BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor	DOCKET NO. 940001-EI ORDER NO. PSC-94-1092-FOF-EI ISSUED: 9-6-94

The following Commissioners participated in the disposition of this matter:

J. TERRY DEASON, Chairman
SUSAN F. CLARK

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

BY THE COMMISSION:

As part of this Commission's continuing fuel cost recovery, oil backout cost recovery, capacity cost recovery, conservation cost recovery, and purchased gas cost recovery proceedings, hearings are held semi-annually. Pursuant to notice, a hearing was held in this docket and in Docket No. 940042-EI on August 11, 1994. The utilities submitted testimony and exhibits in support of their proposed fuel adjustment true-up amounts, fuel cost recovery factors, generating performance incentive factors, oil backout true-up amounts, capacity cost recovery factors and related issues.

Fuel Adjustment Factors

In accordance with the agreement of the parties, we find that the appropriate final fuel adjustment true-up amounts for the amounts for the period October, 1993 through March, 1994 are as follows:

FPC:	\$5,074,211 underrecovery
FPL:	\$2,066,794 overrecovery
FPUC:	\$ 10,735 overrecovery (Marianna)
	\$ 215,029 overrecovery (Fernandina Beach)
GULF:	\$ 810,768 underrecovery
TECO:	\$5,779,224 overrecovery

The estimated fuel adjustment true-up amounts for the period April, 1994 through September, 1994 are as follows:

FPC:	$26,512,241	underrecovery
FPL:	$32,451,868	overrecovery
FPUC:	$ 38,323	underrecovery (Marianna)
	$ 74,042	overrecovery (Fernandina Beach)
GULF:	$ 1,969,504	underrecovery
TECO:	$ 4,827,083	underrecovery

The total fuel adjustment true-up amounts to be collected during the period October, 1994 through March, 1995 are as follows:

FPC:	$31,586,452	underrecovery
FPL:	$34,518,662	overrecovery
FPUC:	$ 27,588	underrecovery (Marianna)
	$ 289,071	overrecovery (Fernandina Beach)
GULF:	$ 2,780,272	underrecovery
TECO:	$ 952,141	overrecovery

The appropriate levelized fuel cost recovery factors for the period October, 1994 through March, 1995 are as follows, in cents/kWh:

FPC:	2.051
FPL:	1.567
FPUC:	Marianna: 3.009
	Fernandina Beach: 3.646
GULF:	2.179
TECO:	2.353

For billing purposes, the new fuel adjustment charge, oil backout charge and capacity cost recovery charge factors shall be effective beginning with the specified fuel cycle and thereafter for the period October, 1994 through March, 1995. Billing cycles may start before October 1, 1994, and the last cycle may be read after March 31, 1995, so that each customer is billed for six months regardless of when the adjustment factor became effective.

Each utility proposed fuel recovery loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class. Those multipliers are shown in Attachment 2 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 2. We find that the proposed factors are appropriate and should be approved. We further find that the appropriate revenue tax factor to be applied in calculating each company's levelized fuel factor for the projection period of October, 1994 through March, 1995, is as follows:

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

COMPANY SPECIFIC FUEL ADJUSTMENT ISSUES

Florida Power and Light Company

At the hearing the parties agreed to defer the following issue to the next fuel adjustment proceeding:

> Is FPL's proposed new methodology for allocating fuel costs to the various customer classes appropriate?

Florida Power Corporation

Florida Power Corporation requested permission to recover the costs associated with the accelerated purchase of locomotives. The parties agreed that the company had demonstrated that the accelerated purchase of locomotives will increase the savings to its ratepayers from $10.9 million to $14.5. We therefore allow FPC to recover the costs associated with the accelerated purchases.

FPC also raised the issue of whether it is appropriate to differentiate fuel charges by metering voltage. The parties agreed that it is. Differentiating fuel charges in this manner will ensure consistency with the treatment of base rate charges, the ECCR and the CCR. We approve.

Tampa Electric Company

The parties agreed that Tampa Electric Company has prudently administered its contract with Consol Coal Company, and we therefore approve recovery of the costs associated with that contract.

Gulf Power Company

The parties stipulated that Gulf should recover all prudently incurred costs associated with the Peabody contract suspension, including the suspension payment and the costs of purchasing replacement coal. Gulf has estimated the contract suspension will result in net fuel savings for Gulf's customers of approximately $14,479,865. We approve the recovering of prudently incurred costs associated with the suspension of the Peabody Contract.

Generic Generating Performance Incentive Factor Issues

There was no controversy among the parties at this hearing as to the appropriate GPIF reward or penalty for past performance. The parties agreed to, and we approve, the following GPIF rewards or penalties for the period October, 1993 through March, 1994?

FPC:	$1,009,345	reward
FPL:	$3,107,919	reward
GULF:	$84,941	(penalty)
TECO:	$406,404	reward

The parties also agreed to targets and ranges for the period April, 1994 through September, 1994, which are shown on Attachment 1 to this order. We approve those targets and ranges.

Generic Oil Backout Issues

In accordance with the agreement of the parties, we find the proper final oil backout true-up amount for the period October, 1993 through March, 1994 period to be:

FPL:	$257,863	overrecovery
TECO:	$ 81,177	underrecovery

The estimated oil backout true-up amount for the period April, 1994 through September, 1994 is:

FPL:	$250,389	overrecovery
TECO:	$ 49,634	overrecovery

The total oil backout true-up amount to be collected during the period October, 1994 through March, 1995 is:

FPL:	$508,252 overrecovery
TECO:	$ 31,543 underrecovery

The projected oil backout cost recovery factor for the period October, 1994 through March, 1995 is:

FPL:	.011 cents per KWH
TECO:	.096 cents per KWH

Generic Capacity Cost Recovery Issues

The parties agree that the following the final capacity cost recovery true-up amounts are appropriate for the period October, 1993 through March, 1994, which we approve:

FPC:	$ 69,905 underrecovery
FPL:	$8,570,760 overrecovery
GULF:	$1,135,019 underrecovery
TECO:	$ 861,751 overrecovery

We approve the following estimated capacity cost recovery true-up amount for the period April, 1994 through September, 1994:

FPC:	$4,622,826 overrecovery
FPL:	$8,210,602 overrecovery
GULF:	$ 56,118 over-recovery
TECO:	$ 742,821 overrecovery

We also approve the following total capacity cost recovery true-up amounts to be collected during the period October, 1994 through March, 1995:

FPC:	$ 4,552,921 overrecovery
FPL:	$16,781,361 overrecovery
GULF:	$ 1,078,901 underrecovery
TECO:	$ 1,604,572 overrecovery

We approve the following appropriate projected net purchased power capacity cost amount to be included in the recovery factor for the period October, 1994 through March, 1995:

FPC:	$ 82,945,428
FPL:	$152,074,783
GULF:	$ 6,956,372
TECO:	$ 9,181,060

Finally, we approve the projected capacity cost recovery factors for the period October, 1994 through March, 1995, as they are shown on Attachment 2 to this order.

Company-Specific Capacity Cost Recovery Issues

Florida Power and Light Company

The parties have stipulated that it was appropriate for FPL to change the amount of annual capacity credit associated with the St. Johns River Power Park from $63,975,761 to $56,945,592. The adjustment appropriately reflects all purchased power capacity revenues and costs that were included in base rates as a result of FPL's 1988 tax savings docket.

The parties also agreed that FPL should recover capacity costs from standby customers through the combination of a reservation charge/daily demand charge component. These charges should be calculated in a manner consistent with the methodology outlined in Order No. 17159.

We approve these agreements for Florida Power and Light Company.

Tampa Electric Company

The following issue is deferred to the next fuel adjustment proceeding:

> Other than economy sales and revenues from the seven entities that were separated out in TECO's last rate case, should Tampa Electric credit all nonfuel revenues from off-system sales back to the retail ratepayers through the fuel adjustment clause and the capacity cost recovery clause?

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, 1994 through March, 1995, and until such factors are modified by subsequent Order. It is further

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

ORDERED that the Generating Performance Incentive Factor rewards and penalty stated in the body of this Order shall be applied to the projected levelized fuel adjustment factors for the period of October, 1994 through March, 1995. 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, 1994 through March, 1995. 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, 1994 through March, 1995 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 6th day of September, 1994.

BLANCA S. BAYÓ, Director
Division of Records and Reporting

by: Kay Flynn
Chief, Bureau of Records

(S E A L)

MCB

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

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

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

GPIF REWARDS/PENALTIES
October 1993 to March 1994

Florida Power Corporation	$1,009,345	Reward
Florida Power and Light Company	$3,107,919	Reward
Gulf Power Company	$84,941	Penalty
Tampa Electric Company	$406,404	Reward

Utility/ Plant/Unit	EAF		Heat Rate	
FPC	Target	Adj. Actual	Target	Adj. Actual
Anclote 1	86.7	88.1	10,247	9,998
Anclote 2	82.1	83.8	9,955	9,874
Crystal River 1	73.1	81.3	10,024	9,971
Crystal River 2	50.8	47.3	9,998	9,761
Crystal River 3	88.7	99.0	10,334	10,414
Crystal River 4	95.3	91.8	9,264	9,378
Crystal River 5	80.7	79.9	9,293	9,207
FPL	Target	Adj. Actual	Target	Adj. Actual
Cape Canaveral 1	48.2	46.0	9,426	9,365
Cape Canaveral 2	94.0	89.1	9,040	9,344
Fort Myers 2	91.4	91.5	9,381	9,368
Manatee 2	94.7	99.4	9,664	9,747
Port Everglades 3	94.2	95.7	9,317	9,594
Port Everglades 4	83.5	85.6	9,171	9,173
Putnam 1	88.6	93.5	9,208	8,698
Putnam 2	95.0	94.9	8,975	8,476
Riviera 3	75.2	76.1	9,975	9,869
Riviera 4	90.4	90.5	9,840	9,890
Sanford 4	95.3	95.7	10,086	9,734
Sanford 5	93.0	96.8	9,461	9,496
Scherer 4	96.0	97.6	8,904	9,416
St. Johns River 1	81.8	82.3	9,385	9,336
St. Johns River 2	80.0	80.8	9,228	9,404
St. Lucie 1	93.1	95.8	10,741	10,894
St. Lucie 2	60.9	73.2	11,152	11,580
Turkey Point 1	88.5	93.6	9,363	8,917
Turkey Point 2	80.0	88.0	9,129	9,163
Turkey Point 3	83.6	87.7	10,881	10,887
Turkey Point 4	93.5	93.4	10,932	10,858
Gulf	Target	Adj. Actual	Target	Adj. Actual
Crist 6	68.8	73.8	10,164	10,042
Crist 7	69.0	61.7	9,945	10,026
Smith 1	64.4	68.1	10,107	10,226
Smith 2	82.6	85.9	10,109	10,302
Daniel 1	76.4	78.0	10,527	10,013
Daniel 2	74.1	74.7	10,134	10,035
TECO	Target	Adj. Actual	Target	Adj. Actual
Big Bend 1	82.0	82.2	9,834	9,990
Big Bend 2	57.2	60.6	9,821	9,966
Big Bend 3	80.0	86.8	9,536	9,589
Big Bend 4	64.7	68.5	9,927	9,974
Gannon 5	80.2	87.3	10,416	10,384
Gannon 6	77.1	81.9	10,129	10,324

GPIF TARGETS
October 1994 to March 1995

Utility/ Plant/Unit	Equivalent Availability – Company EAF	Company POF	Company EUOF	Staff	Heat Rate – Company	Heat Rate – Staff
FPC	**EAF**	**POF**	**EUOF**			
Anclote 1	90.8	7.7	1.5	Agree	9,905	Agree
Anclote 2	96.7	0.0	3.3	Agree	9,805	Agree
Crystal River 1	73.9	15.4	10.7	Agree	10,177	Agree
Crystal River 2	70.4	15.4	14.2	Agree	9,975	Agree
Crystal River 3	92.8	0.0	7.2	Agree	10,400	Agree
Crystal River 4	94.2	0.0	5.8	Agree	9,289	Agree
Crystal River 5	72.8	23.1	4.1	Agree	9,247	Agree
FPL	**EAF**	**POF**	**EUOF**			
Cape Canaveral 1	92.4	0.0	7.6	Agree	9,291	Agree
Cape Canaveral 2	89.9	0.0	10.1	Agree	9,338	Agree
Fort Louderdale 4	92.6	1.7	5.7	Agree	7,225	Agree
Fort Louderdale 5	92.7	0.0	7.3	Agree	7,198	Agree
Fort Myers 2	93.3	0.0	6.7	Agree	9,294	Agree
Manatee 2	95.7	0.0	4.3	Agree	9,758	Agree
Port Everglades 3	94.5	0.0	5.5	Agree	9,307	Agree
Putnam 1	94.2	0.0	5.8	Agree	8,670	Agree
Riviera 3	90.9	0.0	9.1	Agree	9,713	Agree
Riviera 4	82.8	9.3	7.9	Agree	9,672	Agree
Sanford 4	94.6	0.0	5.4	Agree	9,755	Agree
Sanford 5	94.1	0.0	5.9	Agree	9,692	Agree
Scherer 4	84.3	12.1	3.6	Agree	9,933	Agree
St. Johns River 1	76.8	19.2	4.0	Agree	9,336	Agree
St. Johns River 2	95.1	0.0	4.9	Agree	9,375	Agree
St. Lucie 1	60.6	35.2	4.2	Agree	10,854	Agree
St. Lucie 2	91.6	0.0	8.4	Agree	10,763	Agree
Turkey Point 3	93.6	0.0	6.4	Agree	10,865	Agree
Turkey Point 4	60.6	35.2	4.2	Agree	11,002	Agree
Gulf	**EAF**	**POF**	**EUOF**			
Crist 6	83.6	8.8	7.6	Agree	10,410	Agree
Crist 7	69.2	8.8	22.0	Agree	10,317	Agree
Smith 1	87.7	8.8	3.5	Agree	10,137	Agree
Smith 2	84.8	12.6	2.5	Agree	10,237	Agree
Daniel 1	85.4	0.0	14.6	Agree	10,287	Agree
Daniel 2	94.8	0.0	5.2	Agree	9,923	Agree
TECO	**EAF**	**POF**	**EUOF**			
Big Bend 1	85.4	0.0	14.6	Agree	9,957	Agree
Big Bend 2	62.3	30.8	6.9	Agree	9,895	Agree
Big Bend 3	69.4	19.2	11.4	Agree	9,610	Agree
Big Bend 4	89.4	0.0	10.6	Agree	9,832	Agree
Gannon 5	88.1	0.0	11.9	Agree	10,454	Agree
Gannon 6	75.9	9.3	14.8	Agree	10,288	Agree

TOTAL FUEL COST FOR THE PERIOD: October 1994 – March 1995

DATE: 08/04/94

COMPANY	PROPOSED July 1994 – September 1994 October 1994 – March 1995 Levelized	On/Peak	Off/Peak	PRESENT April 1994 – September 1994 July 19! 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)	1.567	1.673	1.525	1.488	1.633	1.415	0.079	0.040	0.110	1.00210	1.570
Fla. Power Corp.	2.055	2.612	1.827	1.968	2.692	1.587	0.087	−0.080	0.240	1.00000	2.055
Tampa Electric	2.353	3.791	2.444	2.894	2.946	2.346	−0.541	0.845	0.098	1.00640	2.368
Gulf Power	2.179	2.226	2.164	2.158	2.253	2.113	0.021	−0.027	0.051	1.01228	2.206
Fla. Public											
Marianna (1)	4.874	NA	NA	4.658	NA	NA	−0.216	NA	NA	1.01260	4.936
Fernandina (1)(2)	5.098	NA	NA	5.308	NA	NA	−0.210	NA	NA	1.00000	5.098

COST FOR 1,000 KWH RESIDENTIAL SERVICE

PRESENT: July 1994 – September 1994

	Fla. Power & Light	Fla. Power Corp.	Tampa Electric (5)	Gulf Power (6)	Florida Public Utilities Marianna (7)	Florida Public Utilities Fernandina
Base	47.38	49.05	51.92	43.25	20.43	19.20
Fuel (3)	14.90	19.75	24.89	21.85	47.17	53.08
Oil Backout	0.12	N/A	0.73	N/A	N/A	N/A
Energy Conservation	2.43	4.40	1.85	0.26	0.12	0.06
Environmental Cost Recovery	0.12	N/A	N/A	1.48	N/A	N/A
Capacity Recovery	5.64	5.11	2.05	0.31	NA	NA
Gross Receipts Tax (4)	0.72	2.01	2.09	0.69	1.74	0.74
Total	$71.31	$80.32	$83.53	$67.84	$69.46	$73.08

PROPOSED: October 1994 – March 1995

	Fla. Power & Light	Fla. Power Corp.	Tampa Electric	Gulf Power	Florida Public Utilities Marianna	Florida Public Utilities Fernandina
Base	47.38	49.05	51.92	43.25	20.43	19.20
Fuel (3)	15.70	20.55	23.68	22.06	49.36	50.98
Oil Backout	0.11	N/A	0.96	N/A	N/A	N/A
Energy Conservation	2.43	4.40	1.85	0.26	0.12	0.06
Environmental Cost Recovery	0.10	N/A	N/A	1.54	N/A	N/A
Capacity Recovery	5.17	7.47	1.93	2.24	N/A	N/A
Gross Receipts Tax (4)	0.73	2.09	2.06	0.71	1.79	0.72
Total	$71.62	$83.56	$82.40	$70.06	$71.70	$70.96

DIFFERENCE

	Fla. Power & Light	Fla. Power Corp.	Tampa Electric	Gulf Power	Florida Public Utilities Marianna	Florida Public Utilities Fernandina
Base	0.00	0.00	0.00	0.00	0.00	0.00
Fuel (3)	0.80	0.80	−1.21	0.21	2.19	−2.10
Oil Backout	−0.01	N/A	0.23	N/A	N/A	N/A
Energy Conservation	0.00	0.00	0.00	0.00	0.00	0.00
Environmental Cost Recovery	−0.02	N/A	N/A	0.06	N/A	N/A
Capacity Recovery	−0.47	2.36	−0.12	1.93	N/A	N/A
Gross Receipts Tax (4)	0.01	0.08	−0.03	0.02	0.05	−0.02
Total	0.31	3.24	−1.13	2.22	2.24	−2.12

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

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

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FOR THE PERIOD: October 1994 – March 1995

COMPANY	GROUP	RATE SCHEDULES	WITHOUT LINE LOSS MULTIPLIER Levelized	WITHOUT LINE LOSS MULTIPLIER * On/Peak	WITHOUT LINE LOSS MULTIPLIER Off/Peak	LINE LOSS MULTIPLIER	WITH LINE LOSS MULTIPLIER Levelized	WITH LINE LOSS MULTIPLIER On/Peak	WITH LINE LOSS MULTIPLIER Off/Peak
FP&L	A	RS-1,RST-1,GST-1,GS-1,SL-2, CILC-G,	1.567	1.673	1.525	1.00210	1.570	1.677	1.529
	A-1	SL-1,OL-1	1.549	NA	NA	1.00210	1.552	NA	NA
	B	GSD-1,GSDT-1	1.567	1.673	1.525	1.00204	1.570	1.677	1.528
	C	GSLD-1,GSLDT-1, CS-1, CST-1	1.567	1.673	1.525	1.00089	1.568	1.675	1.527
	D	GSLD-2,GSLDT-2, CS-2, CST-2	1.567	1.673	1.525	0.99443	1.558	1.664	1.517
	E	GSLD-3,GSLDT-3,CS-3,CST-3	1.567	1.673	1.525	0.96091	1.506	1.608	1.466
	F	CILC-1(D),ISST-1(D)	NA	1.673	1.525	0.99758	NA	1.669	1.522
FPC *	A	Distribution Secondary Delivery	2.055	2.612	1.827	1.00000	2.055	2.612	1.827
	A-1	OL-1,SL-1	1.974	NA	NA	1.00000	1.974	NA	NA
	B	Distribution Primary Delivery	2.055	2.612	1.827	0.99000	2.034	2.585	1.808
	C	Transmission Delivery	2.055	2.612	1.827	0.98000	2.014	2.560	1.790
TECO	A	RS,GS,TS	2.353	2.666	2.239	1.00640	2.368	2.683	2.253
	A-1	SL-1,2,3,OL-1,2	2.302	NA	NA	1.00640	2.317	NA	NA
	B	GSD,GSLD	2.353	2.666	2.239	1.00120	2.356	2.669	2.242
	C	IS-1,IS-3	2.353	2.666	2.239	0.97210	2.287	2.592	2.177
GULF	A	RS,GS,GSD,OS-III,OS-IV	2.179	2.226	2.164	1.01228	2.206	2.253	2.191
	B	LP	2.179	2.226	2.164	0.98106	2.138	2.184	2.123
	C	PX	2.179	2.226	2.164	0.96230	2.097	2.142	2.082
	D	OS-1,OS-2	2.178	NA	NA	1.01228	2.205	NA	NA
FPUC									
Fernandina	A	RS	5.098	NA	NA	1.00000	5.098	NA	NA
	B	GS	4.832	NA	NA	1.00000	4.832	NA	NA
	C	GSD	4.643	NA	NA	1.00000	4.643	NA	NA
	D	OL, OL-2, SL-2, SL-3, CSL	4.058	NA	NA	1.00000	4.058	NA	NA
	E	GSLD					4.799 (1)		
							$6.28/CP KW		
Marianna	A	RS	4.874	NA	NA	1.01260	4.936	NA	NA
	B	GS	4.721	NA	NA	0.99630	4.704	NA	NA
	C	GSD	4.346	NA	NA	0.99630	4.330	NA	NA
	D	GLSD	4.185	NA	NA	0.99630	4.170	NA	NA
	E	OL, OL-2	3.009	NA	NA	1.01260	3.047	NA	NA
	F	SL-1, SL-2	3.009	NA	NA	0.98810	2.973	NA	NA

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PROPOSED CAPACITY COST RECOVERY FACTORS
For the Period: , October 1994 – March 1995

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COMPANY	RATE SCHEDULE	RECOVERY FACTOR (CENTS PER KWH)
FPL	RS1	0.517
	GS1	0.458
	OL1/SL1	0.135
	SL2	0.325
	OS2	0.286
		RECOVERY FACTOR (DOLLARS PER KW)
	GSD1	1.690
	GSLD1/CS1	1.760
	GSLD2/CS2	1.780
	GSLD3/CS3	1.760
	ISST1D	RDC .23, SDD .11
	SST1T	RDC .22, SDD .10
	SST1D	RDC .23, SDD .11
	CILCD,CILCG	1.680
	CILCT	1.600
	MET	1.830
		RECOVERY FACTOR (CENTS PER KWH)
FPC *	RS	0.747
	GS–Transmission	0.581
	GS–Primary	0.587
	GS–Secondary	0.593
	GS – 100% Load Factor	0.409
	GSD–Transmission	0.487
	GSD–Primary	0.491
	GSD–Secondary	0.495
	CS – Primary	0.413
	CS – Secondary	0.417
	IS–Transmission	0.409
	IS–Primary	0.413
	IS–Secondary	0.417
	LS – Lighting Service	0.149
TECO	RS	0.193
	GS,TS	0.178
	GSD	0.134
	GSLD,SBF	0.122
	IS–1 & 3,SBI–1 & 3	0.011
	SL/OL	0.011
GULF	RS,RST	0.224
	GS,GST	0.219
	GSD,GSDT	0.170
	LP,LPT	0.147
	PX,PXT	0.119
	OS–1,OS–II	0.014
	OS–III	0.132
	OS–IV	0.015
	SS	0.363

ATTACHMENT 2

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
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ESTIMATED FOR THE PERIOD: October 1994 – March 1995

FLORIDA POWER & LIGHT COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated Cents/KWH
1.Fuel Cost of System Net Generation (E3)	417,030,531	28,184,276,000	1.47966
2.Spent NUC Fuel Disposal Cost (E2)	8,958,421	9,755,442,000 (a)	0.09183
3.Fuel Related Transactions	7,069,705	0	0.00000
4. Natural Gas Pipeline Enhancements	0	0	0.00000
4a. Fuel Cost of Sales to FKEC	(7,342,607)	(379,284,000)	1.93591
5.TOTAL COST OF GENERATED POWER	425,716,050	27,804,992,000	1.53108
6.Fuel Cost of Purchased Power – Firm (E8)	79,340,740	4,757,009,000	1.66787
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	7,130,110	381,899,000	1.86701
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	443,200	19,909,000	2.22613
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)	42,767,956	2,415,279,000	1.77073
12.TOTAL COST OF PURCHASED POWER	129,682,006	7,574,096,000	1.71218
13.TOTAL AVAILABLE KWH		35,379,088,000	
14.Fuel Cost of Economy Sales (E7)	(6,804,040)	(279,287,000)	2.43622
15.Gain on Economy Sales – 80% (E7A)	(1,734,687)	(279,287,000)(a)	0.62111
16.Fuel Cost of Unit Power Sales (SL2 Partpts) (E7)	(717,521)	(168,528,000)	0.42576
17.Fuel Cost of Other Power Sales (E7)	0	0	0.00000
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(9,256,248)	(447,815,000)	2.06698
19.Net Inadvertant Interchange (E4)	0	0	0.00000
20.TOTAL FUEL AND NET POWER TRANSACTIONS	546,141,808	34,931,273,000	1.56348
21.Net Unbilled (E4)	13,681,159 (a)	875,048,000	0.04098
22.Company Use (E4)	(1,656,221)(a)	(105,932,000)	–0.00496
23.T & D Losses (E4)	(36,326,331)(a)	(2,312,886,000)	–0.10880
24.Adjusted System KWH Sales	546,141,808	33,387,503,000	1.63577
25.Wholesale KWH Sales	1,260,987	77,089,000	1.63575
26.JURISDICTIONAL KWH SALES	544,880,821	33,310,414,000	1.63577
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00035	545,169,608	33,310,414,000	1.63663
28.True–up * (derived in Attachment C)	(34,518,662)	33,310,414,000	–0.10363
29.TOTAL JURISDICTIONAL FUEL COST	510,650,946	33,310,414,000	1.53300
30.Revenue Tax Factor			1.01609
31.Fuel Cost Adjusted for Taxes			1.55767
32.GPIF*	3,107,919	33,310,414,000	0.00933
33.Total fuel cost including GPIF	513,758,865	33,310,414,000	1.56700
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			1.567

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

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FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

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ESTIMATED FOR THE PERIOD: October 1994 – March 1995

FLORIDA POWER CORPORATION

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	172,200,853	11,130,354,000	1.54713
2.Spent NUC Fuel Disposal Cost (E3A)	2,972,984	3,179,662,000 (a)	0.09350
3.Coal Car Investment	0	0	0.00000
4.Adjustments to Fuel Cost	(1,200,000)	0	0.00000
5.TOTAL COST OF GENERATED POWER	173,973,837	11,130,354,000	1.56306
6.Energy Cost of Purchased Power – Firm (E8)	11,781,150	562,578,000	2.09414
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	7,176,500	220,000,000	3.26205
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	423,390	18,000,000	2.35217
9.Energy Cost of Sch.E Purchases (E9)	2,308,161	118,080,000	1.95474
10.Capacity Cost of Sch.E Economy Purchases (E9)	0	0 (a)	0.00000
11.Payments to Qualifying Facilities (E8A)	71,413,950	3,077,460,000	2.32055
12.TOTAL COST OF PURCHASED POWER	93,103,151	3,996,118,000	2.32984
13.TOTAL AVAILABLE KWH		15,126,472,000	
14.Fuel Cost of Economy Sales (E7)	(6,762,000)	(360,000,000)	1.87833
14a.Gain on Economy Sales –80% (E7A)	(866,360)	(360,000,000)(a)	0.24066
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)	(7,766,300)	(310,647,000)	2.50004
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(15,394,660)	(670,647,000)	2.29549
19.Net Inadvertant Interchange (E4)	0	0	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	251,682,328	14,455,825,000	1.74104
21.Net Unbilled (E4)	(6,840,232)(a)	39[illegible],891,000	–0.04905
22.Company Use (E4)	1,645,245 (a)	(94,500,000)	0.01180
23.T & D Losses (E4)	14,080,094 (a)	(808,736,000)	0.10097
24.Adjusted System KWH Sales	251,682,328	13,945,480,000	1.80476
25.Wholesale KWH Sales(Excluding Seminole Supplemental)	(8,694,040)	(484,616,000)	1.79401
26.JURISDICTIONAL KWH SALES	242,988,288	13,460,864,000	1.80515
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.0014	243,304,173	13,460,864,000	1.80749
28.Prior Period True–Up *	31,586,452	13,460,864,000	0.23451
28a. Market Price Refund for 1992	(19,637)	0	0.00000
29.TOTAL JURISDICTIONAL FUEL COST	274,870,988	13,460,864,000	2.04200
30.Revenue Tax Factor			1.00083
31.Fuel Cost Adjusted for Taxes			2.04370
32.GPIF*	1,009,345	13,460,864,000	0.00750
33.Total fuel cost including GPIF	275,880,333	13,460,864,000	2.05120
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			**2.051**

*Based on Jurisdictional Sales

(a) Included for informational purposes only.

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FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

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TAMPA ELECTRIC COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	160,682,999	7,193,453,000	2.23374
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	160,682,999	7,193,453,000	2.23374
6.Fuel Cost of Purchased Power – Firm (E8)	1,564,400	34,785,000	4.49734
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	162,900	6,366,000	2.55891
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)	4,642,600	279,642,000	1.66019
12.TOTAL COST OF PURCHASED POWER	6,369,900	320,793,000	1.98567
13.TOTAL AVAILABLE KWH		7,514,246,000	
14.Fuel Cost of Economy Sales (E7)	7,656,200	468,199,000	1.63524
15.Gain on Economy Sales – 80% (E7A)	1,015,520	468,199,000 (a)	0.21690
16.Fuel Cost of Scedule D Sales (E7)	3,383,400	233,606,000	1.44834
16a.Fuel Cost of Schedule G Sales (E7)	0	0	0.00000
17.Fuel Cost Schedule J Sales (E7)	788,900	45,748,000	1.72445
17a.Fuel Cost Schedule D TPS Sales (E7)	1,426,200	71,744,000	1.98790
18.TOTAL FUEL COST AND GAINS OF POWER SALES	14,270,220	819,297,000	1.74176
19.Net Inadvertant Interchange (E4)	0	0	
19b.Interchange and Wheeling Losses	0	12,865,000	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	152,782,679	6,682,084,000	2.28645
21.Net Unbilled (E4)	(2,983,406)(a)	(130,482,000)	−0.04606
22.Company Use (E4)	370,405 (a)	16,200,000	0.00572
23.T & D Losses (E4)	7,289,820 (a)	318,827,000	0.11254
24.Adjusted System KWH Sales	152,782,679	6,477,539,000	2.35865
25.Wholesale KWH Sales	(101,945)	(4,305,000)	2.36806
26.JURISDICTIONAL KWH SALES	152,680,734	6,473,234,000	2.35865
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00005	152,757,074	6,473,234,000	2.35983
28.True–up * (derived in Attachment C)	(952,141)	6,473,234,000	−0.01471
29.Pyramid Coal Contract Buyout Adjustment	0	6,473,234,000	0.00000
30.TOTAL JURISDICTIONAL FUEL COST	151,804,933	6,473,234,000	2.34512
31.Revenue Tax Factor			1.00083
32.Fuel Cost Adjusted for Taxes	151,930,931		2.34706
33.GPIF * (Already adjusted for taxes)	406,404	6,473,234,000	0.00628
34.Total Fuel Cost including GPIF	152,337,335	6,473,234,000	2.35334
35.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			**2.353**

*Based on Jurisdictional Sales

Effective date for billing purposes:

(a) Included for informational purposes only.

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FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

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GULF POWER COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	111,500,080	5,907,450,000	1.8874
2.Spent NUC Fuel Disposal Cost (E13)	0	0	0.0000
3.Adjustments to Fuel Cost	0	0	0.0000
4.TOTAL COST OF GENERATED POWER	111,500,080	5,907,450,000	1.8874
5.Fuel Cost of Purchased Power – Firm (E8)	0	0	0.0000
6.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	2,335,000	125,150,000	1.8658
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	2,335,000	125,150,000	1.8658
12.TOTAL AVAILABLE KWH (line 4 + line 11)		6,032,600,000	
13.Fuel Cost of Economy Sales (E7)	(473,000)	(27,380,000)	1.7275
14.Gain on Economy Sales – 80% (E7A)	(65,600)	0 (a)	0.0000
15.Fuel Cost of Unit Power Sales (E7)	(12,518,000)	(698,950,000)	1.7910
16.Fuel Cost of Other Power Sales (E7)	(20,595,000)	(1,193,353,000)	1.7258
17.TOTAL FUEL COST AND GAINS OF POWER SALES	(33,651,600)	(1,919,683,000)	1.7530
18.Net Inadvertant Interchange (E4)	0		
19.TOTAL FUEL AND NET POWER TRANSACTIONS	80,183,480	4,112,917,000	1.9496
20.Net Unbilled (E4)	0	0	0.0000
21.Company Use (E4)	193,381 (a)	9,919,000	1.9496
22.T & D Losses (E4)	4,336,183 (a)	222,414,000	1.9496
23.Adjusted System KWH Sales	80,183,480	3,880,584,000	2.0663
24.Wholesale KWH Sales	2,959,438	143,224,000	2.0663
25.JURISDICTIONAL KWH SALES	77,224,042	3,737,360,000	2.0663
26.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00140	77,332,156	3,737,360,000	2.0692
27.True–up *	2,780,272	3,737,360,000	0.0744
28.Total Jurisdictional Fuel Cost	80,112,428	3,737,360,000	2.1436
29.Revenue Tax Factor			1.01609
30.Fuel Cost Adjusted for Taxes			2.1781
31.Special Contract Recovery Cost	121,472	3,737,360,000	0.0033
32.GPIF *	(84,941)	3,737,360,000	–0.0023
33.Total Fuel Cost including GPIF	80,027,487	3,737,360,000	2.1791
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.179

*Based on Jurisdictional Sales
Effective date for billing purposes:

(a) included for informational purposes only.

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FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

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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)	2,497,657	120,834,000	2.06702
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)	2,746,846	120,834,000 (a)	2.27324
10a.Demand Costs of Purchased Power	1,911,000 (a)		
10b.Non–Fuel Energy & Customer Costs of Purchased Power	835,846 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	0	0	0.00000
12.TOTAL COST OF PURCHASED POWER	5,244,503	120,834,000	4.34025
13.TOTAL AVAILABLE KWH	5,244,503	120,834,000	4.34025
14.Fuel Cost of Economy Sales (E7)	0	0	0.00000
15.Gain on Economy Sales – 80% (E7A)	0	0	0.00000
16.Fuel Cost of Unit Power Sales (E7)	0	0	0.00000
17.Fuel Cost of Other Power Sales (E7)	0	0	0.00000
18.TOTAL FUEL COST AND GAINS OF POWER SALES	0	0	0.00000
19.Net Inadvertant Interchange (E4)	0	0	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	5,244,503	120,834,000	4.34025
21.Net Unbilled (E4)	17,708 (a)	408,000	0.01534
22.Company Use (E4)	5,339 (a)	123,000	0.00462
23.T & D Losses (E4)	239,701 (a)	4,834,000	0.20759
24.ADJUSTED SYSTEM KWH SALES	5,244,503	115,469,000	4.54191
25.Less Total Demand Cost Recovery	1,800,784		
26.JURISDICTIONAL KWH SALES	3,443,719	115,469,000	2.98238
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00	3,443,719	115,469,000	2.98238
28.True–up *	27,588	115,469,000	0.02389
29.TOTAL JURISDICTIONAL FUEL COST	3,471,307	115,469,000	3.00627
30.Revenue Tax Factor			1.00083
31.Fuel Cost Adjusted for Taxes	3,499,562	0	3.00876
32.GPIF *	0	115,469,000	0.00000
33.Total Fuel Cost including GPIF	3,471,307	115,469,000	3.00876
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			3.009

*Based on Jurisdictional Sales

(a) included for informational purposes only.

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FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

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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)	2,705,455	146,637,000	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	4,681,528	146,637,000	3.19260
10a.Demand Costs of Purchased Power (E2)	2,268,000 (a)		
10b.Non Fuel Energy and Customer Costs of Purchased Power (E2)	2,413,528 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	0	0	0.00000
12.TOTAL COST OF PURCHASED POWER	7,386,983	146,637,000	5.03760
13.TOTAL AVAILABLE KWH	7,386,983	146,637,000	5.03760
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	7,386,983	146,637,000	5.03760
21.Net Unbilled (E4)	(229,160)(a)	(4,549,000)	−0.16113
22.Company Use (E4)	8,362 (a)	166,000	0.00588
23.T & D Losses (E4)	443,208 (a)	8,798,000	0.31163
24.Adjusted System KWH Sales	7,386,983	142,222,000	5.19398
25.Wholesale KWH Sales	0	0	0.00000
26.JURISDICTIONAL KWH SALES	7,386,983	142,222,000	5.19398
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00	7,386,983	142,222,000	5.19398
27a.GSLD KWH Sales (E11)		42,000,000	
27b.Other Classes KWH Sales (E11)		100,222,000	
27c.GSLD CP KW		120,000 (a)	
28. GPIF			
29.True–up *	(289,071)	142,222,000	−0.20325
30.TOTAL JURISDICTIONAL FUEL COST	7,097,912	142,222,000	4.99073

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FLORIDA PUBLIC UTILITIES–FERNANDINA

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
30a.Demand Purchased Power Costs (line 10a)	2,268,000 (a)		
30b.Non–Demand Purchased Power Costs (lines 6+10b+11)	5,118,983 (a)		
30c.True–up Over/Under Recovery (line 29)	(289,071)(a)		
APPORTIONMENT OF DEMAND COSTS			
31.Total Demand Costs	2,268,000		
32.GSLD Portion of Demand Costs Including line losses (line 27c * $3.708)	741,600	120,000 KW	$6.18
33.Balance to Other Customers	1,526,400	100,222,000	1.52302
APPORTIONMENT OF NON–DEMAND COSTS			
34.Total Non–Demand Costs (line 30b)	5,118,983		
35.Total KWH Purchased (line 12)		146,637,000	
36.Average Cost per KWH Purchased			3.49092
37.Avg. Cost Adjusted for Transmission line losses (line 36 * 1.03)			3.59565
38.GSLD Non–Demand Costs (line 27a * line 37)	1,510,175	42,000,000	0.03596
39.Balance to Other Customers	3,608,808	100,222,000	3.60081
GSLD PURCHASED POWER COST RECOVERY FACTORS			
40a.Total GSLD Demand Costs (Line 32)	741,600	120,000	$6.18
40b.Revenue Tax Factor			1.01609
40c.GSLD Demand Purchased Power factor adjusted for taxes and rounded:			$6.28
40d.Total Current GSLD Non–Demand Costs (line 38)	1,510,175	42,000,000	3.59565
40e.Total Non–Demand Costs including true–up	1,510,175	42,000,000	3.59565
40f.Revenue Tax Factor			1.01609
40g.GSLD Non–demand costs adjusted for taxes			3.654
OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a.Total Demand and Non–Demand Purchased Power Costs of other classes (lines 33 + 39)	5,135,208	100,222,000	5.12383
41b.Less: Total Demand Cost Recovery	1,249,724 (a)		
41c.Total Other Costs to be Recovered	3,885,484 (a)	100,222,000	3.87688
41d.Other Classes' Portion of True–up (line 30 C)	(289,071)	100,222,000	–0.28843
41e.Total Demand and Non–Demand Costs including True–up	3,596,413	100,222,000	3.58845
42.Revenue tax factor			1.01609
			3.64618
43.OTHER CLASSES PURCHASED POWER FACTOR ADJUSTED FOR TAXES ROUNDED TO THE NEAREST .001 CENTS PER KWH:			**3.646**

*Based on Jurisdictional Sales

(a) included for informational purposes only.