BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor	DOCKET NO. 940001-EI ORDER NO. PSC-94-0390-FOF-EI ISSUED: 04/04/94

The following Commissioners participated in the disposition of this matter:

J. TERRY DEASON, Chairman
SUSAN F. CLARK
DIANE K. KIESLING

ORDER APPROVING PROJECTED EXPENDITURES
AND TRUE-UP AMOUNTS FOR FUEL ADJUSTMENT FACTORS;
GPIF TARGETS, RANGES, AND REWARDS;
PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS
FOR OIL BACKOUT COST RECOVERY FACTORS;
AND PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS
FOR CAPACITY COST RECOVERY FACTORS

BY THE COMMISSION:

As part of this Commission's continuing fuel cost recovery, oil backout cost recovery, capacity cost recovery, conservation cost recovery, and purchased gas cost recovery proceedings, hearings are held semi-annually. Pursuant to notice, a hearing was held in this docket and in Dockets No. 940002-EG and 940003-GU, and 940042-EI on March 9, 1994. The utilities submitted testimony and exhibits in support of their proposed fuel adjustment true-up amounts, fuel cost recovery factors, generating performance incentive factors, oil backout true-up amounts, capacity cost recovery factors and related issues.

Fuel Adjustment Factors

In accordance with the agreement of the parties, we find that the appropriate final fuel adjustment true-up amounts for the amounts for the period April, 1993 through September, 1993 are as follows:

FPC:	$18,573,496 underrecovery.
FPL:	$54,419,628 overrecovery.
FPUC:	$87,558 underrecovery. (Marianna)
	$17,891 underrecovery. (Fernandina Beach)
GULF:	$1,734,229 underrecovery.
TECO:	$8,343,904 underrecovery.

The estimated fuel adjustment true-up amounts for the period October, 1993 through March, 1994 are as follows:

FPC:	$23,541,004 overrecovery.	
FPL:	$89,384,887 overrecovery	
FPUC:	$61,955 overrecovery.	(Marianna)
	$136,110 overrecovery.	(Fernandina Beach)
GULF:	$2,995,885 underrecovery.	
TECO:	$5,354,211 underrecovery.	

The total true-up amounts to be collected during the period April, 1994 through September, 1994 are as follows:

FPC:	$4,967,508 overrecovery.	
FPL:	$143,804,515 overrecovery.	
FPUC:	$25,603 underrecovery.	(Marianna)
	$118,219 overrecovery.	(Fernandina Beach)
GULF:	$4,730,114 underrecovery.	
TECO:	$13,698,115 underrecovery.	

Finally, the appropriate levelized fuel cost recovery factors for the period April, 1994 through September,1994 are as follows:

FPC: 1.968 cents per kWh - Standard rates*
2.692 cents per kWh - TOU On-Peak rates*
1.587 cents per kWh - TOU Off-Peak rates*

*Before line loss adjustment.

FPL: 1.488 cents/kwh is the levelized recovery charge for non-time differentiated rates and 1.633 cents/kwh and 1.415 cents/kwh are the levelized fuel recovery charges for the on-peak and off-peak periods, respectively, for the differentiated rates.

FPUC:	Marianna:	2.793¢/kwh
	Fernandina Beach:	3.856¢/kwh

GULF: 2.158 cents per KWH.

TECO: 2.894 cents per KWH before application of the factors which adjust for variations in line losses.

For billing purposes, the new fuel adjustment charge, oil backout charge, conservation cost recovery charge and capacity cost recovery charge factors shall be effective beginning with the specified fuel cycle and thereafter for the period April, 1994 through September, 1994. Billing cycles may start before April 1, 1994, and the last cycle may be read after September 30, 1994, so that each customer is billed for six months regardless of when the adjustment factor became effective.

Each utility proposed fuel recovery loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class. Those multipliers are shown in Attachment A attached hereto. We find that the proposed multipliers are appropriate and should be approved. The utilities further proposed fuel cost recovery factors for each rate group, adjusted for line losses, which are also shown in Attachment A. We find that the proposed factors are appropriate and should be approved. We further find that the appropriate revenue tax factor to be applied in calculating each company's levelized fuel factor for the projection period of April through September, 1994 is as follows:

FPC:	1.00083	
FPL:	1.01609	
FPUC:	1.00083	(Marianna)
	1.01609	(Fernandina Beach)
GULF:	1.01609	
TECO:	1.00083	

Company-Specific Fuel Adjustment Issues

Florida Power and Light Company

Florida Power and Light Company requested that it be permitted to defer recognition of cost changes for the April 1994 through September 1994 period to the October 1994 through March 1995 period. The parties agreed to this request because the sum of the changes decreases the costs for the April 1994 through September 1994 period by approximately $56 million. We find that FPL's request is reasonable under the circumstances and we approve it.

Florida Power Corporation

Florida Power Corporation raised the issue of how "governmental impositions" should be included in the price of water-borne transportation in accordance with the market pricing mechanism that we approved at the August 1993 fuel adjustment hearings. In Order No. PSC-93-1331-FOF-EI, we said that the market price is to be adjusted "for the cost of governmental impositions on EFC's transportation suppliers which cause an increase or decrease in EFC's water-borne transportation costs not in effect as of December 31, 1992." Specifically, the federal government has imposed additional Waterway User Taxes on EFC's river barge transportation suppliers in the form of a "per gallon" tax on fuel. Since EFC's coal originates at various barge loading points at differing distances from New Orleans, different amounts of fuel and, thus, taxes are associated with each origin. FPC converted these varying gallons and tax amounts into a "per ton" amount based on projected origin points and volumes, which are subject to true-up when actual results become available. We approve FPC's methodology.

FPC also raised the issue of how the affiliated coal transportation market-based pricing method should be amended to calculate a transportation charge for foreign coal. The parties agreed that the existing market pricing mechanism for the transportation of domestic coal should be modified to exclude cost components (e.g., river barging costs) not involved in the transportation of foreign coal. This can be accomplished by establishing a price equal to 50.2% of the then-current domestic coal market price (less governmental impositions not related to transloading or trans-Gulf barging) for water-borne transportation of foreign coal purchased F.O.B. IMT. The 50.2% is the proportion of transloading and trans-gulf barging costs to EFC's total 1992 water-borne transportation costs used to derive the initial market price for water-borne transportation of domestic coal. We find that this change in FPC's transportation pricing methodology is appropriate, and we approve it.

Tampa Electric Company

The following issue will be deferred to the August fuel hearings:

> Has Tampa Electric Company prudently administered its contract with Consol Coal Company?

Gulf Power Company

The following issue will be deferred to the August fuel hearings:

> What costs, if any, are appropriate for Gulf to recover through the fuel cost recovery clause as a result of the Peabody contract suspension?

Generating Performance Incentive Factor (GPIF)

There was no controversy among the parties at this hearing as to either the appropriate GPIF reward or penalty for past performance or the proposed GPIF targets and ranges for performance in the upcoming period. The parties agreed to, and we approve, the following GPIF rewards for the period April, 1993 through September, 1993:

FPC:	$1,100,739 reward.
FPL:	$871,893 reward.
GULF:	$128,552 reward.
TECO:	$214,237 penalty.

The parties also agreed to targets and ranges for the period April, 1994 through September, 1994, which are shown on Attachment B to this order. We approve those targets and ranges.

Oil Backout Cost Recovery Factor

In accordance with the agreement of the parties, we find the proper final oil backout true-up amount for the period April, 1993 through September, 1993 period to be:

FPL:	$191,376 overrecovery.
TECO:	$193,724 overrecovery.

The estimated oil backup true-up amount for the period October, 1993 through March, 1994, is:

FPL:	$248,851 underrecovery.
TECO:	$415,515 overrecovery.

The total oil backout true-up amount to be collected or refunded during the period April, 1994 through September, 1994, is:

FPL:	$57,475 underrecovery.
TECO:	$609,239 overrecovery.

Finally, we find that the proper projected oil backout cost recovery factor for the period April, 1994 through September, 1994, is:

FPL:	0.012 ¢/kwh.
TECO:	0.073 ¢/kwh.

Capacity Cost Recovery Factor

The parties agree that the following the final capacity cost recovery true-up amounts are appropriate for the April, 1993 through September, 1993 period, which we approve:

FPC:	$2,576,367 Overrecovery.
FPL:	$6,291,909 Overrecovery.
GULF:	$183,938 Overrecovery.
TECO:	$4,897 Overrecovery.

We approve the following estimated capacity cost recovery true-up amounts for the period October, 1993 through March, 1994

FPC:	$193,412 Underrecovery.
FPL:	$17,123,942 Underrecovery.
GULF:	$41,833 Underrecovery.
TECO:	$918,803 Underrecovery.

We also approve the following total capacity cost recovery true-up amounts to be collected during the period April, 1994 through September, 1994:

FPC:	$2,382,955 Overrecovery.
FPL:	$10,832,033 Underrecovery.
GULF:	$142,105 Overrecovery.
TECO:	$913,906 Underrecovery.

We approve the following appropriate projected net purchased power capacity cost amount to be included in the recovery factor for the period April, 1994 through September, 1994:

FPC:	$60,263,005.
FPL:	$189,974,524.
GULF:	$1,180,247
TECO:	$11,106,718.

Finally we approve the projected capacity cost recovery factors for the period April, 1994 through September, 1994 as they are shown on Attachment A to this order.

In consideration of the above, it is

ORDERED by the Florida Public Service Commission that the findings and stipulations set forth in the body of this Order are hereby approved. It is further

ORDERED that investor-owned electric utilities subject to our jurisdiction are hereby authorized to apply the fuel cost recovery factors set forth herein during the period of April through September, 1994, and until such factors are modified by subsequent Order. It is further

ORDERED that the estimated true-up amounts contained in the above fuel cost recovery factors are hereby authorized subject to final true-up, and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that the Generating Performance Incentive Factor rewards and penalty stated in the body of this Order shall be applied to the projected levelized fuel adjustment factors for the period of April through September, 1994. It is further

ORDERED that the targets and ranges for the Generating Performance Incentive Factors set forth herein are hereby adopted for the period of April through September, 1994. It is further

ORDERED that the estimated true-up amounts included in the above Oil Backout Cost Recovery Factors are hereby authorized subject to final true-up, and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that the investor-owned electric utilities are hereby authorized to apply the capacity cost recovery factors set forth herein during the period of April through September, 1994, and until such factors are modified by subsequent Order. It is further

ORDERED that the estimated true-up amounts contained in the above capacity cost recovery factors are hereby authorized subject to final true-up, and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based.

By ORDER of the Florida Public Service Commission, this 4TH day of APRIL, 1994.

BLANCA S. BAYO, Director
Division of Records and Reporting

by: Kay Flynn
Chief, Bureau of Records

(S E A L)
MCB:bmi

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.59(4), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of Records and Reporting within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water or sewer utility by filing a notice of appeal with the Director, Division of Records and Reporting and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900 (a), Florida Rules of Appellate Procedure.

TOTAL FUEL COST FOR THE PERIOD: April 1994 – September 1994

DATE: 03/10/94
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COMPANY	PROPOSED April 1994 – September 1994 Levelized	On/Peak	Off/Peak	PRESENT February 1994 – March 1994 Februar Levelized	Cents per kwh On/Peak	Off/Peak	DIFFERENCE Levelized	Cents per kwh On/Peak	Off/Peak	RESIDENTIAL LINE LOSS MULTIPLIER	PROPOSED RESIDENTIAL FUEL FACTOR
Fla. Power & Light (5)	1.488	1.633	1.415	1.811	1.940	1.760	−0.323	−0.307	−0.345	1.00161	1.490
Fla. Power Corp.	1.968	2.692	1.587	1.880	2.176	1.757	0.088	0.516	−0.170	1.00380	1.975
Tampa Electric	2.894	3.791	2.444	2.508	2.946	2.346	0.386	0.845	0.098	1.00640	2.913
Gulf Power	2.158	2.253	2.113	1.965	2.012	1.949	0.193	0.241	0.164	1.01228	2.185
Fla. Public											
Marianna (1)	4.658	NA	NA	4.948	NA	NA	0.290	NA	NA	1.01260	4.717
Fernandina (1)(2)	5.308	NA	NA	5.733	NA	NA	−0.425	NA	NA	1.00000	5.308

COST FOR 1,000 KWH RESIDENTIAL SERVICE

PRESENT: February 1994 – March 1994

	Fla. Power & Light	Fla. Power Corp.	Tampa Electric (5)	Gulf Power (6)	Florida Public Utilities Marianna (7)	Fernandina
Base	47.38	49.05	51.92	43.25	20.43	19.20
Fuel (3)	15.84	18.87	24.51	19.89	49.48	57.33
Oil Backout	0.16	NA	1.00	NA	NA	NA
Energy Conservation	2.30	5.90	1.45	0.33	0.13	0.05
Environmental Cost Recovery	0.00	N/A	N/A	1.48	N/A	N/A
Capacity Recovery	5.95	4.75	2.13	0.87	NA	NA
Gross Receipts Tax (4)	0.73	2.01	2.08	0.68	1.03	0.79
Total	$72.36	$80.58	$83.09	$66.50	$71.07	$77.37

PROPOSED: April 1994 – September 1994

	Fla. Power & Light	Fla. Power Corp.	Tampa Electric	Gulf Power	Florida Public Utilities Marianna	Fernandina
Base	47.38	49.05	51.92	43.25	20.43	19.20
Fuel (3)	14.90	19.75	29.13	21.85	47.17	53.08
Oil Backout	0.12	NA	0.73	NA	NA	NA
Energy Conservation	2.43	4.40	1.85	0.26	0.12	0.06
Environmental Cost Recovery	0.12	N/A	N/A	1.48	N/A	N/A
Capacity Recovery	5.64	5.11	2.05	0.31	NA	NA
Gross Receipts Tax (4)	0.72	2.01	2.20	0.69	1.74	0.74
Total	$71.31	$80.32	$87.88	$67.84	$69.46	$73.08

DIFFERENCE

	Fla. Power & Light	Fla. Power Corp.	Tampa Electric	Gulf Power	Florida Public Utilities Marianna	Fernandina
Base	0.00	0.00	0.00	0.00	0.00	0.00
Fuel (3)	−0.94	0.88	4.62	1.96	−2.31	−4.25
Oil Backout	−0.04	NA	−0.27	NA	NA	NA
Energy Conservation	0.13	−1.50	0.40	−0.07	−0.01	0.01
Environmental Cost Recovery	0.12	N/A	N/A	N/A	N/A	N/A
Capacity Recovery	−0.31	0.36	−0.08	−0.56	NA	NA
Gross Receipts Tax (4)	−0.01	0.00	0.12	0.01	0.71	−0.05
Total	−1.05	−0.26	4.79	1.34	−1.61	−4.29

(1) Fuel costs include purchased power demand costs of 1.889 for Marianna and 1.452 cents/KWH for Fernandina allocated to the residential class. (2) All classes except GSLD. (3) Adjusted for line loss.
(4) Additional gross receipts tax is 1% for Gulf, FPL, and FPUC–Fernandina. FPC, TECO and FPUC–Marianna have removed GRT from rates. The entire 2.5% is thus shown seperately.
(5) TECO present rates reflect a rate increase effective January 1, 1994 resulting from Docket No. 920324–EI. (6) Gulf Power present rates reflect $1.48 increase because of the Environmental Cost Recovery Clause, Docket No. 930613, effective February 1, 1994. (7) FPUC–Marianna rate reflect an increase effective February 1994, resulting from Docket No. 930400–EI.

FUEL ADJUSTMENT CENTS PER KWH BASED ON LINE LOSSES BY RATE GROUP

DIVISION OF ELECTRIC AND GAS
DATE: 03/10/94

FOR THE PERIOD: April 1994 – September 1994

COMPANY	GROUP	RATE SCHEDULES	WITHOUT LINE LOSS MULTIPLIER Levelized	* On/Peak	Off/Peak	LINE LOSS MULTIPLIER	WITH LINE LOSS MULTIPLIER Levelized	On/Peak	Off/Peak
FP&L	A	RS-1,RST-1,GST-1,GS-1,SL-2	1.488	1.633	1.415	1.00161	1.490	1.636	1.417
	A-1	SL-1,OL-1	1.450	NA	NA	1.00161	1.452	NA	NA
	B	GSD-1,GSDT-1	1.488	1.633	1.415	1.00155	1.490	1.636	1.417
	C	GSLD-1,GSLDT-1,CS-1,CST-1	1.488	1.633	1.415	1.00046	1.488	1.634	1.416
	D	GSLD-2,GSLDT-2,CS-2,CST-2,OS-2,MET	1.488	1.633	1.415	0.99449	1.480	1.624	1.407
	E	GSLD-3,CS-3,GSLDT-3,CST-3,CILC-1(T),ISST-1(T)	1.488	1.633	1.415	0.96430	1.435	1.575	1.365
	F	CILC-1(D),ISST-1(D)	NA	1.633	1.415	0.99643	NA	1.627	1.410
FPC *	A	Distribution Secondary Delivery	1.968	2.692	1.587	1.00380	1.975	2.702	1.593
	A-1	OL-1,SL-1	1.793	NA	NA	1.00380	1.800	NA	NA
	B	Distribution Primary Delivery	1.968	2.692	1.587	0.98260	1.934	2.645	1.559
	C	Transmission Delivery	1.968	2.692	1.587	0.97250	1.914	2.618	1.543
TECO	A	RS,GS,TS	2.894	3.791	2.444	1.00640	2.913	3.815	2.460
	A-1	SL-1,2,3,OL-1,2	2.646	NA	NA	1.00640	2.663	NA	NA
	B	GSD,GSLD	2.894	3.791	2.444	1.00120	2.897	3.796	2.447
	C	IS-1,IS-3	2.894	3.791	2.444	0.97210	2.813	3.685	2.376
GULF	A	RS,GS,GSD,OS-III,OS-IV	2.158	2.253	2.113	1.01228	2.185	2.281	2.139
	B	LP	2.158	2.253	2.113	0.98106	2.117	2.210	2.073
	C	PX	2.158	2.253	2.113	0.96230	2.077	2.168	2.033
	D	OS-I,OS-II	2.125	NA	NA	1.01228	2.151	NA	NA
FPUC									
Fernandina	A	RS	5.308	NA	NA	1.00000	5.308	NA	NA
	B	GS	5.042	NA	NA	1.00000	5.042	NA	NA
	C	GSD	4.853	NA	NA	1.00000	4.853	NA	NA
	D	OL, OL-2, SL-2, SL-3, CSL	4.268	NA	NA	1.00000	4.268	NA	NA
	E	GSLD					4.799 (1) $4.69/CP KW		
Marianna	A	RS	4.658	NA	NA	1.01260	4.717	NA	NA
	B	GS	4.505	NA	NA	0.99630	4.489	NA	NA
	C	GSD	4.130	NA	NA	0.99630	4.115	NA	NA
	D	GSLD	3.969	NA	NA	0.99630	3.955	NA	NA
	E	OL, OL-2	2.793	NA	NA	1.01260	2.828	NA	NA
	F	SL-1, SL-2	2.793	NA	NA	0.98810	2.760	NA	NA

DIVISION OF ELECTRIC AND GAS
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PROPOSED CAPACITY COST RECOVERY FACTORS
For the Period: April 1994 – September 1994

COMPANY	RATE SCHEDULE	RECOVERY FACTOR (CENTS PER KWH)
FPL	RS1	0.564
	GS1	0.491
	OL1/SL1	0.223
	SL2	0.336
	OS2	0.402
		RECOVERY FACTOR (DOLLARS PER KWH)
	GSD1	1.750
	GSLD1/CS1	1.790
	GSLD2/CS2	1.950
	GSLD3/CS3	1.920
	ISST1D	0.560
	SST1T	0.370
	SST1D	0.640
	CILCD,CILCG	1.710
	CILCT	1.650
	MET	1.860
FPC *	RS	0.511
	GS–Transmission	0.000
	GS–Primary	0.349
	GS–Secondary	0.358
	GS – 100% Load Factor	0.270
	GSD–Transmission	0.294
	GSD–Primary	0.308
	GSD–Secondary	0.316
	CS – Primary	0.243
	CS – Secondary	0.247
	IS–Transmission	0.254
	IS–Primary	0.258
	IS–Secondary	0.265
	LS – Lighting Service	0.101
TECO	RS	0.205
	GS,TS	0.168
	GSD	0.141
	GSLD,SBF	0.125
	IS–1 & 3,SBI–1 & 3	0.011
	SL/OL	0.012
GULF	RS,RST	0.031
	GS,GST	0.031
	GSD,GSDT	0.024
	LP,LPT	0.021
	PX,PXT	0.017
	OS–I,OS–II	0.003
	OS–III	0.019
	OS–IV	0.002
	SS	0.017

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 03/10/94

ESTIMATED FOR THE PERIOD: April 1994 – September 1994

FLORIDA POWER & LIGHT COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated Cents/KWH
1.Fuel Cost of System Net Generation (E3)	562,387,620	34,718,270,000	1.61986
2.Spent NUC Fuel Disposal Cost (E2)	9,495,091	10,339,857,000 (a)	0.09183
3.Fuel Related Transactions	6,293,600	0	0.00000
4. Natural Gas Pipeline Enhancements	0	0	0.00000
4a. Fuel Cost of Sales to FKEC	(8,763,525)	(420,047,000)	2.08632
5.TOTAL COST OF GENERATED POWER	569,412,786	34,298,223,000	1.66018
6.Fuel Cost of Purchased Power – Firm (E8)	117,022,609	6,376,013,000	1.83536
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	245,270	10,876,000	2.25515
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	0	0	0.00000
9.Energy Cost of Sch.E Purchases (E9)	0	0	0.00000
10.Capacity Cost of Sch.E Economy Purchases (E2)	0	0	0.00000
11.Payments to Qualifying Facilities (E8A)	40,223,265	2,237,419,000	1.79775
12.TOTAL COST OF PURCHASED POWER	157,491,144	8,624,308,000	1.82613
13.TOTAL AVAILABLE KWH		42,922,531,000	
14.Fuel Cost of Economy Sales (E7)	(18,862,594)	(728,699,000)	2.58853
15.Gain on Economy Sales – 80% (E7A)	(4,557,878)	(728,699,000)(a)	0.62548
16.Fuel Cost of Unit Power Sales (SL2 Partpts) (E7)	(1,389,207)	(259,647,000)	0.53504
17.Fuel Cost of Other Power Sales (E7)	0	0	0.00000
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(24,809,679)	(988,346,000)	2.51022
19.Net Inadvertant Interchange (E4)	0	0	0.00000
20.TOTAL FUEL AND NET POWER TRANSACTIONS	702,094,251	41,934,185,000	1.67428
21.Net Unbilled (E4)	(9,932,791)(a)	(588,119,000)	−0.02602
22.Company Use (E4)	(2,145,978)(a)	(127,063,000)	−0.00562
23.T & D Losses (E4)	(51,503,346)(a)	(3,049,505,000)	−0.13493
24.Adjusted System KWH Sales	702,094,251	38,169,498,000	1.83941
25.Wholesale KWH Sales	2,475,405	133,411,000	1.85547
26.JURISDICTIONAL KWH SALES	699,618,846	38,036,087,000	1.83936
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00035	699,863,713	38,036,087,000	1.84000
28.True–up * (derived in Attachment C)	(143,804,515)	38,036,087,000	−0.37807
29.TOTAL JURISDICTIONAL FUEL COST	556,059,198	38,036,087,000	1.46190
30.Revenue Tax Factor			1.01609
31.Fuel Cost Adjusted for Taxes			1.48542
32.GPIF*	871,893	38,036,087,000	0.00229
33.Total fuel cost including GPIF	556,931,091	38,036,087,000	1.48771
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			1.488

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

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 03/10/94
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ESTIMATED FOR THE PERIOD: April 1994 – September 1994

FLORIDA POWER CORPORATION

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	233,151,971	13,778,384,000	1.69216
2.Spent NUC Fuel Disposal Cost (E3A)	1,904,281	2,036,664,000 (a)	0.09350
3.Coal Car Investment	0	0	0.00000
4.Adjustments to Fuel Cost	172,868	0	0.00000
5.TOTAL COST OF GENERATED POWER	235,229,120	13,778,384,000	1.70723
6.Energy Cost of Purchased Power – Firm (E8)	4,925,130	246,707,000	1.99635
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	16,070,200	790,000,000	2.03420
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	493,176	23,580,000	2.09150
9.Energy Cost of Sch.E Purchases (E9)	2,851,424	135,820,000	2.09941
10.Capacity Cost of Sch.E Economy Purchases (E9)	0	0 (a)	0.00000
11.Payments to Qualifying Facilities (E8A)	53,527,490	2,364,286,000	2.26400
12.TOTAL COST OF PURCHASED POWER	77,867,420	3,560,393,000	2.18705
13.TOTAL AVAILABLE KWH		17,338,777,000	
14.Fuel Cost of Economy Sales (E7)	(3,036,700)	(190,000,000)	1.59826
14a.Gain on Economy Sales –80% (E7A)	(466,640)	(190,000,000)(a)	0.24560
15.Fuel Cost of Other Power Sales (E7)	0	0	0.00000
15a.Gain on Other Power Sales (E8)	0	0 (a)	0.00000
16.Fuel Cost of Seminole Backup Sales (E7)	0	0	0.00000
16a.Gain on Seminole Back–up Sales (E7B)	0	0 (a)	0.00000
17.Fuel Cost of Seminole Supplemental Sales (E7)	(6,465,100)	(272,101,000)	2.37599
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(9,968,440)	(462,101,000)	2.15720
19.Net Inadvertant Interchange (E4)	0	0	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	303,128,100	16,876,676,000	1.79614
21.Net Unbilled (E4)	7,769,049 (a)	(432,551,000)	0.05099
22.Company Use (E4)	1,697,315 (a)	(94,500,000)	0.01114
23.T & D Losses (E4)	20,020,552 (a)	(1,114,668,000)	0.13141
24.Adjusted System KWH Sales	303,128,100	15,234,957,000	1.98969
25.Wholesale KWH Sales(Excluding Seminole Supplemental)	(10,537,961)	(529,657,000)	1.98958
26.JURISDICTIONAL KWH SALES	292,590,139	14,705,300,000	1.98969
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.0014	292,999,765	14,705,300,000	1.99248
28.Prior Period True–Up *	(4,967,508)	14,705,300,000	–0.03378
28a. Market Price Refund for 1992	0	0	0.00000
29.TOTAL JURISDICTIONAL FUEL COST	288,032,257	14,705,300,000	1.95870
30.Revenue Tax Factor			1.00083
31.Fuel Cost Adjusted for Taxes			1.96030
32.GPIF*	1,100,737	14,705,300,000	0.00750
33.Total fuel cost including GPIF	289,132,994	14,705,300,000	1.96780
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			1.968

*Based on Jurisdictional Sales

(a) Included for informational purposes only.

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 03/10/94
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ESTIMATED FOR THE PERIOD: April 1994 – September 1994

TAMPA ELECTRIC COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	204,538,452	8,530,330,000	2.39778
2.Spent NUC Fuel Disposal Cost (E3A)	0	0 (a)	0.00000
3.Coal Car Investment	0	0	0.00000
4.Adjustments to Fuel Cost	0	0	0.00000
5.TOTAL COST OF GENERATED POWER	204,538,452	8,530,330,000	2.39778
6.Fuel Cost of Purchased Power – Firm (E8)	4,207,200	83,697,000	5.02670
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	931,600	25,077,000	3.71496
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	0	0	0.00000
9.Energy Cost of Sch.E Purchases (E9)	0	0	0.00000
10.Capacity Cost of Sch.E Economy Purchases	0	0 (a)	0.00000
11.Payments to Qualifying Facilities (E8A)	3,846,400	190,220,000	2.02208
12.TOTAL COST OF PURCHASED POWER	8,985,200	298,994,000	3.00514
13.TOTAL AVAILABLE KWH		8,829,324,000	
14.Fuel Cost of Economy Sales (E7)	8,262,400	524,099,000	1.57650
15.Gain on Economy Sales – 80% (E7A)	1,270,000	524,099,000 (a)	0.24232
16.Fuel Cost of Scedule D Sales (E7)	3,704,000	272,547,000	1.35903
16a.Fuel Cost of Schedule G Sales (E7)	0	0	0.00000
17.Fuel Cost Schedule J Sales (E7)	66,400	4,702,000	1.41217
17a.Fuel Cost Schedule D TPS Sales (E7)	3,463,200	156,891,000	2.20739
18.TOTAL FUEL COST AND GAINS OF POWER SALES	16,766,000	958,239,000	1.74967
19.Net Inadvertant Interchange (E4)	0	0	
19b.Interchange and Wheeling Losses	0	17,247,000	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	196,757,652	7,853,838,000	2.50524
21.Net Unbilled (E4)	(3,578,034)(a)	142,822,000	−0.04918
22.Company Use (E4)	420,880 (a)	16,800,000	0.00578
23.T & D Losses (E4)	10,483,402 (a)	418,459,000	0.14409
24.Adjusted System KWH Sales	196,757,652	7,275,757,000	2.70429
25.Wholesale KWH Sales	(719,001)	(26,586,000)	2.70443
26.JURISDICTIONAL KWH SALES	196,038,651	7,249,171,000	2.70429
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00005	196,136,670	7,249,171,000	2.70564
28.True–up * (derived in Attachment C)	13,698,115	7,249,171,000	0.18896
29.Pyramid Coal Contract Buyout Adjustment	0	7,249,171,000	0.00000
30.TOTAL JURISDICTIONAL FUEL COST	209,834,785	7,249,171,000	2.89460
31.Revenue Tax Factor			1.00083
32.Fuel Cost Adjusted for Taxes	210,008,948		2.89701
33.GPIF * (Already adjusted for taxes)	(214,237)	7,249,171,000	−0.00296
34.Total Fuel Cost including GPIF	209,794,711	7,249,171,000	2.89405
35.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.894

*Based on Jurisdictional Sales

Effective date for billing purposes:

(a) Included for informational purposes only.

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 03/10/94
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ESTIMATED FOR THE PERIOD: April 1994 – September 1994

GULF POWER COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	111,171,243	5,957,220,000	1.8662
2.Spent NUC Fuel Disposal Cost (E13)	0	0	0.0000
3.Adjustments to Fuel Cost	0	0	0.0000
4.TOTAL COST OF GENERATED POWER	111,171,243	5,957,220,000	1.8662
5.Fuel Cost of Purchased Power – Firm (E8)	0	0	0.0000
6.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	5,822,000	316,750,000	1.8380
7.Energy Cost of Economy Purchases (Non–Broker) (E9)	0	0	0.0000
8.Energy Cost of Sch.E Purchases (E9)	0	0	0.0000
9.Capacity Cost of Sch.E Economy Purchases (E2)	0	0 (a)	0.0000
10.Payments to Qualifying Facilities (E9A)	0	0	0.0000
11.TOTAL COST OF PURCHASED POWER	5,822,000	316,750,000	1.8380
12.TOTAL AVAILABLE KWH (line 4 + line 11)		6,273,970,000	
13.Fuel Cost of Economy Sales (E7)	(534,000)	(22,680,000)	2.3545
14.Gain on Economy Sales – 80% (E7A)	(54,400)	0 (a)	0.0000
15.Fuel Cost of Unit Power Sales (E7)	(10,851,000)	(570,360,000)	1.9025
16.Fuel Cost of Other Power Sales (E7)	(11,336,000)	(631,726,000)	1.7944
17.TOTAL FUEL COST AND GAINS OF POWER SALES	(22,775,400)	(1,224,766,000)	1.8596
18.Net Inadvertant Interchange (E4)	0		
19.TOTAL FUEL AND NET POWER TRANSACTIONS	94,217,843	5,049,204,000	1.8660
20.Net Unbilled (E4)	0	0	0.0000
21.Company Use (E4)	180,480 (a)	9,672,000	1.8660
22.T & D Losses (E4)	6,379,742 (a)	341,894,000	1.8660
23.Adjusted System KWH Sales	94,217,843	4,697,638,000	2.0056
24.Wholesale KWH Sales	3,334,430	166,256,000	2.0056
25.JURISDICTIONAL KWH SALES	90,883,413	4,531,382,000	2.0056
26.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00140	91,010,649	4,531,382,000	2.0085
27.True–up *	4,730,114	4,531,382,000	0.1044
28.Total Jurisdictional Fuel Cost	95,740,763	4,531,382,000	2.1129
29.Revenue Tax Factor			1.01609
30.Fuel Cost Adjusted for Taxes			2.1469
31.Special Contract Recovery Cost	376,902	4,531,382,000	0.0083
32.GPIF *	128,552	4,531,382,000	0.0028
33.Total Fuel Cost including GPIF	95,869,315	4,531,382,000	2.1580
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.158

*Based on Jurisdictional Sales
Effective date for billing purposes:

(a) included for informational purposes only.

FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 03/10/94
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ESTIMATED FOR THE PERIOD: April 1994 – September 1994

FLORIDA PUBLIC UTILITIES–MARIANNA

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	0	0	0.00000
2.Spent NUC Fuel Disposal Cost (E3A)	0	0	0.00000
3.Coal Car Investment	0	0	0.00000
4.Adjustments to Fuel Cost	0	0	0.00000
5.TOTAL COST OF GENERATED POWER	0	0	0.00000
6.Fuel Cost of Purchased Power – Firm (E8)	2,855,193	149,410,000	1.91098
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	0	0	0.00000
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	0	0	0.00000
9.Energy Cost of Sch.E Purchases (E9)	0	0	0.00000
10.Demand & Non Fuel Cost of Purchased Power (E2)	3,138,733	149,410,000 (a)	2.10075
10a.Demand Costs of Purchased Power	2,106,000 (a)		
10b.Non–Fuel Energy & Customer Costs of Purchased Power	1,032,733 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	0	0	0.00000
12.TOTAL COST OF PURCHASED POWER	5,993,926	149,410,000	4.01173
13.TOTAL AVAILABLE KWH	5,993,926	149,410,000	4.01173
14.Fuel Cost of Economy Sales (E7)	0	0	0.00000
15.Gain on Economy Sales – 80% (E7A)	0	0	0.00000
16.Fuel Cost of Unit Power Sales (E7)	0	0	0.00000
17.Fuel Cost of Other Power Sales (E7)	0	0	0.00000
18.TOTAL FUEL COST AND GAINS OF POWER SALES	0	0	0.00000
19.Net Inadvertant Interchange (E4)	0	0	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	5,993,926	149,410,000	4.01173
21.Net Unbilled (E4)	200,867 (a)	5,007,000	0.14524
22.Company Use (E4)	4,975 (a)	124,000	0.00360
23.T & D Losses (E4)	239,701 (a)	5,975,000	0.17331
24.ADJUSTED SYSTEM KWH SALES	5,993,926	138,304,000	4.33388
25.Less Total Demand Cost Recovery	2,160,481		
26.JURISDICTIONAL KWH SALES	3,833,445	138,304,000	2.77175
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00	3,833,445	138,304,000	2.77175
28.True–up *	25,603	138,304,000	0.01851
29.TOTAL JURISDICTIONAL FUEL COST	3,859,048	138,304,000	2.79026
30.Revenue Tax Factor			1.00083
31.Fuel Cost Adjusted for Taxes	3,499,562	0	2.79258
32.GPIF *	0	138,304,000	0.00000
33.Total Fuel Cost including GPIF	3,859,048	138,304,000	2.79258
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.793

*Based on Jurisdictional Sales

(a) included for informational purposes only.

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
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ESTIMATED FOR THE PERIOD: April 1994 – September 1994

FLORIDA PUBLIC UTILITIES–FERNANDINA

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	0	0	0.00000
2.Spent NUC Fuel Disposal Cost (E2)	0	0	0.00000
3.Coal Car Investment	0	0	0.00000
4.Adjustments to Fuel Cost	0	0	0.00000
5.TOTAL COST OF GENERATED POWER	0	0	0.00000
6.Fuel Cost of Purchased Power – Firm (E8)	3,178,366	172,269,000	1.84500
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	0	0	0.00000
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	0		
9.Energy Cost of Sch.E Purchases (E9)	0	0	0.00000
10.Demand & Non Fuel Cost of Purchased Power	5,217,177	172,269,000	3.02851
10a.Demand Costs of Purchased Power (E2)	2,382,000 (a)		
10b.Non Fuel Energy and Customer Costs of Purchased Power (E2)	2,835,177 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	0	0	0.00000
12.TOTAL COST OF PURCHASED POWER	8,395,543	172,269,000	4.87351
13.TOTAL AVAILABLE KWH	8,395,543	172,269,000	4.87351
14.Fuel Cost of Economy Sales (E7)	0	0	0.00000
15.Gain on Economy Sales – 80% (E7A)	0	0	0.00000
16.Fuel Cost of Unit Power Sales (E7)	0	0	0.00000
17.Fuel Cost of Other Power Sales (E7)	0	0	0.00000
18.TOTAL FUEL COST AND GAINS OF POWER SALES	0	0	0.00000
19.Net Inadvertant Interchange (E4)			
20.TOTAL FUEL AND NET POWER TRANSACTIONS	8,395,543	172,269,000	4.87351
21.Net Unbilled (E4)	21,541 (a)	442,000	0.01336
22.Company Use (E4)	9,552 (a)	196,000	0.00592
23.T & D Losses (E4)	503,726 (a)	10,336,000	0.31230
24.Adjusted System KWH Sales	8,395,543	161,295,000	5.20509
25.Wholesale KWH Sales	0	0	0.00000
26.JURISDICTIONAL KWH SALES	8,395,543	161,295,000	5.20509
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00	8,395,543	161,295,000	5.20509
27a.GSLD KWH Sales (E11)		42,000,000	
27b.Other Classes KWH Sales (E11)		119,295,000	
27c.GSLD CP KW		120,000 (a)	
28. GPIF			
29.True–up *	(118,219)	161,295,000	–0.07329
30.TOTAL JURISDICTIONAL FUEL COST	8,277,324	161,295,000	5.13179

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
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ESTIMATED FOR THE PERIOD: April 1994 – September 1994

FLORIDA PUBLIC UTILITIES–FERNANDINA

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
30a.Demand Purchased Power Costs (line 10a)	2,382,000 (a)		
30b.Non–Demand Purchased Power Costs (lines 6+10b+11)	6,013,543 (a)		
30c.True–up Over/Under Recovery (line 29)	(118,219)(a)		
APPORTIONMENT OF DEMAND COSTS			
31.Total Demand Costs	2,382,000		
32.GSLD Portion of Demand Costs Including line losses (line 27c * $3.708)	741,600	120,000 KW	$6.18
33.Balance to Other Customers	1,640,400	119,295,000	1.37508
APPORTIONMENT OF NON–DEMAND COSTS			
34.Total Non–Demand Costs (line 30b)	6,013,543		
35.Total KWH Purchased (line 12)		172,269,000	
36.Average Cost per KWH Purchased			3.49079
37.Avg. Cost Adjusted for Transmission line losses (line 36 * 1.03)			3.59551
38.GSLD Non–Demand Costs (line 27a * line 37)	1,510,111	42,000,000	0.03596
39.Balance to Other Customers	4,503,432	119,295,000	3.77504
GSLD PURCHASED POWER COST RECOVERY FACTORS			
40a.Total GSLD Demand Costs (Line 32)	741,600	120,000	$6.18
40b.Revenue Tax Factor			1.01609
40c.GSLD Demand Purchased Power factor adjusted for taxes and rounded:			$6.28
40d.Total Current GSLD Non–Demand Costs (line 38)	1,510,111	42,000,000	3.59550
40e.Total Non–Demand Costs including true–up	1,510,111	42,000,000	3.59550
40f.Revenue Tax Factor			1.01609
40g.GSLD Non–demand costs adjusted for taxes			3.653
OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a.Total Demand and Non–Demand Purchased Power Costs of other classes (lines 33 + 39)	6,143,832	119,295,000	5.15012
41b.Less: Total Demand Cost Recovery	1,498,638 (a)		
41c.Total Other Costs to be Recovered	4,645,194 (a)	119,295,000	3.89387
41d.Other Classes' Portion of True–up (line 30 C)	(118,219)	119,295,000	–0.09910
41e.Total Demand and Non–Demand Costs including True–up	4,526,975	119,295,000	3.79477
42.Revenue tax factor			1.01609
			3.85583
43.OTHER CLASSES PURCHASED POWER FACTOR ADJUSTED FOR TAXES ROUNDED TO THE NEAREST .001 CENTS PER KWH:			3.856

*Based on Jurisdictional Sales

(a) included for informational purposes only.

GPIF REWARDS/PENALTIES
April 1993 to September 1993

Florida Power Corporation	$1,100,739	Reward
Florida Power and Light Company	$871,893	Reward
Gulf Power Company	$128,552	Reward
Tampa Electric Company	$214,237	Penalty

Utility/ Plant/Unit	EAF		Heat Rate	
FPC	Target	Adj. Actual	Target	Adj. Actual
Anclote 1	83.4	83.1	9,764	9,667
Anclote 2	94.7	96.0	9,886	9,845
Crystal River 1	84.3	89.8	9,988	10,090
Crystal River 2	78.1	77.4	9,975	10,075
Crystal River 3	72.2	82.9	10,462	10,582
Crystal River 4	83.2	83.0	9,245	9,258
Crystal River 5	94.9	94.6	9,301	9,233
FPL	Target	Adj. Actual	Target	Adj. Actual
Cape Canaveral 1	83.8	85.0	9,082	8,995
Cape Canaveral 2	79.5	78.2	9,202	9,222
Fort Myers 2	91.9	94.9	9,414	9,327
Manatee 1	83.7	93.3	9,710	9,573
Manatee 2	95.4	95.9	9,521	9,645
Martin 1	90.7	89.8	9,172	9,209
Martin 2	96.0	94.0	9,138	9,022
Port Everglades 1	94.8	98.8	9,791	9,657
Port Everglades 2	91.0	97.4	9,713	9,646
Port Everglades 3	93.9	95.5	9,301	9,307
Port Everglades 4	95.4	97.8	9,353	9,306
Riviera 3	91.1	88.4	9,864	9,758
Riviera 4	56.3	57.6	9,776	9,716
Sanford 4	93.8	93.5	9,979	9,718
St. Johns River 1	97.3	96.6	9,344	9,367
St. Johns River 2	98.0	95.7	9,258	9,392
St. Lucie 1	62.5	66.2	10,813	10,791
St. Lucie 2	93.6	88.4	10,795	10,911
Turkey Point 1	74.1	67.8	9,324	8,792
Turkey Point 2	82.5	90.2	9,480	9,476
Turkey Point 3	90.7	98.4	11,258	11,090
Turkey Point 4	60.1	56.2	11,216	11,121
Gulf	Target	Adj. Actual	Target	Adj. Actual
Crist 6	87.8	91.8	10,247	10,163
Crist 7	62.0	64.0	9,989	10,103
Smith 1	84.8	84.2	10,178	10,199
Smith 2	91.8	74.3	10,227	10,292
Daniel 1	98.0	93.5	10,498	10,131
Daniel 2	97.8	99.4	10,408	10,226
TECO	Target	Adj. Actual	Target	Adj. Actual
Big Bend 1	81.0	82.4	9,994	10,106
Big Bend 2	84.0	90.1	9,984	9,985
Big Bend 3	72.6	71.4	9,634	9,739
Big Bend 4	87.0	84.4	9,914	10,128
Gannon 5	59.5	58.5	10,442	10,436
Gannon 6	81.8	80.8	10,268	10,494

Staff Attachment 1
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GPIF TARGETS
April 1994 to September 1994

Utility/ Plant/Unit	Equivalent Availability Company EAF	POF	EUOF	Staff	Heat Rate Company	Staff
FPC	EAF	POF	EUOF			
Anclote 1	92.6	3.8	3.6	Agree	9,634	Agree
Anclote 2	81.7	15.3	3.0	Agree	9,596	Agree
Crystal River 1	85.9	0.0	14.1	Agree	10,118	Agree
Crystal River 2	83.9	0.0	16.1	Agree	10,081	Agree
Crystal River 3	59.8	33.3	6.8	Agree	10,533	Agree
Crystal River 4	87.2	8.2	4.7	Agree	9,268	Agree
Crystal River 5	94.7	0.0	5.3	Agree	9,315	Agree
FPL	EAF	POF	EUOF			
Cape Canaveral 1	94.7	0.0	5.3	Agree	8,978	Agree
Cape Canaveral 2	93.2	0.0	6.8	Agree	9,400	Agree
Fort Myers 1	95.2	0.0	4.8	Agree	10,054	Agree
Fort Myers 2	94.0	0.0	6.0	Agree	9,418	Agree
Manatee 1	92.7	0.0	7.3	Agree	9,658	Agree
Manatee 2	94.5	0.0	5.5	Agree	9,785	Agree
Port Everglades 1	96.0	0.0	4.0	Agree	9,960	Agree
Port Everglades 2	95.3	0.0	4.7	Agree	9,936	Agree
Port Everglades 3	95.2	0.0	4.8	Agree	9,320	Agree
Port Everglades 4	87.1	8.2	4.7	Agree	9,372	Agree
Putnam 1	89.4	4.1	6.5	Agree	8,183	Agree
Putnam 2	94.2	0.0	5.8	Agree	8,302	Agree
Riviera 3	65.4	27.9	6.7	Agree	9,691	Agree
Riviera 4	90.4	0.0	9.6	Agree	9,717	Agree
Sanford 4	94.6	0.0	5.4	Agree	9,760	Agree
Sanford 5	94.1	0.0	5.9	Agree	9,534	Agree
Scherer 4	95.9	0.0	4.1	Agree	8,855	Agree
St. Johns River 1	95.6	0.0	4.4	Agree	9,370	Agree
St. Johns River 2	95.3	0.0	4.7	Agree	9,302	Agree
St. Lucie 1	93.4	0.0	6.6	Agree	10,846	Agree
St. Lucie 2	70.3	10.4	19.3	Agree	10,796	Agree
Turkey Point 1	82.6	0.0	17.4	Agree	9,444	Agree
Turkey Point 2	87.4	0.0	12.6	Agree	9,624	Agree
Turkey Point 3	67.0	28.4	4.6	Agree	11,086	Agree
Turkey Point 4	93.6	0.0	6.4	Agree	11,216	Agree
Gulf	EAF	POF	EUOF			
Crist 6	66.6	24.6	8.9	Agree	10,391	Agree
Crist 7	82.1	0.0	17.9	Agree	10,231	Agree
Smith 1	80.8	13.1	6.1	Agree	10,162	Agree
Smith 2	90.8	0.0	9.2	Agree	10,192	Agree
Daniel 1	86.8	9.3	3.9	Agree	10,449	Agree
Daniel 2	96.8	0.0	3.2	Agree	10,089	Agree
TECO	EAF	POF	EUOF			
Big Bend 1	58.6	30.6	10.8	Agree	10,062	Agree
Big Bend 2	87.6	0.0	12.4	Agree	10,069	Agree
Big Bend 3	83.5	0.0	16.5	Agree	9,676	Agree
Big Bend 4	88.1	0.0	11.9	Agree	10,114	Agree
Gannon 5	82.7	4.4	12.9	Agree	10,408	Agree
Gannon 6	83.1	0.0	16.9	Agree	10,454	Agree