF MAY	2002	$	5,461,712,291
LINE 7	MONTH OF JUNE	2002	$	5,497,534,800
LINE 8	MONTH OF JULY	2002	$	5,497,510,626
LINE 9	MONTH OF AUGUST	2002	$	5,509,469,337
LINE 10	MONTH OF SEPTEMBER	2002	$	5,508,889,456
LINE 11	MONTH OF OCTOBER	2002	$	5,466,342,767
LINE 12	MONTH OF NOVEMBER	2002	$	5,449,200,857
LINE 13	MONTH OF DECEMBER	2002	$	5,444,606,781
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE 1 THROUGH LINE 13 DIVIDED BY 13)		$	5,453,898,000
LINE 15	25 BASIS POINTS			0.0025
LINE 16	REVENUE EXPANSION FACTOR			60.4594%
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$	22,551,903
LINE 18	JURISDICTIONAL SALES			94,729,311,256 KWH
LINE 19	TOTAL SALES			95,936,600,369 KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)			98.74%
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS		$	22,268,104

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2002

Plant / Unit	Weighting Factor (%)	EAF Target (%)	EAF Range Max. (%)	EAF Range Min. (%)	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Cape Canaveral 1	0.60	90.3	93.3	87.3	375.0	-375.9
Cape Canaveral 2	0.43	88.2	91.2	85.2	268.4	-270.4
Lauderdale 4	1.37	91.8	94.3	89.3	855.8	-858.9
Lauderdale 5	1.35	91.9	94.4	89.4	844.8	-845.9
Manatee 1	0.68	81.5	84.5	78.5	426.5	-430.6
Manatee 2	0.63	85.4	87.9	82.9	397.3	-398.1
Martin 1	0.56	89.2	91.7	86.7	351.1	-351.1
Martin 2	0.63	90.8	93.3	88.3	395.6	-396.8
Martin 3	1.54	94.9	97.4	92.4	965.5	-969.3
Martin 4	1.54	87.9	90.4	85.4	965.9	-965.8
Port Everglades 3	0.44	94.3	96.8	91.8	272.9	-273.2
Port Everglades 4	0.44	86.0	88.5	83.5	277.2	-277.4
Putnam 1	0.23	84.7	87.2	82.2	141.7	-142.1
Riviera 3	0.81	84.4	87.9	80.9	505.9	-504.1
Riviera 4	0.54	93.1	95.6	90.6	339.5	-337.9
Turkey Point 1	0.42	85.4	87.9	82.9	261.0	-260.8
Turkey Point 2	0.33	94.3	96.8	91.8	207.8	-207.2
Turkey Point 3	8.45	93.6	96.6	90.6	5,289.6	-6,359.7
Turkey Point 4	7.75	86.0	89.0	83.0	4,849.2	-5,829.3
St. Lucie 1	9.44	86.0	89.0	83.0	5,908.3	-7,103.6
St. Lucie 2	8.69	93.6	96.6	90.6	5,438.7	-6,538.9
Scherer 4	3.16	84.4	86.4	82.4	1,976.4	-1,966.2
	50.04				31,314.0	-35,663.2

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2002

Plant / Unit	Weighting Factor (%)	ANOHR TARGET BTU/KWH	NOF	ANOHR RANGE BTU/KWH	BTU/KWH	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Cape Canaveral 1	1.12	9,163	96.4	9,009	9,317	700.1	-700.1
Cape Canaveral 2	1.49	9,209	94.5	8,983	9,434	930.8	-930.8
Lauderdale 4	2.27	7,351	97.3	7,143	7,559	1,422.7	-1,422.7
Lauderdale 5	2.17	7,303	98.5	7,103	7,502	1,358.5	-1,358.5
Manatee 1	1.81	9,861	90.6	9,667	10,055	1,133.9	-1,133.9
Manatee 2	2.83	10,054	92.7	9,839	10,269	1,769.9	-1,769.9
Martin 1	4.05	9,147	89.7	8,767	9,527	2,535.4	-2,535.4
Martin 2	6.42	8,884	93.5	8,511	9,257	4,019.6	-4,019.6
Martin 3	2.45	6,828	98.9	6,642	7,014	1,532.7	-1,532.7
Martin 4	2.50	6,734	98.2	6,548	6,921	1,563.8	-1,563.8
Port Everglades 3	2.34	9,355	96.6	9,086	9,625	1,464.3	-1,464.3
Port Everglades 4	3.00	9,192	96.7	8,886	9,499	1,878.3	-1,878.3
Putnam 1	1.16	8,679	92.3	8,447	8,911	724.4	-724.4
Riviera 3	1.36	9,809	96.3	9,578	10,039	852.7	-852.7
Riviera 4	1.08	9,797	95.8	9,592	10,002	676.9	-676.9
Turkey Point 1	2.08	8,960	95.7	8,704	9,216	1,304.3	-1,304.3
Turkey Point 2	1.23	9,410	92.9	9,160	9,660	768.0	-768.0
Turkey Point 3	1.69	11,137	100.0	10,967	11,307	1,058.3	-1,010.6
Turkey Point 4	1.20	11,079	100.1	10,848	11,310	748.6	-745.3
St. Lucie 1	2.75	10,793	100.1	10,673	10,913	1,718.5	-1,682.8
St. Lucie 2	4.12	10,826	100.0	10,716	10,937	2,575.6	-2,761.5
Scherer 4	0.84	10,098	99.9	9,960	10,236	525.3	-525.3
	49.96					31,263	-31,362

PROJECTED UNIT HEAT RATE EQUATIONS
FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2002

				ANOHR Equation						
Plant/Unit	ANOHR	NOF	NSC	a	b	Bounds	R-sqr	First	Last	Exclusions
Cape Canaveral 1	9163	96	396	10788	-17	154	0.57	06-98	05-01	11-99
Cape Canaveral 2	9209	94	396	10900	-18	225	0.45	06-98	05-01	11-00
Lauderdale 4	7351	97	430	8271	-9	208	0.37	06-98	05-01	No exclusions
Lauderdale 5	7303	98	430	8470	-12	199	0.50	06-98	05-01	No exclusions
Manatee 1	9861	91	801	11200	-15	194	0.47	06-98	05-01	11-98, 11-00
Manatee 2	10054	93	801	10668	-7	215	0.08	06-98	05-01	02-00-03-00
Martin 1	9147	90	822	11785	-29	380	0.43	06-98	05-01	02-99 - 04-99, 02-01
Martin 2	8884	94	812	11702	-30	373	0.49	06-98	05-01	12-98, 02-99, 03-99
Martin 3	6828	99	457	6891	-1	186	0.00	06-98	05-01	No exclusions
Martin 4	6734	98	457	7134	-4	186	0.17	06-98	05-01	No exclusions
Port Everglades 3	9355	97	391	11090	-18	269	0.38	06-98	05-01	04-99, 03-01
Port Everglades 4	9192	97	403	11568	-25	307	0.51	06-98	05-01	No exclusions
Putnam 1	8679	92	244	11676	-32	232	0.83	06-98	05-01	04-99, 01-01
Riviera 3	9809	96	279	11282	-15	230	0.63	06-98	05-01	02-00
Riviera 4	9797	96	291	11109	-14	205	0.51	06-98	05-01	11-99
Turkey Point 1	8960	96	396	10909	-20	256	0.53	06-98	05-01	No exclusions
Turkey Point 2	9410	93	396	10372	-10	250	0.19	06-98	05-01	No exclusions
Turkey Point 3	11137	100	703	17338	-62	170	0.69	06-98	05-01	10-98, 03-00
Turkey Point 4	11079	100	703	13771	-27	231	0.49	06-98	05-01	No exclusions
St. Lucie 1	10793	100	845	12345	-16	120	0.37	06-98	05-01	04-01
St. Lucie 2	10826	100	719	12021	-12	110	0.27	06-98	05-01	No exclusions
Scherer 4	10098	100	645	10955	-9	138	0.10	06-98	05-01	07-98, 11-99, 04-01

DERIVATION OF WEIGHT FACTORS

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2002

PRODUCTION COSTING SIMULATION
FUEL COST ($000'S)

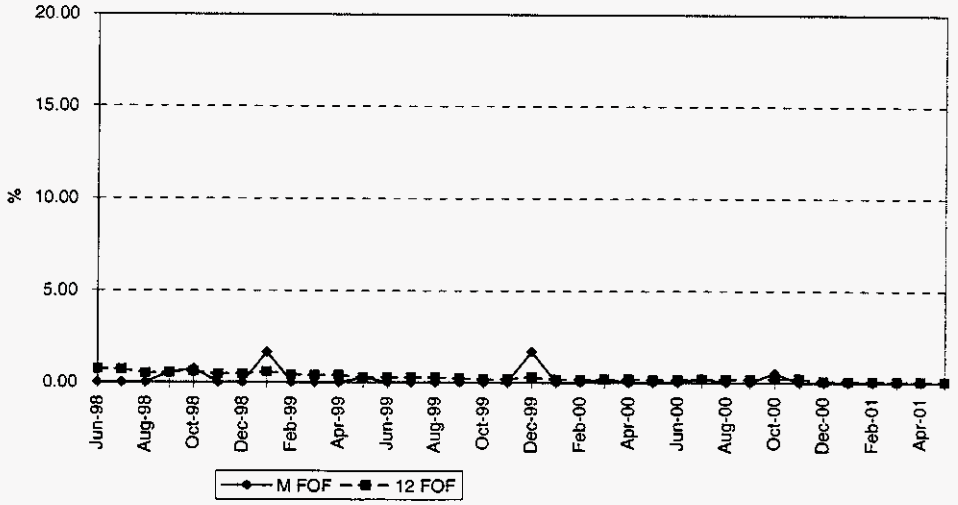
Unit	Performance Indicator	At Target (1)	At Maximum Improvement (2)	Savings (3)	Factor (% Of Savings)
Cape Canaveral 1	EAF	1,919,126	1,919,501	375.0	0.60
	ANOHR	1,919,126	1,919,826	700.1	1.12
Cape Canaveral 2	EAF	1,919,126	1,919,395	268.4	0.43
	ANOHR	1,919,126	1,920,057	930.8	1.49
Lauderdale 4	EAF	1,919,126	1,919,982	855.8	1.37
	ANOHR	1,919,126	1,920,549	1,422.7	2.27
Lauderdale 5	EAF	1,919,126	1,919,971	844.8	1.35
	ANOHR	1,919,126	1,920,485	1,358.5	2.17
Manatee 1	EAF	1,919,126	1,919,553	426.5	0.68
	ANOHR	1,919,126	1,920,260	1,133.9	1.81
Manatee 2	EAF	1,919,126	1,919,524	397.3	0.63
	ANOHR	1,919,126	1,920,896	1,769.9	2.83
Martin 1	EAF	1,919,126	1,919,477	351.1	0.56
	ANOHR	1,919,126	1,921,662	2,535.4	4.05
Martin 2	EAF	1,919,126	1,919,522	395.6	0.63
	ANOHR	1,919,126	1,923,146	4,019.6	6.42
Martin 3	EAF	1,919,126	1,920,092	965.5	1.54
	ANOHR	1,919,126	1,920,659	1,532.7	2.45
Martin 4	EAF	1,919,126	1,920,092	965.9	1.54
	ANOHR	1,919,126	1,920,690	1,563.8	2.50
Port Everglades 3	EAF	1,919,126	1,919,399	272.9	0.44
	ANOHR	1,919,126	1,920,591	1,464.3	2.34
Port Everglades 4	EAF	1,919,126	1,919,403	277.2	0.44
	ANOHR	1,919,126	1,921,005	1,878.3	3.00
Putnam 1	EAF	1,919,126	1,919,268	141.7	0.23
	ANOHR	1,919,126	1,919,851	724.4	1.16
Riviera 3	EAF	1,919,126	1,919,632	505.9	0.81
	ANOHR	1,919,126	1,919,979	852.7	1.36
Riviera 4	EAF	1,919,126	1,919,466	339.5	0.54
	ANOHR	1,919,126	1,919,803	676.9	1.08
Turkey Point 1	EAF	1,919,126	1,919,387	261.0	0.42
	ANOHR	1,919,126	1,920,431	1,304.3	2.08
Turkey Point 2	EAF	1,919,126	1,919,334	207.8	0.33
	ANOHR	1,919,126	1,919,894	768.0	1.23
Turkey Point 3	EAF	1,919,126	1,924,416	5,289.6	8.45
	ANOHR	1,919,126	1,920,185	1,058.3	1.69
Turkey Point 4	EAF	1,919,126	1,923,975	4,849.2	7.75
	ANOHR	1,919,126	1,919,875	748.6	1.20
St. Lucie 1	EAF	1,919,126	1,925,035	5,908.3	9.44
	ANOHR	1,919,126	1,920,845	1,718.5	2.75
St. Lucie 2	EAF	1,919,126	1,924,565	5,438.7	8.69
	ANOHR	1,919,126	1,921,702	2,575.6	4.12
Scherer 4	EAF	1,919,126	1,921,103	1,976.4	3.16
	ANOHR	1,919,126	1,919,652	525.3	0.84
	TOTAL			62,576.8	100.00

(1) FUEL ADJUSTMENT MID BAND CASE - ALL UNIT PERFORMANCE INDICATORS AT TARGET
(2) ALL OTHER UNIT PERFORMANCE AT TARGET
(3) EXPRESSED IN REPLACEMENT ENERGY COSTS.

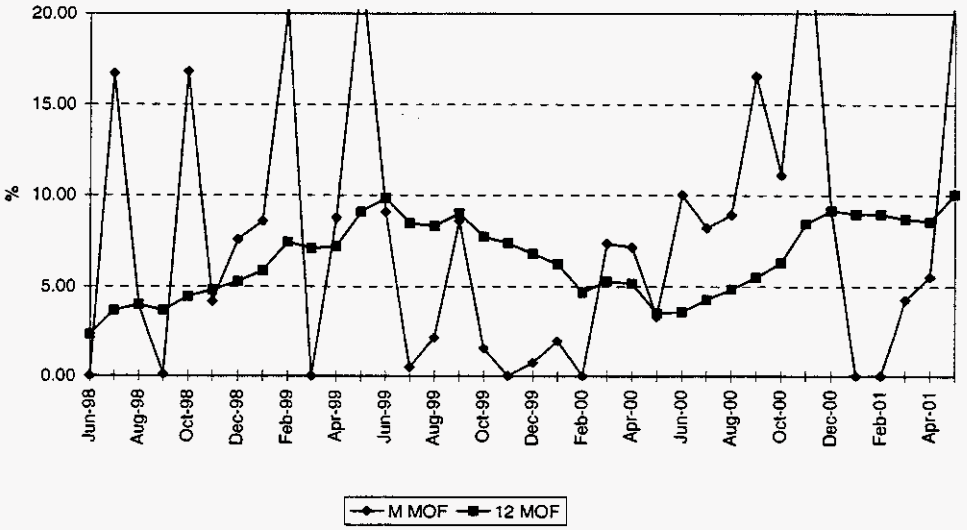
ESTIMATED UNIT PERFORMANCE DATA
FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2002

Plant/Unit	EAF	EPOF	EUOF	EUOR	PH	SH	RSH	UH	EPOH	EFOH	EMOH	NET_GEN
Cape Canaveral 1	90.3	0.0	9.7	12.3	8,760	6,031	1,879	850	0	175	675	2,300,068
Cape Canaveral 2	88.2	3.8	7.7	14.0	8,760	4,154	3,599	1,007	333	166	508	1,553,029
Lauderdale 4	91.8	2.7	5.5	6.6	8,760	6,861	1,181	718	237	166	315	2,866,302
Lauderdale 5	91.9	2.7	5.4	6.5	8,760	6,858	1,192	710	237	166	307	2,900,226
Manatee 1	81.5	7.7	10.8	21.7	8,760	3,420	3,719	1,621	675	158	788	2,482,706
Manatee 2	85.4	7.9	6.4	10.9	8,760	4,577	2,930	1,253	692	158	403	3,399,288
Martin 1	89.2	4.1	6.4	17.6	8,760	2,630	5,210	920	359	210	350	1,938,634
Martin 2	90.8	4.1	4.8	9.3	8,760	4,091	3,889	780	359	166	254	3,108,268
Martin 3	94.9	0.0	5.1	5.5	8,760	7,702	611	447	0	175	272	3,482,294
Martin 4	87.9	4.2	5.4	5.7	8,760	7,835	84	841	368	280	193	3,515,966
Port Everglades 3	94.3	0.0	5.7	8.8	8,760	5,176	3,085	499	0	175	324	1,954,462
Port Everglades 4	86.0	7.9	5.8	8.7	8,760	5,314	2,246	1,200	692	158	350	2,069,470
Putnam 1	84.7	4.8	5.7	9.1	8,760	4,976	2,864	920	420	333	166	1,118,558
Riviera 3	84.4	0.0	15.6	18.1	8,760	6,200	1,193	1,367	0	429	937	1,665,641
Riviera 4	93.1	0.0	6.9	9.8	8,760	5,558	2,598	604	0	175	429	1,547,810
Turkey Point 1	85.4	7.4	6.9	11.4	8,760	4,687	2,820	1,253	648	166	438	1,774,562
Turkey Point 2	94.3	0.0	5.7	14.3	8,760	2,996	5,265	499	0	175	324	1,101,349
Turkey Point 3	93.6	0.0	6.4	6.4	8,760	8,199	0	561	0	280	280	6,003,740
Turkey Point 4	86.0	8.2	5.8	6.3	8,760	7,532	0	1,228	720	254	254	5,513,318
St. Lucie 1	86.0	8.2	5.8	6.3	8,760	7,532	0	1,228	720	254	254	6,626,386
St. Lucie 2	93.6	0.0	6.4	6.4	8,760	8,199	0	561	0	280	280	6,140,276
Scherer 4	84.4	11.8	3.6	4.3	8,760	7,057	354	1,349	1,034	158	158	4,547,052

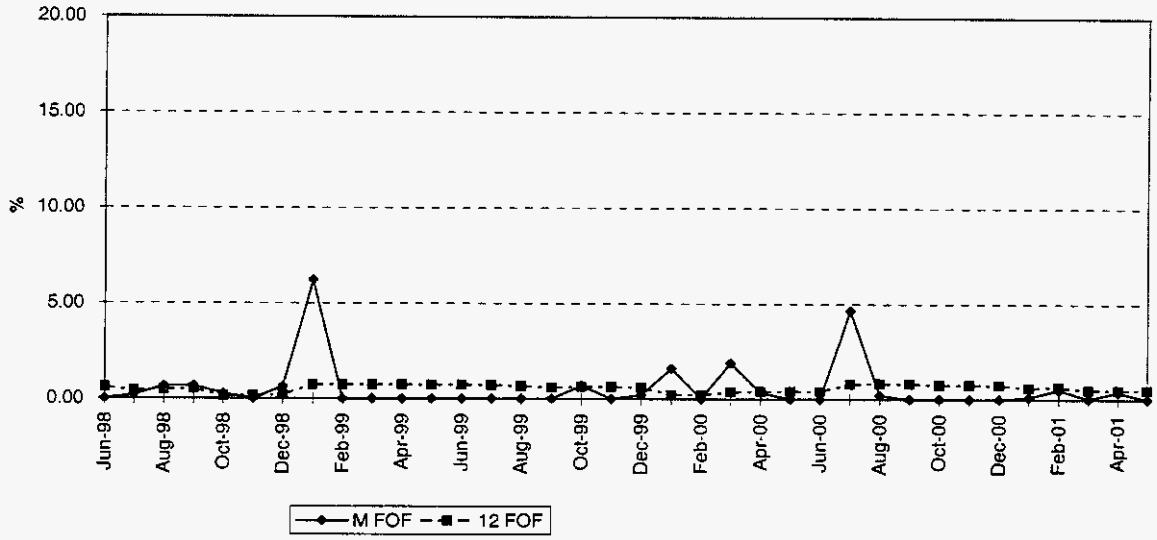
PCC 1
FORCED OUTAGE FACTOR



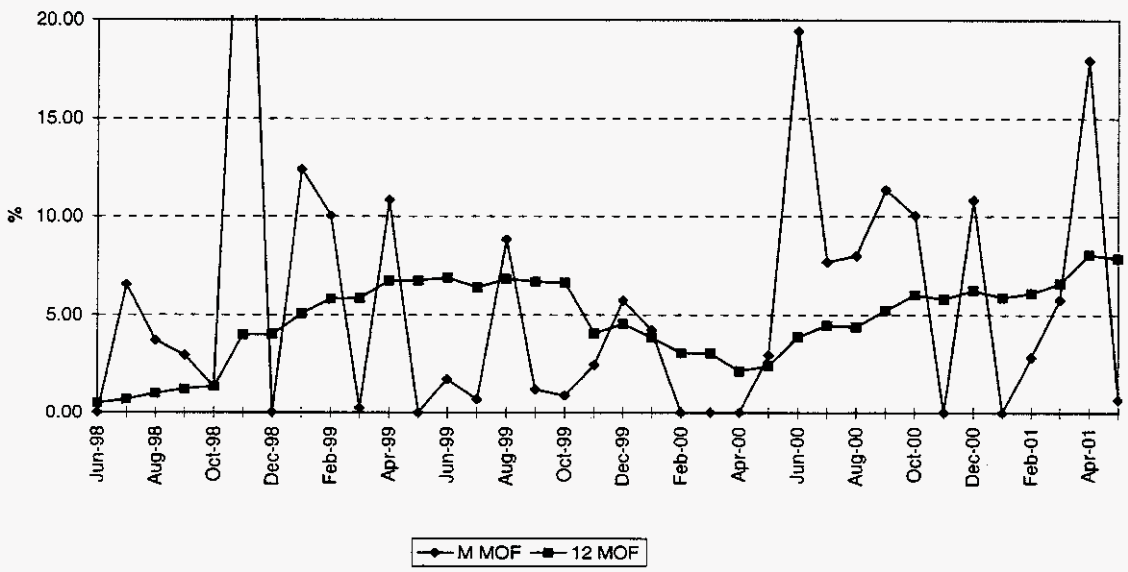
MAINTENANCE OUTAGE FACTOR



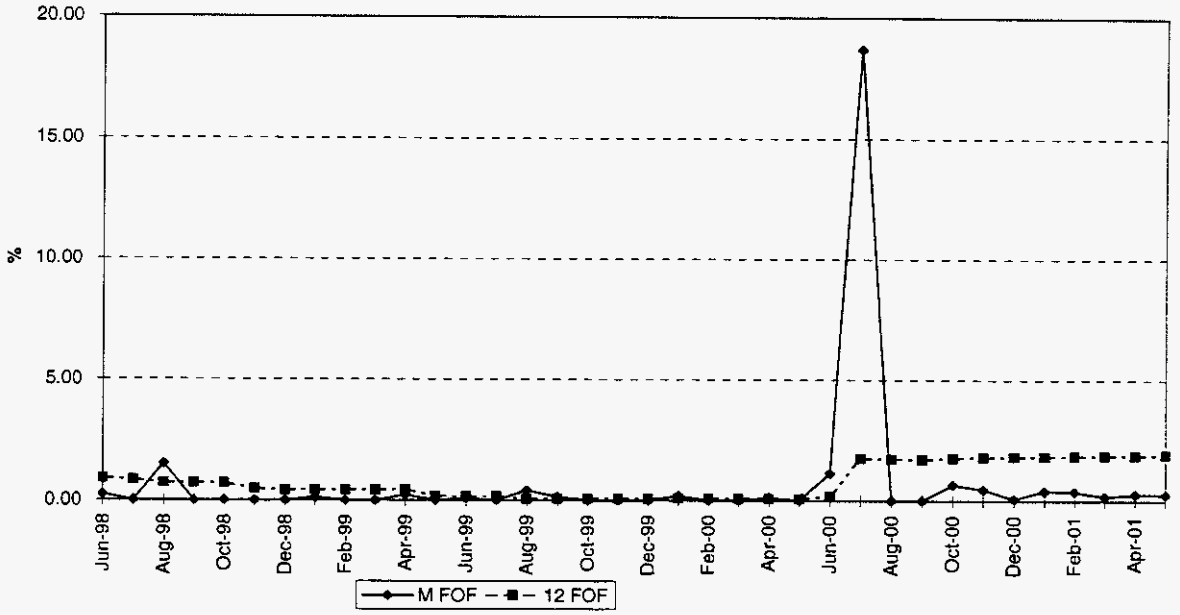
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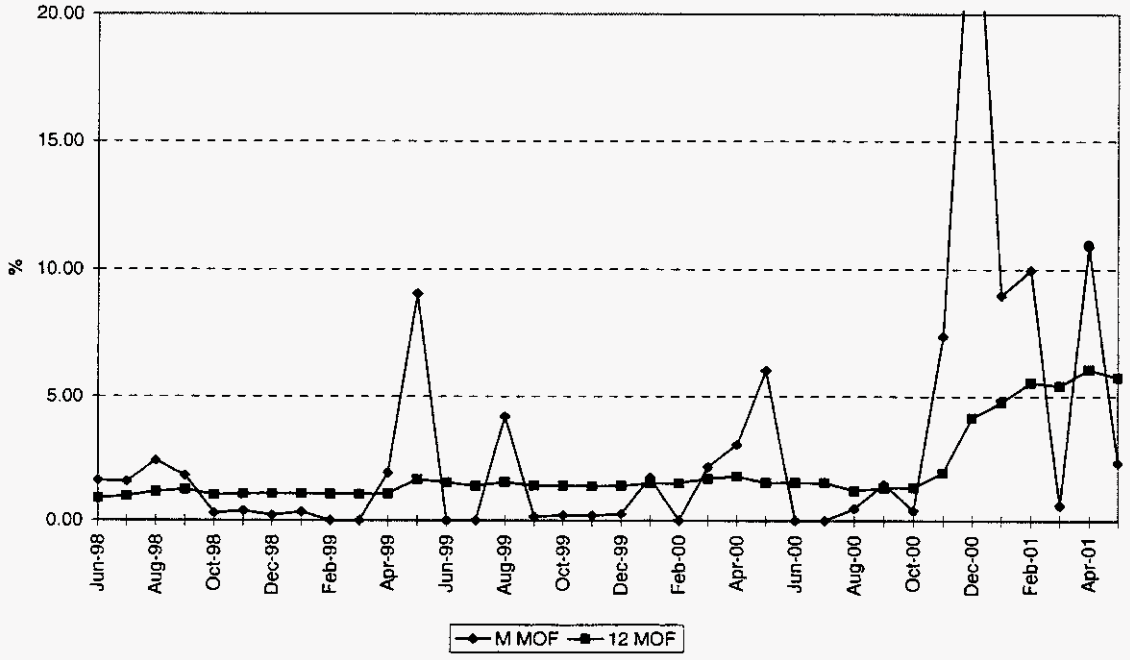
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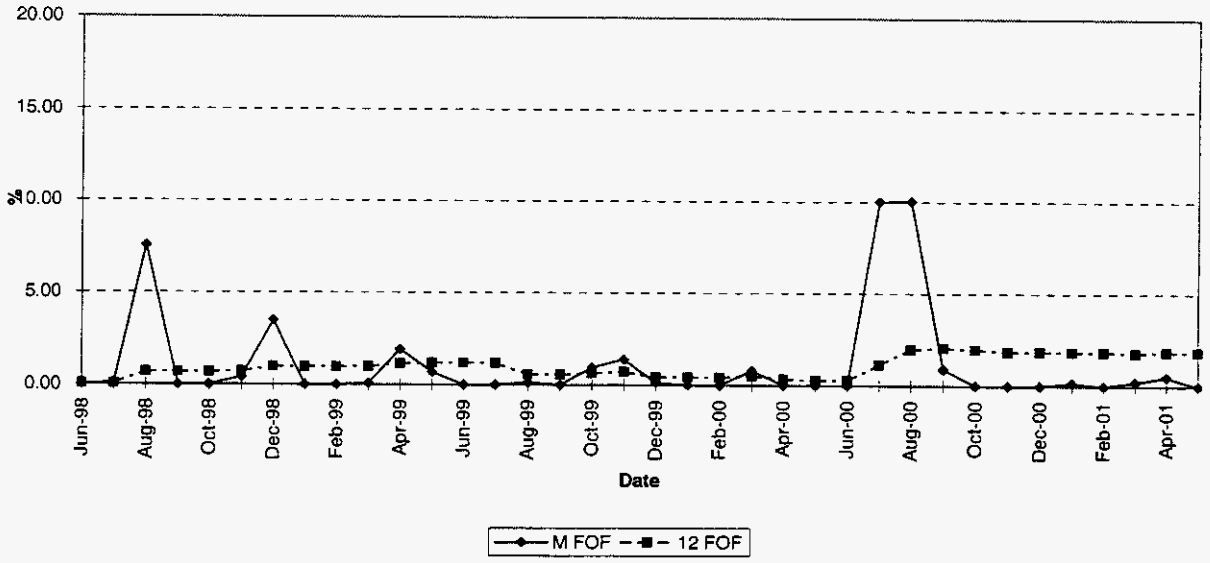
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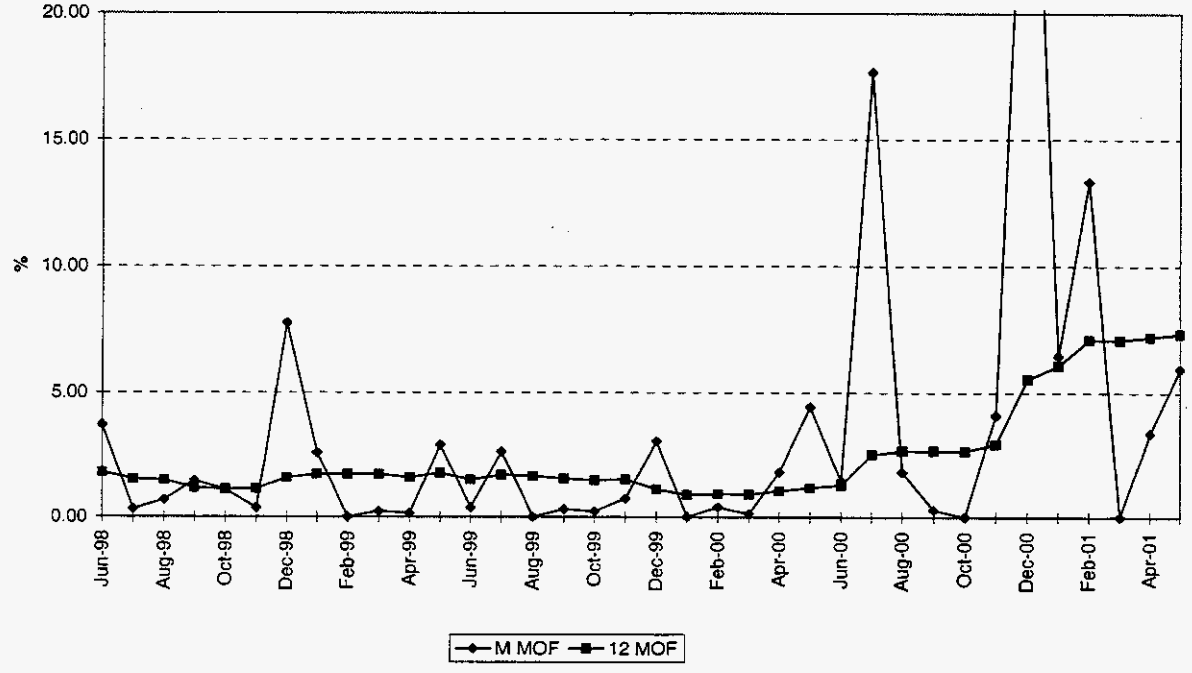
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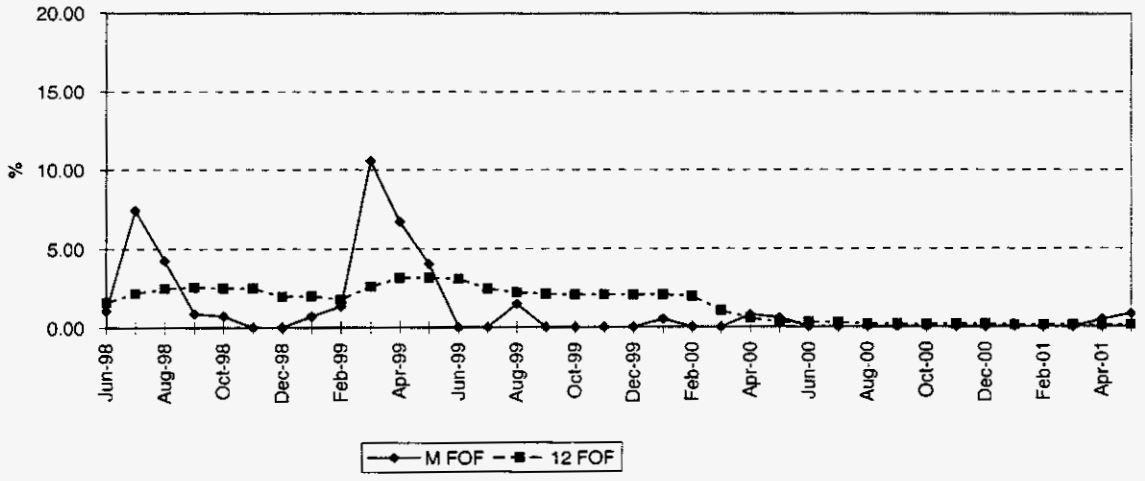
PFL 5
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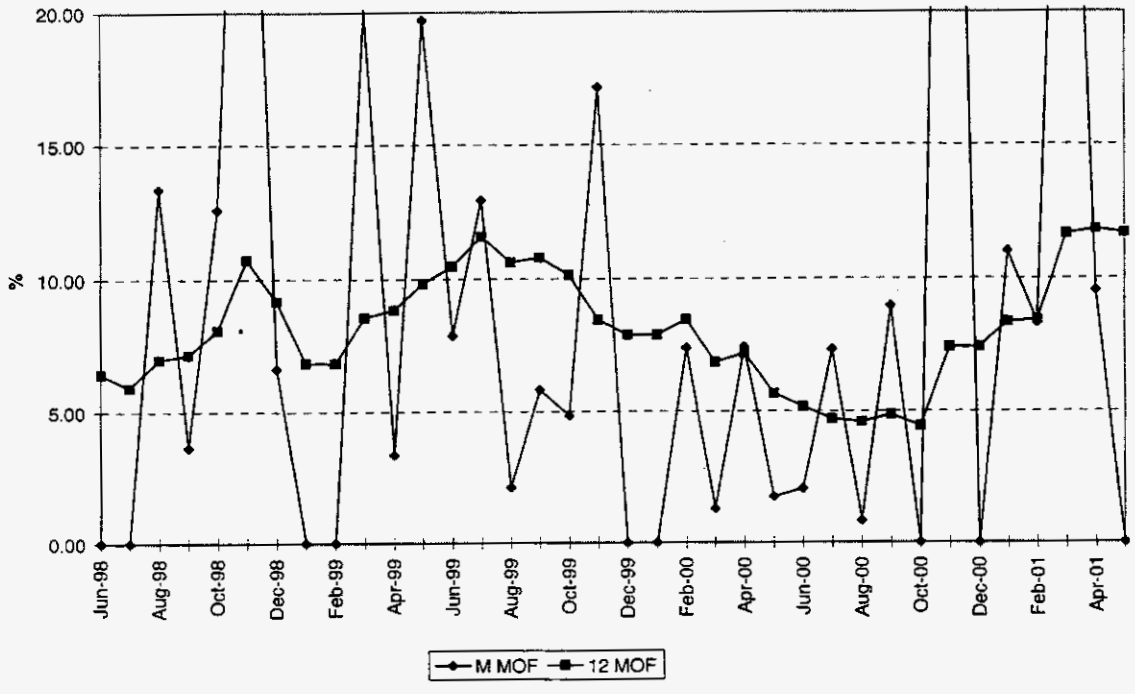
MAINTENANCE OUTAGE FACTOR



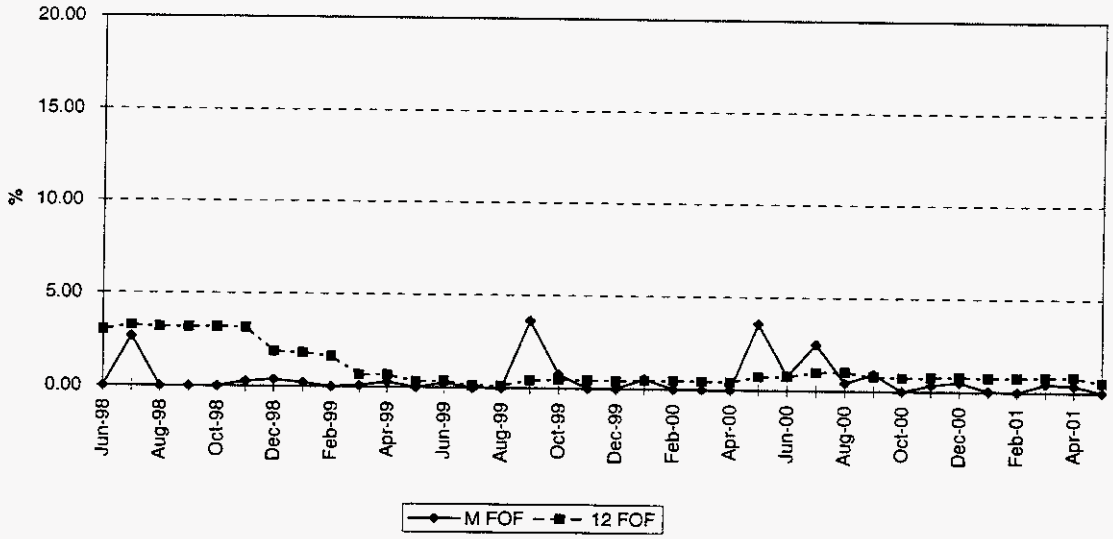
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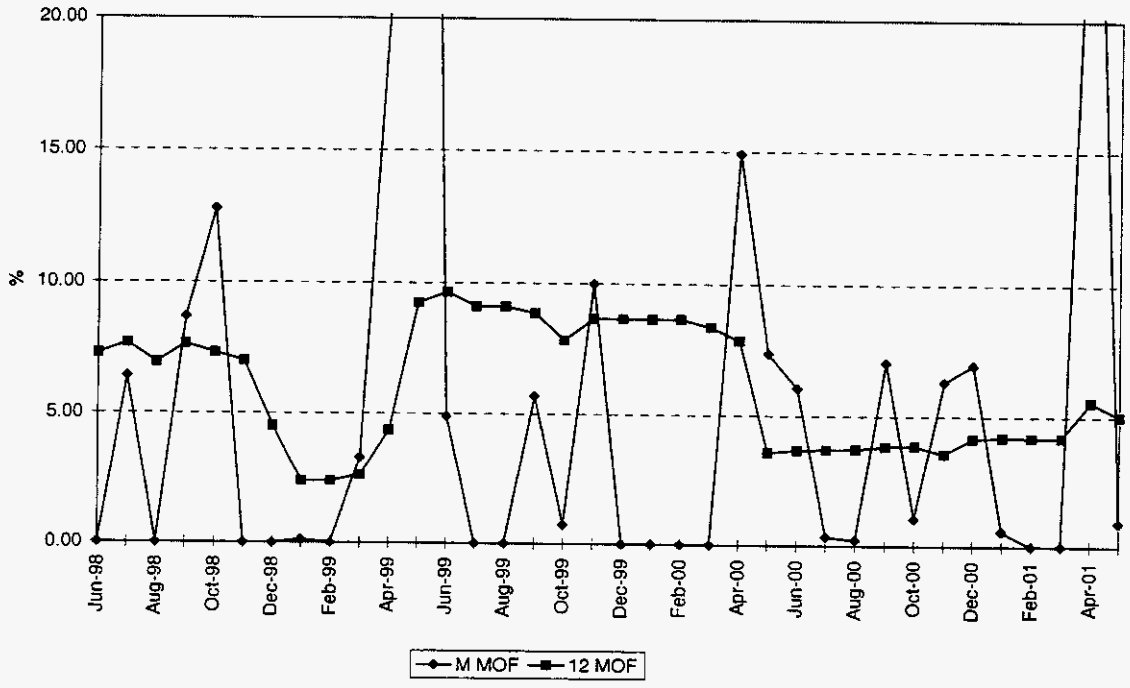
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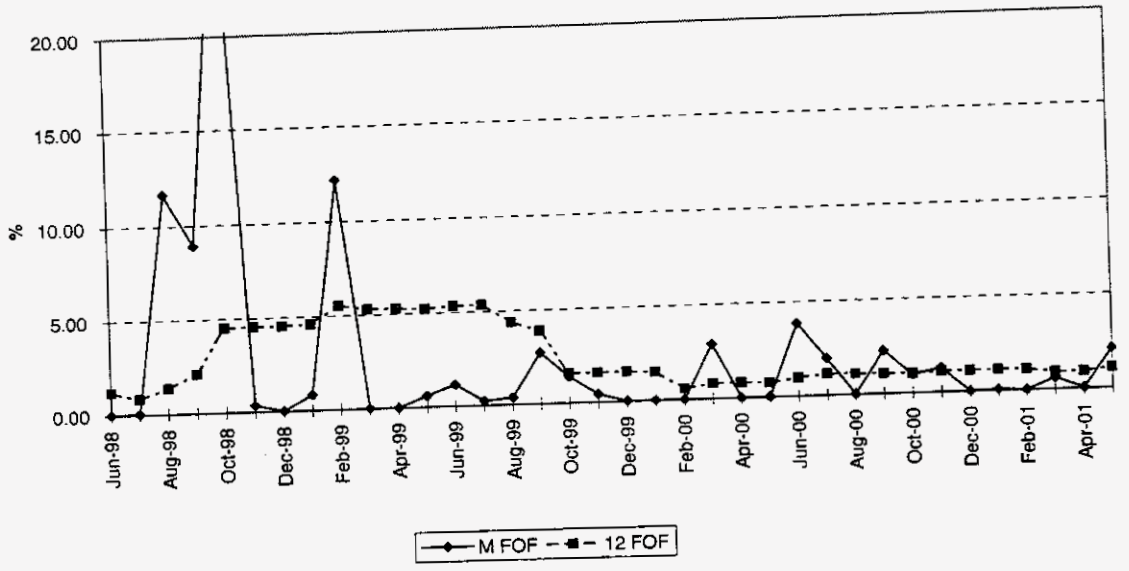
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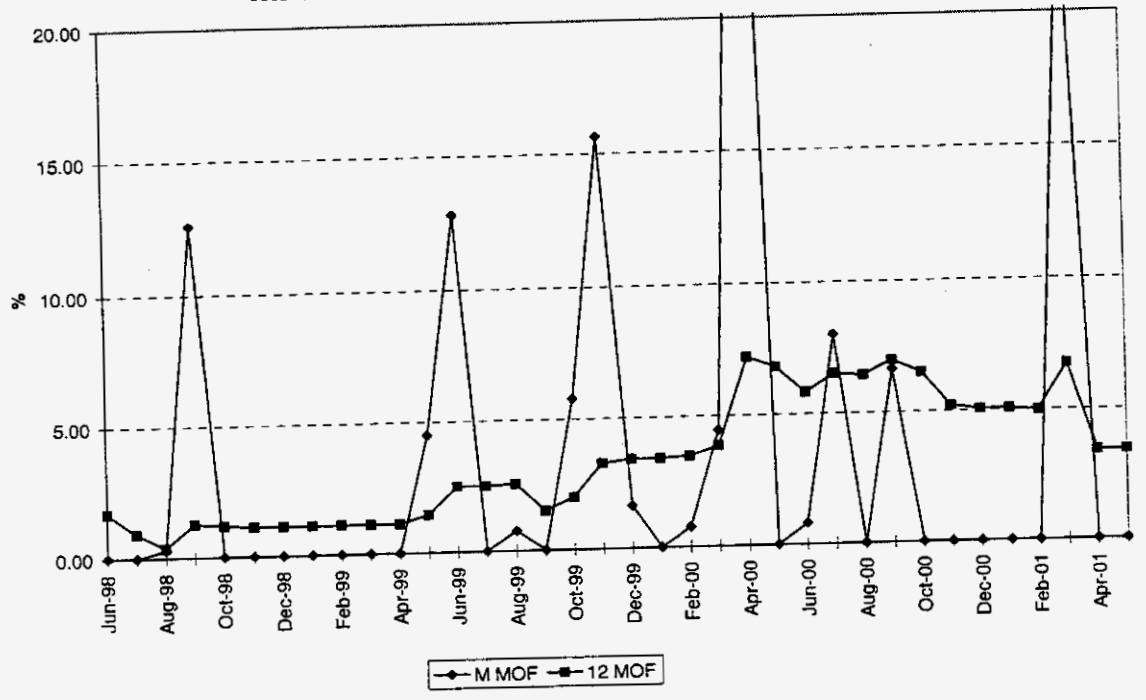
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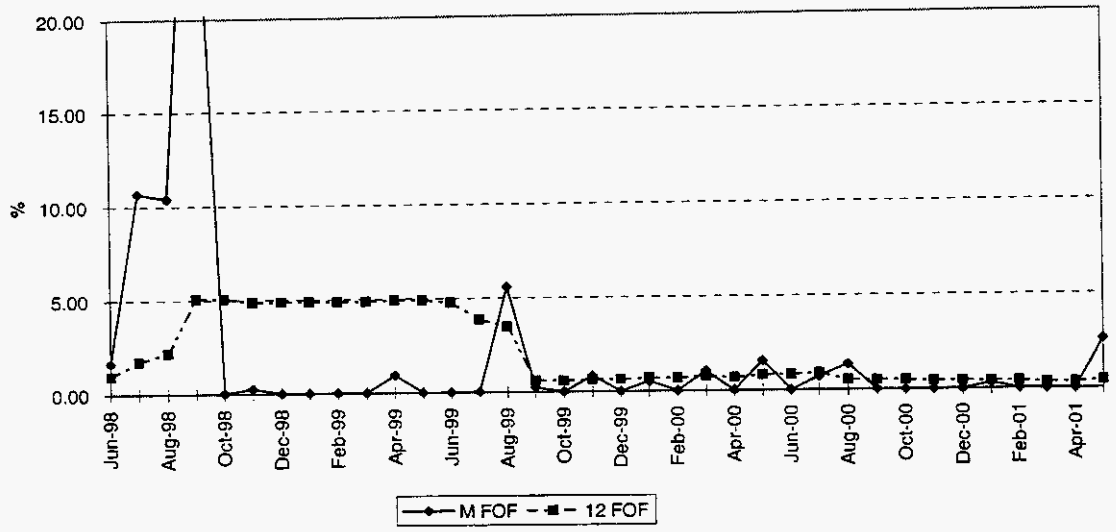
PMR 1
FORCED OUTAGE FACTOR



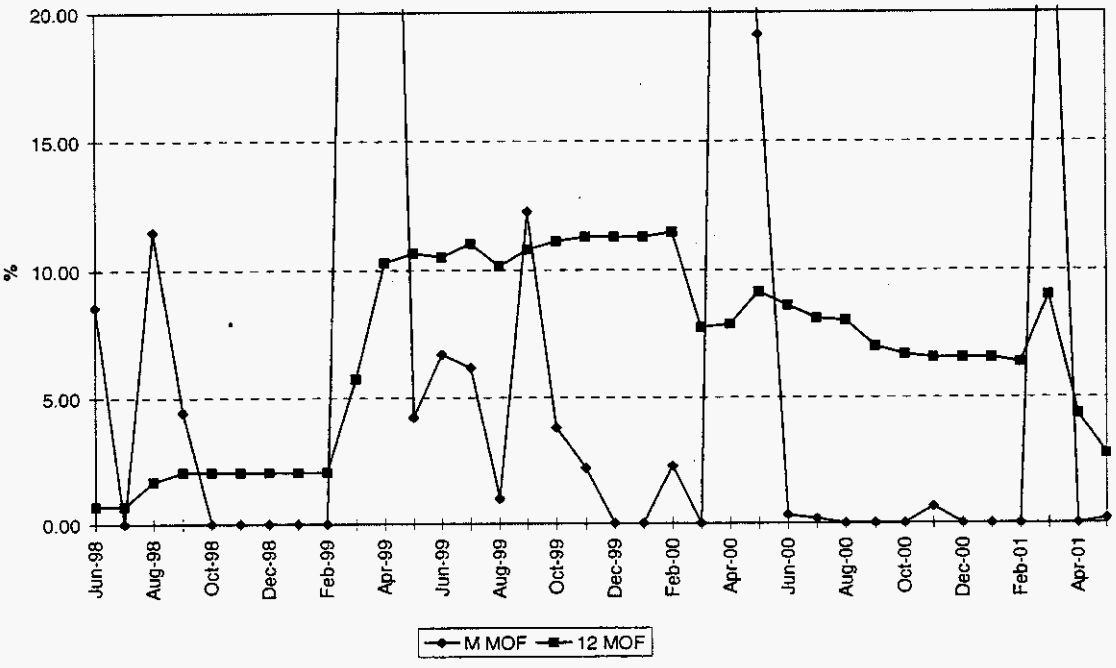
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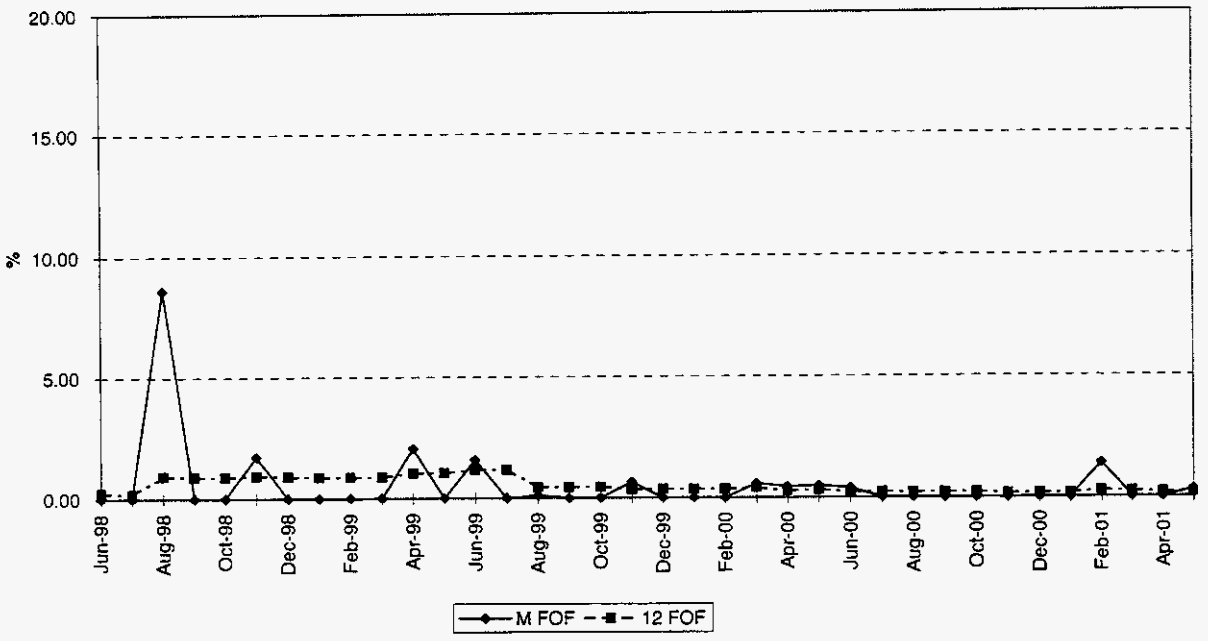
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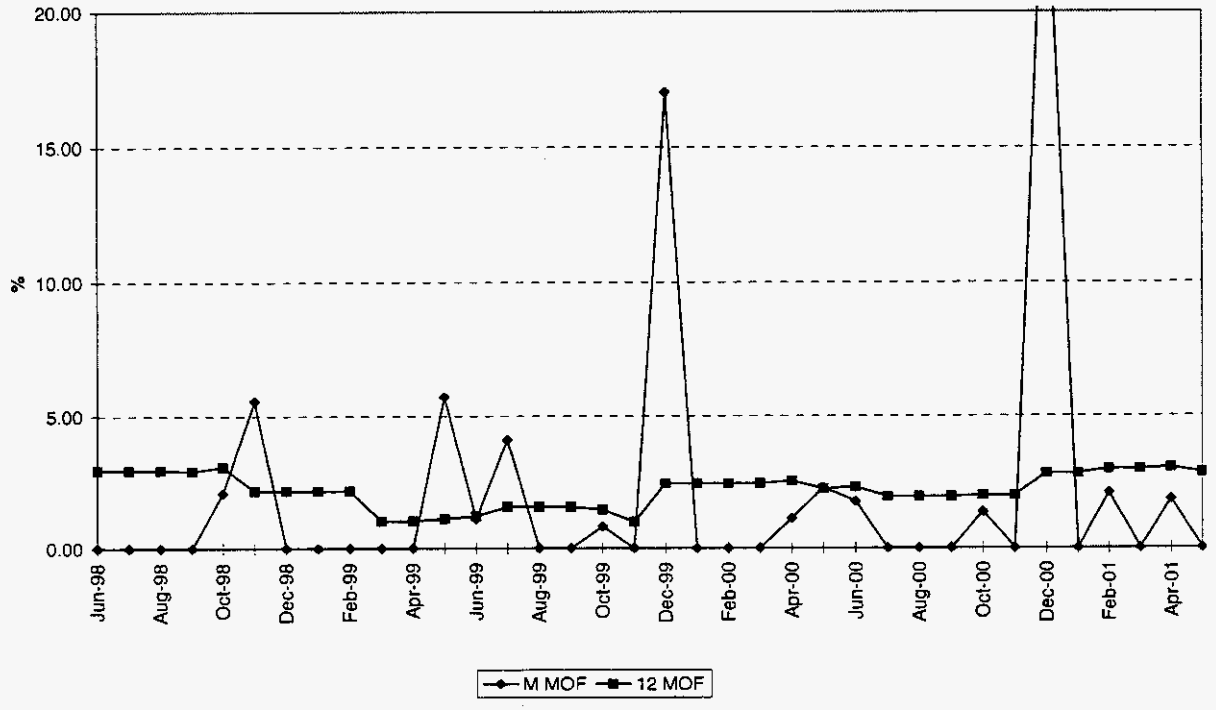
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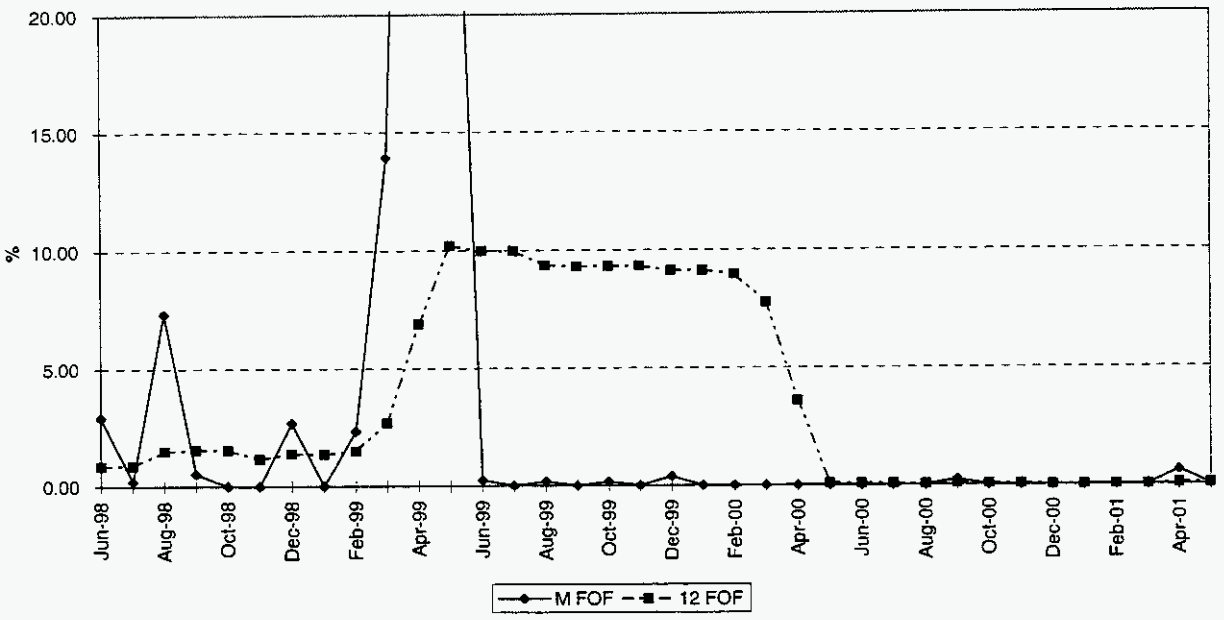
PMG 3
FORCED OUTAGE FACTOR



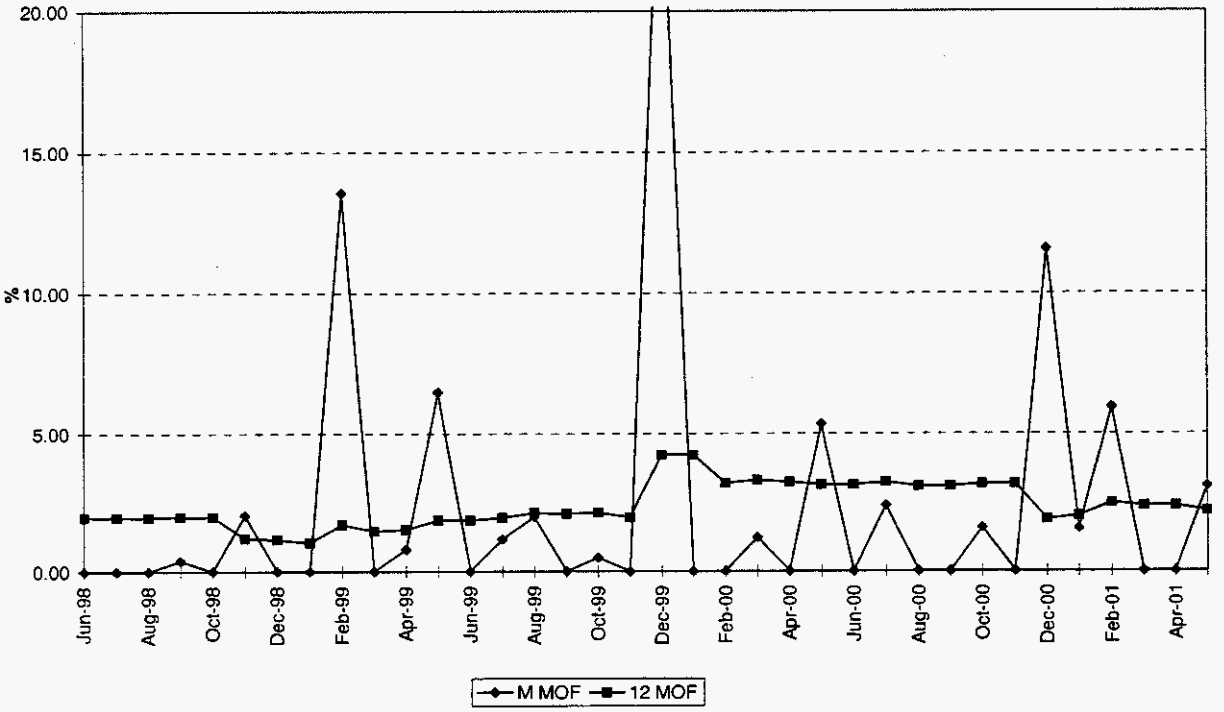
MAINTENANCE OUTAGE FACTOR



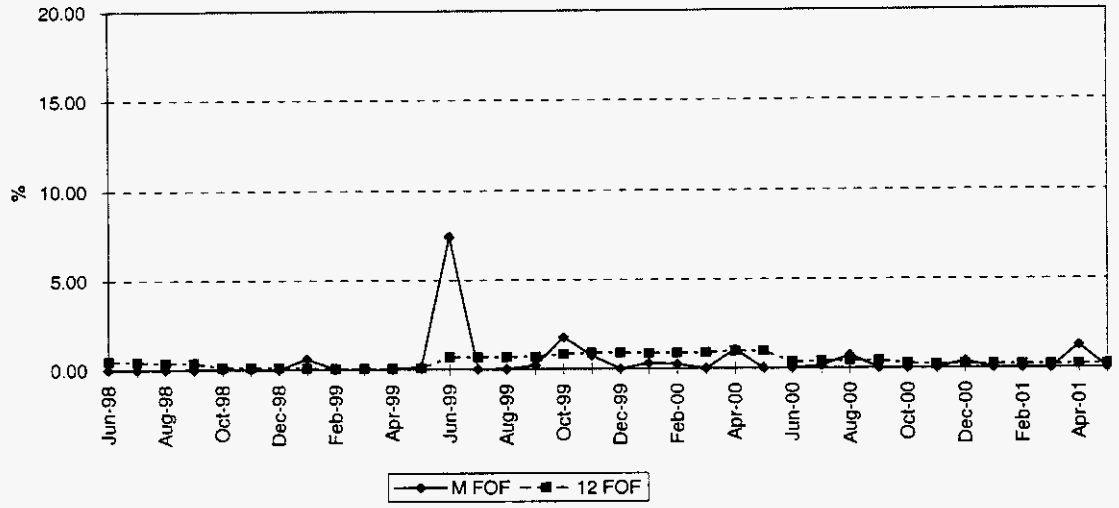
PMG 4
FORCED OUTAGE FACTOR



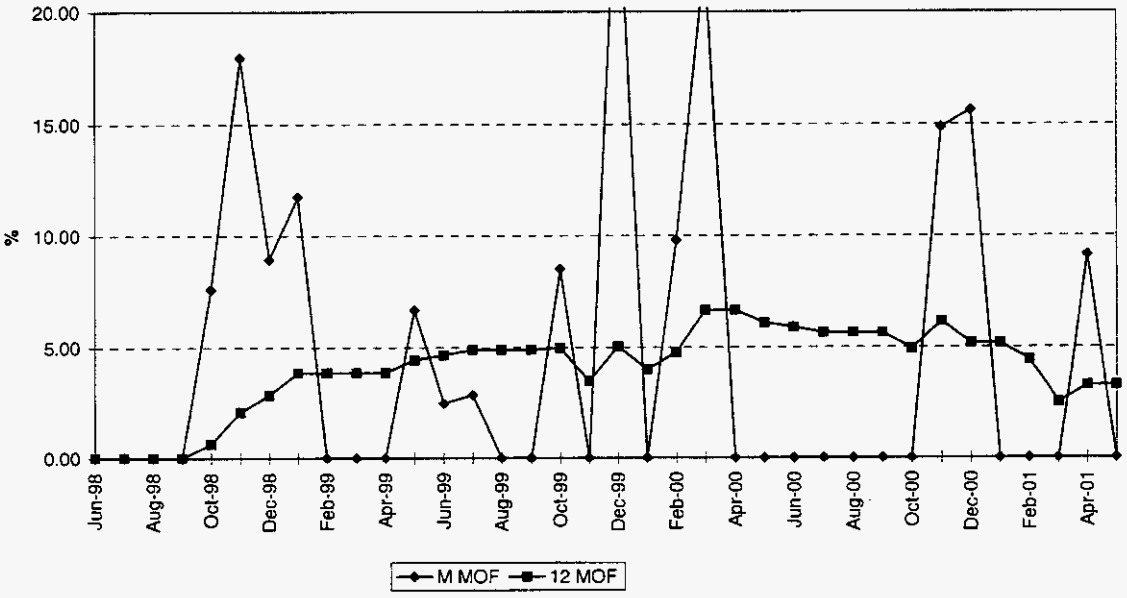
MAINTENANCE OUTAGE FACTOR



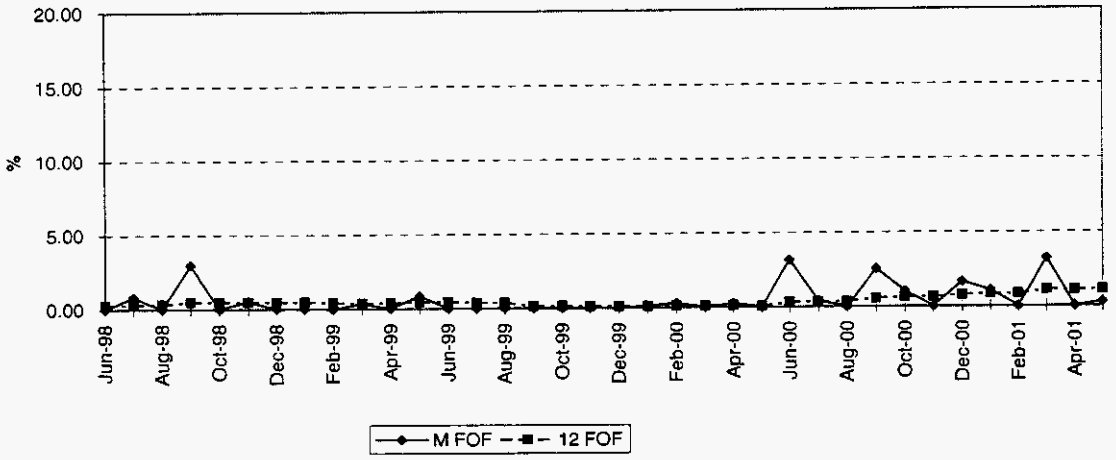
PPE 3
FORCED OUTAGE FACTOR



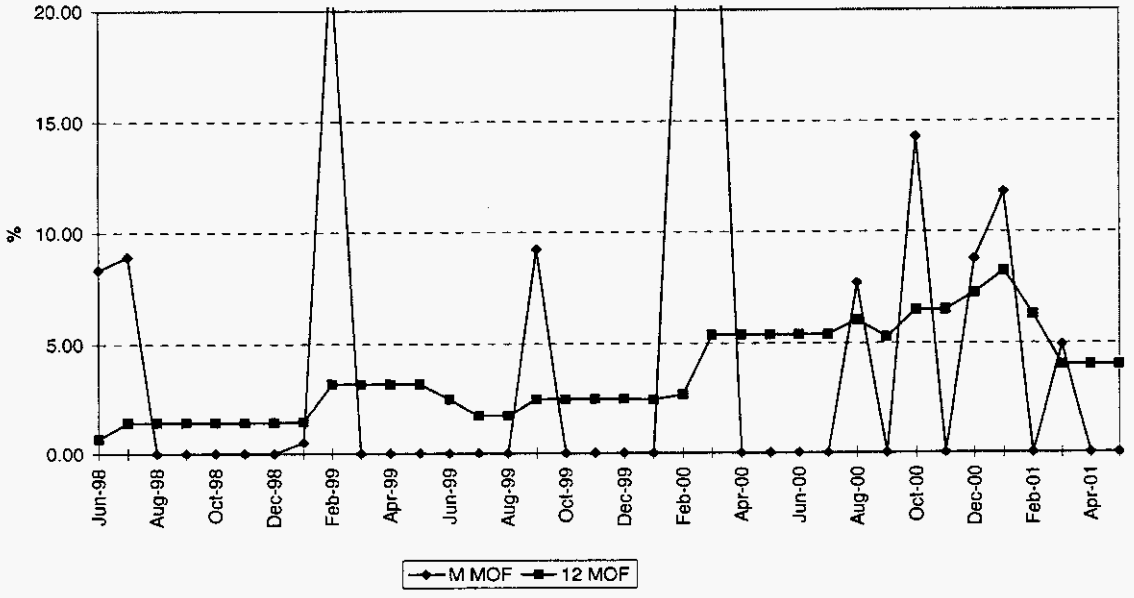
MAINTENANCE OUTAGE FACTOR



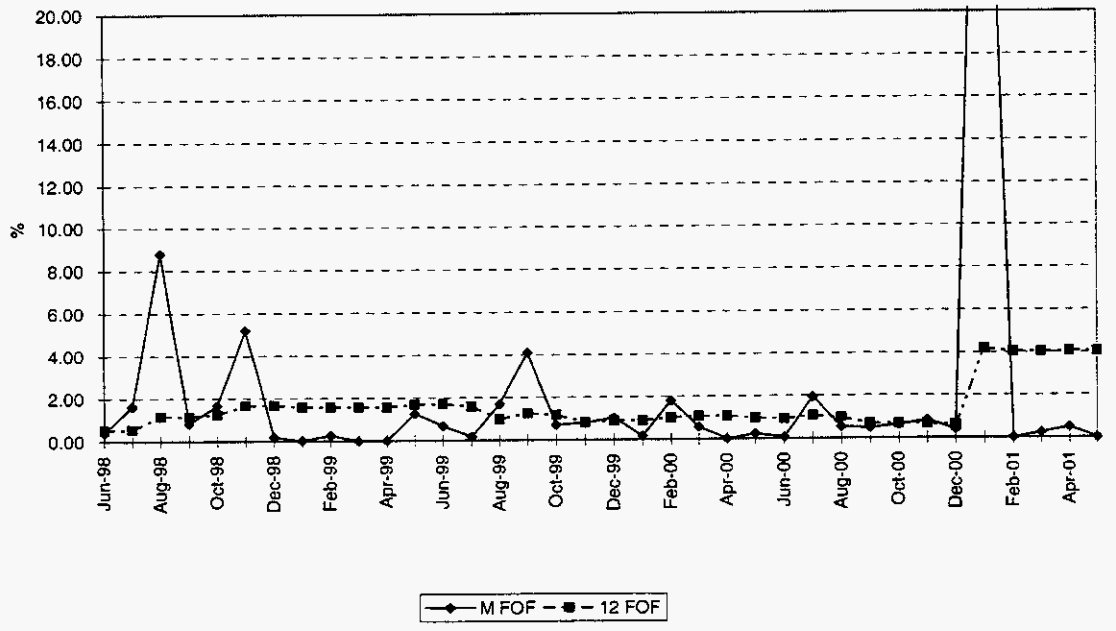
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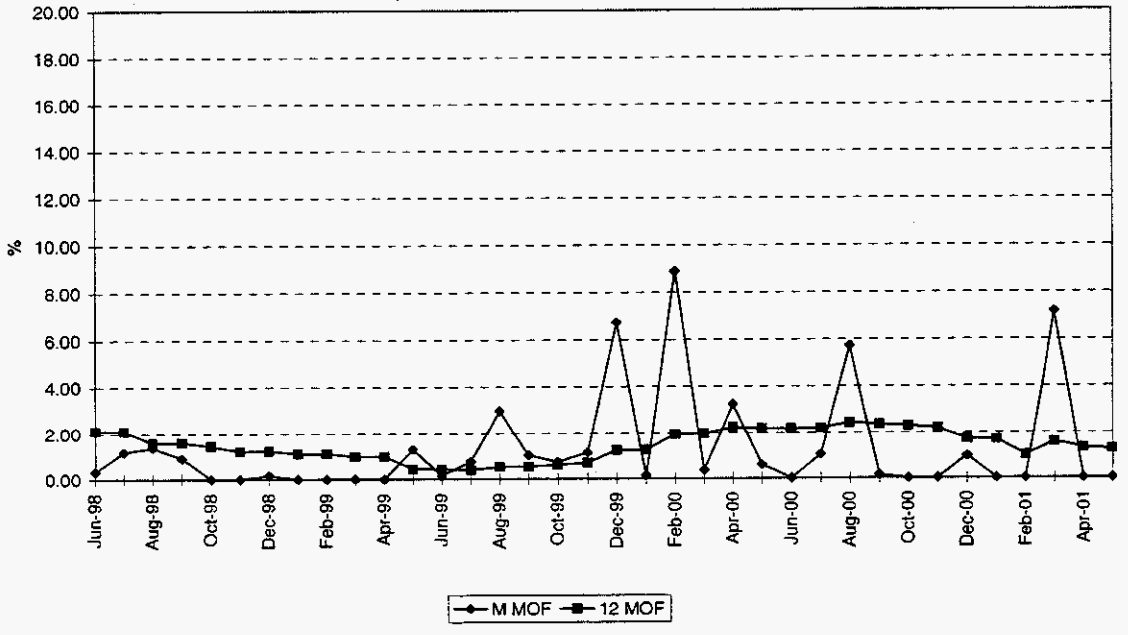
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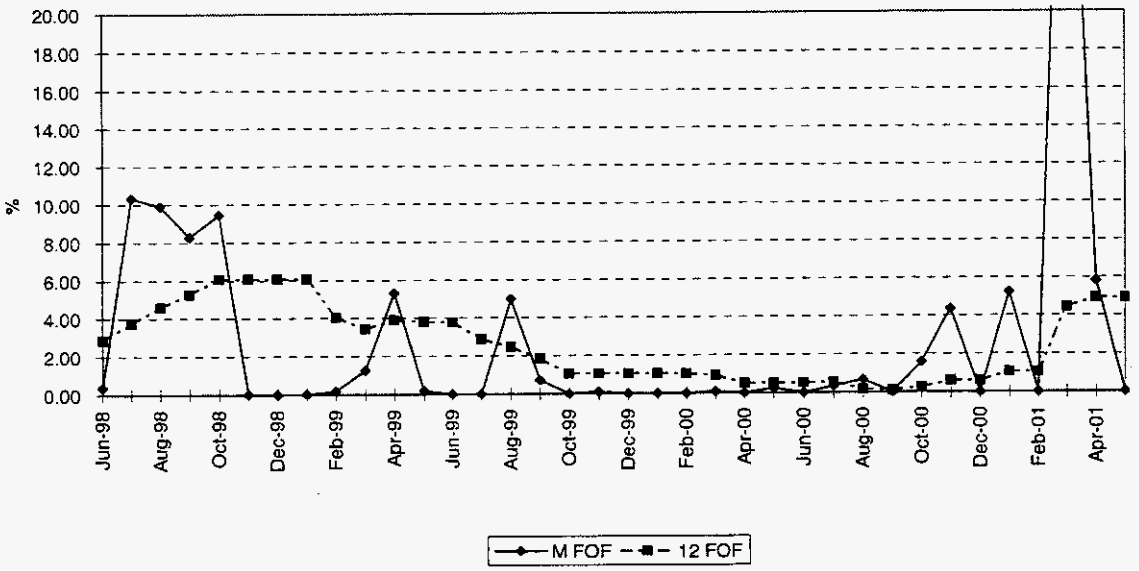
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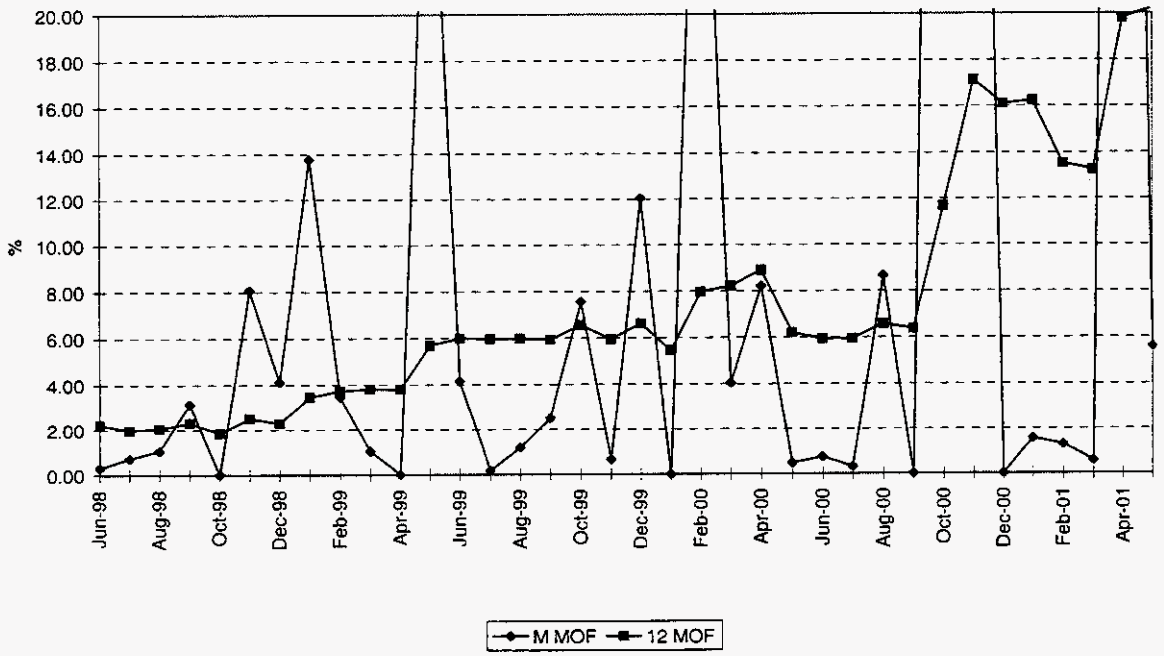
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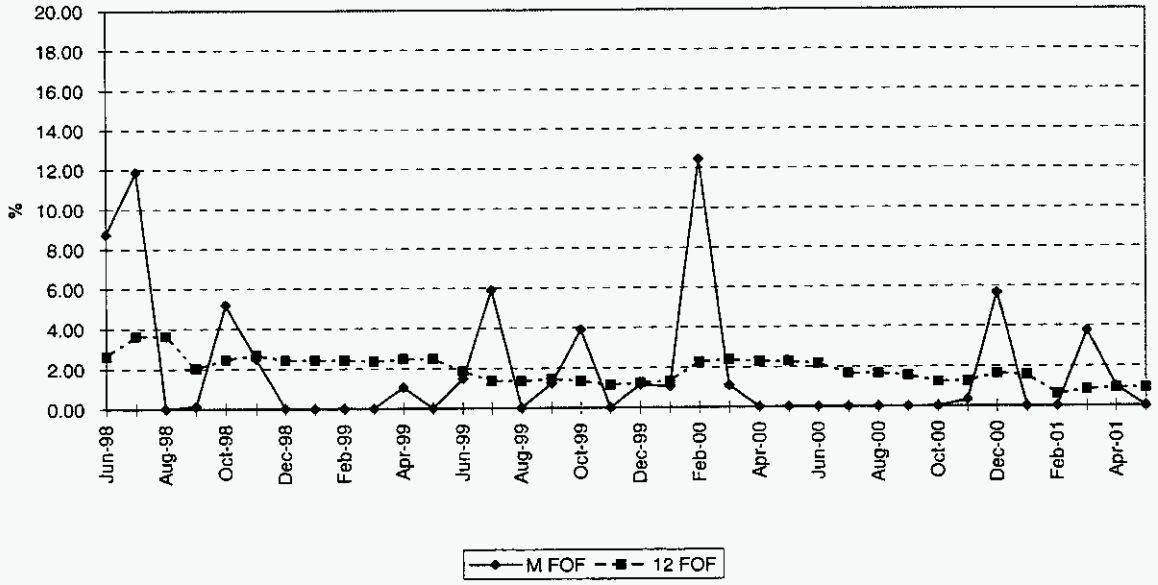
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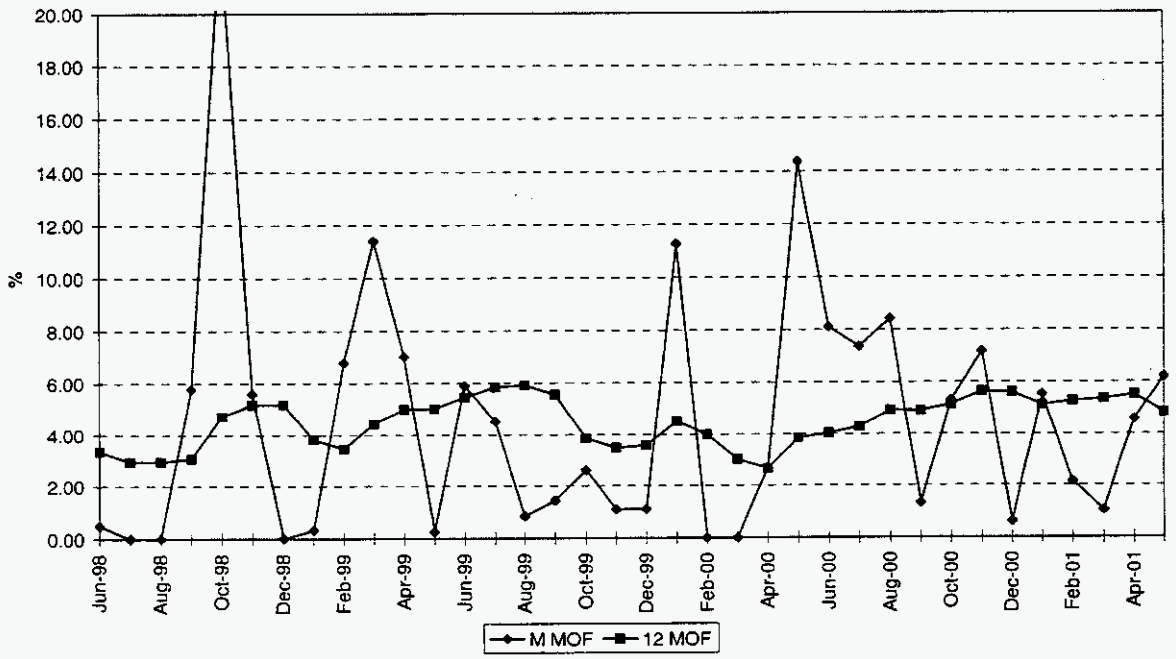
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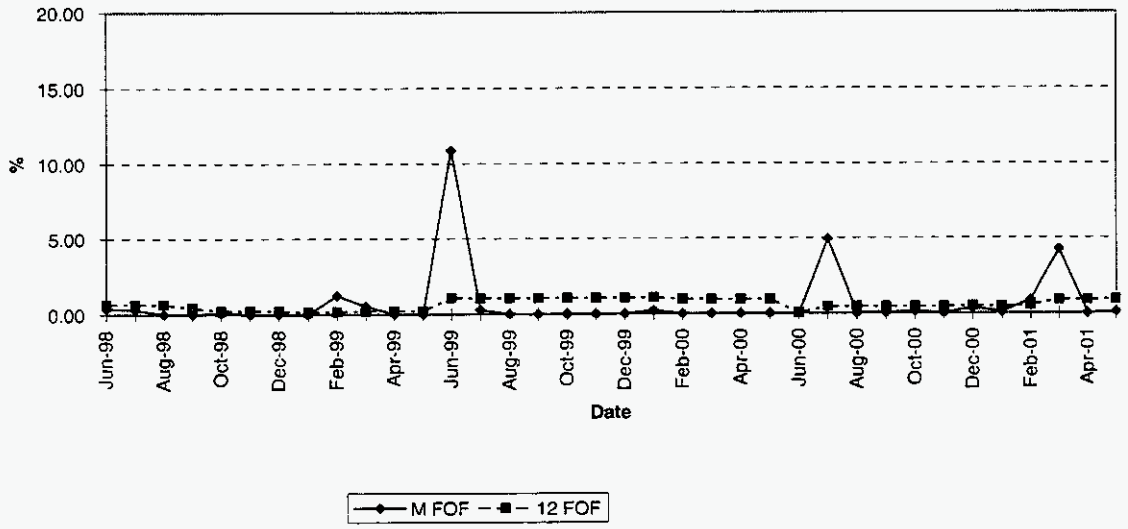
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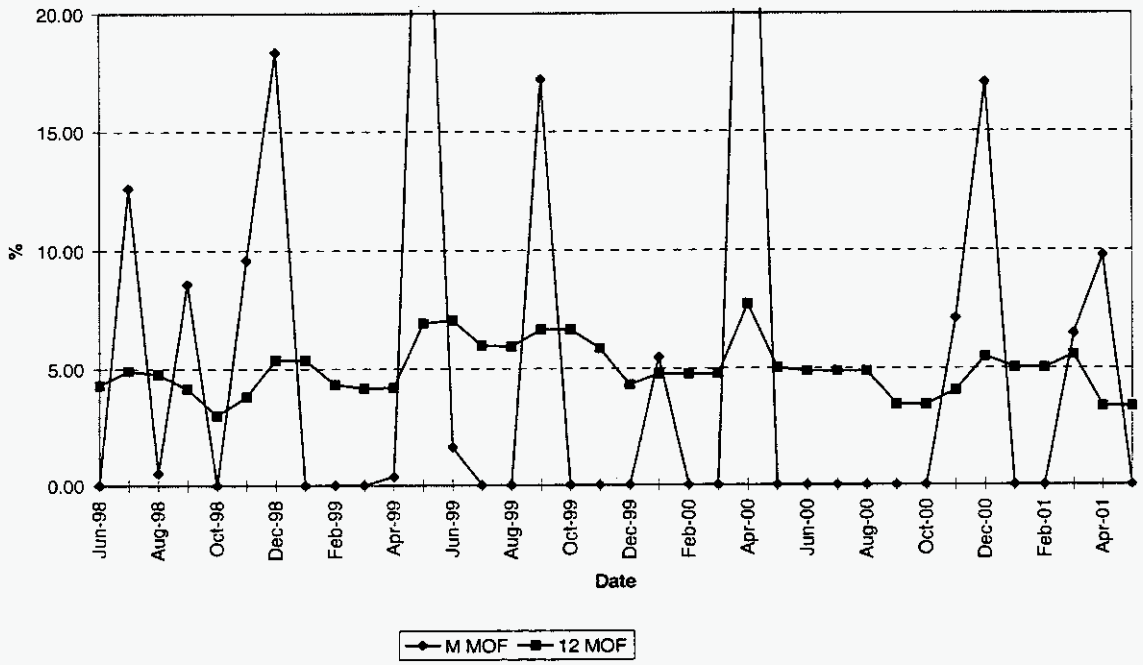
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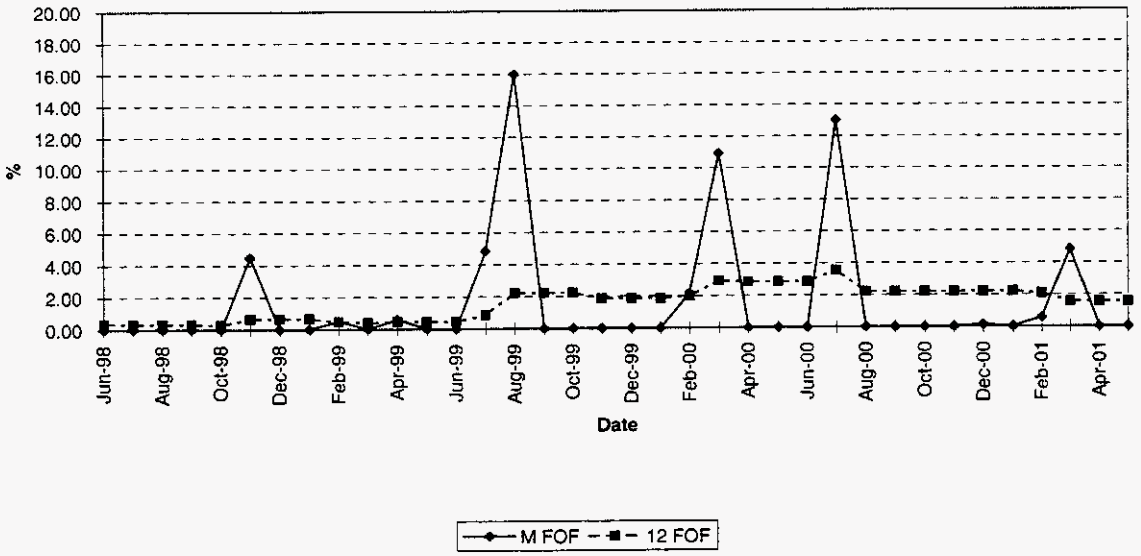
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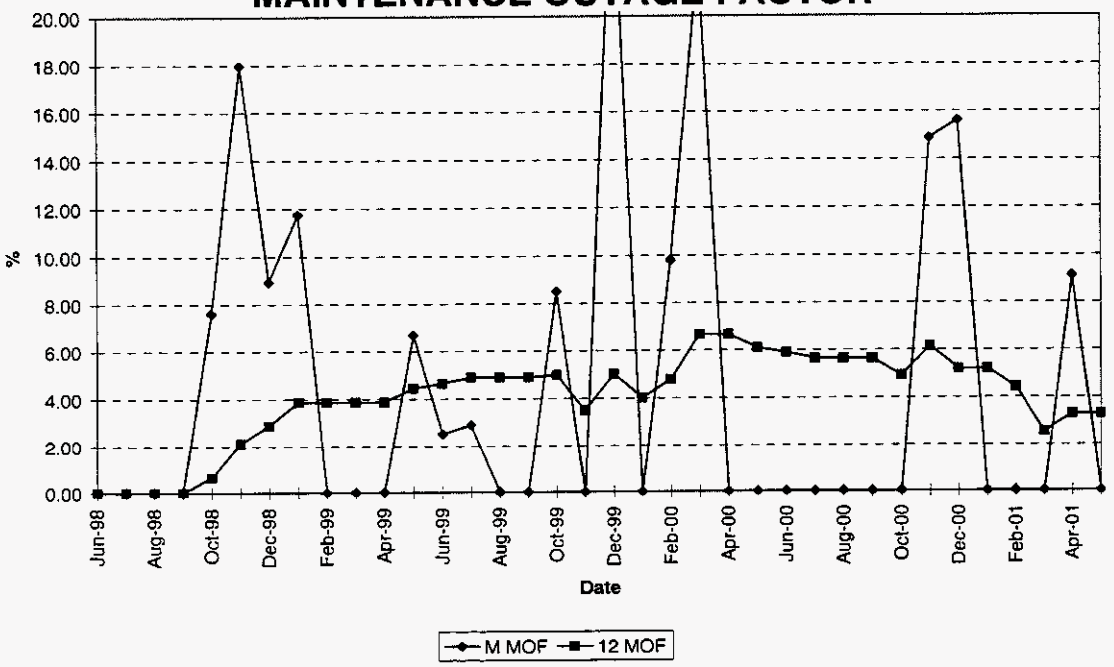
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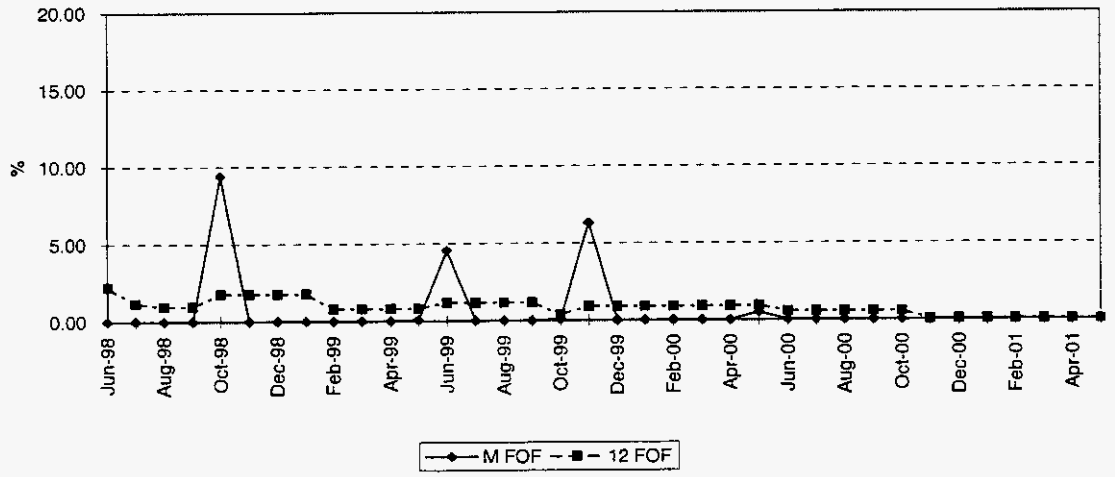
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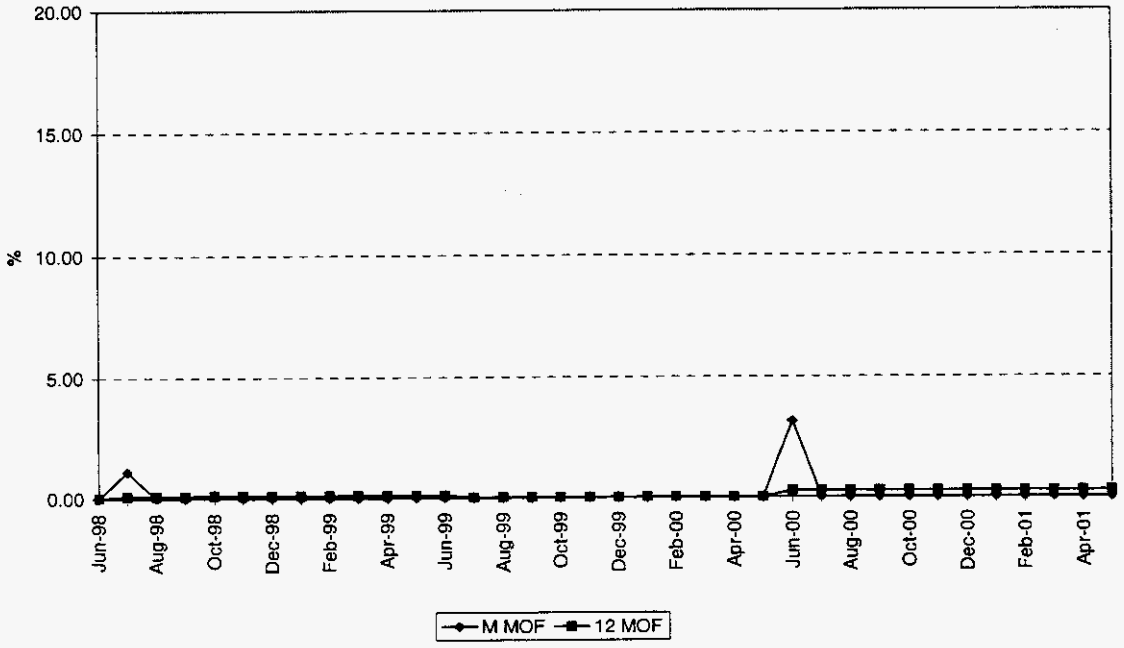
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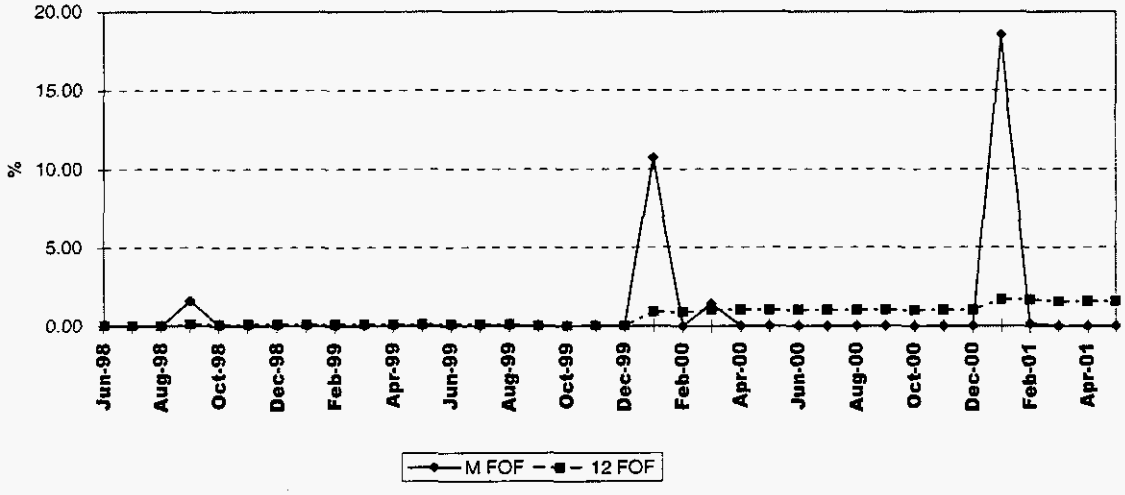
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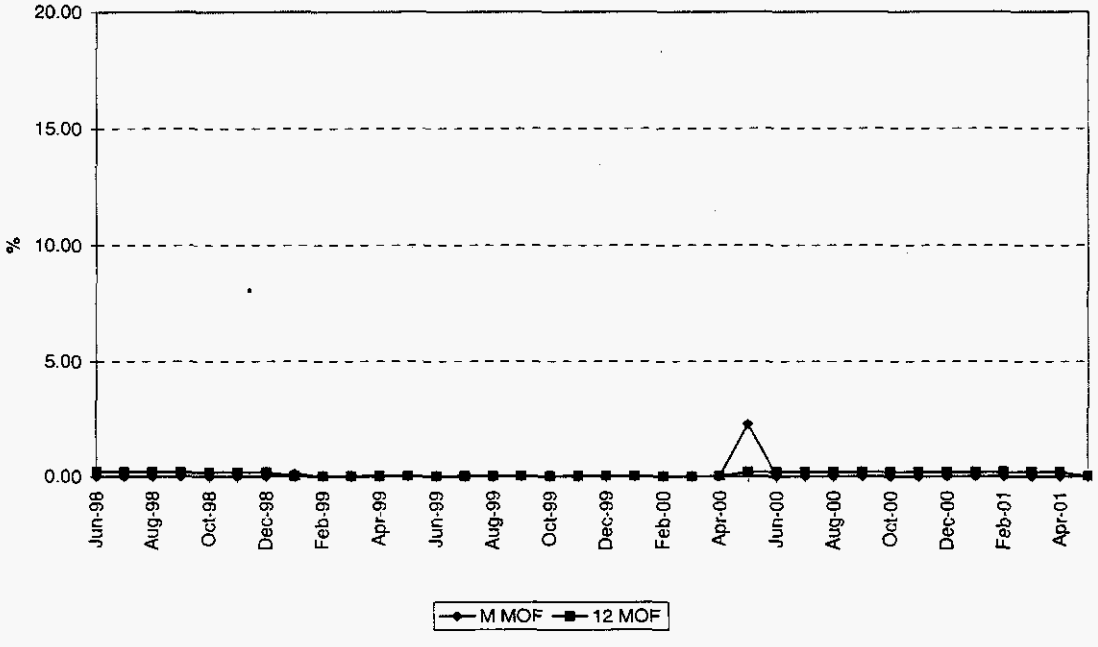
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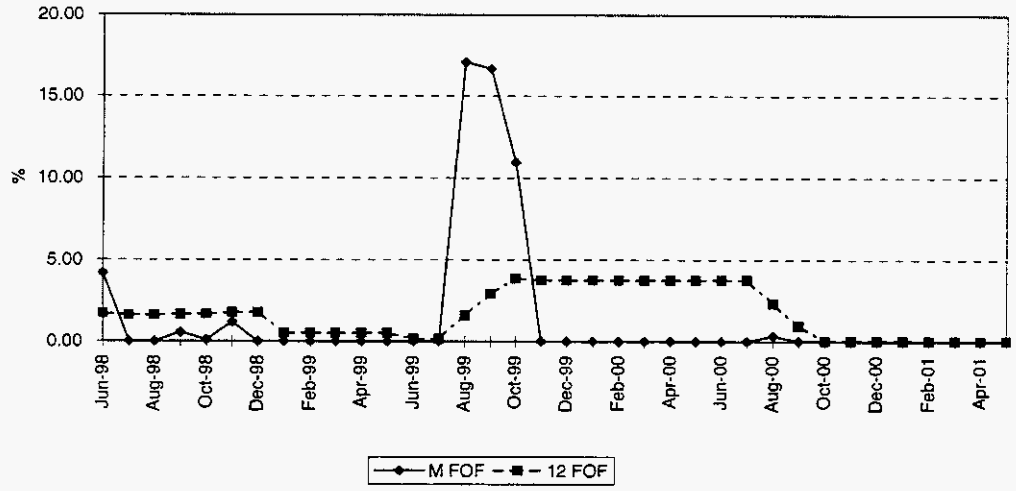
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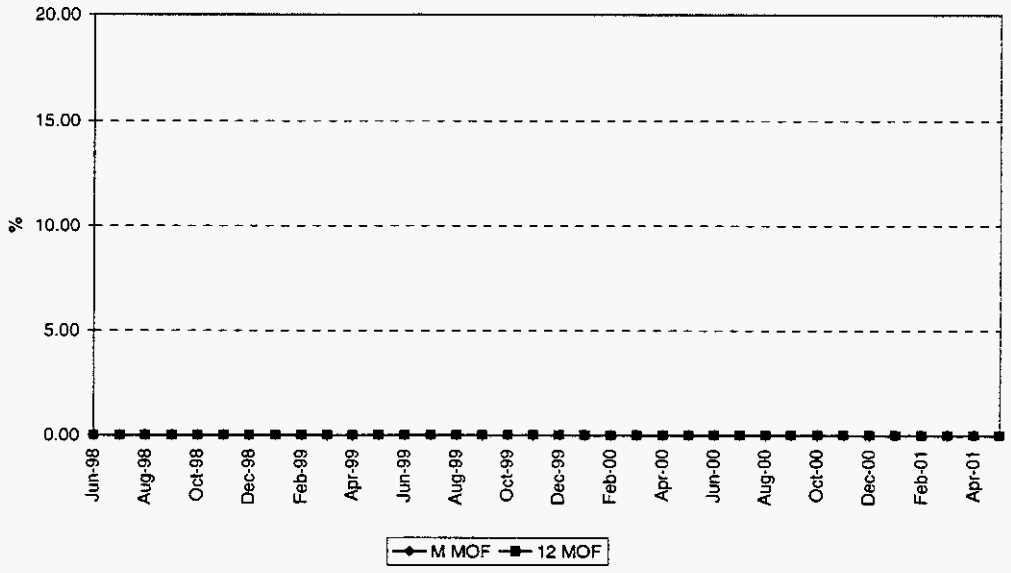
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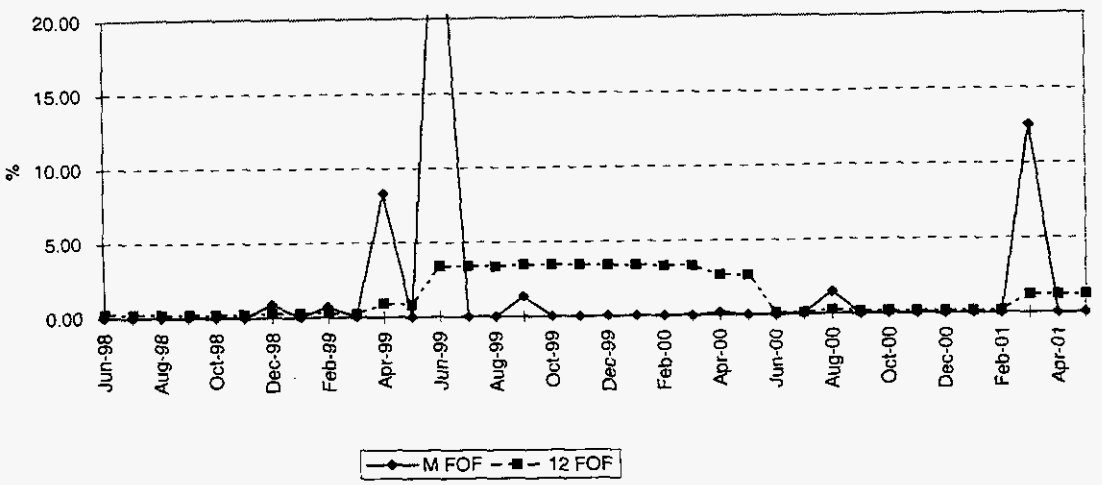
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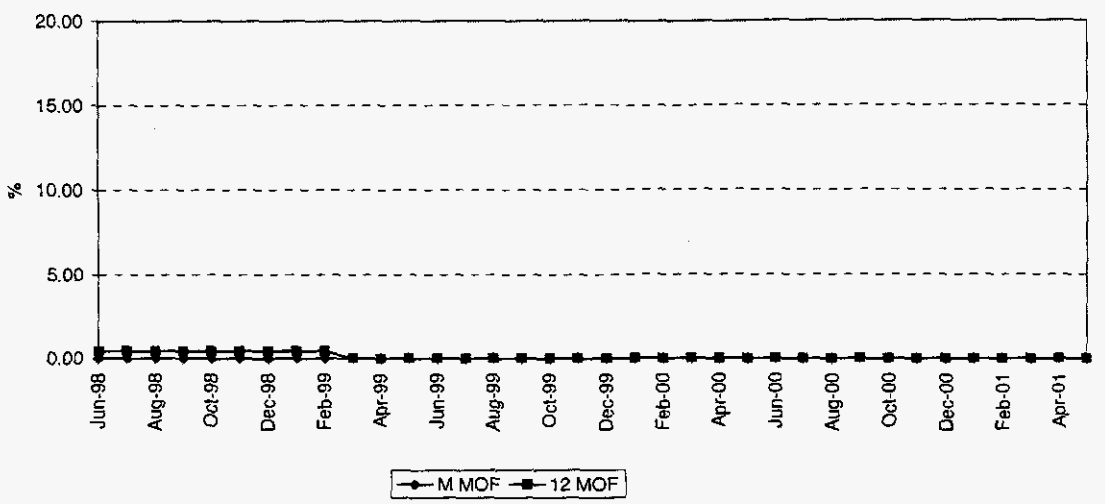
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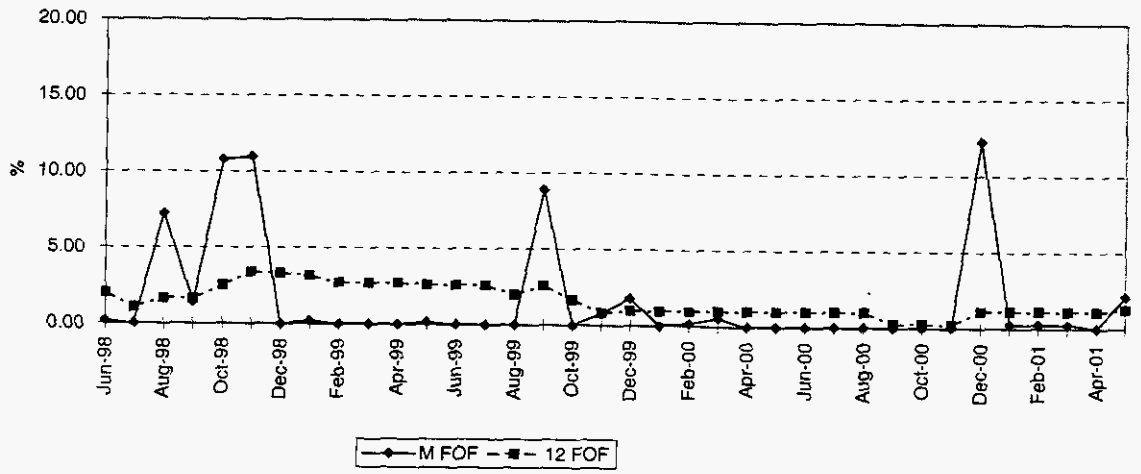
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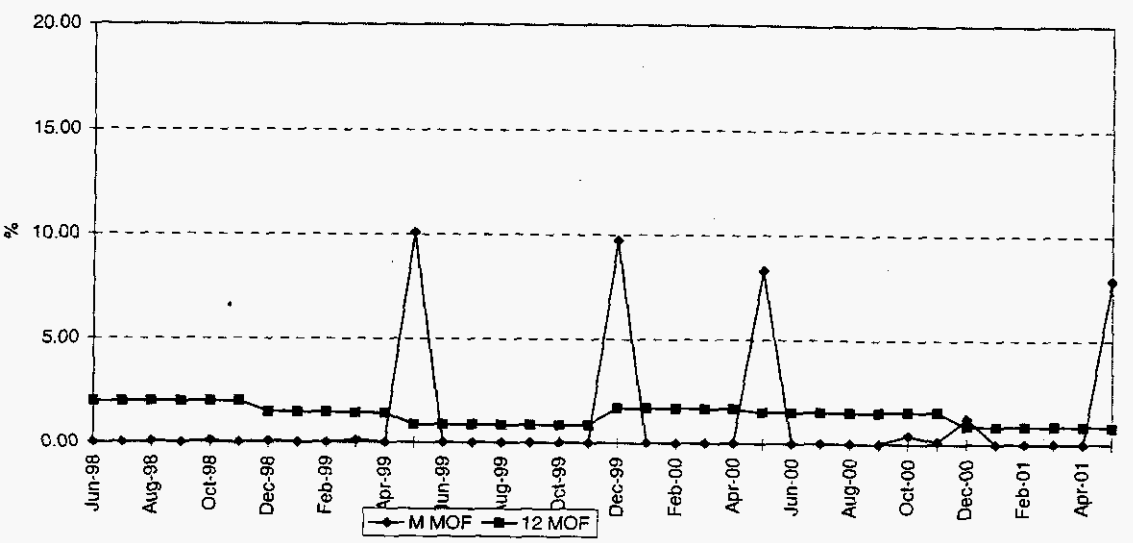
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PSG 4
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



PLANNED OUTAGE SCHEDULE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY

PERIOD OF: JANUARY THROUGH DECEMBER, 2002

PLANT/UNIT	PLAN OUTAGE	REASON FOR OUTAGE	LR MW
Cape Canaveral 1	NONE		
Cape Canaveral 2	04/03/02 - 04/17/02	Minor Boiler/Turbine Valves Overhaul	394
Lauderdale 4	03/09/02 - 03/18/02	Combustor inspection	440
Lauderdale 5	09/28/02 - 10/07/02	Combustor inspection	422
Manatee 1	04/15/02 - 05/12/02	IP/Travel Screens	798
Manatee 2	04/20/02 - 05/19/02	Boiler Overhaul	798
Martin 1	11/30/02 - 12/15/02	Boiler Overhaul	833
Martin 2	03/02/02 - 03/17/02	Boiler Overhaul	821
Martin 3	NONE		
Martin 4	04/20/02 - 05/14/02	CT-B rotor change	448
Martin 4	10/01/02 - 10/08/02	CT-A combustor inspection - 50% CURT	224
Port Everglades 3	NONE		
Port Everglades 4	11/02/02 - 12/01/02	Major Boiler/Turbine Valves	404
Putnam 1	10/26/02 - 11/30/02	GT1 Overhaul/GT2 Combustor Insp-50% Curt	125
Riviera 3	NONE		
Riviera 4	NONE		
Turkey Point 1	11/30/02 - 12/27/02	Boiler Overhaul	398
Turkey Point 2	NONE		
Turkey Point 3	NONE		
Turkey Point 4	03/25/02 - 04/24/02	Refueling Overhaul	717
St. Lucie 1	09/30/02 - 10/30/02	Refueling Overhaul	839
St. Lucie 2	NONE		
Scherer 4	11/09/02 - 12/22/02	Tube Shields/Pulverizer	643

EXHIBIT NO. _____

DOCKET NO: 010001-EI

WITNESS: VARIOUS

DESCRIPTION: COMPOSITE EXHIBIT:

1) FPL's responses to staff's fifth set of interrogatories in Docket No. 010001-EI, numbers 156-160, 162, 166-173
2) FPL's responses to staff's sixth set of interrogatories in Docket No. 010001-EI, numbers 174-177

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI EXHIBIT NO. 29
COMPANY/ WITNESS: FPSC Staff
DATE: 11-20921-01

Q. What were FPL's system total security costs in 1999? In 2000?

A. FPL's total security costs were $12.9 million in 1999 and $12.4 million in 2000.

Q. What are FPL's year-to-date actual system total security costs through August 31, 2001?

A. FPL's year-to-date actual security costs through August 31, 2001 are $7.8 million.

Q. What are FPL's budgeted system total security costs for 2001? For 2002?

A. FPL's budgeted security costs are $10.8 million for 2001 and $13.7 million for 2002. Both of these amounts exclude the incremental power plant security cost that FPL is requesting to be recovered through the fuel clause.

Q. **On what basis (demand or energy) were FPL's security costs allocated to rate classes in FPL's last rate case?**

A. FPL's security costs are recorded in G/L accounts 506, 524, and 549. The costs in these accounts were allocated to rate classes based on demand in the last rate case as authorized by Order No. 13537 in Docket No. 830465-EI, issued on July 24, 1984.

Q. If FPL has revised its estimate of total security costs for 2001 based on recent national security concerns, what are FPL's revised estimated system total security costs for 2001?

A. The estimate for incremental power plant security costs for the fourth quarter of 2001 is $465,000 (1/4 of projected amount of $1,860,000 for 2002).

Q. **What efforts has FPL undertaken to review all existing sources of funding to address those costs identified as incremental security costs on page 3, line 21, of Witness Dubin's supplemental testimony filed November 5, 2001?**

A. For FPL's internal security, FPL has utilized existing operating funds to fund the incremental security costs. For external costs such as local, state, and federal agencies, FPL has negotiated on the basis that those costs are the responsibility of the respective governmental agency. Those negotiations are ongoing.

Q. What is the estimated value of the fuel assets and fuel infrastructure at FPL's nuclear facilities which require the additional $1.5 million security costs to be expended in 2002 as identified on page 3 of Witness Hartzog's November 5, 2001 Supplemental Testimony?

A. The value of the nuclear fuel in the reactors located at the St. Lucie and Turkey Point nuclear plants is $106.1 million as of August 28, 2001. FPL's nuclear units save the customers of FPL approximately $750 million per year in avoided fuel costs when compared to natural gas.

Q. **What is the estimated value of the non-fuel assets and non-fuel infrastructure at FPL's nuclear facilities which require the additional $1.5 million security costs to be expended in 2002 as identified on page 3 of Witness Hartzog's November 5, 2001 Supplemental Testimony?**

A. The net book value of FPL's nuclear units as of August 31, 2001 was $1.1 Billion.

Q. What is the estimated value of the fuel assets and fuel infrastructure at FPL's fossil facilities which require the additional $300,000 security costs to be expended in 2002 as identified on page 3 of Witness Hartzog's November 5, 2001 Supplemental Testimony?

A. The primary basis of the incremental security cost for fossil facilities is due to the proximity to the Turkey Point nuclear units. Accordingly, the value is the same as stated in Interrogatory No. 166. Additionally, the value of FPL's oil inventory at Turkey Point is $7.3 million as of October 2001. The value of FPL's system oil inventory is $95.3 million as of October 2001, which may require additional security in the future.

Q. What is the estimated value of the non-fuel assets and non-fuel infrastructure at FPL's fossil facilities which require the additional $0.3 M security costs to be expended in 2002 as identified on Page 3 of Witness Hartzog's November 5, 2001 Supplemental Testimony?

A. Please see responses to Interrogatory Nos. 167 and 168.

Q. Why does FPL believe that the Commission may be concerned about the appropriateness of using the Fuel and Purchased Power Cost Recovery Clause as a method of recovery of incremental security costs, as mentioned on page 6 of Witness Dubin's supplemental testimony filed November 5, 2001?

A. FPL's testimony states "Even if the Commission is concerned about whether the fuel clause is the most appropriate continuing method of recovery, FPL suggests that the clause should be used as an interim recovery method." FPL's statement was simply recognizing that alternative methods of recovery such as a "surcharge" may also be appropriate. However, to do so would require major programming revisions to FPL's billing system which would result in additional costs of approximately $1.0 million and, even if programming began today, would not be available by January 1, 2002.

The FERC's statement of policy issued September 14, 2001 states:

"The Commission is aware that there may be uncertainty about companies' ability to recover the expenses necessary to further safeguard our energy infrastructure, especially if they are operating under frozen or indexed rates. In order to alleviate this uncertainty, the Commission wants to assure the companies we regulate that we will approve applications to recover prudently incurred costs necessary to further safeguard the reliability and security of our energy supply infrastructure in response to the heightened state of alert. Companies may propose a separate rate recovery mechanism, such as a surcharge to currently existing rates or some other cost recovery method."

Additionally, the NARUC resolution states:

"Resolved, that States should approve applications by gas and electric companies subject to their jurisdiction to recover prudently incurred costs necessary to further safeguard the reliability and security of our energy supply infrastructure and should allow companies to propose separate rate recovery mechanisms, such as a surcharge to existing rates or deferred accounting treatment."

FPL believes it is appropriate to recover these incremental power plant security costs through the fuel clause since they are fuel-related and there are significant uncertainties in these costs. FPL needs this additional security to operate its power plants. The inability to operate one or more of its nuclear generating units will have a significant adverse impact on our fuel costs. As stated in response to Interrogatory No. 166, without nuclear generation, FPL's customers would pay $750 million more per year in replacement fuel costs.

Q. How are FPL's security costs currently recovered?

A. The level of security costs projected for test year 1985 in the last rate case, as authorized by Order No. 13537, in Docket No. 830465-EI, issued on July 24, 1984, are included in base rates. Of course, those levels of security did not contemplate the environment created by the September 11th events.

Q. **What commission decisions, if any, indicate that the Fuel and Purchase Power Cost Recovery clause is the appropriate method of recovery for security costs? Please explain how each identified decision indicates the appropriateness of recovery through the fuel clause.**

A. Order No. 14546 addressed the types of costs to be recovered through the Fuel Cost Recovery Clause. Item No. 10 of this order states:

"Fossil fuel-related costs normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine current base rates and which, if expended, will result in fuel savings to customers. Recovery of such costs should be made on a case by case basis after Commission approval."

In this order, the Commission provided the flexibility to recover costs not normally recovered through the Fuel Cost Recovery Clause on a case by case basis.

Due to the terrorist attacks of September 11, 2001 and subsequent increases in security at FPL's power plants, FPL believes it is appropriate to bring this issue to the Commission for approval for Fuel Cost Recovery treatment. FPL needs this additional security to operate its power plants. The inability to operate one or more of its nuclear generating units will have a significant adverse impact on our fuel costs. As stated in response to Interrogatory No. 166, without nuclear generation, FPL's customers would pay $750 million more per year in replacement fuel costs.

Q. **Would a three month deferral of consideration of the method of recovery of FPL's projected 2002 security costs, as identified in Witness Dubin's testimony, impact FPL's operations and financial condition? Would a six month deferral of consideration of the method of recovery of FPL's projected 2002 security costs, as identified in Witness Dubin's testimony, impact FPL's operations and financial condition? Please explain your response in detail.**

A. From an operations standpoint, FPL will continue to take any measures necessary to protect our power plants. FPL is incurring additional security costs today due to the terrorist attacks of September 11, 2001. To defer the collection of these costs another three to six months would result in FPL to continue to not recover these costs. If the Commission decides to delay consideration, FPL would ask that recovery would be on a retroactive basis regardless of when a decision is made. Please note that these increased costs have not been included in FPL's MFR filing in Docket No. 001148-EI.

Q. **Is FPL proposing to recover any of its projected 2002 incremental security costs, related to increased national security concerns, other than those identified in Witness Hartzog's supplemental testimony of November 5, 2001, through base rate adjustments in Docket 001148-EI, as may be described in Attachment 1 of the Company's revised MFR filing of November 9, 2001?**

A. FPL is not proposing to change base rates in Docket No. 001148-EI. FPL has identified and included in its projected cost for 2002 certain additional security costs (such as additional security costs for our office buildings), however, these costs do not include nor are they related to the incremental power plant security costs requested for recovery through the Fuel Cost Recovery Clause in Docket No. 010001-EI.

Q. If FPL is planning to recover any of its 2002 incremental security costs, related to increased national security concerns, through base rate adjustments in Docket 001148-EI, what are those costs?

A. FPL is not proposing to change base rates in Docket No. 001148-EI. Attachment I to FPL's November 9, 2001 filing in Docket No. 001148-EI provides the incremental security costs reflected in the MFR filing. The additional security costs included on Attachment I to FPL's November 9, 2001 filing in Docket No. 001148-EI are not power plant security costs. Instead, they include additional security costs for FPL's General office, Juno Beach office, Le Jeune Flagler building, and aviation. They also include additional security for power systems (distribution and transmission) and data security software. Incremental power plant security costs requested for recovery through the Fuel Cost Recovery Clause in Docket No. 010001-EI are not reflected in the MFR filing.

Q. **If FPL is proposing to recover 2002 incremental security costs related to increased national security concerns, through base rate adjustments in Docket No. 001148-EI, in addition to the proposed recovery of other 2002 incremental security costs through the Fuel and Purchase Power Cost Recovery Clause in Docket No. 010001-EI, why does FPL believe recovery of incremental security costs is necessary through both base rates and the fuel clause?**

A. FPL is asking to recover only the cost of incremental power plant security costs through the Fuel Cost Recovery Clause since FPL believes these costs are fuel-related and there are significant uncertainties in these costs. FPL believes it is essential to increase security to protect and maintain its fuel supply so that we can continue to provide economical nuclear and fossil generation. FPL's MFR filing reflects all other non-clause costs.

Q. **If FPL is proposing to recover 2002 incremental security costs related to increased national security concerns, through base rate adjustments in Docket No. 001148-EI, in addition to proposing 2002 recovery of other incremental security costs through the Fuel and Purchase Power Cost Recovery Clause in Docket No. 010001-EI, how is FPL proposing to avoid double recovery of 2002 incremental security costs?**

A. FPL is only requesting recovery of incremental power plant security costs through the fuel clause since they are fuel-related. All other security costs are reflected in FPL's MFR filing. See response to Interrogatory No. 174.

EXHIBIT NO. _____

DOCKET NO: 010001-EI

WITNESS: KOREL M. DUBIN

DESCRIPTION: Transcript of Korel M. Dubin's deposition taken on October 22, 2001

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010001-EI EXHIBIT NO. 30
COMPANY
WITNESS: FPSC Staff
DATE: 11-20-21-01

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 010001-EI

In the Matter of

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE AND
GENERATING PERFORMANCE
INCENTIVE FACTOR.
_____/

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DEPOSITION OF:	KOREL M. DUBIN
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
PLACE:	Gerald L. Gunter Building Room 309 2540 Shumard Oak Boulevard Tallahassee, Florida
TIME:	Commenced at 10:30 a.m. Concluded at 1:30 p.m.
DATE:	Monday, October 22, 2001
REPORTED BY:	TRICIA DeMARTE Official FPSC Reporter (850) 413-6736

APPEARANCES:

TIM PERRY, McWhirter, Reeves, McGlothlin, Davidson, Decker, Kaufman, Arnold & Steen, P.A., 117 South Gadsden Street, Tallahassee, Florida 32301 on behalf of Florida Industrial Power Users Group, appearing telephonically.

JONATHAN E. SJOSTROM, Steel, Hector & Davis, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301, appearing on behalf of Florida Power & Light Company.

ROBERT VANDIVER, Deputy Public Counsel, Office of Public Counsel, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

WM. COCHRAN KEATING, IV, Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0870, appearing on behalf of the Commission Staff.

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2	(Late-Filed) Information Concerning Staff Audit Work Papers	60
3	(Late-Filed) Fuel Cost Savings from Capital Projects Recovered through the Fuel Clause	66

S T I P U L A T I O N

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure; that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

KOREL M. DUBIN

appeared as a witness and, after being duly sworn by the court reporter, testified as follows:

DIRECT EXAMINATION

BY MR. KEATING:

Q Good morning, Ms. Dubin.

A Good morning.

MR. KEATING: I just want to make sure we got people's names on the lines. Do we need to take appearances on the record? Okay. This is Cochran Keating with the Commission Staff.

MR. SJOSTROM: John Sjostrom with Steel, Hector & Davis.

MR. VANDIVER: Rob Vandiver with the Office of Public Counsel.

MR. KEATING: I believe that's everybody represented in the room. Is there anybody who would like to make an appearance who's on the phone?

MR. PERRY: Tim Perry on behalf of FIPUG.

MS. DAVIS: This is Terri (phonetic) Davis for Gulf Power.

MS. DAVIS: Linda Davis for Gulf Power.

MR. KEATING: Okay. I think that's everybody I heard before, so we'll go ahead and get started this morning.

MR. SJOSTROM: The person working on the computer, we

can hear you coming through on the speakerphone, so you might want to hit your mute button there, or not.

BY MR. KEATING:

Q It sounds quiet now. We'll go ahead and get started. Ms. Dubin, could you just state your name and your business address for the record?

A My name is Korel Dubin, and my business address is 9250 West Flagler Street, Miami, Florida 33174. And I work for Florida Power & Light Company.

Q And what's your position at FPL?

A I'm manager of regulatory issues in the regulatory affairs department.

Q Just to get some background, when did you become employed in that position?

A In this position? Several years ago. I'm thinking maybe 1998.

Q Okay. And were you employed in FPL's regulatory affairs division in any other position prior to gaining your current position?

A I've been -- in 1985, I was in the rate department. I moved in '91 to regulatory affairs and in 1997 back to rates and then I believe it was in '99 back up to regulatory affairs, all working within the clause area. There was some restructuring.

Q Within the area of the fuel clause?

A Yes.
Q Any of the other clauses?
A Fuel, environmental capacity.
Q If I ask you a question about any decisions that were made after your hire date in the regulatory affairs section, would you be able to respond based on your knowledge?
A If you ask any questions regarding --
Q Any questions concerning decisions made in the regulatory affairs division.
A Regarding the adjustment clauses, I was very familiar with them, yes.
Q Okay. Do you have any knowledge of decisions that were made by FPL's regulatory affairs division prior to your time there?
A I've worked for Florida Power & Light since 1982, and prior to joining the rate department, which is like the sister department to regulatory affairs, I worked in the fuel resources department. Again, a lot of work was in the adjustment clause area.
Q So if I had a question about why FPL was seeking to recover a particular expense for the fuel clause, you would be the right person to ask?
A Yes, I believe so, depending on what expense it is.
Q Well, I guess we'll see as we get to those questions.
A Yes.

Q Do you have your prefiled testimony from August 31st with you?

A Yes, I do.

Q In your testimony at Page 1 --

A Yes.

Q -- at Lines 22 through 24, you state that the calculation of the fuel factors is based on projected fuel cost, using the base case forecast as described in the testimony of FPL Witness Jerry Yupp.

A Uh-huh.

Q Who decides that FPL's base case forecast of fuel prices is the most appropriate forecast to use as an input to calculate the fuel factors?

A Our management. Whenever we prepare a fuel adjustment, we have a base case and a low band and a high band. And all of our testimony and everything is reviewed by our docket management.

Q So are the -- so it's a management decision on whether to use that base case forecast?

A Our forecasts are --

(Telephone interruption.)

Q We were talking about who makes the decision to use FPL's base case fuel forecast as an input to the calculated fuel factors. Is there any particular person or management level at which that decision is made?

A It's made at a -- as a docket management level, and we have a docket team that works on the fuel adjustment that makes recommendations.

Q Okay. So the docket -- does the docket team -- so the docket team makes a recommendation to docket management.

A Uh-huh.

Q Is that how it works?

A Yes.

Q And who is a part of the docket team?

A Myself, Mr. Yupp, Mr. Ungar. We have representatives from accounting, resource planning.

Q And who is -- in docket management --

A Uh-huh.

Q -- who's involved in that?

A Bill Walker.

Q When you receive the low, base, and high case forecast of fuel prices from Mr. Yupp, do you -- in calculating the fuel factors, do you consider any other forecasts?

A Well, if you're asking strictly on a fuel price forecast, we look at those. Of course, we have to look at our maintenance schedules and all those other items.

Q But with respect to which forecast to use, do you take the low, base, and high case forecast as a given to go forward on, or does your review -- or when you get those forecasts, do you consider any other forecasts, whether the

other forecasts may be reasonable?

A We have the recommendations from our forecaster. He gives us the mid, low, and high band. The mid being -- the definition of it is, I believe, the most probable. And we use those forecasts, but we continually monitor the forecasts that we use.

Q But you wouldn't consider any other forecasts? When you get the forecast from Mr. Yupp, that's what you use?

A Yes.

Q And that's -- well, would it be a part of Mr. Yupp's job then to look at other forecasts and determine whether they're reasonable in preparing his forecast?

A I'm not sure if Mr. Yupp himself does that, but I know that other forecasts are also looked at, yes.

Q Okay. Maybe a better way to ask it would be, does the docket team or docket management make the decision on which forecast to use?

A It's recommended from the forecasting group the forecast to use, yes.

Q Do they consider any other forecast besides what the forecasting group provides?

A When you're saying "other forecasts," could you give me an example?

Q Other fuel price forecasts.

A From?

Q From any other source.

A I think that they are looked at from the forecasting standpoint when they're presented to us, yes.

Q In Mr. Yupp's testimony, he talks about how he's developed FPL's projected average net operating heat rates for 2002.

A Uh-huh.

Q Is that something that's used as an input in determining the fuel factor?

A There are a number of inputs that go into the POWRSYM run, which is a simulation -- a computer simulation model which basically models our system for a year's time. And there's a number of different items that go in there, the plan maintenance schedules, different operating constraints of the units, the fuel prices, the load forecasts, the peaks, a variety of information. And out of that comes a lot of calculations, including, I believe, the heat rates, and those are reported on the E-4 Schedule.

Q Okay. Does FPL consider any other heat rate projections besides the ones that are developed by Mr. Yupp?

A I don't think that they said they are developed by Mr. Yupp. I think that all of this information goes into the production model, and it's an output of that.

Q The heat rates are an output?

A Uh-huh.

Q Do you use that output to calculate what the projected fuel factors should be?

A Well, it's part of -- how those units are operating is part of the total fuel cost. Since the customer is charged, the fuel adjustment charge is based on a burn cost or a charge out cost. All of those are factored into it.

Q So when you get that heat rate data as an output, are there any other heat rate forecasts that are considered in calculating the fuel factors?

A Again, when we look at the runs after all the data goes in, then we get, like, some summary data from the run itself. And then the various groups who are responsible for those areas review it, including our power generation area, our nuclear. And then they look at the output to see if it's reasonable, it makes sense, and they would compare the heat rates to operating experience and that kind of thing.

Q When you receive projected data projections of fuel prices or heat rates from Mr. Yupp, do you have any latitude to change those projections in calculating the fuel factors, or do you -- with that respect, calculating the fuel factors, do you have any latitude to change those projections?

A We're constantly monitoring all the different aspects of fuel adjustments, so I guess we could change them. But what we're doing is, we take a forecast, and we use that to run the models.

Q If you could turn to the -- I think Appendix II, the fuel cost recovery E Schedules as part of the August 31st testimony and exhibit filing.

A Uh-huh.

Q For Schedule E-3, which I think begins -- let me find a page number for you. It begins at Page 12.

A Uh-huh.

Q Were the projected data for generation by fuel type that are shown on this schedule created by you or under your supervision?

A Yes. Again, that's an output of the POWRSYM run.

Q Okay. And is that -- I guess to get a better understanding, is that something that the regulatory affairs division runs?

A It's done in resource planning, but let me -- just to give a little bit of history. Back when they established the fuel adjustment to be on a projected basis, it was determined by the Commission that a production costing model would be used to do that, and previously we had PROMOD, and then we had POWRSYM. We came to the Commission and said, here's the production costing model we want to use, and it was approved to be used for fuel adjustment.

Q Turn to the next schedule, E-4. It's on Page 16. I think that runs through Page 67. And I have the same question with respect to that schedule, that that is -- if the data

shown on that schedule was created by you or under your supervision?

A Yes.

Q With respect to Schedule E-5, it begins on Page 68.

A Uh-huh. And again, all of these are a team effort of the docket team, and the inputs that go into the POWRSYM run and reviewed by the team.

Q So is the data that's shown on Schedule E-5 on Pages 68 and 69 created by you or under your supervision?

A Yes.

Q And is the data shown on Schedule E-6, Pages 70 and 71, created by you or under your supervision?

A Yes.

Q And is the data on Schedule E-7 created by you or under your supervision?

A Yes.

Q Okay. Next would be E-8. Is the data on that schedule created by you or under your supervision?

A Yes.

Q Finally, was the data on Schedule E-9 created by you or under your supervision?

A Yes.

Q I just want to refer to a document that I will hand to you in just a second. I just want to make sure I've got the right page. This is a copy of Staff's work papers from its

audit of FPL's fuel-related revenues and expenses for calendar year 2000. For now, I believe this is the only copy we have.

A Okay.

Q And I'd like to refer to work paper 44-5/4-5 Page 2.

A Okay.

Q And I believe there's a vendor identified at the top as EPRI.

A Uh-huh.

Q Are you on that page?

A Yes, I am.

Q Is EPRI an acronym for Electric Power Research Institute?

A Yes, I believe it is.

Q What goods or services did EPRI provide FPL that are referenced in this invoice?

A Mr. Keating, since some of this is blacked out, I'm not sure.

Q Is this the first time that you've seen this, that particular work paper?

A Yes. Mr. Keating, it appears to be a fuel invoice in that it's describing nuclear fuel, conversion, and engineering services.

Q Were these charges to EPRI included in utility accounts which would lead to cost recovery through the fuel clause?

A This is the first time I've seen this document, so I'm not sure.

Q Okay. Perhaps we can come back to this one towards the end of the deposition, and I think I will just move on for now and think about whether there's another way to get the information.

A Just to answer -- maybe this will -- in the normal course of business, nuclear fuel would be recovered through the fuel adjustment. I just have not seen this particular document, and since some of it is blanked out, too, I'm not sure.

Q Does FPL recover any dues or membership fees to any industry organization through the fuel clause?

A Dues or industry fees, I don't believe so.

Q Does FPL recover any dues or membership fees to any civic or charitable organization through the fuel clause?

A No.

Q Does FPL recover any dues or membership fees to any political or governmental organizations through the fuel clause?

A No.

Q Okay. FPL does pay dues and fees to those types of organizations; is that correct?

A I don't have any direct knowledge of that.

Q Okay. Let me refer to the September 20th testimony

that was filed in this docket.

A Okay.

Q Starting at Page 4, Line 6 of your testimony -- or actually, the last sentence starting on Page 4, Line 4 states, "The objective of the fuel cost recovery clause is to keep the utility" --

A Uh-huh.

Q Hold on a second. I may have the wrong page.

A Okay.

Q I'm on the right page, sorry.

A Okay.

Q Again, at Page 4, Lines 4 through 6, it states that the objective of the fuel cost recovery clause is to keep the utility financially whole and to provide proper price signals to customers.

A Yes.

Q Do you agree that the way that fuel factors are set has sort of an averaging effect over a 12-month period?

A It has a levelizing effect or a stable effect over a 12-month period, and that's intended to reduce the volatility.

Q When you say "proper price signals" in the testimony, if there's a -- if the fuel factors are set and there's sort of a levelized effect, could you explain how the customer will get the proper price signals with a levelized factor?

A Well, it can be a levelized factor, not saying that

it's a lower factor, a levelized or stable for a period of time, but not necessarily a lower, so that when fuel prices are high, customers see that, and when fuel prices are low, customers see that.

Q But I guess absent a midcourse correction, though, the fuel prices can fluctuate up and down, but the customers wouldn't see that; correct?

A No, they don't see that. They see more of a stable bill, and that's pretty consistent with what customers have told us as far as -- you know, we've got a few hundred thousand customers on budget billing trying to keep their costs fairly stable. We get a lot of calls in the end of the year for the following year from customers, from condo associations to different small businesses trying to budget for the year. So they would like -- they want a stable price for the year, something they can predict.

Q If the prices is kept stable as the customers have requested, do they get a proper price signal?

A They do in that it could be higher or lower. What they are looking for is predictability and something that's not changing from month to month.

Q So do you believe that the fuel clause provides a proper price signal on an annual basis?

A Yes.

Q Does FPL offer a levelized bill payment program for

its residential customers?

A We offer budget billing.

Q How does that work?

A The same charge is applied, but it smoothes out based on the customer's usage, and it helps to smooth out their bill that way.

Q Is it based on projected usage? I mean, how --

A It's based on their historical usage, and then it's a way to smooth out their usage. They still are charged the same rate, but for example, it will budget over time so that in the winter time they may be using less so that it -- they will be charged a little more there and a little less in the summer to try to even it out.

Q So is it correct that it's an estimate of what their bill would be based on their historical usage, and then that estimate is levelized over a certain period of time?

A Right. It's not the rate or the charge that's changed, it's their usage based on history.

Q Under the budget billing program, does it go up -- how far out would you estimate their usage for purposes of levelizing the bill on a monthly basis?

A Mr. Keating, I don't recall.

Q Under the budget billing program, is it the total bill that's levelized for the customer?

A Yes.

Q Okay. Does the -- do you believe that the levelized bill payment program insulates the residential customers from the effects of sharp increases in oil and gas prices -- oil and natural gas prices?

A I think it assists them in being able to predict what their bill is going to be in some degree. But when there are spikes in the fuel adjustment charge -- excuse me, when there's spikes in oil and gas prices and resulting in increase in the fuel adjustment charge, I think that that may not solve all the problems.

Q Do you believe that by hedging oil and gas purchases that those sharp increases in oil and gas prices that customers could be insulated from those increases a little more?

A I think that, you know, what Florida Power & Light does in all cases is try and minimize the cost to the customer as best as possible and tries to reduce volatility where it can, whether that's through any kind of hedging or any other procurement practices.

Q To receive appropriate price signals, do you believe that customers should experience all the ups and downs of the fuel markets -- of the fuel prices?

A Well, I think it's important that -- the fuel adjustment clause started back in the '70s when we had the energy crisis, and I think it's important for customers to see what their -- the impacts on their fuel. I think it goes along

with, you know, customers are filling their cars with gasoline, and they see the prices rising, and then they can see what kind of prices they'd have in electricity too. It helps them budget.

Q That seeing the -- I'm sorry, I may have missed something at the end. Did you say that the customers could see the fluctuations in the gasoline prices and that would help them budget for electricity?

A Well, I think when they see -- it's easier to understand when they see prices of gasoline going up or down, that their electric bill tends to follow that.

Q But do the gasoline markets and the natural gas and oil markets operate independently?

A They do, they do. But it gives a general feel. I mean, for example, to -- when we asked to recover the underrecovery we had this past year in 2001, one of the main concerns there was -- is that if you recover it when it's happening, it's easier to understand than to carry it forward and now you -- customers are seeing their gasoline charges going down, and you would expect that your electric bill would do the same, which ours is.

Q Do you think the customers should see those increases and decreases in fuel prices on their electric bills to give them appropriate -- so that they can receive appropriate price signals?

A I think that that's one thing. There is some price elasticity when it comes to their electric bill, not that great in the winter time, and it does take a while for it to occur, but there is some.

Q Does Florida Power & Light purchase natural gas for FPL Energy Services?

A Yes.

Q Is FPL Energy Services required to buy transportation capacity from Florida Power & Light for natural gas?

A I don't know.

Q Do you know if Florida Power & Light Energy Services does purchase capacity from Florida Power & Light?

A I know that they purchase natural gas from Florida Power & Light.

Q But you don't know if they purchase the capacity associated with transporting the natural gas?

A I believe they do, but I'd have to check.

Q To your knowledge -- and again, based on what you've just said, I'm not sure if this is in your area or not. To your knowledge, if FPL Energy Services purchases transportation capacity from Florida Power & Light and doesn't sell that capacity, what happens with that leftover surplus capacity?

A I don't know.

Q Turn to Page 6 of the September 20th prefiled testimony.

A Uh-huh.

Q Is it correct that -- and I'm looking at the question that starts at the top of the page and the response.

A Yes.

Q Is it correct that FPL believes it's appropriate to flow revenues from the affiliate back to the retail customers through the fuel cost recovery clause?

A Revenues from the affiliate through --

Q Revenues from sales of natural gas and transportation capacity made by FPL to an affiliate.

A When Florida Power & Light, the utility, makes a sale of natural gas, whether it's to an affiliate or an Enron or an XYZ Company, those revenues go back through the fuel adjustment clause.

Q Do you believe it's appropriate to flow any related losses back to retail customers through the fuel cost recovery clause?

A What do you mean by "losses"?

Q If there was a loss on the sale.

A I believe so. I believe the overall transaction would result in a positive figure. It's similar to an off-system sale where those transactions are done, and then the revenues flow back through the clause.

Q When you say at Line 7 that there's no distinction made between a sale to an affiliated company versus an

unaffiliated company, why is there no distinction?

A Why would there be a distinction? You're making a sale -- Florida Power & Light is selling natural gas, and whether it's an affiliate or an Enron or XYZ Company, it's -- those revenues should be credited back through the fuel adjustment clause. We're talking about the sale from Florida Power & Light, the utility, to another entity, whether it's excess gas or whatever that you would sell. And it's very much the same as when you have an off-system sale, and you would sell power and run those revenues back through to the fuel adjustment clause. It results in a lower fuel charge to FPL's customers.

Q To your knowledge, has FPL made any sales of natural gas to Florida Power & Light Energy Services below FPL's cost?

A I think that Ms. Welch in her testimony in reviewing the -- it says at the bottom of Page 4 of her testimony through Page 5, "Review of daily sales tickets show that sales made to FPLES were at an amount at or over the daily market rate."

Q So do you have any knowledge beyond that audit report as to whether FPL sold natural gas to FPL Energy Services below its cost?

A No.

Q If that were to happen, would the loss on the sale be recovered through the fuel adjustment clause?

A I don't know that that's happened.

Q If it were to happen, based on the how the fuel factor is established, would that loss be flowed through the fuel clause?

A I guess I'd have to see the circumstances of that sale.

Q To your knowledge, has Florida Power & Light Energy Services made any sales of natural gas below cost to its customers?

A FPL Energy Services, when they make their sales, I believe they're -- that percent off tariff is what they use.

Q What's that?

A The percent off tariff. Maybe I'm not characterizing that correctly.

Q I was just going to ask if you could explain how the percent off tariff is structured.

A I'm just going to read you a line from -- Mr. Brandt who works in this sent a letter to Ms. Denise Vandiver after the audit, and there's a definition in this letter. It says, "Percent off tariff pricing is based on providing the customer a fixed percent discount for the term of the contract based on the customer's bill had they remained with the gas local distribution company."

Q What other services are provided by FPL to Florida Power & Light Energy Services besides the provision of natural gas?

A I guess there's some assistance in -- of different personnel and different computer support and that kind of thing. And those are allocated and charged to Energy Services.

Q Does Energy Services pay for the services? Do they pay FPL for the services?

A Yes, they're charged for those services.

Q Are the expenses that are allocated to FPL Energy Services recovered in any way from Florida Power & Light customers?

A I'm sorry, can you say that again?

Q Yeah. Are the charges that are allocated to FPL Energy Services recovered from FPL customers in any way?

A They are charged to Energy Services, so it reduces FPL's expense.

Q And FPL's customers -- so FPL's customers don't see that expense?

A It would result in -- for -- it would result in a lower expense reflected in the surveillance report for those activities.

Q If you could, turn to Page 7 of the August 31st prefiled testimony in this docket.

A My testimony?

Q Yes, I'm sorry. There you discuss FPL's contract dispute with Cedar Bay.

A Uh-huh.

Q Is there any difference between the amount that FPL ultimately paid to Cedar Bay and the approximate $18 million that was approved for recovery by the Commission in 1999?

A There may be some difference, and I'm not sure what that is. It's associated with the 13 million because there was some appeals process going on at the time, so there may be some interest associated with that also.

Q Would there be any other difference besides the interest?

A No.

Q Is FPL requesting recovery of that approximate $18 million in this docket?

A Yes. And in fact, we requested it at the time back in the '99 docket. It was approved for -- or the Commission allowed recovery of it in that fuel factor set at that time, but back then, the full Commission was not the same as the fuel panel. And so they allowed recovery, but they wanted it to be addressed by the full Commission later on. But they did note in their order that it was the type of cost that was routinely recovered through the clauses.

Q Is FPL requesting in this docket approval for recovery -- and this may get back to the first question I asked about this -- of the same amount that it requested in the '99 fuel docket?

A It's not any additional dollars. What we're talking

about here is that that item was left open, and there was a spinoff docket looking for the full Commission. And we just thought, efficiency sake, we've got a docket open here, and now the fuel panel is the full Commission, that it might come to closure in this docket.

Q So has FPL already recovered that total amount?

A Yes, yes.

Q Okay. So this is -- what FPL is seeking in this docket is, I guess, the final approval that the --

A Right. There's a spinoff docket there. There's no schedule set for it or anything else. And rather than going through the administrative costs of that other docket, we have the fuel docket open, we've got the full Commission there, it seemed appropriate to bring it to closure there.

Q If there is any difference between the amount that was ultimately paid to Cedar Bay and the amount that's been recovered -- or the amount -- not the amount that's been recovered but that was approved by the Commission in 1999 for recovery at the time, is that something that FPL is seeking to have approval for here?

A Yes.

Q Okay. But is that something that's already been recovered as well?

A I think it's already been booked as part of the -- that amount.

Q If the Commission were to disallow any part of these amounts, how would the FPL/Cedar Bay contract's regulatory out clause operate? What effect would that have under the contract?

A That I don't know. I do know, though, that when the order in 1990 that approved the Cedar Bay contract itself did state that fuel and capacity costs could be recovered.

Q Do you know who would be familiar with the -- with that contract who may be -- to answer that question?

MR. SJOSTROM: On the reg out clause?

MR. KEATING: Yes.

MR. SJOSTROM: I suspect that would probably be FPL's lawyers.

MR. KEATING: Okay.

THE WITNESS: That's what I was thinking.

MR. KEATING: All right.

BY MR. KEATING:

Q What is your understanding of the Court's reasoning in requiring FPL to pay approximately $18 million to Cedar Bay?

MR. SJOSTROM: I'm going to instruct the witness not to answer that question. Any knowledge that she has of that would come from, you know, discussion with counsel, if I understood the question correctly, and assert the attorney-client privilege.

MR. VANDIVER: I'm sorry, I missed the question.

Could you repeat the question?

MR. KEATING: The question was, what's the witness's understanding of the reasons behind the Court rulings that required FPL to pay approximately $18 million to Cedar Bay?

MR. SJOSTROM: Can I talk with my client for a second?

MR. KEATING: Sure.

MR. SJOSTROM: Maybe we can -- maybe right now would be a good time to take a little break.

MR. KEATING: Okay. Do you want to take about five minutes? Ten minutes?

MR. SJOSTROM: Five minutes would be fine.

MR. KEATING: Okay. We'll take a five-minute break.

(Brief recess.)

MR. SJOSTROM: The previous objection is withdrawn. Perhaps you would like to ask the question again to refresh the witness's memory, though.

BY MR. KEATING:

Q Ms. Dubin, what is your understanding of the reasons behind the Court's ruling requiring FPL to pay approximately $18 million to Cedar Bay?

A It's in two parts. Five million dollars is for fuel, and that was the Court's interpretation of the ruling there where the contract, I guess, pointed to the A Schedules for pricing, and it was to point to a coal price. And somewhere

along the road, the price on the A Schedule between -- became the price of coal and pet coke, and the dispute was that the pet coke should be reported separately and that the pricing should be on coal only. And that's how they came up with that $5 million difference.

Additionally, there is -- the $13 million had to do with the dispute on how the unit was operating, and that part is the capacity portion of it, and it has to do with operating rights. And that's the Court's interpretation of that where Cedar Bay is able to get a bonus or not. That's pretty much what I know.

Q So the 5 million portion are related to, I guess, the pricing of fuel?

A Yes.

Q At some point after the contract of -- after performance began under the contract, the A Schedules reflected -- well, let me go back.

Is it correct that the contract, from what you told me, refers back to coal pricing the A Schedules?

A Uh-huh.

Q And the A Schedules began to reflect pricing for coal and pet coke combined?

A Right.

Q Was it FPL's position that the two should be based on the two combined?

A Yes, I believe so.

Q And it was Cedar Bay's position that the two should be separated, and it should be based just on the coal alone?

A Yes. And that recovery of those two components, the 5 million for the fuel portion has been reflected in the fuel adjustment clause, and the 13 million, since it's capacity-related, has been reflected in the capacity clause and allocated accordingly.

Q Could you explain again the -- well, actually, let me go back to the 5 million. Did the Court rule with respect to the $5 million for fuel in favor of FPL's interpretation or Cedar Bay's?

A The judgment was against us.

Q Okay. And was the judgment against FPL for the 13 million capacity?

A Yes.

Q Could you explain again the capacity -- or the dispute over that portion?

A There was a dispute -- and I don't know all the ins and outs, but basically the way it works is that depending on how the unit operates, Cedar Bay is entitled to a bonus capacity payment. And FPL has the sole discretion of the operating rights there, and the -- there was -- Cedar Bay objected that they weren't allowed to get the bonus as they should. And the judgment was found against FPL, and that was a

jury decision. I don't know if I mentioned that.

Q Have you -- I guess there is a court order that memorializes the decision, a written order?

A Uh-huh. And, Mr. Keating, back in 1999 when we first approached the Commission on this, I was also deposed on this matter, and there were several late-filed exhibits that were filed in the fuel docket which provided all of that information.

Q And you've read the Court's order?

A I've read a very -- a summary part of it.

Q Are you aware of whether the Court cited any -- in its ruling any act of mismanagement on FPL's part?

A No, no.

Q It's your understanding that the Court was simply interpreting the contract terms?

A As I understand it, yes.

Q Let me turn to the September 20th prefiled -- your September 20th prefiled testimony in the docket.

A Okay.

Q At Page 3, Lines 11 through 17, there's a question and answer concerning what's the appropriate rate of return on the unamortized balance of capital projects with an in-service date on or after January 1, 2002, that are expected to reduce long-term fuel costs.

A Yes.

Q And you stated that the return on the unamortized balance should be computed using capital ratios and cost rates approved in the company's last rate proceeding; correct?

A Yes.

Q And what's the basis for that -- for your answer to that question -- your suggestion that we ought to use the capital ratios and cost rates approved in the company's last rate proceeding?

A I guess I'm not suggesting that. That's been the practice now for many years, back since these items have been recovered through the fuel clause back when the Commission approved that in 1985. First of all, the types of items that are included in the fuel adjustment clause, the companies had the burden to show that they result in fuel savings, and they are brought on a case-by-case basis. And then the return on the unamortized balance is used computing the capital ratios and cost rates approved in the company's last rate proceeding. That's been the standard practice. There's been Commission orders on it. And I believe there's an order back in 1985 that talks about it there too. And that's been -- they're long-term assets, and that makes sense to be using that.

Q So the basis for your answer to that question is that it's just the Commission practice?

A Commission practice and a Commission order. When they -- when we recovered the -- let me see if I can find it.

It's been consistent practice all along. And additionally, I was going back through, and back in the '95 fuel docket when we were talking about railcars at Plant Scherer -- I'll read from this order. It's Order PSC-95-1089-FOF-EI. It says, "FPL will recover straight-line depreciation over 15 years, applicable taxes, and, until we revise FPL's capital ratios or its cost rates, a return on average investment at its current weighted average cost of capital of 9.2897 percent."

Q So do you agree with the -- since your answer is based on the past Commission practice, do you agree that the past Commission practice has been -- is appropriate?

MR. SJOSTROM: Object to the form. And the reason I'm objecting, Cochran, if you'll -- indulgence. You keep saying "based on Commission practice," and I think it mischaracterizes the testimony a little bit because she had also said that it's based on the type of asset, that it's a long-term. I just want to make certain that we're not characterizing her answer as solely one based on past Commission practice. I'm sorry.

BY MR. KEATING:

Q I guess, in the absence of an established Commission policy on this matter, would your answer be the same?

A Yes.

Q Is recovery of the amounts that Florida Power & Light receives through the fuel adjustment clause more certain than

recovery of amounts through base rates?

A I don't know if they're more certain. The reason why they are recovered there is because they meet the Commission's criteria of resulting in fuel savings. And each one of the projects that are included in fuel adjustment have been reviewed on a case-by-case basis with the company having the burden to show fuel savings and obtaining Commission approval to do that.

Q Generally, do you believe that the expenses that qualify for the fuel adjustment clause recovery are more certain to be recovered compared to expenses that are recovered in base rates?

A More certain to be recovered?

Q Yeah.

A I don't know that there's that difference. It's just that these costs have resulted in fuel savings, so it's appropriate for them to be recovered here.

Q Do you believe that there's more certainty at least in the short term that the cost recovery through the fuel adjustment clause is more certain than recovery through base rates?

A I think the costs are -- can be recovered. Are they certain to be recovered through the fuel clause? Yes, with the specific approval.

Q To be recovered through base rates, they would have

to be approved on a rate case?

A Yes.

Q Should the rate --

A And that goes towards the recovery through the fuel adjustment clause. It's for costs that weren't anticipated at the time base rates were set and that they resulted in fuel savings. That's pursuant to the Commission's order.

Q Should the rate of return for the unamortized balance of capital projects recovered through the fuel clause be different than the rate of return that capital projects would have earned if the asset was part of rate base?

A I don't know.

Q Do you have an opinion on whether the rate of return should be the same or different based on the recovery mechanism?

A I think it's appropriate to recover them the way that we're doing so. It's a long-term asset, and it's an established procedure that's been in place by the Commission for at least ten years; actually, it's since 1985.

Q I'm pausing to try to avoid phrasing this as a legal question about the Commission's authority. But let me ask, do you see any technical impediments to the Commission approving or authorizing a utility to earn a rate of return on the unamortized balance of the capital project other than the utility's authorized rate of return midpoint?

A Can you say that again, please.

Q Do you believe that there are any technical impediments to authorize a utility to earn a rate of return on the unamortized balance of a capital project other than the utility's authorized rate of return midpoint?

A Technical impediments, is that what you said?

Q Right. If the Commission were to -- if the Commission chose to authorize a utility to earn a rate of return on a capital project other than the rate of return -- other than its authorized rate of return midpoint, would you see any technical problems with that in implementing that decision?

A I don't know of any technical problems, but there may be. I can't think of any offhand.

Q I'm going to try to provide an example to help. Under the idea of allowing recovery of a long-term fuel saving asset through the fuel clause, would it be reasonable for the Commission to approve recovery of a new combined cycle unit through the fuel clause?

A A new combined cycle unit through the fuel clause?

Q Yes.

A No.

Q Why not?

A The types of items -- what we try to do when we've come to the Commission before and asked to recover items that

are perhaps a capital project, we go by the 1985 order. And it's Order 14546. And Item Number 10 in that order says, "Fossil fuel-related costs normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine current base rates and which, if expended, will result in fuel savings to customers. Recovery of such costs should be made on a case-by-case basis after Commission approval."

That's the guideline we use. And we've had a number of times where we've come in -- and they've been pretty specific relating to a reduction in a fuel price. For example, we were able to come in and ask for recovery for some modifications to the plant to make it to be able to burn a different gravity of oil which resulted in fuel savings. That's a direct result in fuel savings.

Now, I think -- I guess there could be an argument that every time you cleaned a boiler, for example, you had some kind of increased deficiency in fuel savings, but I think there's a distinction there to be made between cleaning a boiler and actually making some modifications that would result in a fuel savings. And those are the types of guidelines that we follow.

Q Can you differentiate between a combined cycle unit and railcars or gas pipelines and types of items that have been approved for recovery through the fuel clause before?

A Well, railcars and the gas pipelines in particular, they have resulted in fuel savings, but there also is a transportation component. And back in 1985 when the Commission addressed what types of costs would be included in the fuel adjustment, there was not only the notion of something that resulted in fuel savings but also some transportation costs.

And those transportation costs, it was pretty clear in that order that transportation to delivery point would be something that would be recoverable through the clause, but transportation, for example, from the terminal to the plant, inland barging and other pipeline between the terminal and the plant would not be. And that's part of the distinction, not just fuel savings but also the transportation component.

In addition to that, when FPL made the case for those transportation items, it was also the lowest cost alternative. So there was also the burden on the company to also describe that and to explain that and illustrate that.

Q So I guess going back to, I guess it was the 10th numbered --

A Number 10, yes.

Q -- paragraph from the Commission order. Based on, I guess, the criteria that are set up there for recovery of the capital project fuel clause, as you were speaking I wrote down a couple of things. You have to demonstrate fuel savings?

A Yes.

Q And one of the other items -- one of the other matters was it had to be fuel-related. Do you think that that's a distinction that can be made between a combined cycle unit and the railcars or gas pipelines, that perhaps the combined cycle unit isn't strictly a fuel-related capital project?

A I'm not sure there. I know we haven't evaluated that to -- for fuel adjustment, but usually looking at something fuel-related, something that results in fuel savings and additionally the transportation aspect of it.

Q Okay. What is the maximum rate of return that the Commission can authorize a utility to recover on the unamortized balance of a capital project?

A The maximum rate of return? I don't know offhand.

Q Do you know what the minimum rate of return the Commission could authorize a utility to recover on the unamortized balance on a capital project would be?

MR. SJOSTROM: Did you do you understand the question?

A Yeah, could you maybe rephrase that?

Q Yeah, I'll rephrase it. What is the minimum rate of return that the Commission could authorize a utility to recover on the unamortized balance of a capital project?

A I'm not sure. As I said before, that we use what was approved in the last rate proceeding.

Q Do you have an opinion on what the maximum or minimum rate of return should be?

A No, I don't have an opinion. I think what we use is appropriate.

Q Why do you believe that the rate of return that FPL uses is the appropriate rate of return?

A Well, it's a well-established practice that's been used now for a number of years, and it's consistent with the Commission orders.

Q If not for a Commission order on the subject, would you believe that that was the appropriate rate of return to use?

A It's consistent with their practice, and it's a long-term asset. It makes sense to use that.

Q Let me turn back to the -- are you still on the September 20th testimony?

A Yes.

Q At Page 3, there's a question and answer starting at Line 19 on Page 3 which runs through Line 6 on Page 4.

A Yes.

Q And I asked you a question earlier related to the last sentence in the answer. There you mention that the objective of the fuel clause is to keep the utility financially whole.

A Uh-huh.

Q How would you define "financially whole"?
A It's a pass through recovery of the fuel expense.
Q Would FPL remain financially whole if the Commission used revenue in excess of FPL's authorized ROE ceiling to reduce expenses and recover through the clause?
A I don't believe that that would be appropriate. The fuel clause is designed for a specific purpose to recover fuel expenses, and it's set because fuel expenses are a volatile expense item.
Q If FPL was earning revenue in excess of its ROE ceiling and that excess was used to offset costs somewhere else, wouldn't FPL remain financially whole?
A One doesn't have to do with the other. The fuel adjustment clause is designed for that specific purpose, to recover fuel costs.
Q With respect to the recovery of capital project costs through the fuel clause, how much of fuel costs been reduced by capital projects, say, over the last ten years?
A I don't have that number at my fingertips, but in order for the project to be approved to begin with, it had to result in fuel savings, and so that had to be demonstrated beforehand. I don't know. It's substantial, though.
Q It had to be projected to result in fuel savings to get approved; correct?
A It had to be projected to result in fuel savings, and

also I believe there was discovery in 1999 that asked for a reporting on how things were going. And we reported on it then. I don't know the numbers off the top of my head.

Q So FPL has provided savings information related to the capital projects?

A Yes. And, Mr. Keating, my estimate just off the top of my head would be somewhere in the tens of millions.

Q I'm going to follow up with a more specific question that I don't suppose you'll have the answer on the tip of your tongue either.

A Okay.

Q For every dollar capital projects recovered through the fuel clause, approximately how many dollars of savings have there been?

A That I don't know. I would suppose, though, it would be different for each project. But just keep in mind that before those costs could be recovered, we had to show fuel savings beforehand. They were approved.

Q Do you believe that absent recovery of those projects through the fuel clause, that those projects would have been undertaken?

A I think you'd have to look at them -- each one, but I would assume, yes, they would have been.

Q Does FPL have a policy of encouraging reduction of fuel costs through capital projects?

A With a policy?

Q Yes.

A Florida Power & Light's objective is always to try to have the lowest fuel costs that we can to minimize the fuel costs to the customers, whether it's through a capital project or procurement procedures.

Q Maybe a better way of asking is, what criteria does FPL use when it evaluates whether to pursue a capital project?

A Usually a recommendation is brought to the docket team to take a look at. And what we do is a thorough evaluation of fuel savings, as well as to make sure that it's the lowest cost option, and bring that to management to see if it's something that we would like to pursue.

Q Is -- but FPL also evaluates capital projects -- let me go back.

What criteria does FPL use to evaluate projects regardless of whether they would -- before you even look at a cost recovery mechanism?

A I think they do all kinds of comparisons. I'm not really in the area of looking at those capital type things. They come to me to say, this is a capital project that results in fuel savings, and we want you to take a look at it. That's where I get involved.

Q Do you know if Florida Power & Light has as one of its -- as one of the criteria for evaluating capital projects,

whether that project can be recovered through the fuel clause?

A A criteria for examining?

Q Yes.

A I believe they look at capital projects for all their different -- whatever the different needs are and to keep costs low. I don't think they look at specifically whether or not it's going to be fuel cost recovery. If they see that it results in fuel savings, then they may bring it to the docket team to take a look at.

Q Do you believe that recovery through the fuel clause can be a deciding factor in whether to make a capital expenditure?

A I don't think it's necessarily a deciding factor. I think you look at it as whatever is a good business decision is a good business decision to make.

Q Is the fuel clause the only mechanism for recovering a prudent fuel-related capital expenditure?

A No.

Q What other mechanism could be used?

A Base rates, and if it's an environmental type project, the environmental clause.

Q Is the dollar amount of the capital project a factor for FPL in determining whether a particular cost recovery mechanism will be sought?

A I think it is in a way. We certainly wouldn't come

in with every little tiny project, and we would -- something that would be something significant and result in significant fuel savings.

Q I have a few questions concerning the issue that Staff raised regarding the coal inventories of Plant Scherer.

A Okay.

Q Is coal in Plant Scherer stored in separate piles with respect to whether it is to be burned at facilities owned by Florida Power & Light?

A I believe it's a common coal pile, and then there's some percentage taken for our share.

Q Is the coal to be burned at the Plant Scherer facilities owned by Florida Power & Light physically separated by whether it was mined in Bureau of Mines Region 8 or by sulfur content?

A I don't know.

Q Let me ask it differently. You stated in response to the first question there was a common coal pile.

A Right, there is a common coal pile.

Q Do you know if that common coal pile is comprised of an assortment of different types of coal?

A There are different types of coal. There's western coal and some different types of coal, yes.

Q Do you know if any specific type of coal is stored separately from that common pile?

A I don't know that it's stored separately.

Q Are inventory data from -- for coal from Bureau of Mines Region 8 or other regions maintained separately?

A I don't know.

Q Do you know if inventory data for high versus low sulfur content coal is maintained separately?

A I don't know about that coal procedure there. I know what comes back to Florida Power & Light and included as the adjustments in their A Schedules for fuel adjustment.

Q Do you know who would be familiar with how that inventory data is maintained?

A Our accounting department, I believe.

Q Is -- if I wanted to follow up and ask anybody in particular, would there be any particular person?

A I'm not sure, Mr. Keating. I can see who that might be.

Q I'm going to hand you a portion of -- this is Schedule A-5 for the month of December 1999 for FPL.

A Okay.

MR. SJOSTROM: Thanks.

Q And I turned to the page I want to reference. At the bottom of the page, there's a table with three columns.

A Uh-huh.

Q And in the second column, I think it's in -- for December '99, FPL made a negative 567,958 unit adjustment to

its Plant Scherer of coal inventory without an accompanying adjustment for dollars; is that correct?

A Yes.

Q Do you know, I guess, what happened to the dollars associated with those units?

A I'd have to look into that specific adjustment.

Q Could you provide a late-filed deposition exhibit that would show --

A Sure.

Q -- what happened with the dollars associated with those units?

MR. KEATING: That would be Exhibit 1. How do I want to title this?

THE WITNESS: So for November 1999, the 567,958 MMBtus, and you're looking for the dollars associated with them.

MR. KEATING: Do you want a title for that? We'll call it, "Dollar Amount Associated with November 1999 Plant Scherer Coal Inventory Adjustment." And Scherer is S-C-H-E-R-E-R.

(Late-Filed Deposition Exhibit 1 identified.)

BY MR. KEATING:

Q Are the coal inventories for Plant Scherer maintained using tons as the unit of measurement?

A Yes.

Q Is it correct that FPL is currently reporting to the Public Service Commission in Florida the coal inventory for Plant Scherer in MMBtus?

A I'm sorry, I misspoke. It's -- SJRPP is reported in tons, and coal at Scherer is reported in MMBtus. And it does have to do -- and, Mr. Keating, I can't recall exactly, but there's a blending of the western coal, and in order to be able to do it, it has to be used in MMBtus. And in tons, it reflects incorrect figures. And a number of years ago, we came to Staff when we were looking at the A Schedules and how to report this, and we went through descriptions of what we were doing. And like I said, I don't recall the whole thing, but -- and the agreement was that we would report the coal for Scherer in MMBtus.

Q It's reported for the Scherer in MMBtus in Florida; SJRPP in tons?

A Yes.

Q Do you know how the coal inventories for Plant Scherer are maintained? Are they maintained in MMBtus --

A Yes, I believe so.

Q -- or in tons?

A As you know, the Plant Scherer is in Georgia, and we get information from their accounting group, and what's available as far as how they report things are in MMBtu. And this schedule is broken down differently than the

A-5 Schedules, rather. It was supposed to be in barrels and tons, and we did not have the ability to report Scherer that way. So we had gone to Staff and asked them if it would be okay if we reported it in MMBtu. And that's been a number of years now that we have done that.

Q Are you familiar with a Commission order that -- an order that would require reporting in a different manner?

A No. Different than MMBtu?

Q Yes.

A (Shaking head negatively.)

Q How does FPL measure the coal quantities that it purchases for Plant Scherer for use at Plant Scherer?

A The amount of burn, is that what you're talking about?

Q The amount that -- how does it measure what's purchased and burned?

A There's an oversight there as far as their accounting area goes. I don't know exactly, but it's very similar to SJRPP that we have an oversight.

Q I'm sorry, what do you mean by an "oversight"?

A There's a committee that is made up of both FPL and Scherer.

Q Okay. So you wouldn't know, but that committee would know how -- well, I guess I'll repeat the question. I'm not sure I understood the answer, if you were saying that I needed

to ask someone else or if you knew the answer. How does FPL measure the quantity of coal that it purchases and burns at Plant Scherer?

A There's a committee and there's an audit procedure of what is purchased and burned at Scherer.

Q Okay. Do you know, does it measure those quantities in tons or by MMBtus?

A I believe it's in MMBtu. As I stated before, that there is a -- it's in MMBtus because of the way it's recorded as well as there's a blending of coals with western coal which -- like I said, I don't recall all the details of it, but in order to be able to report it, it has to be in MMBtus.

I'm just trying to go from memory, Mr. Keating. This was probably five or six years ago that it was determined that we were going to do it this way.

Q The amount of coal Plant Scherer has is measured using an aerial surveying method; is that correct?

A Yes.

Q And does the aerial method result in an approximate amount by ton?

A I believe so.

Q How are those results converted to MMBtus?

A There's a conversion formula. I'm not sure what it is, but there's a conversion formula.

Q Do you know what the formula is based on, generally?

How the formula works?

A There's a conversion factor that's applied to tonnage to get to MMBtu. I'm looking at my engineers over here. I'm not sure of the exact formula. I could put that on the late-filed exhibit, though, if you'd like to see the conversion.

Q That would be great. It will be great for one of our engineers to look at. Do you want to include that in Late-Filed Exhibit 1?

A Sure, we can put it there.

Q Okay. We can just add to the title --

MR. SJOSTROM: And converting factor.

Q -- "and conversion factor."

Why does Florida Power & Light use a one-month unit price in adjustments rather than a period averaging the price with respect to its coal inventory at Plant Scherer?

A That's the standard practice for the accounting in Georgia, and that's why it's used. Plant Scherer, as you know, is in Georgia, although I believe that it's -- I know for SJRPP we use the six months. I've gone back and done the calculation, and we're talking about, you know, over time there's a wash. I looked at the last year and a half, and the difference it made was $239 in the favor of the customer.

Q Is that the one-month unit price adjustment treatment that's required by the Georgia Public Service Commission?

A As I understand it, yes.

Q Does FPL have the data available to use a period average unit price for its adjustment?

A Yes. And that's the calculation I just did. Over time whether you use one month or you use six months, it's just about a wash and a $239 difference.

Q Are you aware of whether this Commission by order requires either particular method to be used?

A Yes. The Florida Public Service Commission requires it to be the last six months, and the Georgia requires the last month. So we're in a predicament that we have a plant in Georgia that's using one. We're reporting our numbers here in Florida, and they're different. But again, I think that the intent of the -- or the tone of the order was to make that adjustment and over time it's a wash.

Q But if FPL does have the data available to make an adjustment -- a period average unit price adjustment that does technically comply with the Commission's order even if there's little difference, why doesn't FPL report it in that manner?

A Mr. Keating, we could do that. It should be no problem to do that.

MR. KEATING: Can we take just about five minutes? And I think we're close to wrapping it up, and if we take a few minutes, I'll make sure --

MR. SJOSTROM: That will be fine.

MR. KEATING: -- we've covered everything that we think we need to.

MR. SJOSTROM: Very well.

(Brief recess.)

MR. KEATING: We just have a few more questions to finish up.

BY MR. KEATING:

Q Todd is going to hand you FPL Group's most recent Form 10-Q filed with SEC on August 8th.

A Okay.

Q And this is document that Staff downloaded off FPL Group's Web site. If you could, turn to Page 7 of 44 in that document. Let me first ask if you're familiar at all with that document?

A I haven't seen it, but I know what it is.

Q Does it appear to be the -- what I've said, Form 10-Q for Florida Power & Light?

A Yes.

Q At the bottom of Page 7, the document states, "Upon settlement, any gains or losses will be passed through the fuel and purchased power cost recovery clause (fuel clause) and the capacity cost recovery clause (capacity clause)." Does that reflect your understanding of how FPL would seek to recover gains and losses resulting from its hedging activities?

A Yes.

Q Under what circumstances would FPL seek to recover hedging gains and losses through the fuel clause?

A I think it's part of the procurement of fuel, and that you would look at the total procurement, not just necessarily one transaction at a time, and see that it's resulted in fuel savings.

Q If it resulted -- so if it resulted in fuel savings, FPL would seek to recover those gains through the fuel clause --

A When you're talking about --

Q -- or reflect those gains in the fuel clause?

A Any of our fuel procurement expenditures are included in the fuel adjustment clause and with the objective being to lower the total overall cost to the customer.

Q If there were net savings as a result of FPL's fuel hedging, would it reflect those savings in the fuel clause?

A Yes.

Q If there were net losses as a result of FPL's hedging activities, would it seek to recover those through the fuel clause?

A Yes. But what I was trying to say is that you're not looking at one specific transaction. If you look at it in the entirety, that you would see that there's an overall lower cost of fuel to the customer.

Q Are you saying that for this year -- in this year's

filing in the fuel clause? Is that what -- I'm trying to understand if you're saying there's been overall savings, and that's what's being reflected in the --

A I think there's overall savings in our fuel procurement strategy in its entirety.

Q Okay. Is that for -- to be reflected in next year's fuel factor?

A It's in all fuel factors.

Q Isn't it a possibility that there could be a net loss as a result of FPL's hedging activities?

A There may be a loss on a specific transaction, but the overall strategy -- the overall procurement strategy and hedging strategy would result in fuel savings to customers. After all, that's why we do that. And, Mr. Keating, if I'm not mistaken, in discovery responses we have some savings figures; I think they're by fuel type.

Q So my original question was, under what circumstances would FPL seek to recover hedging gains and losses through the fuel clause? Is it your answer that -- if I understand your answer right, are you saying that under all circumstances?

A Yes.

Q Would your answer be the same with respect to whether FPL would seek to recover hedging gains and losses through the capacity clause?

A I'm trying to think of a circumstance where those

costs may be capacity-related, and I guess if they were capacity-related, that would be the case. But from what I can think of right off the top of my head, they would all be energy or fuel-related and therefore included in the fuel adjustment clause.

Q I'm just going to go back to a couple of questions that I asked earlier, and I may ask for one or two more late-filed deposition exhibits. First, I asked a question related to Staff's audit work papers for fuel-related revenue expenses for calendar year 2000, in particular a work paper 44-5/4-5 which, I believe, is Page 2 of that packet that we handed you.

A Yes.

Q That page identified -- that page is an invoice to EPRI; is that correct?

A It appears it, yes.

Q And because of the -- because some of that information was redacted, you weren't sure what goods or services exactly were provided to EPRI; is that correct?

A Yes. It does say "nuclear fuel invoice," so it would seem it's for nuclear fuel.

Q Okay. I believe I asked you this, but I don't recall the answer, and maybe I ought to base this on the assumption that the invoice is for nuclear fuel. Would the charges to EPRI included in utility accounts which could lead to cost

recovery through the fuel clause, assuming that they are for nuclear fuel?

A Mr. Keating, where it says, the account distribution is redacted on this, so I can't tell. If it's nuclear fuel, though, it would be included in the fuel adjustment clause.

MR. KEATING: What I'd like to try to do is get certain information related to that in a late-filed exhibit. And what I want to try to avoid, I guess, is confidentiality concerns, if some of this has been treated confidential already. But what I'd like to find out specifically is, is what -- is the goods or services provided to EPRI and whether the charges to EPRI are included in accounts which would lead to cost recovery through the fuel clause, and I think -- and finally, if they were, just an explanation of why they would be recovered through the fuel clause. I guess it's Late-Filed Exhibit Number 2. Just title that "Information Concerning Staff Audit Work Papers."

(Late-Filed Deposition Exhibit 2 identified.)

BY MR. KEATING:

Q Do I need to go back through that, or are you comfortable with what the information that we're looking for is?

A Uh-huh.

Q Okay.

A May I have a copy of this?

Q Yes. We'll make a copy --

A Otherwise I'll have to go dig through the audit to find it. So I would appreciate that.

Q And I had asked a few questions about FPL's sales of natural gas to FPL Energy Services.

A Yes.

Q I asked, is Florida Power & Light Energy Services required to buy transportation capacity from FPL. You didn't know the answer to that question; correct?

A And, Mr. Keating, it struck me later. I believe the answer there, it's the -- when we sell gas, it's delivered, so it has that in there.

Q So if FPL Energy Services is buying gas from FPL, there's going to be a transportation capacity component?

A Yes, there is.

Q Do you know what amount of capacity that FPL Energy Services is required to purchase from FPL?

A No.

Q Okay. Do you know who would be able to answer that question?

A Are you talking about somebody -- the question goes to what Energy Services is required?

Q Right. What amount of capacity Energy Services is required to purchase from FPL.

A I'm not sure who would know that. Someone in Energy

Services, though.

Q Is there anybody at FPL that may be able to answer?

A I believe it will be Mr. Brandt.

Q Mr. Brandt?

A Uh-huh. He's the one that the audit was conducted with.

Q And the third question, I had asked that -- I believe you weren't familiar with is, what happens to capacity that FPLES -- that Energy Services purchases from FPL but does not sell?

A Purchases from -- if they buy gas from us?

Q Yes. I mean, is it -- do you know if that would be returned -- that capacity would be returned to Florida Power & Light or to FGT or sold to another party?

A I'm not sure.

Q Do you know who would have that information?

A Perhaps Mr. Yupp may be able to answer that.

MR. YUPP: Maybe.

MR. KEATING: Mr. Yupp is forewarned that he may be asked that question.

MR. SJOSTROM: Sooner rather than later.

(Discussion of the record.)

BY MR. KEATING:

Q I had also asked some questions earlier regarding your testimony that a fuel cost recovery clause would provide

proper price signals to ratepayers.

A Yes.

Q Do you believe that between fuel hearings that the fuel clause provides proper price signals?

A In that the fuel charge is higher or lower, there is a true-up mechanism which would reflect those additional or reduce costs at a later period. But for the most part, during the year, it should provide them with the level of their fuel charge, because if there is a significant increase or decrease in the fuel charge and it results in something that's plus or minus ten percent, then a change would be made.

Q If there were -- if the fuel factor changed monthly to keep up with the market, would that provide a more accurate price signal?

A I don't believe so, because you would be truing up then even if you provided it monthly. It used to be done like that, I believe, in the mid '70s, although I wasn't around then, but you're still going to have a couple month lax. So no matter you do, you are going to have some kind of a true-up. So I think that the -- what we try to do is strike the balance between a proper price signal and be able to give them some predictability.

Q On another subject, I had asked a question as to whether, to your knowledge, FPL had sold natural gas to FPL Energy Services below cost at any time.

A Uh-huh.

Q And if that were -- and I believe you stated that, to your knowledge, that had not occurred.

A I think I pointed to a statement in Ms. Welch's testimony that talked about the daily rate being higher than the market rate.

Q Okay. And after that, I followed up and asked if it were to happen, if FPL were to sell natural gas to Energy Services below cost, would the loss be recovered through the fuel adjustment clause, and I believe you stated that it would -- you'd have to see the circumstances?

A Yes. But any sale of natural gas, whether it's to an affiliate or a nonaffiliate, the expenses and revenues associated with those would go through the fuel adjustment clause.

Q There were a couple other questions I had asked about savings from capital projects that were being recovered through the fuel clause.

A Yes.

Q I know you didn't have that information on the tip of your tongue today, so I'd like to ask for a third late-filed exhibit with that information.

A Mr. Keating, since I do believe that that same request was made, oh, about a year and a half ago and it's the subject of discovery, do you want us to go back and can we

point to that or --

Q Is that something you could use, I guess, as a basis for an updated --

A Okay. Perhaps we'll look at that.

Q -- response?

If the information is mostly out there -- I think if we had something that was updated to 2001 or as recent as possible, that would be helpful.

A Okay.

Q And I don't recall -- do you recall the time period of that discovery request?

A I think it was about a year and a half ago.

Q Do you recall over what period of time that you were asked to review the savings?

A I think it was from the beginning of the projects, but I'll have to go back and take a look.

Q Okay. If it does go back to when the project -- when recovery began, I guess, consistent with what you've prepared before --

A Okay.

Q -- if you could, provide fuel cost savings from capital projects being recovered through the fuel clause for that period.

A Okay.

MR. KEATING: That will be Late-Filed Exhibit 3.

(Late-Filed Deposition Exhibit 3 identified.)

BY MR. KEATING:

Q The second question I had along those lines that perhaps you can include this information in that same late-filed exhibit was, for each dollar of capital projects recovered through the fuel clause, how many dollars of savings has there been. Is that something that could also be provided in that late-filed exhibit?

A For each dollar of capital projects?

Q I guess the ratio of the costs going through to the savings produced.

A We'll take a look and see what we can do.

Q I've got just one other question. With respect to the Commission's practice of proving recovery of certain capital projects through the fuel clause, do you believe that that practice properly compensates Florida Power & Light for the risks that it incurs when it recovers a long-term fuel savings asset?

A Properly -- could you repeat that, please.

Q Yeah. Does allowing recovery of those projects through the fuel clause properly compensate FPL for the risks that it incurs with the project?

A What do you mean by "risk"?

Q I guess simply the financial risk that FPL incurs.

A We recover the cost of the project, so --

Q Are there -- besides financial risks, are there other types of risks that FPL incurs when it undertakes a capital project?

A The -- we ask for recovery of the cost of that project because the project results in fuel savings, and it makes good business sense to go ahead and do that project. We get -- we recover the cost of the project and at the same time provide fuel savings to the customer, reducing their bill. It's good for everyone.

Q Are there other risks related to the project besides the financial risk?

A Other risk? I don't know.

Q I'll try to rephrase the question or state it a different way. When FPL takes on a capital project, it expects some return on that project; is that correct?

A Yes.

Q And what does -- does recovery through the fuel clause provide the appropriate rate of return?

A Outside of a rate case, the Commission's order states that outside -- something that wasn't anticipated when your base rates were set, it allows the company to recover it, and again, basing it on the criteria that it's going to result in fuel savings to the customer, so the customer is going to be the one that has a lower fuel charge because of it.

Q Once the Commission has approved a capital project --

strike that.

A Okay.

MR. KEATING: I think that's all the questions I have.

MR. SJOSTROM: Thank you.

Counsel.

CROSS EXAMINATION

BY MR. VANDIVER:

Q Good afternoon, Ms. Dubin.

A Good afternoon.

Q I'm Rob Vandiver with the Office of Public Counsel. Mr. Keating asked you some questions about a combined cycle plant and the recoverability of capital -- that being the capital project recoverable through the fuel clause. I'm not quite sure I understood your answer fully. Could you walk through it again, please. And I'm referring to your testimony, just so we're all clear, your September 20th testimony, Page 3 -- Page 2 and 3.

A There have been a few instances where we have come to the Commission and asked them to recover a capital expenditure through the fuel adjustment clause, and we base it on the Commission's criteria established in that 1985 order. So there's an instance where we -- where something may result in fuel savings, and so we can evaluate a project and see if it makes sense to bring it to the Commission for their

consideration and approval.

But I think there's a number of things that can result in fuel savings which I don't think the Commission intended for this. Cleaning a boiler, for example, is what I had stated before. Although it would increase the efficiency and probably result in fuel savings, I don't believe that that's what the Commission intended when it stated this in the order.

Now, modifications to a plant to have it burn a different sulfur grade of fuel oil or a different gravity of fuel oil where that modification was being done specifically to reduce fuel costs, that to me seems to be the types of things, and those examples are the types of things we have brought to the Commission for their consideration and approval through the fuel clause under the criteria of this 1985 order.

Q Wouldn't those be recoverable through the environmental clause as well, arguably?

A And I believe that's true. Those particular items, I believe, occurred probably prior to the environmental clause.

Q The environmental clause was in 1993, was it not?

A Right. Some of those items I just mentioned I believe occurred in 1987.

Q Did you answer my clause (sic) about the combined cycle plant?

A The combined cycle plant is not something that we had

considered as one of these types of projects.

Q So it would not be, in your professional opinion, recoverable under Number 10 there on Page 3?

A I guess it could be. It could be, but it has not been the type of thing that FPL has brought for consideration.

Q Would FPL consider that not recoverable as a matter of company policy pursuant to Number 10 on Page 3?

A I don't know if we have a company policy, but it has not been the type of thing that we would have taken a look at.

Q You all have not considered it to date?

A No.

Q Would you consider it in the future?

MR. SJOSTROM: Object to the form of the question. You can answer it.

THE WITNESS: I can answer it?

MR. SJOSTROM: As best you can.

MR. VANDIVER: Okay.

BY MR. VANDIVER:

Q Is there anything in Paragraph 10 that precludes such recovery, in your view?

A I'm not sure if Paragraph 10 goes to that. It's on a case-by-case basis.

Q All right. Did I understand you earlier to put a qualifier of transportation --

A Yes.

Q -- on Paragraph 10?

A Not on Paragraph 10. If you looked at the entire order --

Q I have the entire order here.

A And they were talking about transportation costs.

Q Could you show me where in that order the transportation qualifier is?

A And I'm not sure what page this is. Page 2.

Q Page 2.

A Okay. There's a section called "Transportation Charges," and I'll read from the order. It says, "The costs associated with moving fuel to fuel storage locations and terminals dedicated to the supply of a utility's generating facilities are subject to significant changes to the fluctuation in distances, deliverly, volumes, and price. Consequently, such costs should be recovered through the fuel adjustment clauses." And it goes on to talk about what I had talked with you before about moving between the delivery point and then further.

Q And that goes to all of these other things that are later referenced that that paragraph relates to this Number 10 later on?

A Yes.

Q Okay.

A Yes. And there was an attachment to this order. I'm

not sure it's here.

Q I don't think it's there.

A And specifically, the Commission in this 1985 proceeding addressed railcars.

Q Okay. And so they were specifically tied together.

A Right. At the time -- and I worked on this docket. At the time, the utilities were all recovering things differently, and they were looking for something standard so that all the utilities would be treated the same way. So they were looking at all the components, dockage, wharfage, all of those things associated with buying fuel, as well as how railcars were being treated. And at the time, there's an exhibit here which lists a bunch of different items, and railcars is on there. And it specifically says it should be recovered through the fuel adjustment clause.

Q Was that particular order specifically going to railcars? Was that the issue in that particular one, or was it kind of an omnibus transportation thing?

A It was -- it covered everything. This came out of a normal fuel adjustment proceeding where our fuel witness was Renee Silva at the time, and they were asking -- the Commissioners were asking each witness, well, what types of things -- when you say "included in your price of oil," what do you include in there? And they were talking about dockage, wharfage, inspections, and all the other costs associated

besides just the product itself. And so different utilities had different responses, and then it resulted in this docket where they looked at everything to see what would be recovered.

Q Was the Commission at that time trying to standardize the practice amongst the utilities?

A Yes. Yes, to be consistent with everyone.

Q Thank you. Can I get that back, please.

A Yes.

Q Thank you. Figure out who's on first. Do you have the response to Staff's Interrogatory 128?

A I think I do.

Q Okay.

A Yes, I have it.

Q And am I correct that this has the capital projects that -- I'm sorry, do you all need a moment to look at it?

A No, that's okay.

THE WITNESS: Unless you do?

MR. SJOSTROM: No, I'm fine.

BY MR. VANDIVER:

Q Am I correct that this is the FPL capital projects that are currently being recovered through the fuel clause?

A Yes.

Q Okay. And in here we have, as you pointed out, the coal cars and the two gas laterals.

A Yes.

Q And can you explain to me what the Turkey Point nuclear thermal uprate is?

A There was -- and I'm going to give you my brief explanation because without -- without going back and looking at it. There were a few things done to uprate the Turkey Point unit, increasing its output and therefore reducing fuel costs.

Q How is that transportation-related?

A Not transportation-related. This is a fuel savings. This specifically goes to the Number 10 fuel savings.

Q Okay. Now, we talked before in that order about it -- I recall that we just talked in that order about it all being transportation-related.

A I'm sorry.

MR. SJOSTROM: I object to the form of the question. I don't recall that at all.

A If I answered --

Q I'm sorry.

A -- it that way, I didn't mean to. There are two components to recovery: One being something that results in fuel savings and also transportation. They don't necessarily need to be together to request recovery. They could just go to Number 10 resulting in fuel savings.

Q I misunderstood then. Okay. So there's kind of two ways to get in under this deal under Number 10 then. There's a

transportation thing. I misunderstood your earlier answer then. There's a couple of ways we can get in under this deal under Number 10 then. There's a transportation way --

A Uh-huh.

Q -- and there's just a straight fuel savings way, isn't there?

A Yes.

Q And this thermal uprate doesn't have anything to do with transportation, does it?

A No, it does not.

Q Okay.

A But all of the these items that have been recovered through the fuel adjustment have been presented to the Commission, like it says, on a case-by-case basis where the company had the burden to demonstrate the fuel savings.

Q Sure. So they come in on a case-by-case basis, and you all say, here's one that can save everybody money. Let's run it through the fuel clause, it's my understanding. And then the Commission says yea or nay based on your show; is that correct?

A Yes.

Q Is that my understanding of how this deal works?

And it may be transportation-related one day, and the next day it may not be; is that right?

A No. It depends on the justification used for each

one. When we provide to the Commission the request, we justify it based on fuel savings or transportation or both.

Q On that discrete project?

A Yes.

Q And this one is not transportation-related, the other three are?

A When you say "this one," the thermal uprate?

Q Yes, ma'am.

A No, that was just strictly on fuel savings.

Q Right. And the gas laterals are, of course, for the gas and coal that carries the coal --

A Yes.

Q -- to the Plant Scherer and St. Johns' River Power Park up there near Jacksonville; is that correct?

A Yes.

Q All right. When's the last time FPL had a rate case?

A It would have been 1985 unless you're looking at the -- it depends. There's some definitions.

Q I'm talking a real full-blown, knock-down, drag-out rate case.

MR. SJOSTROM: Object to the form of the question.

Q A full revenue requirements rate case that did not result in a settlement or where full revenue requirements MFRs were filed.

A It would have been 1984, 1985, and also there was a

review in 1988 with the 1988 tax savings docket.

Q The 1988 case did not go to hearing, did it?

A I don't believe so, no.

Q In 1985, did you participate in that case?

A Slightly, just a little bit in preparing some MFRs. I was in the fuel department then.

Q Is it your understanding that in a rate case, that accounting adjustments are sometimes made, and there is an accounting cleanup made generally in the company's books and records?

A Accounting cleanup?

Q Yes. That adjustments are made and in the immortal words of a past Commissioner, we get the pot right in accounting adjustments and the like.

A I believe that's true, yes.

Q Do you think it might be -- and is it also your understanding that FPL is presently in for a rate case this time?

A There's an MFR review, yes.

Q Do you think it would be a good idea -- and again, I want to direct your attention again to your testimony on Page 3, Line 4. Fossil fuel cost is normally recovered through base rates; is that correct?

A Yes.

Q And these -- is it five projects?

A Yes.

Q Do you think it will be a good idea to shift recovery of these five projects to base rates during this rate case of FPL at this time?

A No. I think they're appropriately being recovered right now through the fuel clause.

Q What would be the advantages and disadvantages of shifting recovery to base rates at this time?

A They are already being accounted for this way and administratively being booked in this format as far as -- and follow through on the fuel savings part. And the railcars, for example, I would assume would stay. It seems to be appropriately recovered through the fuel adjustment clause.

Q Yes. You've given the advantages of recovery for the fuel clause. What would be the advantages of recovery through base rates in making that shift? Can you think of any?

A I can't think of --

Q You can't think of a one?

MR. SJOSTROM: Are you in a hurry? How much longer are you going to go on? Just because it's going on 1:30 and --

MR. VANDIVER: I know it's getting late, but I have very little left.

MR. SJOSTROM: Your voice is starting to sound weak on me.

MR. VANDIVER: I'm winding down. I don't have very

much more.

BY MR. VANDIVER:

Q You can't think of any?

A Of?

Q Of transferring these costs over to base rates and getting that on that side of the house and going forward and new.

A I think it continues to be appropriate to recover them through fuel.

Q Fair enough. A question that Mr. Keating asked concerning the coal pile issue, you said a committee of Scherer and FPL. Would that be personnel from Georgia Power Company?

A I believe so.

Q I was just curious about that. I'm sorry to go back to this, and if you don't know, that's fine. The thermal uprate, what precisely is the thermal uprate?

A There was a -- I think what I've said is really all that I can tell you about. It's something that we did a few years back, and I was not the witness on it. So I do know that it was an uprating of the unit which allowed for it to be somewhat more efficient, or something along those lines, which resulted in fuel savings.

Q And that went through the normal fuel adjustment clause, and it was found to be cost-effective just as these other --

A Yes.

Q -- four projects were, and it went through the normal --

A Right. And that's a number of years ago. It was in one of our nuclear witnesses' testimony -- I believe it was Mr. Wade -- maybe five or six years ago.

Q But it was sometime between the '96 and 2000 time frame?

A Yes, yes.

MR. VANDIVER: Okay. That's all I have. Thank you.

THE WITNESS: Okay.

MR. SJOSTROM: Are we done?

MR. KEATING: I believe so.

MR. SJOSTROM: All right. Thank you.

(Deposition concluded at 1:30 p.m.)

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Under penalties of perjury, I declare that I have read my deposition and that it is true and correct subject to any changes in form or substance entered here.

DATE _____ KOREL M. DUBIN

STATE OF FLORIDA)
: CERTIFICATE OF OATH
COUNTY OF LEON)

I, the undersigned authority, certify that KOREL M. DUBIN personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 30th DAY OF OCTOBER, 2001.

Tricia DeMarte

TRICIA DeMARTE
Notary Public - State of Florida

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, TRICIA DeMARTE, Official FPSC Commission Reporter, do hereby certify that I was authorized to and did stenographically report the foregoing deposition at the time and place herein stated.

I FURTHER CERTIFY that this transcript, consisting of 80 pages, constitutes a true record of the testimony given by the witness.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 30th DAY OF OCTOBER, 2001.

Tricia DeMarte

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