BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor.	DOCKET NO. 930001-EI ORDER NO. PSC-93-1331-FOF-EI ISSUED: 9/13/93

The following Commissioners participated in the disposition of this matter:

J. TERRY DEASON, Chairman
SUSAN F. CLARK
LUIS J. LAUREDO

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 the Commission's continuing fuel and energy cost recovery, oil backout cost recovery, conservation cost recovery and purchased gas cost recovery proceedings, hearings are held in February and August of each year in this docket and in two related dockets. Pursuant to notice, a hearing was held in this docket and in Docket Nos. 930002-EG and 930003-GU on August 18, 1993. 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

We find that the appropriate final fuel adjustment true-up amounts for the period October 1992 through March, 1993, are as follows:

FPC: $228,132 underrecovery.

FPL: $19,735,395 overrecovery.

FPUC:	$84,775 overrecovery. (Marianna)
	$49,454 underrecovery. (Fernandina Beach)
GULF:	$5,171,964 overrecovery.
TECO:	$6,953,869 underrecovery.

The estimated fuel adjustment true-up amounts for the period April, 1993, through September, 1993, are as follows:

FPC:	$10,056,545 underrecovery.
FPL:	$11,313,942 underrecovery.
FPUC:	$31,182 underrecovery. (Marianna)
	$161,327 overrecovery. (Fernandina Beach)
GULF:	$1,122,246 overrecovery.
TECO:	$1,341,110 underrecovery.

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

FPC:	$10,284,677 underrecovery.
FPL:	$8,421,453 overrecovery.
FPUC:	$53,593 overrecovery. (Marianna)
	$111,873 overrecovery. (Fernandina Beach)
GULF:	$6,294,210 overrecovery.
TECO:	$8,294,979 underrecovery.

Finally, the appropriate levelized fuel cost recovery factors for the period October, 1993, through March, 1994, are as follows:

FPC: 1.880 cents per Kwh - Standard rates*
2.176 cents per Kwh - TOU On-Peak rates*
1.757 cents per Kwh - TOU Off-Peak rates*
* Before line loss adjustment.

FPL: 1.811 cents/kwh is the levelized recovery charge for non-time differentiated rates and 1.940 cents/kwh and 1.760 cents/kwh are the levelized fuel recovery charges for the on-peak and off-peak periods, respectively, for the differentiated rates.

FPUC: 2.862¢/kwh (Marianna)
4.402¢/kwh (Fernandina Beach)

These factors are calculated to include true-up and revenue tax, exclude demand cost recovery, and have not been adjusted for line losses.

GULF: 1.965 cents per KWH.

TECO: 2.508 cents per KWH before application of the factors which adjust for variations in line losses.

The above factors should be effective beginning with the specified fuel cycle and thereafter for the period October, 1993, through March, 1994. Billing cycles may start before October 1, 1993, and the last cycle may be read after March 31, 1994, so that each customer is billed for six months regardless of when the adjustment factor became effective.

With respect to Florida Power Corporation, the effective date of the new charges will be the effective date of the base rate changes associated with FPC's recent rate case, Docket No. 910890-EI, instead of October 1, 1993. Florida Power Corporation's present charges will remain in effect until those base rate changes are implemented.

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.

The other fuel adjustment issues raised in this docket pertain to specific utilities and are discussed below.

Florida Power Corporation

Florida Power Corporation requested that it be allowed to recover the fuel costs associated with FPC's recently renegotiated contract with Tampa Electric Company through the Fuel Cost Recovery Clause. The parties agreed that FPC should be allowed to recover those costs. This contract is a revision to the Purchased Power Agreement which we approved in Order No. PSC-92-1468-FOF-EU. The order states that the fuel costs associated with the contract are appropriate for recovery through the fuel cost recovery clause. Energy charges for the revised contract are identical to the original contract. Similarly, we approve of FPC's request here.

Florida Power Corporation also requested that it be allowed to recover the fuel costs associated with FPC's UPS agreement with the Southern Company through the Fuel Cost Recovery Clause. The parties agreed that FPC should be allowed to recover those costs. The fuel costs associated with the UPS agreement are appropriate for recovery through the fuel cost recovery clause. FPC has projected that the Southern UPS purchase will save the company's ratepayers approximately $336 million. We agree, and accordingly, we approve recovery of FPC's fuel costs associated with FPC's UPS agreement with the Southern Company through the Fuel Cost Recovery Clause.

Florida Power Corporation requested that it be permitted to recover through the fuel adjustment clause $972,000 in payments to the Department of Energy (DOE) for costs of the decontamination and decommissioning of the DOE's uranium enrichment plants. FPC requested recovery of these costs at the February, 1993, hearings, and the issue was deferred until this proceeding. The parties agreed that FPL should be permitted to recover those costs. As a recipient of enrichment services from DOE's facilities, FPC's payments to DOE are required by the National Energy Policy Act of 1992 and are therefore recoverable as a necessary cost of doing business. The amount of $972,000 included in FPC's projections for the April - September 1993 period at the February 1993 hearings represents 3/4 of the payment to DOE required for 1993. The remainder of the 1993 payment and all future DOE payments should be approved for fuel cost recovery. We approve of FPC's recovery of $972,000 through the Fuel Cost Recovery Clause.

Florida Power Corporation also requested approval of a market pricing mechanism for water-borne transportation services provided by Electric Fuels Corporation (EFC). The parties agreed that the Commission should approve a base price of $23.00 effective January 1, 1993 for waterborne transportation services provided to Florida Power Corporation through Electric Fuels Corporation. We also agree. The base price will be adjusted January 1 each year, thereafter, using a composite index comprised of five specific indices with ten percent of the base price remaining fixed. In addition, the market price will be subject to further adjustment 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.

The market price for EFC's water-borne deliveries would cover the transportation components to the Crystal River plant site. This would include short-haul rail/truck transportation to the up-river dock, up-river barge transloading, river barge transportation, Gulf barge transloading (IMT), Gulf barge transportation (Dixie Fuels), as well as port fees and assist tug. The market price would also cover, i.e., replace, the return on EFC's equity investment in IMT and Dixie Fuels currently provided under cost-plus pricing for water transportation.

Florida Power and Light Company

Florida Power and Light Company requested recovery of the cost of the Martin gas pipeline lateral through the Fuel Cost Recovery Clause. According to the terms of Order No. 14546, the Commission has the flexibility to review fossil fuel related costs not specifically addressed in the order on a case-by-case basis to determine whether those costs are appropriate for recovery through the fuel clause.

The weight of the evidence is that the Martin gas pipeline lateral has reduced costs, or at the very minimum has not resulted in any increased costs, and the decision was made with the ratepayers' interest in mind, which is to minimize cost. In accordance with Order No. 14546, recognizing the unique facts and circumstances regarding FPL's decision to construct the lateral, to alleviate regulatory lag, and to encourage utilities to take actions to reduce fuel costs to customers, we find that it is appropriate in this case to recover the depreciation and return on investment in the Martin gas pipeline lateral through the fuel recovery clause until Florida Power and Light Company's next rate case. At that time, we can review whether these costs should be removed from the fuel cost recovery clause and treated as additions to utility plant-in-service recovered through base rates. It is understood that the investment in the lateral will not be included in the rate base calculation for surveillance report purposes.

Florida Power and Light Company also requested that it be permitted to recover through the fuel adjustment clause $2,580,000 in payments to the Department of Energy (DOE) for the cost of the decontamination and decommissioning of the DOE's uranium enrichment plants. FPL requested recovery of these costs at the February, 1993, hearings, and the issue was deferred until this proceeding. The parties agreed that FPL should be allowed to recover those costs. The company has indicated that it is doing everything it can to ensure the charges and method of calculation related to the decommissioning and decontamination costs are appropriate. Accordingly, we approve FPL's request to recover $2,580,000 in payments to the DOE for the cost of decontamination and decommissioning of the DOE's uranium enrichment plants through the Fuel Cost Recovery Clause.

Gulf Power Company

We find that Gulf Power Company may recover $366,237, which represents 25% of fuel savings benefits for the October, 1993 through March, 1994 period that occurred as a result of Gulf's special contract with Monsanto. Because of the special contract, Monsanto deferred its cogeneration project from the initial proposed in-service date of October 1989 until August of this year, when Monsanto actually began commercial operation of the project. The special contract expired in December, 1992, but the fuel savings benefits continued until the cogeneration project began operating.

Tampa Electric Company

One issue identified at the prehearing conference was the calculation of the appropriate 1992 benchmark price for coal transportation services provided by Tampa Electric Company's affiliates. TECO's calculated benchmark price of $24.86/ton differs from the benchmark price of $22.68/ton calculated by staff and agreed to by OPC. In spite of this difference, the parties stipulated that this is a moot issue because actual costs for transportation are below the benchmark prices calculated by TECO and staff. Accordingly, we approve the stipulation that the issue is moot.

Another issue was whether Tampa Electric Company adequately justified any costs associated with the purchase of transportation services from its affiliates in excess of the 1992 benchmark price. Since Tampa Electric Company's actual costs for transportation services provided by its affiliates are below the benchmark price, we find that no justification is required.

Generic Generating Performance Incentive Factor Issues

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 October, 1992, through March, 1993.

FPC: $1,219,167 reward.

FPL: $686,414 reward.

GULF: $372,865 reward.

TECO: $130,923 reward.

The parties also agreed to the targets and ranges for the period October, 1993, through March, 1994, which are shown on Attachment "B" to this order. We approve those targets and ranges.

Company-Specific GPIF Issues

Florida Power Corporation

We will permit Florida Power Corporation to adjust the actual heat rates for Crystal River Units #1 and #2, which were affected by EPA-mandated flow reduction during the winter 1992-93 period.

We also approve the adjustments due to outages caused by the winter storm of March 11, 1993.

Florida Power and Light Company

We will approve Florida Power and Light Company's adjustments due to outages caused by Hurricane Andrew, which continued into the winter period.

Also, we approve the addition of Putnam Units #1 and #2 to the GPIF for Florida Power and Light Company.

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 October, 1992, through March, 1993, to be $272,190 underrecovery for FPL and $1,478,238 overrecovery for TECO. The estimated oil backout true-up amount for the period April, 1993, through September, 1993, to be $271,053 underrecovery for FPL and $85,825 overrecovery for TECO.

The total oil backout true-up amount to be collected or refunded during the period October, 1993, through March, 1994, is $543,243 underrecovery for FPL and $4,605 underrecovery for TECO.

Finally, we find the proper projected oil backout cost recovery factor for the period October, 1993 through March, 1994 is .016 cents/kwh for FPL and .100 cents/kwh for TECO.

Capacity Cost Recovery Factor

The final capacity cost recovery true-up amount for the October, 1992 through March, 1993 period was $1,446,627 underrecovery for FPC, $5,704,243 underrecovery for FPL, $710,213 overrecovery for Gulf, and $209,062 underrecovery for TECO. We approve those amounts.

The estimated capacity cost recovery true-up amount for the period April, 1993, through September, 1993, is $1,526,096 overrecovery for FPC, $6,471,505 underrecovery for FPL, $79,938 overrecovery for Gulf, and underrecovery of $654,008 for TECO. We approve those estimates.

We approve the following total capacity cost recovery true-up amounts to be collected/refunded during the period October, 1993, through March, 1994: $79,469 overrecovery for FPC; $12,175,749 underrecovery for FPL; $790,151 overrecovery for Gulf; and $863,070 underrecovery for TECO.

We approve the following amounts of projected net purchased power capacity costs to be included in the recovery factors for the period October, 1993, through March, 1994: $47,780,468 for FPC; $177,728,223 for FPL; $2,627,443 for Gulf; and $9,970,336 for TECO.

Finally, the appropriate capacity cost recovery factors to be applied for the period October, 1993 through March, 1994 are as follows:

FPC: See Attachment "C".

FPL:

RATE CLASS	CAPACITY RECOVERY FACTOR ($/KW)	CAPACITY RECOVERY FACTOR ($/KWH)
RS1	-	0.00595
GS1	-	0.00518
GSD1	1.85	-
OS2	-	0.00424
GSLD1/CS1	1.89	-
GSLD2/CS2	2.06	-
GSLD3/CS3	2.02	-
ISST1D	0.59	-
SST1T	0.39	-
SST1D	0.68	-
CILCD/CILCG	1.80	-
CILCT	1.74	-
MET	1.96	-
OL1/SL1	-	0.00235
SL2	-	0.00354

GULF:

RATE CLASS	CAPACITY COST RECOVERY FACTORS ¢/KWH
RS, RST	0.087
GS, GST	0.086
GSD, GSDT	0.066
LP, LPT	0.058
PX, PXT	0.048
OSI, OSII	0.009
OSIII	0.052
OSIV	0.006
SS	0.047

TECO: The appropriate factors are as follows:

Rate Schedules	Factor
RS	.213 cents per KWH
GS, TS	.176 cents per KWH
GSD	.146 cents per KWH
GSLD, SBF	.130 cents per KWH
IS-1 & 3, SBI-1 & 3	.012 cents per KWH
SL, OL	.012 cents per KWH

The other capacity cost recovery issues raised in this docket pertain to specific utilities and are discussed below.

Company Specific Capacity Cost Recovery Issues

Florida Power Corporation

Florida Power Corporation requested recovery of the capacity costs associated with FPC's recently renegotiated contract with Tampa Electric Company through the Capacity Cost Recovery Clause. The parties agreed with FPC's request for recovery of the capacity costs associated with FPC's renegotiated contract with TECO through the Capacity Cost Recovery Clause. This contract is a revision to the Purchased Power Agreement between TECO and the Sebring Utilities Commission that was assumed by FPC as part of its Sebring acquisition which was approved by the Commission in Order No. PSC-92-1468-FOF-EU. The revised contract is for 50 MWs of capacity and will provide additional annual savings in excess of $1 million above the savings provided under the original contract. Order No. PSC-92-1468-FOF-EU states that the capacity costs associated with the contract are appropriate for recovery through the capacity cost recovery clause. Accordingly, we agree with FPC's request to recover the capacity costs associated with FPC's recently renegotiated contract with TECO through the Capacity Cost Recovery Clause.

FPC also requested to recover the capacity costs associated with FPC's UPS agreement with the Southern Company through the Capacity Cost Recovery Clause, and the parties agreed. We find that the capacity costs associated with the UPS agreement are appropriate for recovery through the capacity cost recovery clause.

FPC has projected that the Southern UPS purchase will save the company's ratepayers approximately $336 million.

Florida Power and Light Company

The company specific capacity cost issue for Florida Power and Light Company was whether FPL should be allowed to recover capacity costs through a factor applied to billed kw demand for customer classes having metered demand. Currently, purchased power capacity costs are allocated to the customer classes on a demand basis and recovered from all customers on an energy basis. We find that FPL's proposal to recover capacity costs on demand basis from its demand class customers is reasonable. The capacity costs of purchased power are analogous to the costs of building capacity. Presumably, if the utility had not purchased the capacity then additional plant would be needed to serve the utility's load. Therefore, the capacity costs incurred to purchase power shall be recovered in a manner consistent with the way production plant is recovered in base rates.

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 October, 1993 through March, 1994, and until such factors are modified by subsequent Order. Florida Power Corporation is authorized to apply its fuel cost recovery factors on the same date as any rate adjustment ordered in Docket No. 910890-EI. 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 stated in the body of this Order shall be applied to the projected levelized fuel adjustment factors for the period of October, 1993 through March, 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 October, 1993 through March, 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 October, 1993 through March, 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 13TH day of SEPTEMBER, 1993.

Steve Tribble

STEVE TRIBBLE, Director
Division of Records and Reporting

(S E A L)
DLC/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 this order, which is preliminary, procedural or intermediate in nature, may request: 1) reconsideration within 10 days pursuant to Rule 25-22.038(2), Florida Administrative Code, if issued by a Prehearing Officer; 2) reconsideration within 15 days pursuant to Rule 25-22.060, Florida Administrative Code, if issued by the Commission; or 3) 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 wastewater utility. A motion for reconsideration shall be filed with the Director, Division of Records and Reporting, in the form prescribed by Rule 25-22.060, Florida Administrative Code. Judicial review of a preliminary, procedural or intermediate ruling or order is available if review of the final action will not provide an adequate remedy. Such review may be requested from the appropriate court, as described above, pursuant to Rule 9.100, Florida Rules of Appellate Procedure.

ATTACHMENT A
ORDER NO. PSC-93-1331-FOF-EI
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TOTAL FUEL COST FOR THE PERIOD: October 1993 - March 1994

DATE: 8/18/93
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Note: FPC factors will become effective concurrent with the November 1, 1993 base rate change resulting from Docket No. 910890-EI

COMPANY	PROPOSED October 1993 - March 1994 Levelized	On/Peak	Off/Peak	PRESENT April - September 1993 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)	1.811	1.940	1.760	2.259	2.431	2.172	-0.448	-0.491	-0.412	1.00161	1.814
Fla. Power Corp.	1.880	2.176	1.757	2.171	2.780	1.854	-0.291	-0.604	-0.097	1.00380	1.887
Tampa Electric	2.508	2.946	2.346	2.508	3.275	2.146	0.000	-0.329	0.200	1.00640	2.524
Gulf Power	1.965	2.012	1.949	2.216	2.390	2.135	-0.251	-0.378	-0.186	1.01228	1.989
Fla. Public											
Marianna (1)	4.887	NA	NA	5.290	NA	NA	-0.403	NA	NA	1.01260	4.948
Fernandina (1)(2)	5.733	NA	NA	5.753	NA	NA	-0.020	NA	NA	1.00000	5.733

COST FOR 1,000 KWH RESIDENTIAL SERVICE

PRESENT: April 1993 - September 1993

	Fla. Power & Light	Fla. Power Corp. (5) (6)	Tampa Electric	Gulf Power (7)	Florida Public Utilities Marianna	Florida Public Utilities Fernandina
Base	47.38	47.93	49.80	43.25	17.22	19.20
Fuel (3)	22.62	21.77	24.51	22.43	53.57	57.53
Oil Backout	0.13	NA	0.65	NA	NA	NA
Energy Conservation	2.05	4.59	1.28	0.15	0.11	0.05
Capacity Recovery	4.42	2.89	2.17	0.48	NA	NA
Gross Receipts Tax (4)	0.79	1.98	2.01	0.68	0.73	0.79
Total	$77.39	$79.16	$80.42	$66.99	$71.63	$77.57

PROPOSED: October 1993 - March 1994

	Fla. Power & Light	Fla. Power Corp.	Tampa Electric	Gulf Power	Florida Public Utilities Marianna	Florida Public Utilities Fernandina
Base	47.38	49.05	49.80	43.25	17.22	19.20
Fuel (3)	18.14	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	N/A	N/A	N/A	N/A	N/A	N/A
Capacity Recovery	5.95	4.75	2.13	0.87	NA	NA
Gross Receipts Tax (4)	0.76	2.01	2.02	0.66	0.69	0.79
Total	$74.69	$80.58	$80.91	$65.00	$67.52	$77.37

DIFFERENCE	Fla. Power & Light	Fla. Power Corp.	Tampa Electric	Gulf Power	Florida Public Utilities Marianna	Florida Public Utilities Fernandina
Base	0.00	1.12	0.00	0.00	0.00	0.00
Fuel (3)	-4.48	-2.90	0.00	-2.54	-4.09	-0.20
Oil Backout	0.03	NA	0.35	NA	NA	NA
Energy Conservation	0.25	1.31	0.17	0.18	0.02	0.00
Capacity Recovery	1.53	1.86	-0.04	0.39	NA	NA
Gross Receipts Tax (4)	-0.03	0.03	0.01	-0.02	-0.04	0.00
Total	-2.70	1.42	0.49	-1.99	-4.11	-0.20

(1) Fuel costs include purchased power demand costs of 2.024 for Marianna and 1.331 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. FPC and TECO have removed all g.r.t. from rates. The entire 2.5% g.r.t. is thus shown seperately for these companies effective Feb. 3, 1993 for TECO and April, 1993 for FPC. (5) FPC present base rates reflect increase effective April 1, 1993 resulting from rate case, Docket No. 910890-EI. Proposed base rates reflect increase effective November 1, 1993. (6) TECO fuel rates include refund factor of 0.73 cents/kWh attributable to stipulation of Gatliff Coal issue in the February 1993 fuel adjustment hearing.

TOTAL FUEL COST FOR THE PERIOD: October 1993 – March 1994

DATE: 8/18/93
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Note: FPC factors will become effective concurrent with the November 1, 1993 base rate change resulting from Docket No. 910890–EI.

COMPANY	PROPOSED October 1993 – March 1994 Levelized	On/Peak	Off/Peak	PRESENT April – September 1993 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)	1.811	1.940	1.760	2.259	2.431	2.172	-0.448	-0.491	-0.412	1.00161	1.814
Fla. Power Corp.	1.880	2.176	1.757	2.171	2.780	1.854	-0.291	-0.604	-0.097	1.00380	1.887
Tampa Electric	2.508	2.946	2.346	2.508	3.275	2.146	0.000	-0.329	0.200	1.00640	2.524
Gulf Power	1.965	2.012	1.949	2.216	2.390	2.135	-0.251	-0.378	-0.186	1.01228	1.989
Fla. Public											
Marianna (1)	4.887	NA	NA	5.290	NA	NA	-0.403	NA	NA	1.01260	4.948
Fernandina (1)(2)	5.733	NA	NA	5.753	NA	NA	-0.020	NA	NA	1.00000	5.733

COST FOR 1,000 KWH RESIDENTIAL SERVICE

PRESENT: April 1993 – September 1993

	Fla. Power & Light	Fla. Power Corp. (5) (6)	Tampa Electric	Gulf Power (7)	Florida Public Utilities Marianna	Fernandina
Base	47.38	47.93	49.80	43.25	17.22	19.20
Fuel (3)	22.62	21.77	24.51	22.43	53.57	57.53
Oil Backout	0.13	NA	0.65	NA	NA	NA
Energy Conservation	2.05	4.59	1.28	0.15	0.11	0.05
Capacity Recovery	4.42	2.89	2.17	0.48	NA	NA
Gross Receipts Tax (4)	0.79	1.98	2.01	0.68	0.73	0.79
Total	$77.39	$79.16	$80.42	$66.99	$71.63	$77.57

PROPOSED: October 1993 – March 1994

	Fla. Power & Light	Fla. Power Corp.	Tampa Electric	Gulf Power	Florida Public Utilities Marianna	Fernandina
Base	47.38	49.05	49.80	43.25	17.22	19.20
Fuel (3)	18.14	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	N/A	N/A	N/A	N/A	N/A	N/A
Capacity Recovery	5.95	4.75	2.13	0.87	NA	NA
Gross Receipts Tax (4)	0.76	2.01	2.02	0.66	0.69	0.79
Total	$74.69	$80.58	$80.91	$65.00	$67.52	$77.37

DIFFERENCE

	Fla. Power & Light	Fla. Power Corp.	Tampa Electric	Gulf Power	Florida Public Utilities Marianna	Fernandina
Base	0.00	1.12	0.00	0.00	0.00	0.00
Fuel (3)	-4.48	-2.90	0.00	-2.54	-4.09	-0.20
Oil Backout	0.03	NA	0.35	NA	NA	NA
Energy Conservation	0.25	1.31	0.17	0.18	0.02	0.00
Capacity Recovery	1.53	1.86	-0.04	0.39	NA	NA
Gross Receipts Tax (4)	-0.03	0.03	0.01	-0.02	-0.04	0.00
Total	-2.70	1.42	0.49	-1.99	-4.11	-0.20

(1) Fuel costs include purchased power demand costs of 2.024 for Marianna and 1.331 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. FPC and TECO have removed all g.r.t. from rates. The entire 2.5% g.r.t. is thus shown seperately for these companies effective Feb. 3, 1993 for TECO and April, 1993 for FPC. (5) FPC present base rates reflect increase effective April 1, 1993 resulting from rate case, Docket No. 910890 – EI. Proposed base rates reflect increase effective November 1, 1993. (6) TECO fuel rates include refund factor of 0.73 cents/kWh attributable to stipulation of Gatliff Coal issue in the February 1993 fuel adjustment hearing.

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

DIVISION OF ELECTRIC AND GAS
DATE: 8/18/93

FOR THE PERIOD: OCTOBER – MARCH 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	1.811	1.940	1.760	1.00161	1.814	1.943	1.763
	A-1	SL-1,OL-1	1.789	NA	NA	1.00161	1.792	NA	NA
	B	GSD-1,GSDT-1	1.811	1.940	1.760	1.00155	1.814	1.943	1.763
	C	GSLD-1,GSLDT-1,CS-1,CST-1	1.811	1.940	1.760	1.00046	1.812	1.940	1.761
	D	GSLD-2,GSLDT-2,CS-2,CST-2,OS-2,MET	1.811	1.940	1.760	0.99449	1.801	1.929	1.750
	E	GSLD-3,CS-3,GSLDT-3,CST-3,CILC-1(T),ISST-1(T)	1.811	1.940	1.760	0.96430	1.747	1.870	1.697
	F	CILC-1(D),ISST-1(D)		1.940	1.760	0.99643		1.933	1.754
FPC *	A	Distribution Secondary Delivery	1.880	2.176	1.757	1.00380	1.887	2.184	1.764
	A-1	OL-1,SL-1	1.835	NA	NA	1.00380	1.842	NA	NA
	B	Distribution Primary Delivery	1.880	2.176	1.757	0.98260	1.847	2.138	1.726
	C	Transmission Delivery	1.880	2.176	1.757	0.97250	1.828	2.116	1.709
TECO	A	RS,GS,TS	2.508	2.946	2.346	1.00640	2.524	2.965	2.361
	A-1	SL-1,2,3,OL-1,2	2.327	NA	NA	1.00640	2.342	NA	NA
	B	GSD,GSLD	2.508	2.946	2.346	1.00120	2.511	2.950	2.349
	C	IS-1,IS-3	2.508	2.946	2.346	0.97210	2.438	2.864	2.281
GULF	A	RS,GS,GSD,OS-III,OS-IV	1.965	2.012	1.949	1.01228	1.989	2.037	1.973
	B	LP	1.965	2.012	1.949	0.98106	1.928	1.974	1.912
	C	PX	1.965	2.012	1.949	0.96230	1.89[illegible]	1.936	1.876
	D	OS-1,OS-2	1.962	NA	NA	1.01228	1.986	NA	NA
FPUC									
Fernandina	A	RS	5.733	NA	NA	1.00000	5.733	NA	NA
	B	GS	5.489	NA	NA	1.00000	5.489	NA	NA
	C	GSD	5.315	NA	NA	1.00000	5.315	NA	NA
	D	OL, OL-2, SL-2, SL-3, CSL	4.779	NA	NA	1.00000	4.779	NA	NA
	E	GSLD					4.799 (1)		
							$4.69/CP KW		
Marianna	A	RS	4.886	NA	NA	1.01260	4.948	NA	NA
	B	GS	4.630	NA	NA	0.99630	4.612	NA	NA
	C	GSD	4.205	NA	NA	0.99630	4.189	NA	NA
	D	OL, OL-2	2.862	NA	NA	1.01260	2.898	NA	NA
	E	SL-1, SL-2	2.862	NA	NA	0.98810	2.828	NA	NA

* Effective date for FPC will coincide with rate change resulting from rate case, Docket No. 910890-EI. Effective date is expected to be early November, 1993.

(1) Informational Purposes Only–GSLD class is billed actual fuel cost

PROPOSED CAPACITY COST RECOVERY FACTORS
For the Period: OCTOBER - MARCH 1994

DIVISION OF ELECTRIC AND GAS
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COMPANY	RATE SCHEDULE	RECOVERY FACTOR (CENTS PER KWH)
FPL	RS1	0.595
	GS1	0.518
	OL1/SL1	0.235
	SL2	0.354
	OS2	0.424
		RECOVERY FACTOR (DOLLARS PER KWH)
	GSD1	1.850
	GSLD1/CS1	1.890
	GSLD2/CS2	2.060
	GSLD3/CS3	2.020
	ISST1D	0.590
	SST1T	0.390
	SST1D	0.680
	CILCD,CILCG	1.800
	CILCT	1.740
	MET	1.960
FPC *	RS	0.475
	GS-Transmission	0.000
	GS-Primary	0.324
	GS-Secondary	0.333
	GS - 100% Load Factor	0.250
	GSD-Transmission	0.228
	GSD-Primary	0.286
	GSD-Secondary	0.294
	CS - Curtailable	0.225
	IS-Transmission	0.236
	IS-Primary	0.239
	LS - Lighting Service	0.094
TECO	RS	0.213
	GS,TS	0.176
	GSD	0.146
	GSLD,SBF	0.130
	IS-1 & 3,SBI-1 & 3	0.012
	SL/OL	0.012
GULF	RS,RST	0.087
	GS,GST	0.086
	GSD,GSDT	0.066
	LP,LPT	0.058
	PX,PXT	0.048
	OS-I,OS-II	0.009
	OS-III	0.052
	OS-IV	0.006
	SS	0.047

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

DIVISION OF ELECTRIC AND GAS
DATE: 8/18/93
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ESTIMATED FOR THE PERIOD: October 1993 – March 1994

FLORIDA POWER & LIGHT COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated Cents/KWH
1.Fuel Cost of System Net Generation (E3)	428,331,606	25,048,676,000	1.71000
2.Spent NUC Fuel Disposal Cost (E2)	9,198,412	10,016,782,000 (a)	0.09183
3.Fuel Related Transactions	(4,833,548)	0	0.00000
4. Natural Gas Pipeline Enhancements	0	0	0.00000
4a. Fuel Cost of Sales to FKEC	(8,454,740)	(368,148,000)	2.29656
5.TOTAL COST OF GENERATED POWER	424,241,730	24,680,528,000	1.71893
6.Fuel Cost of Purchased Power – Firm (E8)	138,435,500	7,599,700,000	1.82159
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	24,657,800	1,254,100,000	1.96617
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	12,626,500	677,900,000	1.86259
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)	26,881,700	1,444,300,000	1.86123
12.TOTAL COST OF PURCHASED POWER	202,601,500	10,976,000,000	1.84586
13.TOTAL AVAILABLE KWH		35,656,528,000	
14.Fuel Cost of Economy Sales (E7)	(8,849,300)	(312,300,000)	2.83359
15.Gain on Economy Sales – 80% (E7A)	(3,043,520)	(312,300,000)(a)	0.97455
16.Fuel Cost of Unit Power Sales (SL2 Partpts) (E7)	(2,039,800)	(250,600,000)	0.81397
17.Fuel Cost of Other Power Sales (E7)	(1,026,200)	(36,700,000)	2.79619
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(14,958,820)	(599,600,000)	2.49480
19.Net Inadvertant Interchange (E4)	0	0	0.00000
20.TOTAL FUEL AND NET POWER TRANSACTIONS	611,884,410	35,056,928,000	1.74540
21.Net Unbilled (E4)	26,188,923 (a)	1,500,452,000	0.07725
22.Company Use (E4)	1,854,926 (a)	(106,275,000)	0.00547
23.T & D Losses (E4)	44,518,317 (a)	(2,550,605,000)	0.13132
24.Adjusted System KWH Sales	611,884,410	33,900,500,000	1.80494
25.Wholesale KWH Sales	1,315,005	72,970,000	1.80212
26.JURISDICTIONAL KWH SALES	610,569,405	33,827,530,000	1.80495
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00035	610,783,104	33,827,530,000	1.80558
28.True–up * (derived in Attachment C)	(8,421,453)	33,827,530,000	–0.02490
29.TOTAL JURISDICTIONAL FUEL COST	602,361,651	33,827,530,000	1.78070
30.Revenue Tax Factor			1.01609
31.Fuel Cost Adjusted for Taxes			1.80935
32.GPIF*	686,414	33,827,530,000	0.00203
33.Total fuel cost including GPIF	603,048,065	33,827,530,000	1.81138
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			1.811

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

FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 8/18/93
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ESTIMATED FOR THE PERIOD: October 1993 – March 1994

FLORIDA POWER CORPORATION

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	175,308,006	11,198,967,000	1.56539
2.Spent NUC Fuel Disposal Cost (E3A)	2,882,259	3,082,630,000 (a)	0.09350
3.Coal Car Investment	0	0	0.00000
4.Adjustments to Fuel Cost	239,700	0	0.00000
5.TOTAL COST OF GENERATED POWER	178,429,965	11,198,967,000	1.59327
6.Energy Cost of Purchased Power – Firm (E8)	3,364,687	156,964,000	2.14360
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	10,598,000	410,000,000	2.58488
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	392,610	18,000,000	2.18117
9.Energy Cost of Sch.E Purchases (E9)	11,819,990	534,315,000	2.21218
10.Capacity Cost of Sch.E Economy Purchases (E9)	0	0 (a)	0.00000
11.Payments to Qualifying Facilities (E8A)	41,227,590	1,844,941,000	2.23463
12.TOTAL COST OF PURCHASED POWER	67,402,877	2,964,220,000	2.27388
13.TOTAL AVAILABLE KWH		14,163,187,000	
14.Fuel Cost of Economy Sales (E7)	(6,789,500)	(400,000,000)	1.69738
14a.Gain on Economy Sales –80% (E7A)	(800,000)	(400,000,000)(a)	0.20000
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)	(4,651,600)	(290,638,000)	1.60048
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(12,241,100)	(690,638,000)	1.77243
19.Net Inadvertant Interchange (E4)	0	0	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	233,591,742	13,472,549,000	1.73383
21.Net Unbilled (E4)	(6,399,161)(a)	369,083,000	–0.04900
22.Company Use (E4)	1,638,441 (a)	(94,500,000)	0.01255
23.T & D Losses (E4)	11,930,885 (a)	(688,135,000)	0.09136
24.Adjusted System KWH Sales	233,591,742	13,058,997,000	1.78874
25.Wholesale KWH Sales(Excluding Seminole Supplemental)	(8,593,442)	(481,277,000)	1.78555
26.JURISDICTIONAL KWH SALES	224,998,300	12,577,720,000	1.78886
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.0014	225,313,298	12,577,720,000	1.79137
28.Prior Period True–Up *	10,284,677	12,577,720,000	0.07768
28a. Market Price Refund for 1992	(514,584)	0	0.00000
29.TOTAL JURISDICTIONAL FUEL COST	235,083,391	12,577,720,000	1.86910
30.Revenue Tax Factor			1.00083
31.Fuel Cost Adjusted for Taxes			1.87070
32.GPIF*	1,219,167	12,577,720,000	0.00970
33.Total fuel cost including GPIF	236,302,558	12,577,720,000	1.88040
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			1.880

*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: October 1993 – March 1994

TAMPA ELECTRIC COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	168,457,246	7,604,115,000	2.21534
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	168,457,246	7,604,115,000	2.21534
6.Fuel Cost of Purchased Power – Firm (E8)	2,190,100	39,176,000	5.59041
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	1,240,600	34,418,000	3.60451
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)	3,838,100	198,843,000	1.93022
12.TOTAL COST OF PURCHASED POWER	7,268,800	272,437,000	2.66807
13.TOTAL AVAILABLE KWH		7,876,552,000	
14.Fuel Cost of Economy Sales (E7)	10,946,900	686,959,000	1.59353
15.Gain on Economy Sales – 80% (E7A)	1,637,040	686,959,000 (a)	0.23830
16.Fuel Cost of Scedule D Sales (E7)	3,744,000	229,070,000	1.63443
16a.Fuel Cost of Schedule G Sales (E7)	0	0	0.00000
17.Fuel Cost Schedule J Sales (E7)	1,855,400	81,877,000	2.26608
17a.Fuel Cost Schedule D TPS Sales (E7)	1,601,300	76,356,000	2.09715
18.TOTAL FUEL COST AND GAINS OF POWER SALES	19,784,640	1,074,262,000	1.84170
19.Net Inadvertant Interchange (E4)	0	0	
19b.Interchange and Wheeling Losses	0	20,901,000	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	155,941,406	6,781,389,000	2.29955
21.Net Unbilled (E4)	(3,296,037)(a)	(143,334,000)	–0.05019
22.Company Use (E4)	358,730 (a)	15,600,000	0.00546
23.T & D Losses (E4)	7,866,117 (a)	342,072,000	0.11978
24.Adjusted System KWH Sales	155,941,406	6,567,051,000	2.37460
25.Wholesale KWH Sales	(2,097,507)	(88,178,000)	2.37872
26.JURISDICTIONAL KWH SALES	153,843,899	6,478,873,000	2.37455
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00005	153,920,821	6,478,873,000	2.37573
28.True–up * (derived in Attachment C)	8,294,979	6,478,873,000	0.12803
29.Pyramid Coal Contract Buyout Adjustment	0	6,478,873,000	0.00000
30.TOTAL JURISDICTIONAL FUEL COST	162,215,800	6,478,873,000	2.50377
31.Revenue Tax Factor			1.00083
32.Fuel Cost Adjusted for Taxes	162,350,439		2.50584
33.GPIF * (Already adjusted for taxes)	130,923	6,478,873,000	0.00202
34.Total Fuel Cost including GPIF	162,481,362	6,478,873,000	2.50786
35.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.508

*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: 8/18/93

ESTIMATED FOR THE PERIOD: October 1993 – March 1994

GULF POWER COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	89,286,559	4,687,000,000	1.9050
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	89,286,559	4,687,000,000	1.9050
5.Fuel Cost of Purchased Power – Firm (E8)	0	0	0.0000
6.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	5,557,000	311,510,000	1.7839
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	5,557,000	311,510,000	1.7839
12.TOTAL AVAILABLE KWH (line 4 + line 11)		4,998,510,000	
13.Fuel Cost of Economy Sales (E7)	(488,000)	(28,100,000)	1.7367
14.Gain on Economy Sales – 80% (E7A)	(68,000)	0 (a)	0.0000
15.Fuel Cost of Unit Power Sales (E7)	(7,567,000)	(423,760,000)	1.7857
16.Fuel Cost of Other Power Sales (E7)	(8,427,000)	(552,172,000)	1.5262
17.TOTAL FUEL COST AND GAINS OF POWER SALES	(16,550,000)	(1,004,032,000)	1.6484
18.Net Inadvertant Interchange (E4)	0		
19.TOTAL FUEL AND NET POWER TRANSACTIONS	78,293,559	3,994,478,000	1.9600
20.Net Unbilled (E4)	0	0	0.0000
21.Company Use (E4)	188,611 (a)	9,623,000	1.9600
22.T & D Losses (E4)	4,317,488 (a)	220,280,000	1.9600
23.Adjusted System KWH Sales	78,293,559	3,764,575,000	2.0797
24.Wholesale KWH Sales	2,878,638	138,416,000	2.0797
25.JURISDICTIONAL KWH SALES	75,414,921	3,626,159,000	2.0797
26.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00140	75,520,502	3,626,159,000	2.0827
27.True–up *	(6,294,210)	3,626,159,000	–0.1736
28.Total Jurisdictional Fuel Cost	69,226,292	3,626,159,000	1.9091
29.Revenue Tax Factor			1.01609
30.Fuel Cost Adjusted for Taxes			1.9398
31.Special Contract Recovery Cost	548,167	3,626,159,000	0.0151
32.GPIF *	372,865	3,626,159,000	0.0103
33.Total Fuel Cost including GPIF	69,599,157	3,626,159,000	1.9652
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			1.965

*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: 8/18/93
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ESTIMATED FOR THE PERIOD: October 1993 – March 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)	2,313,491	117,019,000	1.97702
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)	2,668,563	117,019,000 (a)	2.28045
10a.Demand Costs of Purchased Power	1,859,000 (a)		
10b.Non–Fuel Energy & Customer Costs of Purchased Power	809,563 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	0	0	0.00000
12.TOTAL COST OF PURCHASED POWER	4,982,054	117,019,000	4.25747
13.TOTAL AVAILABLE KWH	4,982,054	117,019,000	4.25747
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	4,982,054	117,019,000	4.25747
21.Net Unbilled (E4)	57,220 (a)	1,344,000	0.05159
22.Company Use (E4)	3,832 (a)	90,000	0.00346
23.T & D Losses (E4)	199,292 (a)	4,681,000	0.17970
24.ADJUSTED SYSTEM KWH SALES	4,982,054	110,904,000	4.49222
25.Less Total Demand Cost Recovery	1,804,241		
26.JURISDICTIONAL KWH SALES	3,177,813	110,904,000	2.86537
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00	3,177,813	110,904,000	2.86537
28.True–up *	(53,593)	110,904,000	–0.04832
29.TOTAL JURISDICTIONAL FUEL COST	3,124,220	110,904,000	2.81705
30.Revenue Tax Factor			1.01609
31.Fuel Cost Adjusted for Taxes	3,499,562	0	2.86238
32.GPIF *	0	110,904,000	0.00000
33.Total Fuel Cost including GPIF	3,124,220	110,904,000	2.86238
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.862

*Based on Jurisdictional Sales

(a) included for informational purposes only.

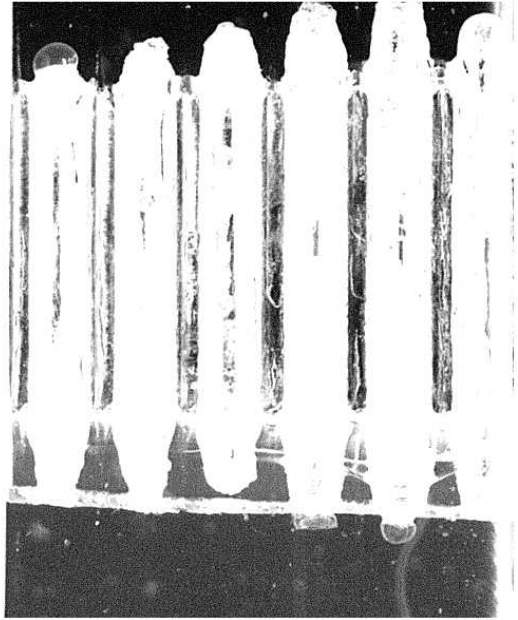
FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 8/18/93
PAGE 9 OF 10

ESTIMATED FOR THE PERIOD: October 1993 – March 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)	5,629,410	146,029,000	3.85499
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	2,202,386	146,029,000	1.50818
10a.Demand Costs of Purchased Power (E2)	2,018,500 (a)		
10b.Non Fuel Energy and Customer Costs of Purchased Power (E2)	183,886 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	93,840	2,400,000	3.91000
12.TOTAL COST OF PURCHASED POWER	7,925,636	148,429,000	5.33968
13.TOTAL AVAILABLE KWH	7,925,636	148,429,000	5.33968
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	7,925,636	148,429,000	5.33968
21.Net Unbilled (E4)	(140,861)(a)	(2,638,000)	–0.09920
22.Company Use (E4)	8,650 (a)	162,000	0.00609
23.T & D Losses (E4)	475,499 (a)	8,905,000	0.33486
24.Adjusted System KWH Sales	7,925,636	142,000,000	5.58143
25.Wholesale KWH Sales	0	0	0.00000
26.JURISDICTIONAL KWH SALES	7,925,636	142,000,000	5.58143
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00	7,925,636	142,000,000	5.58143
27a.GSLD KWH Sales (E11)		43,200,000	
27b.Other Classes KWH Sales (E11)		98,800,000	
27c.GSLD CP KW		112,200 (a)	
28. GPIF			
29.True–up *	(111,873)	142,000,000	–0.07878
30.TOTAL JURISDICTIONAL FUEL COST	7,813,763	142,000,000	5.50265



FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE 8/18/93
PAGE 10 OF 10

ESTIMATED FOR THE PERIOD October 1993 – March 1994

FLORIDA PUBLIC UTILITIES – FERNANDINA

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
30a Demand Purchased Power Costs (line 10a)	2,018,500 (a)		
30b Non – Demand Purchased Power Costs (lines 6+10b+11)	5,907,136 (a)		
30c True – up Over/Under Recovery (line 29)	(111,873)(a)		
APPORTIONMENT OF DEMAND COSTS			
31 Total Demand Costs	2,018,500		
32 GSLD Portion of Demand Costs Including line losses (line 27c * $5.665)	635,613	112,200 KW	$5.67
33 Balance to Other Customers	1,382,887	98,800,000	1.39968
APPORTIONMENT OF NON – DEMAND COSTS			
34 Total Non – Demand Costs (line 30b)	5,907,136		
35 Total KWH Purchased (line 12)		148,429,000	
36 Average Cost per KWH Purchased			3.97977
37 Avg. Cost Adjusted for Transmission line losses (line 36 * 1.03)			4.09917
38 GSLD Non – Demand Costs (line 27a * line 37)	1,770,841	43,200,000	0.04099
39 Balance to Other Customers	4,136,295	98,800,000	4.18653
GSLD PURCHASED POWER COST RECOVERY FACTORS			
40a Total GSLD Demand Costs (Line 32)	635,613	112,200	$5.67
40b Revenue Tax Factor			1.01609
40c GSLD Demand Purchased Power factor adjusted for taxes and rounded			$5.76
40d Total Current GSLD Non – Demand Costs (line 38)	1,770,841	43,200,000	4.09917
40e Total Non – Demand Costs including true – up	1,770,841	43,200,000	4.09917
40f Revenue Tax Factor			1.01609
40g GSLD Non – demand costs adjusted for taxes			4.162
OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a Total Demand and Non – Demand Purchased Power Costs of other classes (lines 33 + 39)	5,519,182	98,800,000	5.58622
41b Less Total Demand Cost Recovery	1,126,907 (a)		
41c Total Other Costs to be Recovered	4,392,275 (a)	98,800,000	4.44562
41d Other Classes' Portion of True – up (line 30 C)	(111,873)	98,800,000	–0.11323
41e Total Demand and Non – Demand Costs including True – up	4,280,402	98,800,000	4.33239
42 Revenue tax factor			1.01609
			4.40210
43 OTHER CLASSES PURCHASED POWER FACTOR ADJUSTED FOR TAXES ROUNDED TO THE NEAREST .001 CENTS PER KWH			4.402

*Based on Jurisdictional Sales

(a) included for informational purposes only

ATTACHMENT B
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GPIF REWARDS/PENALTIES
October 1992 to March 1993

Florida Power Corporation	$1,219,167	Reward
Florida Power and Light Company	$686,414	Reward
Gulf Power Company	$372,865	Reward
Tampa Electric Company	$130,923	Reward

Utility/ Plant/Unit	EAF		Heat Rate	
FPC	Target	Adj Actual	Target	Adj Actual
Anclote 1	95.4	97.9	10,111	10,157
Anclote 2	82.7	86.7	9,971	9,734
Crystal River 1	72.3	73.3	9,938	10,011
Crystal River 2	69.6	62.0	9,964	9,983
Crystal River 3	80.0	97.1	10,534	10,400
Crystal River 4	93.6	95.3	9,255	9,230
Crystal River 5	61.5	57.7	9,321	9,249
FPL	Target	Adj Actual	Target	Adj Actual
Cape Canaveral 1	48.0	49.0	9,676	9,324
Cape Canaveral 2	93.5	94.4	8,996	8,991
Fort Myers 1	79.7	81.1	10,050	10,010
Fort Myers 2	97.0	94.0	9,456	9,315
Manatee 1	82.3	93.4	9,597	9,444
Manatee 2	76.4	79.7	9,464	9,426
Martin 2	96.1	93.1	9,946	10,270
Port Everglades 2	73.3	75.9	9,622	9,697
Port Everglades 3	93.1	98.2	9,329	9,443
Port Everglades 4	93.9	93.4	9,293	9,213
Riviera 3	65.8	69.1	9,500	9,445
St. Lucie 1	88.3	96.1	10,718	10,822
St. Lucie 2	93.6	47.1	10,702	10,821
Turkey Point 2	86.0	84.7	9,303	9,295
Turkey Point 3	79.1	77.6	10,943	10,782
Turkey Point 4	69.2	81.2	10,965	10,995
Gulf	Target	Adj Actual	Target	Adj Actual
Crist 6	81.1	79.4	10,372	10,110
Crist 7	69.2	77.7	10,040	10,040
Smith 1	87.8	86.7	10,329	10,025
Smith 2	62.7	62.3	10,325	9,958
Daniel 1	76.6	64.2	10,272	10,310
Daniel 2	77.7	76.7	10,247	9,734
TECO	Target	Adj Actual	Target	Adj Actual
Big Bend 1	79.9	71.5	9,862	9,927
Big Bend 2	81.0	85.6	9,819	9,811
Big Bend 3	69.6	61.1	9,522	[illegible]
Big Bend 4	84.3	90.5	9,939	9,908
Gannon 5	83.0	88.4	10,259	10,254
Gannon 6	56.6	63.0	10,252	[illegible]

GPIF TARGETS
October 1993 to March 1994

Utility/ Plant/Unit	Equivalent Availability				Heat Rate	
	Company			Staff	Company	Staff
FPC	EAF	POF	EUOF			
Anclote 1	86.7	11.0	2.3	Agree	10,247	Agree
Anclote 2	82.1	15.4	2.6	Agree	9,955	Agree
Crystal River 1	73.1	14.8	12.0	Agree	10,024	Agree
Crystal River 2	50.8	38.5	10.8	Agree	9,998	Agree
Crystal River 3	88.7	0.0	11.3	Agree	10,334	Agree
Crystal River 4	95.3	0.0	4.7	Agree	9,264	Agree
Crystal River 5	80.7	15.4	4.0	Agree	9,293	Agree
FPL	EAF	POF	EUOF			
Cape Canaveral 1	48.2	48.9	2.9	Agree	9,426	Agree
Cape Canaveral 2	94.0	0.0	6.0	Agree	9,040	Agree
Fort Myers 2	91.4	0.0	8.6	Agree	9,381	Agree
Manatee 2	94.7	0.0	5.2	Agree	9,664	Agree
Port Everglades 3	94.2	0.0	5.8	Agree	9,317	Agree
Port Everglades 4	83.5	11.5	5.0	Agree	9,171	Agree
Putnam 1	88.6	3.6	7.8	Agree	9,208	Agree
Putnam 2	95.0	0.0	5.0	Agree	8,976	Agree
Riviera 3	75.2	18.7	6.1	Agree	9,975	Agree
Riviera 4	90.4	0.0	9.6	Agree	9,839	Agree
Sanford 4	95.3	0.0	4.7	Agree	10,086	Agree
Sanford 5	93.0	0.0	7.0	Agree	9,461	Agree
Scherer 4	96.0	0.0	4.0	Agree	8,904	Agree
St. Johns River 1	81.8	14.8	3.4	Agree	9,386	Agree
St. Johns River 2	80.0	16.5	3.5	Agree	9,228	Agree
St. Lucie 1	93.1	0.0	6.9	Agree	10,742	Agree
St. Lucie 2	60.9	24.7	14.4	Agree	11,152	Agree
Turkey Point 1	88.5	0.0	11.5	Agree	9,363	Agree
Turkey Point 2	80.0	7.7	12.3	Agree	9,129	Agree
Turkey Point 3	83.6	6.5	9.8	Agree	10,882	Agree
Turkey Point 4	93.5	0.0	6.5	Agree	10,932	Agree
Gulf	EAF	POF	EUOF			
Crist 6	68.8	23.6	7.6	Agree	10,164	Agree
Crist 7	69.0	13.7	17.3	Agree	9,945	Agree
Smith 1	64.4	31.3	4.3	Agree	10,107	Agree
Smith 2	82.6	13.7	3.7	Agree	10,109	Agree
Daniel 1	76.4	18.7	4.9	Agree	10,527	Agree
Daniel 2	74.1	24.2	1.7	Agree	10,134	Agree
TECO	EAF	POF	EUOF			
Big Bend 1	82.0	3.8	14.2	Agree	9,834	Agree
Big Bend 2	57.2	34.6	8.2	Agree	9,821	Agree
Big Bend 3	80.0	7.1	12.9	Agree	9,536	Agree
Big Bend 4	64.7	26.9	8.4	Agree	9,927	Agree
Gannon 5	80.2	7.1	12.7	Agree	10,416	Agree
Gannon 6	[illegible]	[illegible]	15.2	Agree	10,129	Agree

ATTACHMENT C
ORDER NO. PSC-93-1331-FOF-EI
DOCKET NO. 930001-EI
PAGE 28

Florida Power Corporation
Docket 930001-EI
Witness: K. H. Wieland
Exhibit [illegible]
Part D
Sheet 5 of 5

CALCULATION OF CAPACITY COST RECOVERY FACTOR

For the Period of October 1993 through March 1994

RATE CLASS	(1) AVERAGE 12 CP DEMAND MW	(2) AVERAGE 12 CP DEMAND %	(3) ANNUAL AVERAGE DEMAND MW	(4) ANNUAL AVERAGE DEMAND %	(5) 12/13 of 12 CP 12/13 * (2)	(6) 1/13 of Ann Demand 1/13 * (4)	(7) Demand Allocation (5) + (6)	(8) Dollar Allocation (7) * [illegible]	(9) MWH Sales @ Meter Level (Oct 93 - Mar 94)	(10) Capacity Cost Recovery Factor (c/KWh)
I. Residential Service	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
II. General Service Non-Demand		[illegible]		[illegible]				[illegible]	[illegible]	
Transmission	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Primary	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Secondary	[illegible]	[illegible]	[illegible]	[illegible]			[illegible]			
Total										
III. GS - 100% L.F.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
IV. General Service Demand	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Transmission	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Primary	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Secondary	[illegible]	[illegible]	[illegible]	[illegible]			[illegible]			
Total										
V. Curtailable Service	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
VI. Interruptible Service	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Transmission	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Primary	[illegible]	[illegible]	[illegible]	[illegible]			[illegible]			
Total										
VII. Lighting Service	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL RETAIL	[illegible]	100.000%	[illegible]	100.000%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]