BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and purchase power cost recovery clause and generating performance incentive factor.	) DOCKET NO. 970001-EI) ORDER NO. PSC-97-0359-FOF-EI) ISSUED: March 31, 1997

APPEARANCES:

JAMES A. MCGEE, Esquire, Post Office Box 14042, St. Petersburg, Florida 33733-4042
On behalf of Florida Power Corporation (FPC).

MATTHEW M. CHILDS, Esquire, P.A., Steel Hector & Davis, LLP, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301
On behalf of Florida Power & Light Company (FPL).

WILLIAM B. WILLINGHAM, Esquire, Rutledge, Ecenia, Underwood, Purnell & Hoffman, P.A., P.O. Box 551, Tallahassee, Florida 32302-0551
On behalf of Florida Public Utilities Company (FPUC).

JEFFREY A. STONE, Esquire, and RUSSELL A. BADDERS, Esquire, Beggs & Lane, 700 Blount Building, 3 West Garden street, P.O. Box 12950, Pensacola, Florida 32576-2950
On behalf of Gulf Power Company (Gulf).

LEE L. WILLIS, Esquire, and JAMES D. BEASLEY, Esquire, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302
On behalf of Tampa Electric Company (TECO).

JOSEPH A. MCGLOTHLIN, Esquire, and VICKI GORDON KAUFMAN, Esquire, McWhirter Reeves McGlothlin Davidson Rief and Bakas, P.A., 117 South Gadsden Street, Tallahassee, Florida 32301
On behalf of Florida Industrial Power Users Group (FIPUG).

JOHN ROGER HOWE, Esquire, Deputy Public Counsel, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399.
On behalf of the Citizens of the State of Florida (OPC).

VICKI D. JOHNSON, Esquire, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Commission Staff (Staff).

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

THE FOLLOWING COMMISSIONERS PARTICIPATED IN THE DISPOSITION OF THIS MATTER:

JULIA L. JOHNSON, Chairman
J. TERRY DEASON
DIANE K. KIESLING

BY THE COMMISSION:

As part of the Commission's continuing fuel, energy conservation, purchased gas, and environmental cost recovery proceedings, a hearing was held on February 19, 1997, in this docket and in Docket Nos. 970002-EG, 970003-GU and 970007-EI. The hearing addressed the issues set out in the Prehearing Order, Order No. PSC-97-0180-PHO-EI, issued February 18, 1997. The parties stipulated to a resolution for some of the issues presented. They are described below. The approved fuel and capacity cost recovery factors are set forth in Attachment 2, which is incorporated in this Order.

Generic Fuel Adjustment Issues

We approve as reasonable, the following stipulations as to the appropriate final fuel adjustment true-up amounts for the period April, 1996 through September, 1996:

FPC:	$59,049,902 underrecovery.	
FPL:	$13,513,839 underrecovery.	
FPUC:	Marianna:	$459,638 overrecovery.
	Fernandina Beach:	$56,002 underrecovery.
GULF:	$3,892,089 overrecovery.	
TECO:	$3,401,136 underrecovery.	

We approve as reasonable, the following stipulations as to the appropriate estimated fuel adjustment true-up amounts for the period October, 1996 through March, 1997:

FPC:	$29,634,301 underrecovery.	
FPL:	$63,591,152 underrecovery.	
FPUC:	Marianna:	$32,276 overrecovery.
	Fernandina Beach:	$247,915 overrecovery.
GULF:	$2,698,394 underrecovery.	
TECO:	$4,991,759 overrecovery.	

We approve as reasonable, the following stipulations as to the appropriate total fuel adjustment true-up amounts to be collected during the period April, 1997 through September, 1997:

FPC:	$47,121,201 underrecovery.	
FPL:	$77,104,991 underrecovery.	
FPUC:	Marianna:	$491,914 overrecovery.
	Fernandina Beach:	$191,913 overrecovery.
GULF:	$1,193,695 overrecovery.	
TECO:	$1,590,623 overrecovery.	

We approve as reasonable, the following stipulations as to the levelized fuel cost recovery factors for the period April, 1997 through September, 1997:

FPC:	2.327 cents/kwh	
FPL:	2.192 cents/kwh	
FPUC:	Marianna:	2.179 cents/kwh
	Fernandina Beach:	2.859 cents/kwh
GULF:	2.154 cents/kwh	
TECO:	2.415 cents/kwh	

For billing purposes, the new factors shall be effective beginning with the first billing cycle for April, 1997, and thereafter through the last billing cycle for September, 1997. The first billing cycle may start before April 1, 1997, and the last billing cycle may end after September 30, 1997, so long as each customer is billed for six months, regardless of when the factors became effective.

The parties agreed to, and we approve as appropriate, the following fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class:

FPC:

Group	Delivery Voltage Level	Line Loss Multiplier
A.	Transmission	0.9800
B.	Distribution Primary	0.9900
C.	Distribution Secondary	1.0000
D.	Lighting Service	1.0000

FPL: The approved fuel recovery line loss multipliers are shown on pages 4 and 5 of this Order.

FPUC:	Marianna:	All Rate Schedules	1.0000
	Fernandina Beach:	All Rate Schedules	1.0000

GULF:

Group	Rate Schedules	Line Loss Multipliers
A	RS, GS, GSD, SBS OSIII, OSIV	1.01228
B	LP, SBS	0.98106
C	PX, PXT, RTP, SBS	0.96230
D	OSI, OSII	1.01228

TECO:

Group	Multiplier
Group A	1.0072
Group A1	n/a*
Group B	1.0013
Group C	0.9687

*Group A1 is based on Group A, 15% of On-Peak and 85% of Off-Peak.

We approve as reasonable, the stipulations as to the appropriate fuel cost recovery factors for each rate group, adjusted for line losses:

FPC:

		Fuel Cost Factors (cents/kWh)		
		Time Of Use		
Group	Delivery Voltage Level	Standard	On-Peak	Off-Peak
A.	Transmission	2.285	2.957	1.919
B.	Distribution Primary	2.309	2.988	1.940
C.	Distribution Secondary	2.332	3.018	1.959
D.	Lighting Service	2.157		

FPL:

GROUP	RATE SCHEDULE	AVERAGE FACTOR	FUEL RECOVERY LOSS MULTIPLIER	FUEL RECOVERY FACTOR
A	RS-1, GS-1, SL-2	2.192	1.00201	2.196
A-1	SL-1, OL-1	2.135	1.00201	2.139
B	GSD-1	2.192	1.00200	2.196
C	GSLD-1 & CS-1	2.192	1.00173	2.196
D	GSLD-2, CS-2, OS-2 & MET	2.192	0.99640	2.184
E	GSLD-3 & CS-3	2.192	0.96159	2.108
A	RST-1, GST-1			
	ON-PEAK	2.418	1.00201	2.423
	OFF-PEAK	2.081	1.00201	2.085
B	GSDT-1 ON-PEAK	2.418	1.00200	2.423
	CILC-1(G)			
	OFF-PEAK	2.081	1.00200	2.085
C	GSLDT-1 &			
	ON-PEAK	2.418	1.00173	2.422
	CST-1 OFF-PEAK	2.081	1.00173	2.084
D	GSLDT-2 &			
	ON-PEAK	2.418	0.99640	2.409
	CST-2 OFF-PEAK	2.081	0.99640	2.073
E	GSLDT-3, CST-3			
	ON-PEAK	2.418	0.96159	2.325
	CILC-1(T) &ISST-1(T)			
	OFF-PEAK	2.081	0.96159	2.001
F	CILC-1(D) &			
	ON-PEAK	2.418	0.99814	2.413
	ISST-1(D)			
	OFF-PEAK	2.081	0.99814	2.077

FPUC:

Marianna

Rate Schedule	Adjustment
RS	$0.04184
GS	$0.04114
GSD	$0.03630
GSLD	$0.03494
OL	$0.02681
SL	$0.02660

Fernandina Beach

Rate Schedule	Adjustment
RS	$0.04470
GS	$0.04319
GSD	$0.04033
CSL	$0.03117
OL	$0.03117
SL	$0.03117

GULF:

Group	Rate Schedules*	Fuel Cost Factors ¢/KWH Standard	Time of Use On-Peak	Time of Use Off-Peak
A	RS, GS, GSD, SBS, OSIII, OSIV	2.180	2.662	1.952
B	LP, SBS	2.113	2.580	1.892
C	PX, RTP, SBS	2.073	2.531	1.856
D	OSI, OSII	2.014	N/A	N/A

*The recovery factor applicable to customers taking service under Rate Schedule SBS is determined as follows: customers with a Contract Demand in the range of 100 to 499 KW will use the recovery factor applicable to Rate Schedule GSD; customers with a Contract Demand in the range of 500 to 7,499 KW will use the recovery factor applicable to Rate Schedule LP; and customers with a Contract Demand over 7,499 KW will use the recovery factor applicable to Rate Schedule PX.

TECO:	Standard	On-Peak	Off-Peak
Group A	2.432	2.941	2.190
Group A1	2.303	n/a	n/a
Group B	2.418	2.924	2.177
Group C	2.339	2.829	2.106

The parties agreed to and we approve as appropriate, the following revenue tax factor to be applied in calculating each company's levelized fuel factor for the projection period of April, 1997, through September, 1997:

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

We approve the parties' stipulation as to the accounting procedures to be used by the investor-owned utilities to record adjustments due to differences between the "per books" inventory quantities and the semi-annual coal inventory survey quantities. The following accounting procedures are reasonable and shall be used:

1. Surveys of the coal inventory shall be conducted semiannually.

2. The coal inventory at each plant site shall be considered separately and adjusted according to the procedures in this order.

3. All adjustments booked shall be made to both the quantity and dollars as recorded on the utility's books. These adjustments shall be booked to the inventory account prior to the calculation of the total available tons and dollars for that month.

4. If the difference between the book inventory quantity and the semiannual survey results is less than or equal to ±3% of the semiannual survey results (based on tons), no adjustment shall be made.

5. If the difference between the book inventory quantity and the semiannual survey results is greater than ± 3% of the semiannual survey results (based on tons), an adjustment shall be made to the book inventory equal to the difference between ± 3% of the semiannual survey results and the total difference.

6. The quantity to be adjusted shall be priced at the weighted average cost of the sum of the total available book inventory dollars (before consumption) divided by the sum of the total available book inventory quantity (before consumption) for the most recent six (6) month period preceding the month during which the survey is conducted.

7. The entire adjustment, both tons and dollars, shall be either debited or credited, whichever is appropriate, to the book inventory account for the month during which the survey is conducted. The offsetting entry shall be made to fuel expense for the same month.

8. Adjustment, greater that 2% (± 5% less ± 3%) of the semiannual survey results (based on tons), that may significantly affect either the utility or its customers if booked entirely in one month, may be amortized to fuel expense over an appropriate time period. The appropriate time period selected by the utility shall be subject to the review and approval of the Commission.

9. The utility shall notify the Division of Electric and Gas and the appropriate District Field Office of the results of any semiannual surveys regardless of whether any adjustments are made. The notification shall be made by the 15th day of the month subsequent to the month during which the surveys are conducted and shall include, as a minimum, the "per books" quantities, the survey quantities, and the calculation of any adjustments on a per plant basis.

The parties agreed to defer until the August, 1997, fuel adjustment hearing, several issues relating to the recovery of transmission costs associated with broker transactions to allow parties the opportunity to file testimony. The following issues have been deferred:

> How should transmission costs be accounted for when determining the transaction price of an economy, Schedule C, broker transaction between two directly interconnected utilities?
>
> If the cost of transmission is used to determine the transaction price of an economy, Schedule C, broker transaction between two directly interconnected utilities, how should the costs of this transmission be recovered?
>
> How should transmission costs be accounted for when determining the transaction price of an economy, Schedule C, broker transaction that requires wheeling between two non-directly interconnected utilities?
>
> If the cost of transmission is used to determine the transaction price of an economy, Schedule C, broker transaction that requires wheeling between two non-directly interconnected utilities, how should the costs of this transmission be recovered?

<u>**Company-Specific Fuel Adjustment Issues**</u>

<u>Florida Power Corporation</u>

We approve the parties' stipulation that Florida Power Corporation should be allowed to recover the cost of converting Debary Unit 7, Bartow Units 3 and 4, and Suwannee Unit 1 to burn natural gas. The conversion of these units to burn natural gas is estimated to save FPC's ratepayers more than $22 million over the next 5 years at a cost of approximately $7.5 million. Order No. 14546, issued July 8, 1985 allows a utility to recover fossil-fuel related costs which result in fuel savings when those costs were not previously addressed in determining base rates. FPC shall be allowed to recover the projected cost of conversion through its fuel clause beginning April 1, 1997 to be depreciated over the next five years using straight line depreciation. FPC shall also be allowed to recover a return on average investment at the rate authorized in Docket 910890-EI, 8.37%, as well as applicable taxes. We will audit the actual costs once the conversion is complete to true-up original projections and to verify the prudence of the individual cost components included for recovery.

We deny Florida Power Corporation's request that the costs associated with the settlement agreement between the utility and Lake Cogen, Ltd. be recovered through the Fuel and Purchased Power Cost Recovery Clause for the period April, 1997 through September, 1997. This Commission has not made a decision as to whether the cogeneration settlement agreements are in the public interest or benefit the ratepayers. Absent that determination, it is inappropriate to include these costs in this projection period.

For the same reasons as expressed above, we deny FPC's request that the costs associated with its settlement agreement with Pasco Cogen, Ltd. be recovered through the Fuel and Purchased Power Cost Recovery Clause for the period April, 1997 through September, 1997.

There were several issues in this proceeding relating to Florida Power Corporation's request to recover replacement fuel costs associated with its extended outage at Crystal River No. 3 nuclear unit. FPC requested approval to recover the fuel replacement costs incurred during the period September, 1996 through March, 1997. FPC also requested permission to recover these costs over the twelve-month period April, 1997 through March, 1998.

We have a great deal of difficulty with allowing recovery of these costs. To a limited extent, we agree with the arguments of Public Counsel that given the significance of these costs, FPC should have made some initial presentation as to the reasonableness of these costs. In the past, we have permitted utilities to recover costs on a preliminary basis, subject to audit, "true-up" with interest and an after-the-fact prudence review. Thus, we do not believe it was unreasonable for FPC to expect that it would have the opportunity to meet the burden of proof in a proceeding specifically designed to determine the prudence of these costs. In the future, however, when a utility seeks to recover costs which have a significant impact on the utility's fuel adjustment factor, the utility must affirmatively demonstrate prior to approval for recovery that the actions or events that gave rise to the need for the recovery and the underlying costs are reasonable.

We are confronted with two options to resolve this matter. If we permit recovery now, we can later order a refund of these costs, with interest, if we determine the costs were imprudently incurred. We may also deny recovery at this time, until we have investigated the outage and assessed the reasonableness of management's actions, both before and after the outage occurred. If we delay recovery of these costs until it is determined that all or a significant portion were prudently incurred, however, we may be putting a significant burden on customers at some future period. That burden

We deny Florida Power Corporation's request that the costs associated with the settlement agreement between the utility and Lake Cogen, Ltd. be recovered through the Fuel and Purchased Power Cost Recovery Clause for the period April, 1997 through September, 1997. This Commission has not made a decision as to whether the cogeneration settlement agreements are in the public interest or benefit the ratepayers. Absent that determination, it is inappropriate to include these costs in this projection period.

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We are confronted with two options to resolve this matter. If we permit recovery now, we can later order a refund of these costs, with interest, if we determine the costs were imprudently incurred. We may also deny recovery at this time, until we have investigated the outage and assessed the reasonableness of management's actions, both before and after the outage occurred. If we delay recovery of these costs until it is determined that all or a significant portion were prudently incurred, however, we may be putting a significant burden on customers at some future period. That burden will be heightened by interest which will accumulate on the unrecovered costs. Under FPC's proposal, this burden will be mitigated to some extent because FPC has requested a twelve-month recovery period and the company has not included any fuel replacement costs in the projected period.

Thus, for these reasons, we find that FPC may recover the fuel replacement costs associated with the Crystal River No. 3 nuclear unit outage over the twelve-month period April, 1997 to March, 1998. Given the magnitude of these costs, this outage will greatly increase the rates paid by FPC's customers. To protect the ratepayers, it is imperative that we begin our investigation now, as opposed to waiting until the outage is over. Therefore, we will immediately initiate an investigation and establish a docket to allow FPC and other parties to file testimony detailing the actions and circumstances which led to the outage. If an adjustment is needed, we will make a mid-course correction to FPC's fuel adjustment factor.

Florida Power and Light Company

We approve the parties' stipulation that Florida Power and Light Company should recover the depreciation expense and return on investment for rail cars purchased to deliver coal to the Scherer Plant. Pursuant to Order No. 14546, issued July 8, 1985, unanticipated fuel-related costs not included in the computation of base rates may be considered for recovery through a utility's fuel clause. When economically beneficial to a utility's ratepayers, the cost of purchasing or leasing rail cars is considered to be a fuel-related expense that should be recovered through the fuel clause. FPL's proposal is consistent with our approval in Order No. PSC-95-1089-FOF-EI for the previous purchase of 462 Scherer rail cars.

We also approve the parties' stipulation that Florida Power and Light Company should recover the costs of implementing certain equipment modifications and additions at some of its generating plants and fuel storage facilities to use "low gravity" fuel oil. These modifications will allow FPL to operate these plants using a heavier more economic grade of residual fuel oil called "low gravity" fuel oil. These modifications are estimated to save FPL's ratepayers more than $19 million over the next three years at a cost of approximately $2 million. Order No. 14546, issued July 8, 1985 allows a utility to recover fossil-fuel related costs which result in fuel savings when those costs were not previously addressed in determining base rates. Thus, FPL shall be allowed to recover the projected cost of the modifications through its fuel clause beginning April, 1997. We will audit the actual costs once the modifications are complete to true-up original projections and to verify the prudence of the individual costs components included for recovery.

Tampa Electric Company

We approve the parties' agreement that Tampa Electric Company appropriately calculated its proposed refund factors for refunding the $25 million in excess earnings as required by Order No. PSC-96-0670-S-EI.

An issue was raised concerning TECO's treatment of the fuel revenues associated with its wholesale sales in this fuel adjustment proceeding. The parties agreed that this issue is moot in view of the Commission's decision at the February 18, 1997, agenda conference, that for prospective wholesale sales, fuel revenues shall be credited to the fuel clause based on system average costs, unless the utility can demonstrate that such sales provide benefits to the ratepayers. That decision did not affect any wholesale sales which were addressed in this fuel adjustment proceeding, with the exception of the new sales to the Florida Municipal Power Agency and the City of Lakeland. The fuel revenues from these sales were credited based on their actual amounts in this fuel adjustment proceeding. However, the appropriate treatment of these revenues will be addressed in Docket No. 970171-EU, which has been set for hearing on June 11, 1997.

Generic Generating Performance Incentive Factor Issues

There was no controversy among the parties as to the appropriate GPIF reward or penalty for past performance. The parties agreed to, and we approve, the GPIF rewards and penalties for performance achieved during the period April, 1996 through September, 1996 as shown on Attachment 1, page 1 of 2.

We approve the GPIF targets and ranges for the period April, 1997 through September, 1997 as shown on Attachment 1, page 2 of 2. Because Crystal River No. 3 nuclear unit will not be operating during the upcoming period, we find that FPC's removal of the unit from its calculation of targets and ranges is appropriate. By excluding Crystal River No. 3, the targets and ranges for FPC's remaining units have been adjusted such that those units must operate more efficiently for GPIF purposes.

Generic Capacity Cost Recovery Issues

The parties agreed to and we approve as appropriate, the following final capacity cost recovery true-up amounts for the period April, 1996 through September, 1996:

FPC:	$3,700,279 overrecovery.
TECO:	$12,560 overrecovery.

The parties agreed to and we approve as appropriate, the following estimated capacity cost recovery true-up amounts for the period October, 1996 through April, 1997:

FPC:	$2,452,455 underrecovery.
TECO:	$228,378 overrecovery.

The parties agreed to and we approve as appropriate, the following total capacity cost recovery true-up amounts to be collected during the period April, 1997 through September, 1997:

FPC:	$1,247,824 overrecovery.
TECO:	$240,938 overrecovery.

The parties also agreed to and we approve as appropriate, the projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period April, 1997 through September, 1997 as shown below.

FPC:	$136,477,442
TECO:	$11,422,680

We approve the parties' stipulation that the projected capacity cost recovery factors for the period April, 1997 through September 1997 are as follows:

FPC:

Rate Class	CCR Factor
Residential	.993 cents/kWh
General Service Non-Demand	.787 cents/kWh
@ Primary Voltage	.779 cents/kWh
@ Transmission Voltage	.771 cents/kWh
General Service 100% Load Factor	.542 cents/kWh
General Service Demand	.655 cents/kWh
@ Primary Voltage	.648 cents/kWh
@ Transmission Voltage	.641 cents/kWh
Curtailable	.549 cents/kWh
@ Primary Voltage	.544 cents/kWh
@ Transmission Voltage	.538 cents/kWh
Interruptible	.514 cents/kWh
@ Primary Voltage	.509 cents/kWh
@ Transmission Voltage	.504 cents/kWh
Lighting	.189 cents/kWh

TECO:

Rate Schedules	Factor
RS	.179 cents per KWH
GS, TS	.173 cents per KWH
GSD, EV-X	.132 cents per KWH
GSLD, SBF	.118 cents per KWH
IS-1 & 3, SBI-1 & 3	.010 cents per KWH
SL/OL	.021 cents per KWH

Company Specific Capacity Cost Recovery Issues

Florida Power Corporation

As discussed previously in this Order, it is inappropriate to permit recovery of costs which have not been approved by the Commission. Therefore, we deny Florida Power Corporation's request to recover the capacity costs associated with its settlement agreements with Lake Cogen, Ltd. and Pasco Cogen, Ltd. through the capacity cost recovery clause for the period April, 1997 through September, 1997.

Florida Power & Light Company

The parties agreed that Florida Power & Light Company should be permitted a mid-course correction to reduce its capacity cost recovery clause factors, effective April, 1997. The capacity factors now in effect for FPL were originally established to be effective for the period October, 1996 through September, 1997. However, because FPL has experienced an over-recovery of approximately $28.8 million, we find that it is appropriate to reduce the factors effective April, 1997. The over-recovery is primarily due to the fact that payments to two cogenerators (Okeelanta and Osceola), which were projected to be made during the period June, 1996 through December, 1996, did not occur. The appropriate factors are:

RATE CLASS	CAPACITY RECOVERY FACTOR ($/KW)	CAPACITY RECOVERY FACTOR ($/KWH)
RS1	-	0.00503
GS1	-	0.00456
GSD1	1.74	-
OS2	-	0.00330
GSLD1/CS1	1.74	-
GSLD2/CS2	1.78	-
GSLD3/CS3	1.74	-
CILCD/CILCG	1.79	-
CILCT	1.79	-
MET	1.87	-
OL1/SL1	-	0.00083
SL2	-	0.00320

RATE CLASS	CAPACITY RECOVERY FACTOR (RESERVATION DEMAND CHARGE) ($/KW)	CAPACITY RECOVERY FACTOR (SUM OF DAILY DEMAND CHARGE) ($/KW)
ISST1D	.23	.11
SST1T	.21	.10
SST1D	.22	.11

Tampa Electric Company

Finally, we approve the parties' stipulation that the treatment of the non-fuel revenues associated with Tampa Electric Company's wholesale sales to the Florida Municipal Power Agency and the City of Lakeland shall be considered in a separate docket (Docket No. 970171-EU) in order to afford the parties an opportunity to submit testimony. The parties agree that when this issue is ultimately resolved, Tampa Electric's surveillance reporting results will be adjusted to the extent necessary to reflect the treatment ultimately approved, going back to the time when Tampa Electric began receiving revenues under the two wholesale contracts in question.

It is therefore,

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

ORDERED that Florida Power & Light Company, Florida Power Corporation, Tampa Electric Company, Gulf Power Company and Florida Public Utilities Company are hereby authorized to apply the fuel cost recovery factors set forth herein during the period of April, 1997 through September, 1997. It is further

ORDERED that the estimated true-up amounts contained in the fuel cost recovery factors approved herein 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 penalties stated in the body of this Order shall be applied to the projected levelized fuel adjustment factors for the period of April, 1997 through September, 1997. It is further

ORDERED that Florida Power & Light Company, Florida Power Corporation, and Tampa Electric Company are hereby authorized to apply the capacity cost recovery factors as set forth in the body of this Order and until such factors are modified by subsequent Order. It is further

ORDERED that the estimated true-up amounts contained in the capacity cost recovery factors approved herein 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 31st day of March, 1997.

BLANCA S. BAYÓ, Director
Division of Records and Reporting

by: Kay Flynn
Chief, Bureau of Records

(S E A L)

VDJ

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), 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, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, 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 and/or wastewater 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.

GPIF REWARDS/PENALTIES

April 1996 to September 1996

Utility	Amount	Reward/Penalty
Florida Power Corporation	$ 431,674	Reward
Gulf Power Company	$ 82,198	Reward
Tampa Electric Company	($ 298.369)	Penalty

Utility/ Plant/Unit	EAF		Heat Rate	
FPC	**Target**	**Adjusted Actual**	**Target**	**Adjusted Actual**
Anclote 1	96.1	94.9	9,665	9,617
Anclote 2	97.1	94.9	9,784	9,717
Crystal River 1	86.9	84.8	10,046	9,961
Crystal River 2	80.5	92.3	9,940	9,871
Crystal River 3	90.0	61.4	10,492	10,452
Crystal River 4	70.4	63.7	9,368	9,397
Crystal River 5	94.9	95.4	9,279	9,329

Gulf	**Target**	**Adjusted Actual**	**Target**	**Adjusted Actual**
Crist 6	82.2	89.9	10,597	10,219
Crist 7	71.6	76.4	10,500	10,166
Smith 1	87.3	91.0	10,219	10,271
Smith 2	91.7	97.0	10,422	10,448
Daniel 1	92.8	94.9	10,493	10,715
Daniel 2	96.7	92.4	10,280	10,751

TECO	**Target**	**Adjusted Actual**	**Target**	**Adjusted Actual**
Big Bend 1				
Big Bend 2	86.7	84.8	10,077	10,104
Big Bend 3	85.9	87.2	10,020	10,144
Big Bend 4	87.1	84.2	9,746	9,883
Gannon 5	89.7	92.7	10,149	10,107
Gannon 6	90.4	87.2	10,343	10,636
	64.8	67.3	10,443	11,025

GPIF TARGETS
April 1997 to September 1997

Utility/ Plant/Unit	Approved EAF			Approved Heat Rate
	Company			Company
FPC	EAF	POF	EUOF	
Anclote 1	91.3	3.8	4.9	9,719
Anclote 2	95.3	0.0	4.7	9,669
Crystal River 1	88.7	2.2	9.1	9,766
Crystal River 2	83.5	2.2	14.3	9,763
Crystal River 4	94.1	0.0	5.9	9,289
Crystal River 5	75.5	21.3	3.2	9,267
Gulf	EAF	POF	EUOF	
Crist 6	84.4	8.7	6.9	10,833
Crist 7	80.0	8.7	11.3	10,499
Smith 1	96.2	0.0	3.8	10,244
Smith 2	82.6	10.4	7.0	10,406
Daniel 1	87.8	4.9	7.3	10,253
Daniel 2	91.9	4.9	3.2	10,062
TECO	EAF	POF	EUOF	
Big Bend 1	67.8	22.4	9.8	9,968
Big Bend 2	84.9	0.0	15.1	10,079
Big Bend 3	84.3	0.0	15.7	9,969
Big Bend 4	91.5	0.0	8.5	9,992
Gannon 5	90.0	0.0	10.0	10,448
Gannon 6	86.3	3.8	9.9	10,471

RESIDENTIAL FUEL FACTORS FOR THE PERIOD: April - September 1997

		Florida Power & Light	Florida Power Corporation	Tampa Electric Company	Gulf Power Company	Florida Public Utilities Co. (2) Marianna	Florida Public Utilities Co. (2) Fernandina Beach
Present (cents per kwh):	October 1996 - March 1997	2.209	2.058	2.418	2.345	4.951	5.053
Approved (cents per kwh):	April - September 1997	**2.196**	**2.332**	**2.432**	**2.180**	**4.184**	**4.470**
	Increase/Decrease:	-0.013	0.274	0.014	-0.165	-0.767	-0.583

TOTAL COST FOR 1,000 KILOWATT HOURS - RESIDENTIAL SERVICE

PRESENT: October 1996 - March 1997	Florida Power & Light	Florida Power Corporation	Tampa Electric Company	Gulf Power Company	Florida Public Utilities Co. (2) Marianna	Florida Public Utilities Co. (2) Fernandina Beach
Base Rate	47.46	49.05	50.18 (3)	43.25	20.43	19.20
Fuel	22.09	20.58	24.18	23.45	49.51	50.53
Energy Conservation	2.09	1.38	1.62	0.41	0.19	0.09
Environmental Cost Recovery	0.17	N/A	0.41	1.24	N/A	N/A
Capacity Recovery	6.21	10.30	1.98	0.78	N/A	N/A
Gross Receipts Tax (1)	0.80	2.08	2.01	0.71	1.80	0.72
Total	**$78.82**	**$83.39**	**$80.38**	**$69.84**	**$71.93**	**$70.54**

APPROVED: April - September 1997	Florida Power & Light	Florida Power Corporation	Tampa Electric Company	Gulf Power Company	Florida Public Utilities Co. (2) Marianna	Florida Public Utilities Co. (2) Fernandina Beach
Base Rate	47.46	49.05	50.23 (4)	43.25	20.43	19.20
Fuel	21.96	23.32	24.32	21.80	41.84	44.70
Energy Conservation	2.62	2.80	1.63	0.35	0.81	0.79
Environmental Cost Recovery	0.17	N/A	0.33	1.24	N/A	N/A
Capacity Recovery	5.03	9.93	1.79	0.78 (5)	N/A	N/A
Gross Receipts Tax (1)	0.79	2.18	2.01	0.69	1.62	0.66
Total	**$78.03**	**$87.28**	**$80.31**	**$68.11**	**$64.70**	**$65.35**

INCREASE / (DECREASE)	Florida Power & Light	Florida Power Corporation	Tampa Electric Company	Gulf Power Company	Florida Public Utilities Co. (2) Marianna	Florida Public Utilities Co. (2) Fernandina Beach
Base Rate	0.00	0.00	0.05	0.00	0.00	0.00
Fuel	-0.13	2.74	0.14	-1.65	-7.67	-5.83
Energy Conservation	0.53	1.42	0.01	-0.06	0.62	0.70
Environmental Cost Recovery	0.00	N/A	-0.08	0.00	N/A	N/A
Capacity Recovery	-1.18	-0.37	-0.19	0.00	N/A	N/A
Gross Receipts Tax (1)	-0.01	0.10	0.00	-0.02	-0.18	-0.06
Total	**($0.79)**	**$3.89**	**($0.07)**	**($1.73)**	**($7.23)**	**($5.19)**

(1) Additional gross receipts tax is 1% for Gulf, FPL and FPUC-Fernandina Beach. FPC, TECO and FPUC-Marianna have removed all GRT from their rates, and thus entire 2.5% is shown separately. (2) Fuel costs include purchased power demand costs of 2.005 for Marianna and 1.611 cents/KWH for Fernandina allocated to the residential class.
(3)TECO present base rates include .174 cents per kwh refund. (Order No. PSC-96-0670-S-EI) (4) TECO proposed base rates include .169 cents/kwh refund (Order No. PSC-96-0670-S-EI)
(5) Gulf capacity reflects mid-course correction effective 1/1/97.

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

FOR THE PERIOD: April - September 1997

COMPANY	GROUP	RATE SCHEDULES	BEFORE LINE LOSSES Standard	BEFORE LINE LOSSES TIME OF USE On/Peak	BEFORE LINE LOSSES TIME OF USE Off/Peak	LINE LOSS MULTIPLIER	FINAL FACTORS ADJUSTED FOR LINE LOSSES Standard	FINAL FACTORS TIME OF USE On/Peak	FINAL FACTORS TIME OF USE Off/Peak
FP&L	A	RS-1,RST-1,GST-1,GS-1,SL-2	2.192	2.418	2.081	1.00201	2.196	2.423	2.085
	A-1	SL-1,OL-1	2.135	NA	NA	1.00201	2.139	NA	NA
	B	GSD-1,GSDT-1, CILC-1(G)	2.192	2.418	2.081	1.00200	2.196	2.423	2.085
	C	GSLD-1,GSLDT-1, CS-1, CST-1	2.192	2.418	2.081	1.0017[illegible]	2.196	2.422	2.084
	D	GSLD-2,GSLDT-2, CS-2, CST-2, OS-2, MET	2.192	2.418	2.081	0.99640	2.184	2.409	2.073
	E	GSLD-3,GSLDT-3,CS-3,CST-3,CILC-1(T),ISST-1(T)	2.192	2.418	2.081	0.96159	2.108	2.325	2.001
	F	CILC-1(D),ISST-1(D)	NA	2.418	2.081	0.99814	NA	2.413	2.077
FPC	1	Distribution Secondary Delivery	2.332	3.018	1.959	1.00000	2.332	3.018	1.959
	2	Distribution Primary Delivery	2.332	3.018	1.959	0.99000	2.309	2.988	1.940
	3	Transmission Delivery	2.332	3.018	1.959	0.98000	2.285	2.957	1.919
	4	Lighting Service	2.157	NA	NA	1.00000	2.157	NA	NA
TECO	A	RS, RST, GS, GST, TS	2.415	2.920	2.174	1.00720	2.432	2.941	2.190
	A-1	SL-2,OL-1,3	2.415	NA	NA	NA	2.303	NA	NA
	B	GSD, GSDT, EV-X, GSLD, GSLDT, SBF, SBFT	2.415	2.920	2.174	1.00130	2.418	2.924	2.177
	C	IS-1 & 3, IST1 &3, SBI-1 & 3, SBIT1 & 3	2.415	2.920	2.174	0.96870	2.339	2.829	2.106
GULF	A	RS,GS,GSD,OS-III,OS-IV, SBS(100 to 499 kW)	2.154	2.630	1.928	1.01228	2.180	2.662	1.952
	B	LP, SBS(Contract Demand of 500 to 7499 kW)	2.154	2.630	1.928	0.98106	2.113	2.580	1.892
	C	PX, PXT, RTP,SBS (Contract Demand above 7499 kW)	2.154	2.630	1.928	0.96230	2.073	2.531	1.856
	D	OS-1,OS-2	1.990	NA	NA	1.01228	2.014	NA	NA
FPUC									
Fernandina Beach:	A	RS	4.470	NA	NA	1.00000	4.470	NA	NA
	B	GS	4.319	NA	NA	1.00000	4.319	NA	NA
	C	GSD	4.033	NA	NA	1.00000	4.033	NA	NA
	D	OL, OL-2, SL-2, SL-3, CSL	3.117	NA	NA	1.00000	3.117	NA	NA
	E	GSLD					Actual Fuel Cost plus $6.28 per CP kW		
Marianna:	A	RS	4.184	NA	NA	1.00000	4.184	NA	NA
	B	GS	4.114	NA	NA	1.00000	4.114	NA	NA
	C	GSD	3.630	NA	NA	1.00000	3.630	NA	NA
	D	GLSD	3.494	NA	NA	1.00000	3.494	NA	NA
	E	OL, OL-2	2.681	NA	NA	1.00000	2.681	NA	NA
	F	SL-1, SL-2	2.660	NA	NA	1.00000	2.660	NA	NA

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CAPACITY COST RECOVERY FACTORS

For the Period: **April - September 1997**

COMPANY	RATE SCHEDULE	RECOVERY FACTOR (CENTS PER KWH)	
FPL *	RS1, RST-1	0.503	
	GS1, GST-1	0.456	
	OL1/SL1	0.083	
	SL2	0.320	
	OS2	0.330	
		RECOVERY FACTOR (DOLLARS PER KW)	
	GSD-1, GSDT-1	$1.74	
	GSLD-1, GSLDT-1 / CS-1, CST-1	$1.74	
	GSLD-2, GSLDT-2 / CS-2, CST-2	$1.78	
	GSLD-3, GSLDT-3 / CS-3, CST-3	$1.74	SDD
	ISST-1D = RDC/SDD	$0.23	$0.11
	SST-1T = RDC/SDD	$0.21	$0.10
	SST-1D = RDC/SDD	$0.22	$0.11
	CILC-1D,CILC-1G	$1.79	
	CILC-1T	$1.79	
	MET	$1.87	
		RECOVERY FACTOR (CENTS PER KWH)	
FPC	RS-1, RST-1, RSL-1	0.993	
	GS-1, GST-1 -Transmission	0.771	
	GS-1, GST-1 - Primary	0.779	
	GS-1, GST-1 -Secondary	0.787	
	GS -2 100% Load Factor	0.542	
	GSD-1, GSDT-1, SS-1-Transmission	0.641	
	GSD-1, GSDT-1, SS-1 - Primary	0.648	
	GSD-1, GSDT-1, SS-1 - Secondary	0.655	
	CS-1, CST-1, SS-3 - Transmission	0.538	
	CS, CST, SS-3 - Primary	0.544	
	CS-1, CST-1, SS-3 - Secondary	0.549	
	IS-1 & 2, , IST-1 & 2, SS-2 - Transmission	0.504	
	IS-1 &2, IST-1 &2, SS-2 - Primary	0.509	
	IS-1 &2, IST-1 &2, SS-2 - Secondary	0.514	
	LS-1 - Lighting Service	0.189	
TECO	RS, RST	0.179	
	GS, GST, TS	0.173	
	GSD, GSDT, EV-X	0.132	
	GSLD, GSLDT, SBF, SBFT	0.118	
	IS-1 & 3, IST-1 & 3, SBI-1 & 3, SBIT-1 & 3	0.010	
	SL/OL	0.021	
GULF **	RS, RST	0.167	
	GS, GST	0.161	
	GSD, GSDT	0.121	
	LP,LPT	0.110	
	PX, PXT, RTP	0.091	
	OS-I, OS-II	0.040	
	OS-III	0.096	
	OS-IV	0.203	
	SBS	0.114	

* FPL factors reflect a mid-course correction effective April - September 1997.

**Gulf factors are effective Octber 1996 - September 1997

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FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: **April - September 1997**

FLORIDA POWER & LIGHT COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated Cents/KWH
1.Fuel Cost of System Net Generation (E3)	647,351,780	37,177,272,000	1.74126
2.Spent NUC Fuel Disposal Cost (E2)	10,224,339	10,978,567,000 (a)	0.09313
3.Fuel Related Transactions	9,436,142	0	0.00000
4. Natural Gas Pipeline Enhancements	0	0	0.00000
4a. Fuel Cost of Sales to FKEC	(11,387,249)	(521,189,000)	2.18486
5.TOTAL COST OF GENERATED POWER	655,625,012	36,656,083,000	1.78858
6.Fuel Cost of Purchased Power - Exclusive of economy (E7)	72,596,350	4,373,246,000	1.66001
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	28,050,590	1,532,816,000	1.83000
8.Energy Cost of Economy Purchases (Non-Broker) (E9)	25,191,640	1,144,681,000	2.20076
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. Misssion Settlement	1,129,590	0	
12.Payments to Qualifying Facilities (E8)	81,519,989	4,254,160,000	1.91624
13.TOTAL COST OF PURCHASED POWER	208,488,159	11,304,903,000	1.84423
14.TOTAL AVAILABLE KWH		47,960,986,000	
15.Fuel Cost of Economy Sales (E6)	(15,141,129)	(580,752,000)	2.60716
16.Gain on Economy Sales - 80% (E6A)	(2,375,393)	(580,752,000) (a)	0.40902
17.Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(1,095,050)	(262,195,000)	0.41765
18.Fuel Cost of Other Power Sales (E6)	0	0	0.00000
19.TOTAL FUEL COST & GAINS OF POWER SALES	(18,611,572)	(842,947,000)	2.20792
20.Net Inadvertant Interchange (E4)	0	0	0.00000
21.TOTAL FUEL AND NET POWER TRANSACTIONS	845,501,599	47,118,039,000	1.79443
22.Net Unbilled Sales	19,799,562 (a)	1,103,388,000	0.04625
23.Company Use	2,536,505 (a)	141,354,000	0.00592
24.T & D Losses	54,957,604 (a)	3,062,673,000	0.12837
25.Adjusted System KWH Sales	845,501,599	42,810,624,000	1.97498
26.Wholesale KWH Sales	3,275,896	165,869,000	1.97499
27.JURISDICTIONAL KWH SALES	842,225,703	42,644,755,000	1.97498
28.Jurisdictional KWH Sales Adjusted for Line Loss - 1.00071	842,823,683	42,644,755,000	1.97638
29.True-up * (derived in Attachment C)	77,104,991	42,644,755,000	0.18081
30.TOTAL JURISDICTIONAL FUEL COST	919,928,674	42,644,755,000	2.15720
31.Revenue Tax Factor			1.01609
32.Fuel Cost Adjusted for Taxes			2.19191
33.GPIF*	0	42,644,755,000	0.00000
34.Total fuel cost including GPIF	$919,928,674	42,644,755,000	2.19191
35.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.192

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

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FUEL AND PURCHASED POWER CAPACITY CLAUSE
CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: **April - September 1997**

FLORIDA POWER CORPORATION

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	248,196,433	14,195,910,000	1.74837
2.Spent NUC Fuel Disposal Cost	2,826,190	3,022,663,000 (a)	0.09350
3.Coal Car Investment	0	0	0.00000
4.Adjustments to Fuel Cost	1,403,322	0	0.00000
5.TOTAL COST OF GENERATED POWER	252,425,945	14,195,910,000	1.77816
6.Energy Cost of Purchased Power -Excl. of cogen, econ. (E7)	23,994,980	1,248,361,000	1.92212
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	18,582,810	630,000,000	2.94965
8.Energy Cost of Economy Purchases (Non-Broker) (E9)	1,708,387	85,551,000	1.99692
9.Energy Cost of Sch.E Purchases (E9)	0	0	0.00000
10.Capacity Cost of Economy Purchases (E9)	685,336	61,971,000 (a)	1.10590
11.Payments to Qualifying Facilities (E8)	79,049,660	3,893,407,000	2.03035
12.TOTAL COST OF PURCHASED POWER	124,021,173	5,857,319,000	2.11737
13.TOTAL AVAILABLE KWH		20,053,229,000	
14.Fuel Cost of Economy Sales (E6)	(9,378,410)	(470,000,000)	1.99541
14a.Gain on Economy Sales -80% (E6)	(1,848,720)	(470,000,000) (a)	0.39334
15.Fuel Cost of Other Power Sales (E6)	0	0	0.00000
15a.Gain on Other Power Sales (E6)	0	0 (a)	0.00000
16.Fuel Cost of Unit Power Sales (E6)	0	0	0.00000
16a.Gain on Unit Power Sales (E6)	0	0 (a)	0.00000
17.Fuel Cost of Stratified Sales (E6)	(9,016,247)	(332,765,000)	2.70949
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(20,243,377)	(802,765,000)	2.52171
19.Net Inadvertant Interchange	0	0	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	356,203,741	19,250,464,000	1.85036
21.Net Unbilled	11,615,524 (a)	(623,012,000)	0.06653
22.Company Use	1,694,752 (a)	(90,900,000)	0.00971
23.T & D Losses	20,083,301 (a)	(1,077,191,000)	0.11503
24.Adjusted System KWH Sales	356,203,741	17,459,361,000	2.04019
25.Wholesale KWH Sales (Excluding Supplemental sales)	(12,809,353)	(627,876,000)	2.04011
26.JURISDICTIONAL KWH SALES	343,394,388	16,831,485,000	2.04019
27.Jurisdictional KWH Sales Adjusted for Line Losses - 1.0013	343,840,801	16,831,485,000	2.04284
28.Prior Period True-Up * (E1-B, sheet 1)	47,121,201	16,831,485,000	0.27996
28a. Market Price True-up	0	16,831,485,000	0.00000
29.TOTAL JURISDICTIONAL FUEL COST	390,962,002	16,831,485,000	2.32280
30.Revenue Tax Factor			1.00083
31.Fuel Cost Adjusted for Taxes	391,286,500		2.32473
32.GPIF*	431,674	16,831,485,000	0.00256
33.Total fuel cost including GPIF	391,718,174	16,831,485,000	2.32729
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.327

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

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FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: **April - September 1997**

TAMPA ELECTRIC COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	205,716,191	9,712,909,000	2.11797
2.Spent NUC Fuel Disposal Cost	0	0	0.00000
3.Coal Car Investment	0	0	0.00000
4. Adjustments to Fuel Cost (Ft. Meade/Wauchula Wheeling)	(18,000)	9,712,909,000	-0.00019
4a .Adjustments to Fuel Cost (Allowances)	0	9,712,909,000 (a)	0.00000
5.TOTAL COST OF GENERATED POWER	205,698,191	9,712,909,000	2.11778
6.Fuel Cost of Purchased Power - Exclusive of Economy (E7)	11,292,400	365,771,000	3.08729
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	1,142,800	27,572,000	4.14478
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 (a)	0.00000
11.Payments to Qualifying Facilities (E8)	4,752,900	228,147,000	2.08326
12.TOTAL COST OF PURCHASED POWER	17,188,100	621,490,000	2.76563
13.TOTAL AVAILABLE KWH		10,334,399,000	
14.Fuel Cost of Economy Sales (E6)	13,363,400	845,283,000	1.58094
15.Gain on Economy Sales - 80% (E6)	1,775,440	845,283,000 (a)	0.21004
16.Fuel Cost of Scedule D Sales (Jurisdictional)(E6)	785,800	48,139,000	1.63236
16a.Fuel Cost of Schedule D Sales - Separated (E6)	3,214,100	231,226,000	1.39003
16b Fuel Cost Schedule D HPP Sales - Contract (E6)	1,960,000	88,101,000	2.22472
16c. Fuel Cost Schedule J Sales Juris. (E6)	29,800	1,856,000	1.60560
17. Fuel Cost of Other Power Sales (FMPA, Lakeland)	2,571,900	171,284,000	1.50154
18.TOTAL FUEL COST AND GAINS OF POWER SALES	23,700,440	1,385,889,000	1.71013
19.Net Inadvertant Interchange	0	0	
19b.Interchange and Wheeling Losses	0	25,400,000	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	199,185,851	8,923,110,000	2.23225
21.Net Unbilled	3,963,137 (a)	177,540,000	0.04780
22.Company Use	409,841 (a)	18,360,000	0.00494
23.T & D Losses	9,751,562 (a)	436,849,000	0.11763
24.Adjusted System KWH Sales	199,185,851	8,290,361,000	2.40262
25.Wholesale KWH Sales	(1,884,920)	(77,897,000)	2.41976
26.JURISDICTIONAL KWH SALES	197,300,931	8,212,464,000	2.40246
27.Jurisdictional KWH Sales Adjusted for Line Loss - 1.00013	197,326,580	8,212,464,000	2.40277
28.True-up *	(1,590,623)	8,212,464,000	-0.01937
29.Peabody Coal Contract Buyout Amort.	2,693,543	8,212,464,000	0.03280
	0	8,212,464,000	0.00000
30.TOTAL JURISDICTIONAL FUEL COST	198,429,500	8,212,464,000	2.41620
31.Revenue Tax Factor			1.00083
32.Fuel Cost Adjusted for Taxes	198,594,197		2.41820
33.GPIF * (Already adjusted for taxes)	(298,369)	8,212,464,000	-0.00363
34.Total Fuel Cost including GPIF	198,295,828	8,212,464,000	2.41457
35.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			**2.415**

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

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FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: April - September 1997

GULF POWER COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	115,470,345	5,941,530,000	1.9434
2.Net Cost of Emission Allowances	0	0	0.0000
3.Adjustments to Fuel Cost	0	0	0.0000
4.TOTAL COST OF GENERATED POWER	115,470,345	5,941,530,000	1.9434
5.Fuel Cost of Purchased Power - Firm (E7)	0	0	0.0000
6.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	0	0	0.0000
7.Energy Cost of Economy Purchases (Non-Broker) (E9)	10,597,000	529,330,000	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 (E8)	25,241	1,210,000	2.0860
11.TOTAL COST OF PURCHASED POWER	10,622,241	530,540,000	2.0022
12.TOTAL AVAILABLE KWH (line 4 + line 11)		6,472,070,000	
13.Fuel Cost of Economy Sales (E6)	(585,000)	(21,810,000)	2.6823
14.Gain on Economy Sales - 80% (E6)	(60,800)	(26,670,000) (a)	0.2280
15.Fuel Cost of Unit Power Sales (E6)	(7,075,000)	(391,830,000)	1.8056
16.Fuel Cost of Other Power Sales	(9,944,000)	(618,844,000)	1.6069
17.TOTAL FUEL COST AND GAINS OF POWER SALES	(17,664,800)	(1,032,484,000)	1.7109
18.Net Inadvertant Interchange	0		
19.TOTAL FUEL AND NET POWER TRANSACTIONS	108,427,786	5,439,586,000	1.9933
20.Net Unbilled	0	0	0.0000
21.Company Use	211,031 (a)	10,587,000	1.9933
22.T & D Losses	7,090,407 (a)	355,712,000	1.9933
23.Adjusted System KWH Sales	108,427,786	5,073,287,000	2.1372
24.Wholesale KWH Sales	3,869,187	181,040,000	2.1372
25.JURISDICTIONAL KWH SALES	104,558,599	4,892,247,000	2.1372
26.Jurisdictional KWH Sales Adjusted for Line Loss - 1.00140	104,704,981	4,892,247,000	2.1402
27.True-up *	(1,193,695)	4,892,247,000	-0.0244
28.Total Jurisdictional Fuel Cost	103,511,286	4,892,247,000	2.1158
29.Revenue Tax Factor			1.01609
30.Fuel Cost Adjusted for Taxes			2.1498
31.Special Contract Recovery Cost	123,125	4,892,247,000	0.0025
32.GPIF *	82,198	4,892,247,000	0.0017
33.Total Fuel Cost including GPIF	103,593,484	4,892,247,000	2.1540
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.154

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

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**FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION**

ESTIMATED FOR THE PERIOD: April - September 1997

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 (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 (E7)	3,531,583	160,526,000	2.20001
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)	2,720,980	160,526,000 (a)	1.69504
10a.Demand Costs of Purchased Power	2,525,800 (a)		
10b.Non-Fuel Energy & Customer Costs of Purchased Power	195,180 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	0	0	0.00000
12.TOTAL COST OF PURCHASED POWER	6,252,563	160,526,000	3.89505
13.TOTAL AVAILABLE KWH	6,252,563	160,526,000	3.89505
14.Fuel Cost of Economy Sales (E6)	0	0	0.00000
15.Gain on Economy Sales - 80% (E6)	0	0	0.00000
16.Fuel Cost of Unit Power Sales (E6)	0	0	0.00000
17.Fuel Cost of Other Power Sales	0	0	0.00000
18.TOTAL FUEL COST AND GAINS OF POWER SALES	0	0	0.00000
19.Net Inadvertant Interchange	0	0	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	6,252,563	160,526,000	3.89505
21.Net Unbilled	116,852 (a)	3,000,000	0.07864
22.Company Use	4,207 (a)	108,000	0.00283
23.T & D Losses	343,894 (a)	8,829,000	0.23144
24.ADJUSTED SYSTEM KWH SALES	6,252,563	148,589,000	4.20796
25.Less Total Demand Cost Recovery	2,525,800		
26.JURISDICTIONAL KWH SALES	3,726,763	148,589,000	2.50810
27.Jurisdictional KWH Sales Adjusted for Line Loss - 1.00	3,726,763	148,589,000	2.50810
28.True-up *	(491,914)	148,589,000	-0.33106
29.TOTAL JURISDICTIONAL FUEL COST	3,234,849	148,589,000	2.17704
30.Revenue Tax Factor			1.00083
31.Fuel Cost Adjusted for Taxes	3,237,534	0	2.17885
32.GPIF *	0	148,589,000	0.00000
33.Total Fuel Cost including GPIF	3,234,849	148,589,000	2.17885
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.179

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

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FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: **April - September 1997**

FLORIDA PUBLIC UTILITIES-FERNANDINA BEACH

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 (E7)	3,415,568	185,126,000	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 (E2)	4,382,736	185,126,000	2.36743
10a.Demand Costs of Purchased Power	2,706,000 (a)		
10b.Non Fuel Energy and Customer Costs of Purchased Power (E2)	1,676,736 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	17,952	960,000	1.87000
12.TOTAL COST OF PURCHASED POWER	7,816,256	186,086,000	4.20035
13.TOTAL AVAILABLE KWH	7,816,256	186,086,000	4.20035
14.Fuel Cost of Economy Sales (E6)	0	0	0.00000
15.Gain on Economy Sales - 80% (E6)	0	0	0.00000
16.Fuel Cost of Unit Power Sales (E6)	0	0	0.00000
17.Fuel Cost of Other Power Sales (E6)	0	0	0.00000
18.TOTAL FUEL COST AND GAINS OF POWER SALES	0	0	0.00000
19.Net Inadvertant Interchange			
20.TOTAL FUEL AND NET POWER TRANSACTIONS	7,816,256	186,086,000	4.20035
21.Net Unbilled	130,673 (a)	3,111,000	0.07484
22.Company Use	0 (a)	0	0.00000
23.T & D Losses	351,737 (a)	8,374,000	0.20145
24.Adjusted System KWH Sales	7,816,256	174,601,000	4.47664
25.Wholesale KWH Sales	0	0	0.00000
26.JURISDICTIONAL KWH SALES	7,816,256	174,601,000	4.47664
27.Jurisdictional KWH Sales Adjusted for Line Loss - 1.00	7,816,256	174,601,000	4.47664
27a.GSLD KWH Sales		39,000,000	
27b.Other Classes KWH Sales		135,601,000	
27c.GSLD CP KW		126,000 (a)	
28. GPIF			
29.True-up *	(191,913)	174,601,000	-0.10992
30.TOTAL JURISDICTIONAL FUEL COST	7,624,343	174,601,000	4.36672

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**FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION**

ESTIMATED FOR THE PERIOD: April - September 1997

FLORIDA PUBLIC UTILITIES-FERNANDINA BEACH

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
30a.Demand Purchased Power Costs (line 10a)	2,706,000 (a)		
30b.Non-Demand Purchased Power Costs (lines 6+10b+1	5,110,256 (a)		
30c.True-up Over/Under Recovery (line 29)	(191,913)(a)		
APPORTIONMENT OF DEMAND COSTS			
31.Total Demand Costs	2,706,000		
32.GSLD Portion of Demand Costs Including line losses (line 27c * $6.18)	778,680	126,000 kw	$6.18 /kw
33.Balance to Other Classes	1,927,320	135,601,000	1.42132
APPORTIONMENT OF NON-DEMAND COSTS			
34.Total Non-Demand Costs (line 30b)	5,110,256		
35.Total KWH Purchased (line 12)		186,086,000	
36.Average Cost per KWH Purchased			2.74618
37.Avg. Cost Adjusted for Transmission line losses (line 36 * 1.03)			2.82857
38.GSLD Non-Demand Costs (line 27a * line 37)	1,103,115	39,000,000	2.82850
39.Balance to Other Customers	4,007,141	135,601,000	2.95510
GSLD PURCHASED POWER COST RECOVERY FACTORS			
40a.Total GSLD Demand Costs (Line 32)	778,680	126,000 kw	$6.18 /kw
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)	1,103,115	39,000,000	2.82850
40e.Total Non-Demand Costs including true-up	1,103,115	39,000,000	2.82850
40f.Revenue Tax Factor			1.01609
40g.GSLD Non-demand costs adjusted for taxes			2.874
OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a.Total Demand and Non-Demand Purchased Power Costs of other classes (lines 33 + 39)	5,934,461	135,601,000	4.37641
41b.Less: Total Demand Cost Recovery	1,927,320 (a)		
41c.Total Other Costs to be Recovered	4,007,141 (a)	135,601,000	2.95510
41d.Other Classes' Portion of True-up (line 30 C)	(191,913)	135,601,000	-0.14153
41e.Total Demand and Non-Demand Costs including True	3,815,228	135,601,000	2.81357
42.Revenue tax factor			1.01609
			2.85884
43.OTHER CLASSES PURCHASED POWER FACTOR ADJUSTED FOR TAXES ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.859

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

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