BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.	DOCKET NO. 950001-EI ORDER NO. PSC-95-0321-PHO-EI ISSUED: MARCH 7, 1995

Pursuant to Notice, a Prehearing Conference was held on February 20, 1995, in Tallahassee, Florida, before Commissioner J. Terry Deason, as Prehearing Officer.

APPEARANCES:

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On behalf of Florida Power Corporation

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On behalf of Florida Power and Light Company.

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On behalf of Florida Public Utilities Company.

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On behalf of Florida Steel Corporation.

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On behalf of Gulf Power Company.

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On behalf of Tampa Electric Company.

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On behalf of the Florida Industrial Power Users Group.

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On behalf of the Citizens of the State of Florida.

Martha Carter Brown, Esquire, and Vicki D, Johnson, Esquire, Florida Public Service Commission, 101 E. Gaines Street, Tallahassee, Florida 32399-0863
On behalf of the Commission Staff.

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On behalf of the Commissioners.

PREHEARING ORDER

I. CASE BACKGROUND

As part of the Commission's continuing fuel and energy conservation cost, purchased gas cost, and environmental cost recovery proceedings, a hearing is set for March 8-9, 1994 in this docket and in Dockets No. 940002-EG, 940003-GU and 940007-EI. The hearing will address the issues set out in the body of this prehearing order.

II. PROCEDURE FOR HANDLING CONFIDENTIAL INFORMATION

A. Any information provided pursuant to a discovery request for which proprietary confidential business information status is requested shall be treated by the Commission and the parties as confidential. The information shall be exempt from Section 119.07(1), Florida Statutes, pending a formal ruling on such request by the Commission, or upon the return of the information to the person providing the information. If no determination of confidentiality has been made and the information has not been used in the proceeding, it shall be returned expeditiously to the person providing the information. If a determination of confidentiality has been made and the information was not entered into the record of the proceeding, it shall be returned to the person providing the information within the time periods set forth in Section 366.093(2), Florida Statutes.

B. It is the policy of the Florida Public Service Commission that all Commission hearings be open to the public at all times. The Commission also recognizes its obligation pursuant to Section 366.093, Florida Statutes, to protect proprietary confidential business information from disclosure outside the proceeding.

In the event it becomes necessary to use confidential information during the hearing, the following procedures will be observed:

1) Any party wishing to use any proprietary confidential business information, as that term is defined in Section 366.093, Florida Statutes, shall notify the Prehearing Officer and all parties of record by the time of the Prehearing Conference, or if not known at that time, no later than seven (7) days prior to the beginning of the hearing. The notice shall include a procedure to assure that the confidential nature of the information is preserved as required by statute.

2) Failure of any party to comply with 1) above shall be grounds to deny the party the opportunity to present evidence which is proprietary confidential business information.

3) When confidential information is used in the hearing, parties must have copies for the Commissioners, necessary staff, and the Court Reporter, in envelopes clearly marked with the nature of the contents. Any party wishing to examine the confidential material that is not subject to an order granting confidentiality shall be provided a copy in the same fashion as provided to the Commissioners, subject to execution of any appropriate protective agreement with the owner of the material.

4) Counsel and witnesses are cautioned to avoid verbalizing confidential information in such a way that would compromise the confidential information. Therefore, confidential information should be presented by written exhibit when reasonably possible to do so.

5) At the conclusion of that portion of the hearing that involves confidential information, all copies of confidential exhibits shall be returned to the proffering party. If a confidential exhibit has been admitted into evidence, the copy provided to the Court Reporter shall be retained in the Commission Clerk's confidential files.

Post-hearing procedures

Unless the Commission reaches a decision on the issues in this case from the bench, Rule 25-22.056(3), Florida Administrative Code, provides that each party shall file a post-hearing statement of issues and positions. A summary of each position of no more than 50 words, set off with asterisks, shall be included in that statement. If a party's position has not changed since the issuance of the prehearing order, the post-hearing statement may simply restate the prehearing position; however, if the prehearing position is longer than 50 words, it must be reduced to no more than 50 words. The rule also provides that if a party fails to file a post-hearing statement in conformance with the rule, that party shall have waived all issues and may be dismissed from the proceeding.

A party's proposed findings of fact and conclusions of law, if any, statement of issues and positions, and brief, shall together total no more than 60 pages, and shall be filed at the same time. The prehearing officer may modify the page limit for good cause shown. Please see Rule 25-22.056, Florida Administrative Code, for other requirements pertaining to post-hearing filings.

III. PREFILED TESTIMONY AND EXHIBITS; WITNESSES

Testimony of all witnesses to be sponsored by the parties has been prefiled. All testimony which has been prefiled in this case will be inserted into the record as though read after the witness has taken the stand and affirmed the correctness of the testimony and associated exhibits. All testimony remains subject to appropriate objections. Each witness will have the opportunity to orally summarize his or her testimony at the time he or she takes the stand. Upon insertion of a witness' testimony, exhibits appended thereto may be marked for identification. After all parties and Staff have had the opportunity to object and cross-examine, the exhibit may be moved into the record. All other exhibits may be similarly identified and entered into the record at the appropriate time during the hearing.

Witnesses are reminded that, on cross-examination, responses to questions calling for a simple yes or no answer shall be so answered first, after which the witness may explain his or her answer.

The Commission frequently administers the testimonial oath to more than one witness at a time. Therefore, when a witness takes the stand to testify, the attorney calling the witness is directed to ask the witness to affirm whether he or she has been sworn.

Witnesses whose names are preceded by an asterisk (*) have been excused. The parties have stipulated that the testimony of those witnesses will be inserted into the record as though read, and cross-examination will be waived. The parties have also stipulated that all exhibits submitted with the witnesses' testimony shall be identified as shown in Section VII of this Prehearing Order and admitted into the record.

IV. ORDER OF WITNESSES

Witness	Appearing For	Issues #
*Karl H. Wieland	FPC	1-9, 18-23
*Larry G. Turner	FPC	11, 12
B.T. Birkett	FPL	1-9, 10a, 10b, 14-22
R. Silva	FPL	1-4, 10b, 11, 12, 13
*C. Villard	FPL	4-7, 10a
*Bachman	FPUC	1-8
Steven M. Fietek	FSC	10b, 10c
*M. L. Gilchrist	Gulf	1, 2, 4
*M. W. Howell	Gulf	1, 2, 4, 18, 19, 21
*S. D. Cranmer	Gulf	1, 2, 3, 4, 6, 7, 18, 19, 20, 21, 22
*G. D. Fontaine	Gulf	13, 14

Witness	Appearing For	Issues #
*W. N. Cantrell	TECO	14,15,16,17
*G. A. Keselowsky	TECO	11,12
D. M. Mestas, Jr.	TECO	24A
*M. J. Pennino	TECO	1,2,3,4,5,6,7,8, 9,18,19,20,21,22, 24B
*E. A. Townes	TECO	24B

V. BASIC POSITIONS

FPC: None necessary.

FPL: None necessary.

FPUC: Florida Public Utilities has properly projected its costs and calculated its true-up amounts and purchased power cost recovery factors. Those factors should be approved by the Commission.

FSC: Florida Steel contends that, in the case of Florida Power & Light Company ("FPL"), a number of significant ratemaking issues, as enumerated in Florida Steel's Petition for Leave to Intervene and as described below, warrant full review by the Commission at this time, and these issues should be examined as part of this fuel proceeding. Alternatively, in the event some of these issues are deemed to be beyond the scope of issues customarily addressed in a fuel proceeding before the Commission, such issues should be set for hearing in a separate proceeding at the earliest possible time. The impact of these issues on FPL's rates may be substantial and, to the extent FPL's rates are not currently just and reasonable, Florida Steel and FPL's other ratepayers are entitled to an appropriate adjustment without delay.

GULF: It is the basic position of Gulf Power Company that the proposed fuel factors and capacity cost recovery factors present the best estimate of Gulf's fuel and purchased power expense (both energy and capacity) for the period

April 1995 through September 1995 including the true-up calculations, GPIF and other adjustments allowed by the Commission.

TECO: The Commission should approve Tampa Electric's calculation of its fuel adjustment, capacity cost recovery, GPIF, and oil backout cost recovery true-up calculations and projections, including the proposed fuel adjustment factor of 2.386 cents per KWH before application of factors which adjust for variation in line losses; the proposed capacity cost recovery factor of .142 cents per KWH before applying the 12 CP and 1/13 allocation methodology; a GPIF reward of $146,321; and an oil backout cost recovery factor of .081 cents per KWH.

FIPUG: None at this time.

OPC: None necessary.

STAFF: Staff's positions are preliminary and based on materials filed by the parties and on discovery. The preliminary positions are offered to assist the parties in preparing for the hearing. Staff's final positions will be based upon all the evidence in the record and may differ from the preliminary positions.

VI. ISSUES AND POSITIONS

STIPULATED
ISSUE 1: What are the appropriate final fuel adjustment true-up amounts for the period April, 1994 through September, 1994?

FPC: $2,284,495 underrecovery.

FPL: $6,684,993 underrecovery.

FPUC:

Marianna:	$230,486 (underrecovery)
Fernandina Beach:	$25,350 (underrecovery)

GULF: $2,394,382 underrecovery

TECO: $3,968,565 overrecovery

STIPULATED
ISSUE 2: What are the estimated fuel adjustment true-up amounts for the period October, 1994 through March, 1995?

FPC: $12,575,671 overrecovery.

FPL: $21,299,545 overrecovery.

FPUC:

Marianna:	$86,548 (overrecovery)
Fernandina Beach:	$162,890 (overrecovery)

GULF: $577,273 underrecovery.

TECO: $2,455,113 underrecovery.

STIPULATED
ISSUE 3: What are the total fuel adjustment true-up amounts to be collected during the period April, 1995 through September, 1995?

FPC: $10,291,176 overrecovery.

FPL: $14,614,552 overrecovery, subject to adjustment pending resolution of company-specific issues.

FPUC:

Marianna:	$143,938 underrecovery
Fernandina Beach:	$137,540 overrecovery

GULF: $2,971,655 underrecovery.

TECO: $6,423,678 overrecovery.

STIPULATED
ISSUE 4: What are the appropriate levelized fuel cost recovery factors for the period April, 1995 through September, 1995?

FPC: 1.891 cents per kWh - before line loss adjustment.

FPL: 1.744 cents/kwh is the levelized recovery charge, subject to adjustment pending resolution of company-specific issues.

FPUC: Excluding demand cost recovery, the appropriate levelized fuel cost recovery factors for the period April, 1995 through September, 1995 should be:

Marianna:	3.221¢/kwh
Fernandina Beach:	3.584¢/kwh

GULF: 2.315 cents per KWH.

TECO: 2.386 cents per KWH before application of the factors which adjust for variations in line losses.

STIPULATED
ISSUE 5: What should be the effective date of the new fuel adjustment charge, oil backout charge and conservation cost recovery charge for billing purposes?

POSITION: The new factors should be effective beginning with the first billing cycle for April, 1995, and thereafter through the last billing cycle for September, 1995. The first billing cycle may start before April 1, 1995, and the last billing cycle may end after September 30, 1995, so long as each customer is billed for six months regardless of when the factors became effective.

STIPULATED
ISSUE 6: What are the appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class?

FPC:

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

FPL: The appropriate Fuel Cost Recovery Loss Multipliers and Price Multipliers are provided in response to Issue No. 7.

FPUC: Marianna

Rate Schedule	Multiplier
RS	1.0126
GS	0.9963
GSD	0.9963
GSLD	0.9963
OL, OL-2	1.0126
SL-1, SL-2	0.9881

Fernandina Beach

All Rate Schedules	1.0000

GULF: See table below:

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

TECO:

Group	Multiplier
Group A	1.0064
Group A1	1.0064*
Group B	1.0012
Group C	0.9721

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

STIPULATED
ISSUE 7: What are the appropriate Fuel Cost Recovery Factors for each rate group adjusted for line losses?

FPC:

		Fuel Cost Factors (cents/kWh)		
			Time Of Use	
Group	Delivery Voltage Level	Standard	On-Peak	Off-Peak
A.	Transmission	1.856	2.376	1.583
B.	Distribution Primary	1.875	2.400	1.599
C.	Distribution Secondary	1.894	2.424	1.616
D.	Lighting Service	1.767		

FPL:

RATE SCHEDULE	**PRICE MULTIPLIER**	**LOSS MULTIPLIER**	**FUEL RECOVERY FACTOR (¢/kWh)**
RS-1	1.009	1.00210	1.764
GS-1	1.018	1.00210	1.779
GSD-1	0.996	1.00204	1.741
GSLD-1	0.982	1.00092	1.714
GSLD-2	0.970	0.99500	1.683
GSLD-3	0.959	0.96091	1.607
CS-1	0.990	1.00024	1.726
CS-2	0.958	0.99656	1.666
CILC-D	0.957	0.99757	1.666
CILC-G	0.972	1.00210	1.699
CILC-T	0.944	0.96091	1.582
MET	0.961	0.98063	1.643
OL-1	0.834	1.00210	1.458
SL-1	0.834	1.00210	1.457
SL-2	0.947	1.00210	1.655

RATE SCHEDULE	**PRICE MULTIPLIER**	**LOSS MULTIPLIER**	**ON PEAK FUEL RECOVERY (¢/kWh)**	**OFF PEAK FUEL RECOVERY (¢/kWh)**
RST-1	1.009	1.00210	2.000	1.650
GST-1	1.018	1.00210	2.017	1.664
GSDT-1	0.996	1.00204	1.974	1.628
GSLDT-1	0.982	1.00092	1.943	1.603
GSLDT-2	0.970	0.99500	1.908	1.574
GSLDT-3	0.959	0.96091	1.822	1.503
CST-1	0.990	1.00024	1.957	1.615
CST-2	0.958	0.99656	1.889	1.558
CILC-D	0.957	0.99757	1.889	1.558
CILC-G	0.972	1.00210	1.926	1.589
CILC-T	0.944	0.96091	1.794	1.480

FPUC:

Marianna Rate Schedule	Adjustment
RS	5.151¢/kwh
GS	4.915¢/kwh
GSD	4.541¢/kwh
GSLD	4.381¢/kwh
OL, OL-2	3.262¢/kwh
SL-1, SL-2	3.183¢/kwh

Fernandina Beach Rate Schedule	Adjustment
RS	5.036¢/kwh
GS	4.770¢/kwh
GSD	4.581¢/kwh
OL, & SL	3.996¢/kwh

GULF: See table below: (Cranmer)

Group	Rate Schedules	Fuel Cost Factors ¢/KWH		
		Standard	Time of Use	
			On-Peak	Off-Peak
A	RS, GS, GSD, OSIII, OSIV	2.343	2.564	2.238
B	LP, SBS	2.271	2.485	2.169
C	PX, RPT, SBS	2.228	2.438	2.128
D	OSI, OSII	2.268	N/A	N/A

TECO:

	Standard	On-Peak	Off-Peak
Group A	2.401	2.844	2.154
Group A1	2.258	-	-
Group B	2.389	2.829	2.143
Group C	2.319	2.747	2.080

STIPULATED
ISSUE 8: What is the appropriate revenue tax factor to be applied in calculating each company's levelized fuel factor for the projection period of April through September, 1995?

FPC: 1.0083

FPL: 1.01609

FPUC: Marianna: 1.00083
Fernandina Beach: 1.01609

GULF: 1.01609

TECO: 1.00083

STIPULATED
ISSUE 9: Is it appropriate to recover the cost of SO_2 emission allowances through the Fuel and Purchased Cost Recovery Clause?

POSITION: The cost and revenues associated with SO_2 emission allowances are more appropriately recovered through the Environmental Cost Recovery Clause. However, if a utility is not participating in the ECRC, then it would be appropriate to recover those dollars through the Fuel and Purchased Power Cost Recovery Clause. Although, at such time a utility begins participating in the ECRC, any SO_2 emission allowance dollars should be removed from the Fuel clause and recovered through the ECRC.

Company-Specific Fuel Adjustment Issues

Florida Power and Light Company

ISSUE 10A: Is FPL's proposed new methodology for allocating fuel costs to the various customer classes appropriate?

FPL: Yes. FPL is proposing to change the method of allocating fuel costs among the rate classes. The current method charges all rate classes the same average cost per kWh. In the Company's proposal the kWh's consumed in each hour are such that kWh's consumed in hours with higher loads are allocated a higher proportion of fuel costs and vice versa.

FPL believes that this allocation method is more appropriate because this method addresses the fact that costs of each kWh consumed are not the same during every hour of the day due to the differences in prices between fuels and efficiencies between generating units. (This issue was deferred from the August 1994 Fuel Hearing.) (Birkett)

FSC: Yes. Agree with FPL.

FIPUG: Yes. Agree with FPL.

OPC: No position.

STAFF: No. The proposed fuel allocation methodology is inconsistent with the way that generating plant costs are allocated to the customer classes. This is important because an inverse relationship exists between the capital costs of the generating units and the cost of fuel needed to operate the generating units. Consequently, if the customer class is assigned a larger portion of the fuel costs because it contributes relatively more to the higher peaking load hours, then the capital cost of the generating units should be allocated in the same fashion.

ISSUE 10B: Is it appropriate for Florida Power and Light Company to recover $2,754,502 for modifications made to generating units through the Fuel and Purchased Power Cost Recovery Clause?

FPL: Yes. FPL has included in the proposed Fuel Cost Recovery Factor the cost of implementing certain equipment modifications at some of its generating facilities to enable these facilities to operate using a less expensive grade of residual fuel oil. The Company has estimated that these modifications costing approximately $2.8 million will yield savings of approximately $8.38 million during the April through September 1995 period and $81.3 million from 1995 through 1999. Since these or similar modifications have not been made at any other generating unit, FPL believes that these costs have not been recognized in cost levels used to determine FPL's current base rates. Therefore, these expenditures appear to be the type of a cost that were addressed in Order No. 14546 which, with Commission approval, allows for recovery through the Fuel Cost Recovery Clause of certain not previously recognized or anticipated base rate expenses that provide fuel savings to customers. For these reasons, FPL believes that it is appropriate to bring this issue forward for Commission consideration and approval. (Silva/Birkett)

FSC: No.

FIPUG: No. These costs should be recovered through base rates.

OPC: No.

STAFF: FPL has made certain equipment modifications to Cape Canaveral Unit #1 and #2, Fort Myers Unit #2, Riviera Unit #3 and #4 and Sanford Unit #3, #4 and #5. The additional equipment will enable the units to operate using a more economic grade of residual fuel oil while remaining in compliance with emission constraints. The $2,754,502 capital expenditure will result in measurable fuel cost savings for FPL's ratepayers throughout the projection period and beyond. Therefore, it is appropriate for FPL to recover $2,754,502 for the equipment modifications through the Fuel and Purchased Power Cost Recovery Clause.

ISSUE 10C: Has Florida Power and Light Company reasonably estimated its natural gas prices for the period April through September 1995?

FPL: Yes.

FSC: No. FPL's projections overstate the price of natural gas by at least $65.5 million for the period, and FPL should be required to reduce its fuel cost collections accordingly.

FIPUG: Agree with FSC.

OPC: No position.

STAFF: FPL's estimation of as-burned natural gas prices are not unreasonably overstated. Though a utility likes to hedge against rising fuel prices, FPL has not over-projected the price of natural gas to a point that warrants an amended filing. If in fact FPL's forecast of natural gas prices causes its recovery to move beyond the 10% threshold, FPL should file for a Mid-Course correction, as required by this Commission, to bring the utility's recovery back in line.

Generic Generating Performance Incentive Factor Issues

STIPULATED
ISSUE 11: What is the appropriate GPIF reward or penalty for performance achieved during the period April, 1994 through September, 1994?

FPC: $ 986,547 reward.

FPL: $3,065,156 reward.

GULF: $ 22,931 reward.

TECO: $ 146,321 reward.

STIPULATED
ISSUE 12: What should the GPIF targets/ranges be for the period April, 1995 through September, 1995?

FPC: See Staff Attachment 1, page 2 of 2.

FPL: See Staff Attachment 1, page 2 of 2.

GULF: See Staff Attachment 1, page 2 of 2.

TECO: See Staff Attachment 1, page 2 of 2.

Company-Specific GPIF Issues

Florida Power and Light Company

ISSUE 13: Should the forced outage hours for St. Lucie Unit 1 be adjusted to remove the outage hours caused by the June 6, 1994 severe thunderstorm?

POSITION: Yes. The GPIF manual provides for adjustments to the Equivalent Availability Factor (EAF) of generating units under certain circumstances. Section 4.3.1 of the manual identifies several circumstances which would warrant the adjustment of the EAF including those which are "Natural or externally caused disaster(s)". The severe storm of June 6,1994, was a naturally occurring disturbance which was responsible for the transformer trip and subsequent unit trip. The effects of the storm directly responsible for the loss in unit availability should, and have been, removed before calculating the PSL1 unit EAF performance during the April 1994 through September 1994 period.

Generic Oil Backout Issues

STIPULATED
ISSUE 14: What is the final oil backout true-up amount for the April, 1994 through September, 1994 period?

FPL: $11,602 overrecovery.

TECO: $30,836 underrecovery.

STIPULATED
ISSUE 15: What is the estimated oil backout true-up amount for the period October, 1994 through March, 1995?

FPL: $527,531 underrecovery.

TECO: $183,974 overrecovery.

STIPULATED
ISSUE 16: What is the total oil backout true-up amount to be collected during the period April, 1995 through September, 1995?

FPL: $515,929 underrecovery.

TECO: $153,138 overrecovery.

STIPULATED
ISSUE 17: What is the projected oil backout cost recovery factor for the period April, 1995 through September, 1995?

FPL: .012 cents/kwh.

TECO: .081 cents/kwh.

Company-Specific Oil Backout Issues

None.

Generic Capacity Cost Recovery Issues

STIPULATED
ISSUE 18: What is the appropriate final capacity cost recovery true-up amount for the period April, 1994 through September, 1994?

FPC: $6,943,182 overrecovery.

FPL: $2,159,836 overrecovery.

GULF: $ 221,434 overrecovery.

TECO: $ 35,650 underrecovery, subject to adjustment pending resolution of company-specific issues.

STIPULATED
ISSUE 19: What is the estimated capacity cost recovery true-up amount for the period October, 1994 through March, 1995?

FPC: $10,515,204 underrecovery.

FPL: $12,962,747 overrecovery.

GULF: $ 101,423 underrecovery.

TECO: $ 1,065,382 overrecovery, subject to adjustment pending resolution of company-specific issues.

STIPULATED
ISSUE 20: What is the total capacity cost recovery true-up amount to be collected during the period April, 1995 through September, 1995?

FPC: $ 3,572,022 underrecovery.

FPL: $15,122,583 overrecovery.

GULF: $ 120,011 overrecovery.

TECO: $ 1,029,732 overrecovery, subject to adjustment pending resolution of company-specific issues.

STIPULATED
ISSUE 21: What is the appropriate projected net purchased power capacity cost recovery amount to be included in the recovery factor for the period April, 1995 through September, 1995?

FPC: $116,445,839.

FPL: $144,171,942

GULF: $2,672,392.

TECO: $10,827,805, subject to adjustment pending resolution of company-specific issues.

STIPULATED
ISSUE 22: What are the projected capacity cost recovery factors for the period April, 1995 through September, 1995?

FPC: See page 3 of 10 of attachment A.

FPL: RATE CLASS RECOVERY	**CAPACITY RECOVERY FACTOR ($/KW)**	**CAPACITY FACTOR ($/KWH)**
RS1	-	0.00415
GS1	-	0.00367
GSD1	1.36	-
OS2	-	0.00229
GSLD1/CS1	1.41	-
GSLD2/CS2	1.43	-
GSLD3/CS3	1.41	-
CILCD/CILCG	1.35	-
CILCT	1.29	-
MET	1.47	-
OL1/SL1	-	0.00109
SL2	-	0.00261

RATE CLASS	**CAPACITY RECOVERY FACTOR (RESERVATION DEMAND CHARGE)**	**CAPACITY RECOVERY FACTOR (SUM OF DAILY DEMAND CHARGE) ($/KW)**
ISST1D	.18	.09
SST1T	.17	.08
SST1D	.18	.09

(Birkett)

GULF: See table below:

RATE CLASS	CAPACITY COST RECOVERY FACTORS ¢/KWH
RS, RST	0.070
GS, GST	0.068
GSD, GSDT, SBS	0.053
LP, LPT, SBS	0.046
PX, PXT, RPT, SBS	0.037
OSI, OSII	0.005
OSIII	0.041
OSIV	0.005

TECO: The appropriate factors are as follows, subject to adjustment pending resolution of company specific issues:

Rate Schedules	Factor
RS	.187 cents per KWH
GS, TS	.173 cents perKWH
GSD	.130 cents per KWH
GSLD, SBF	.119 cents per KWH
IS-1 & 3, SBI-1 & 3	.011 cents per KWH
SL, OL	.029 cents perKWH

Company-Specific Capacity Cost Recovery Issues

Tampa Electric Company

ISSUE 23A: Should the $1,106,760 "Option Payment" that Tampa Electric received from Polk in 1993 be treated as a credit in the capacity cost recovery clause?

TECO: No. (Mestas)

FIPUG: Agree with Staff.

OPC: Agree with Staff.

STAFF: Yes. The option payment that Tampa Electric received from Polk was possible because of a cogeneration contract between the parties. The ratepayer, however, bears all of the risk and costs associated with the contract on a dollar for dollar basis. In return for bearing the risk, the ratepayer should receive all of the monetary benefits that also result from this contract. To allow the company/shareholder to keep the option payment would be asymmetrical treatment of these dollars because it allows the ratepayer to bear the risk and the company/shareholder to receive the benefit. The company should be required to credit the full amount of the option payment, with interest, to the retail ratepayer in the capacity cost recovery clause.

STIPULATED
ISSUE 23B: 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 offsystem sales back to the retail ratepayers through the fuel adjustment clause and the capacity cost recovery clause?

POSITION: No. The Company should not be required to credit the revenues it receives from long-term firm Schedule D interchange sales. This is because at the time of TECO's last rate case the firm Schedule D interchange sales were treated as a separated (wholesale) class of customers. By separating this class of customers from the retail jurisdiction, the company and its shareholders were effectively required to carry all of the risk associated with the portion of rate base and expenses that was assigned to this wholesale class of customers. Requiring the company to credit the revenues it could receive from potential additional Schedule D sales to the retail jurisdiction, without recognizing that the company and its shareholders may also experience a shortfall in the revenues that were separated from the retail jurisdiction, would be inequitable and asymmetrical treatment.

VII. EXHIBIT LIST

The exhibits of the parties whose testimony has been stipulated into the record are identified by as asterisk next to the name of the witness. Parties have also stipulated that all exhibits submitted with the witnesses' testimony shall be admitted into the record.

Witness	Proffered By	I.D. No.	Description
*Wieland	FPC	(KWH-1)	True-up Variance Analysis
*Wieland	FPC	(KHW-2)	Schedules 1 through A13 (True-up)
*Wieland	FPC	(KHW-3)	Forecast Assumptions (Parts A-C), andCapacity Cost Recovery Factors (Part D)
*Wieland	FPC	(KHW-4)	Schedules E1 through E11 and H1 (Projections)
*Turner	FPC	(LTG-1)	Standard Form GPIF Schedules (Reward/Penalty)
*Turner	FPC	(LTG-2)	Standard Form GPIF Schedules (Targets/Ranges)
*Birkett	FPL	(BTB-1)	Appendix I/Fuel Cost Recovery True-Up Calculation
*Birkett	FPL	(BTB-2)	Appendix II/Capacity Cost Recovery True-Up Calculation
*Birkett	FPL	(BTB-3)	Appendix III/Oil Backout Cost Recovery True-Up Calculation
*Birkett	FPL	(BTB-4)	Appendix IV/A Schedules October 1993 - March 1994

Witness	Proffered By	I.D. No.	Description
Silva	FPL	_____ (RS-1)	Appendix I/Fuel Cost Recovery Forecast Assumptions
Birkett	FPL	_____ (BTB-5)	Appendix II/Fuel Cost Recovery Calculation of Factor
Birkett	FPL	_____ (BTB-6)	Appendix III/Fuel Cost Recovery Estimated/Actual True-Up Calculation
*Birkett	FPL	_____ (BTB-7)	Appendix IV/Capacity Cost Recovery Calculation of Factors
*Birkett	FPL	_____ (BTB-8)	Appendix V/Oil Backout Cost Recovery Calculation of Factor
*Silva	FPL	_____ (RS-2)	Document No. 1/GPIF Results
*Silva	FPL	_____ (RS-3)	Document No. 1/GPIF Targets and Ranges
Birkett	FPL	_____ (BTB-9)	Rebuttal Document No. 1 Fuel Cost Recovery, Equipment Modifications-Present Value Calculation
Silva	FPL	_____ (RS-4)	Rebuttal Document No. 1 Fuel Cost Recovery Estimated/Actual Period
Silva	FPL	_____ (RS-5)	Rebuttal Document No. 2 Fuel Cost Recovery Natural Gas Comparison
*Bachman	FPUC	_____ (GMB-1)	Schedules E1, E1-A, E1-B, E1B-1, E2, E7, and E-10(Marianna Division) Schedules E1-A, E1B, E1B-1, E2, E7, E8, and E10,(Fernandina Beach Division)

Witness	Proffered By	I.D. No.	Description
Fietek	FSC	(SMF-1)	Direct testimony and Schedules 1 - 4
*Gilchrist	Gulf	(MLG-1)	coal suppliers April 94 - Sept. '94
*Gilchrist	Gulf	(MLG-2)	Projected vs. Actual Fuel Cost Sept. '94 - Sept. '94
*Howell	Gulf	(MWH-1)	Projected Capacity Transactions Apr. - Sept. '95
*Cranmer	Gulf	(SDC-1)	Fuel and capacity cost 12; 13; H-1; CCE-1; CCE-2; A-1 through A-12 for June - Nov. 1994.
*Cranmer	Gulf	(SDC-2)	Schedules E-1 through E-11; 12; 13; H-1; CCE-1; CCE-2; A-1 through A-12 for June - Nov. 1994.
*Fontaine	Gulf	(GDF-2)	GPIF Targets and Ranges
*Pennino	TECO	(MJP-1)	Fuel cost recovery final true-up April 1994 - September 1994
*Pennino	TECO	(MJP-2)	Fuel adjustment projection, April 1995 - September 1995
*Pennino	TECO	(MJP-3)	Capacity cost recovery projection, April 1995 - September 1995
*Pennino	TECO	(MJP-4)	Description of wholesale agreements
*Keselowsky	TECO	(GAK-1)	Generating Performance Incentive Factor Results, April 1994 -September 1994

Witness	Proffered By	I.D. No.	Description
*Keselowsky	TECO	(GAK-2)	GPIF Targets and Ranges for October 1994 - March 1995
*Keselowsky	TECO	(GAK-3)	Estimated Unit Performance Data, April 1995 - September 1995
*Cantrell and Townes	TECO	(RFT/EAT-1)	Schedules Supporting Oil Backout Cost Recovery Factor - Actual, April 1994 - September 1994
*Cantrell and Townes	TECO	(WNC/EAT-2)	Schedules Supporting Oil Backout Cost Recovery Factor, April 1995 - September 1995
*Cantrell and Townes	TECO	(WNC/EAT-3)	Gannon Conversion Project Comparison of Projected Payoff with Original Estimate as of November 1994

Parties and Staff reserve the right to identify additional exhibits for the purpose of cross-examination.

VIII. PROPOSED STIPULATIONS

There are proposed stipulations to all issues - subject to adjustment pending resolution of company specific issues - except Issues 10a, 10b,10c, and 23a.

IX. PENDING MOTIONS

None at this time.

X. RULINGS

None at this time.

XI. <u>OTHER MATTERS</u>

At the prehearing conference, FSC withdrew the following issues it had initially proposed for consideration:

ISSUE: (a) Whether, as Florida Steel contends is the case, the rate of return on equity of 12.8% (+ 1.0%) currently allowed FPL is excessive and results in rates that are unjust and unreasonable within the meaning of section 266.06, Florida Statutes, and whether these excessive amounts should be deducted from the fuel charges.

ISSUE: (b) Whether, as Florida Steel contends is the case, the rate of return on equity which FPL in fact earned during 1994 and is expected to earn during 1995 is in excess of the currently allowed rate of return of 12.8% (± 1.0%), resulting in rates that are unjust, unreasonable and in violation of law within the meaning of section 366.06, Florida Statutes, and whether these excessive amounts should be deducted from the fuel charges.

ISSUE: (c) Whether, as Florida Steel contends is the case, FPL acted imprudently in delaying until 1993, and not implementing at an earlier time, its major cost reduction program, including a workforce reduction of some 1,700 positions, which resulted in a $138 million pretax charge to its earnings as reflected in its December 31, 1993 financial statements, thereby resulting in rates that are unjust and unreasonable within the meaning of section 366.06, Florida Statutes.

ISSUE: (d) Whether, as Florida Steel contends is the case, the demand charge discount provided to it and other transmission level CILC-1 customers, in relation to the demand charge to non-transmission level customers and non-interruptible customers, is sufficient in light of the lower cost to FPL of providing transmission level service to CILC-1 class customers, thereby resulting in rates that are unjust, unreasonable, unjustly discriminatory and in violation of law within the meaning of section 366.06, Florida Statutes.

Staff recommended that these issues were not appropriate for this docket, but that FSC may wish to petition for the issues to be heard by the Commission in another more appropriate docket. Accordingly, FSC withdrew its proposed issues. FSC stated that in withdrawing the issues from consideration in this proceeding it did not waive any rights it may have to address the issues in another proceeding, including the effective date for any relief granted.

It is therefore,

ORDERED by Commissioner J. Terry Deason, as Prehearing Officer, that this Prehearing Order shall govern the conduct of these proceedings as set forth above unless modified by the Commission.

By ORDER of Commissioner J. Terry Deason, as Prehearing Officer, this 7th day of March, 1995.

J. Terry Deason

J. Terry Deason, Commissioner
and Prehearing Officer

(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 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.

STAFF ATTACHMENT 1

GPIF REWARDS/PENALTIES
April 1994 to September 1994

Florida Power Corporation	$986,547	Reward
Florida Power and Light Company	$3,065,156	Reward
Gulf Power Company	$22,931	Reward
Tampa Electric Company	$146,321	Reward

Utility/ Plant/Unit	EAF		Heat Rate	
FPC	Target	Adj. Actual	Target	Adj. Actual
Anclote 1	92.6	89.2	9,634	9,584
Anclote 2	81.7	82.1	9,596	9,678
Crystal River 1	85.9	89.7	10,118	9,993
Crystal River 2	83.9	85.5	10,081	9,874
Crystal River 3	59.8	62.9	10,533	10,497
Crystal River 4	87.2	86.0	9,268	9,320
Crystal River 5	94.7	96.7	9,315	9,256
FPL	Target	Adj. Actual	Target	Adj. Actual
Cape Canaveral 1	94.7	91.7	8,978	8,824
Cape Canaveral 2	93.2	90.9	9,400	9,556
Fort Myers 1	95.2	96.1	10,054	10,057
Fort Myers 2	94.0	93.8	9,418	9,481
Manatee 1	92.7	91.9	9,658	9,635
Manatee 2	94.5	96.6	9,785	9,869
Port Everglades 1	96.0	92.9	9,960	9,969
Port Everglades 2	95.3	87.1	9,936	9,907
Port Everglades 3	95.2	87.3	9,320	9,422
Port Everglades 4	87.1	91.2	9,372	9,554
Putnam 1	89.4	95.0	8,183	8,159
Putnam 2	94.2	94.3	8,302	8,143
Riviera 3	65.4	67.5	9,691	9,434
Riviera 4	90.4	91.3	9,717	9,655
Sanford 4	94.6	98.2	9,760	9,483
Sanford 5	94.1	97.9	9,534	9,476
Scherer 4	95.9	99.7	8,855	9,689
St. Johns River 1	95.6	99.4	9,370	9,475
St. Johns River 2	95.3	98.7	9,302	9,427
St. Lucie 1	93.4	94.8	10,846	10,942
St. Lucie 2	70.3	82.1	10,796	10,902
Turkey Point 1	82.6	98.0	9,444	9,066
Turkey Point 2	87.4	96.0	9,624	9,670
Turkey Point 3	67.0	68.6	11,086	11,131
Turkey Point 4	93.6	96.0	11,216	11,220
Gulf	Target	Adj. Actual	Target	Adj. Actual
Crist 6	66.6	64.4	10,391	10,588
Crist 7	82.1	90.8	10,231	10,341
Smith 1	80.8	85.0	10,162	10,143
Smith 2	90.8	98.4	10,192	10,421
Daniel 1	86.8	84.8	10,449	10,301
Daniel 2	96.8	97.8	10,089	9,961
TECO	Target	Adj. Actual	Target	Adj. Actual
Big Bend 1	58.6	59.1	10,062	9,988
Big Bend 2	87.6	79.2	10,069	10,214
Big Bend 3	83.5	90.9	9,676	9,930
Big Bend 4	88.1	92.6	10,114	10,173
Gannon 5	82.7	83.9	10,408	10,495
Gannon 6	83.1	90.7	10,454	10,668

STAFF ATTACHMENT 1

GPIF TARGETS
April 1995 to September 1995

Utility/ Plant/Unit	Equivalent Availability				Heat Rate	
	Company			Staff	Company	Staff
FPC	EAF	POF	EUOF			
Anclote 1	97.1	0.0	2.9	Agree	9,268	Agree
Anclote 2	97.2	0.0	2.8	Agree	9,565	Agree
Crystal River 1	60.2	31.2	8.6	Agree	10,130	Agree
Crystal River 2	83.6	0.0	16.4	Agree	10,053	Agree
Crystal River 3	94.0	0.0	6.0	Agree	10,532	Agree
Crystal River 4	92.9	0.0	7.1	Agree	9,377	Agree
Crystal River 5	90.6	3.8	5.6	Agree	9,274	Agree
FPL	EAF	POF	EUOF			
Cape Canaveral 1	91.2	0.0	8.8	Agree	9,230	Agree
Cape Canaveral 2	89.8	0.0	10.2	Agree	9,252	Agree
Fort Lauderdale 4	89.5	5.5	5.0	Agree	7,335	Agree
Fort Lauderdale 5	95.7	0.0	4.3	Agree	7,362	Agree
Fort Myers 2	91.7	0.0	8.3	Agree	9,337	Agree
Manatee 2	96.0	0.0	4.0	Agree	9,600	Agree
Port Everglades 3	85.6	6.0	8.4	Agree	9,209	Agree
Port Everglades 4	96.0	0.0	4.0	Agree	9,313	Agree
Putnam 1	96.0	0.0	4.0	Agree	8,540	Agree
Putnam 2	84.2	11.4	4.4	Agree	8,519	Agree
Riviera 3	93.6	0.0	6.4	Agree	9,610	Agree
Riviera 4	90.9	0.0	9.1	Agree	9,805	Agree
Sanford 5	96.0	0.0	4.0	Agree	9,694	Agree
Scherer 4	96.0	0.0	4.0	Agree	9,956	Agree
St. Lucie 1	93.6	0.0	6.4	Agree	10,882	Agree
St. Lucie 2	83.3	0.0	16.7	Agree	10,877	Agree
Turkey Point 1	82.7	12.6	4.7	Agree	9,309	Agree
Turkey Point 2	95.6	0.0	4.4	Agree	9,262	Agree
Turkey Point 3	85.1	8.7	6.2	Agree	11,133	Agree
Turkey Point 4	93.1	0.0	6.9	Agree	11,218	Agree
Gulf	EAF	POF	EUOF			
Crist 6	76.6	13.1	10.3	Agree	10,804	Agree
Crist 7	76.4	8.7	14.9	Agree	10,675	Agree
Smith 1	81.4	13.1	5.5	Agree	10,147	Agree
Smith 2	87.7	4.9	7.4	Agree	10,270	Agree
Daniel 1	90.5	4.4	5.1	Agree	10,291	Agree
Daniel 2	97.5	0.0	2.5	Agree	10,107	Agree
TECO	EAF	POF	EUOF			
Big Bend 1	83.4	1.1	15.5	Agree	10,137	Agree
Big Bend 2	88.1	0.0	11.9	Agree	10,055	Agree
Big Bend 3	67.1	23.0	9.9	Agree	9,607	Agree
Big Bend 4	90.6	0.0	9.4	Agree	10,036	Agree
Gannon 5	88.7	0.0	11.3	Agree	10,052	Agree
Gannon 6	80.4	5.5	14.1	Agree	10,335	Agree

TOTAL FUEL COST FOR THE PERIOD: April 1995 – September 1995 DATE: 02/20/95

	PROPOSED April 1995 – September 1995			PRESENT December 1994 – March 1995 Cents per kwh			DIFFERENCE Cents per kwh			RESIDENTIAL LINE LOSS MULTIPLIER	PROPOSED RESIDENTIAL FUEL FACTOR
COMPANY	Levelized	On/Peak	Off/Peak	Levelized	On/Peak	Off/Peak	Levelized	On/Peak	Off/Peak		
Fla. Power & Light (5)	1.744	1.800	1.716	1.567	1.673	1.525	0.177	0.127	0.191	1.00210	1.747
Fla. Power Corp.	1.894	2.425	1.616	2.055	2.612	1.827	−0.161	−0.187	−0.211	1.00000	1.894
Tampa Electric	2.386	2.666	2.239	2.353	2.666	2.239	0.033	0.000	0.000	1.00640	2.401
Gulf Power	2.315	2.533	2.211	2.179	2.226	2.164	0.136	0.307	0.047	1.01228	2.343
Fla. Public											
Marianna (1)	5.086	NA	NA	4.874	NA	NA	0.212	NA	NA	1.01260	5.151
Fernandina (1)(2)	5.036	NA	NA	4.976	NA	NA	0.060	NA	NA	1.00000	5.036

COST FOR 1,000 KWH RESIDENTIAL SERVICE

PRESENT: December 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	49.76
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	NA	NA
Gross Receipts Tax (4)	0.73	2.09	2.06	0.71	1.79	0.71
Total	$71.62	$83.56	$82.40	$70.06	$71.70	$69.73

PROPOSED: April 1995 – September 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)	17.64	18.94	24.01	23.43	51.51	50.36
Oil Backout	0.12	N/A	0.81	N/A	N/A	N/A
Energy Conservation	2.52	3.31	1.54	0.26	0.18	0.12
Environmental Cost Recovery	0.10	N/A	N/A	1.36	N/A	N/A
Capacity Recovery	4.15	9.18	1.87	0.70	N/A	N/A
Gross Receipts Tax (4)	0.74	2.06	2.06	0.71	1.85	0.71
Total	$72.65	$82.54	$82.21	$69.71	$73.97	$70.39

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)	1.94	−1.61	0.33	1.37	2.15	0.60
Oil Backout	0.01	N/A	−0.15	N/A	N/A	N/A
Energy Conservation	0.09	−1.09	−0.31	0.00	0.06	0.06
Environmental Cost Recovery	0.00	N/A	N/A	−0.18	N/A	N/A
Capacity Recovery	−1.02	1.71	−0.06	−1.54	N/A	N/A
Gross Receipts Tax (4)	0.01	−0.03	0.00	0.00	0.06	0.00
Total	1.02	−1.02	−0.19	−0.35	2.27	0.66

(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.

ATTACHMENT A

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

DIVISION OF ELECTRIC AND GAS
DATE: 02/20/95

FOR THE PERIOD: April 1995 – September 1995

			WITHOUT LINE LOSS MULTIPLIER				WITH LINE LOSS MULTIPLIER		
COMPANY	GROUP	RATE SCHEDULES	Levelized	* On/Peak	Off/Peak	LINE LOSS MULTIPLIER	Levelized	On/Peak	Off/Peak
FP&L	A	RS-1,RST-1,GST-1,GS-1,SL-2, CILC-G	1.744	1.800	1.716	1.00210	1.747	1.804	1.720
	A-1	SL-1,OL-1	1.730	NA	NA	1.00210	1.734	NA	NA
	B	GSD-1,GSDT-1	1.744	1.800	1.716	1.00204	1.747	1.804	1.720
	C	GSLD-1,GSLDT-1, CS-1, CST-1	1.744	1.800	1.716	1.00089	1.745	1.802	1.718
	D	GSLD-2,GSLDT-2, CS-2, CST-2	1.744	1.800	1.716	0.99443	1.734	1.790	1.707
	E	GSLD-3,GSLDT-3,CS-3,CST-3	1.744	1.800	1.716	0.96091	1.676	1.730	1.649
	F	CILC-1(D),ISST-1(D)	NA	1.800	1.716	0.99758	NA	1.796	1.712
FPC *	A	Distribution Secondary Delivery	1.894	2.425	1.616	1.00000	1.894	2.424	1.616
	A-1	OL-1,SL-1	1.767	NA	NA	1.00000	1.767	NA	NA
	B	Distribution Primary Delivery	1.894	2.425	1.616	0.99000	1.875	2.400	1.599
	C	Transmission Delivery	1.894	2.425	1.616	0.98000	1.856	2.376	1.583
TECO	A	RS,GS,TS	2.386	2.826	2.140	1.00640	2.401	2.844	2.154
	A-1	SL-1,2,3,OL-1,2	2.258	NA	NA	1.00000	2.258	NA	NA
	B	GSD,GSLD	2.386	2.826	2.140	1.00120	2.389	2.829	2.143
	C	IS-1,IS-3	2.386	2.826	2.140	0.97210	2.319	2.747	2.080
GULF	A	RS,GS,GSD,OS-III,OS-IV, SBS(100 to 500 kW)	2.315	2.533	2.211	1.01228	2.343	2.564	2.238
	B	LP, SBS(Contract Demand of 500 to 7499 kW)	2.315	2.533	2.211	0.98106	2.271	2.485	2.169
	C	PX, SBS(Contract Demand above 7499 kW)	2.315	2.533	2.211	0.96230	2.228	2.438	2.128
	D	OS-1,OS-2	2.240	NA	NA	1.01228	2.268	NA	NA
FPUC									
Fernandina	A	RS	5.036	NA	NA	1.00000	5.036	NA	NA
	B	GS	4.770	NA	NA	1.00000	4.770	NA	NA
	C	GSD	4.581	NA	NA	1.00000	4.581	NA	NA
	D	OL, OL-2, SL-2, SL-3, CSL	3.996	NA	NA	1.00000	3.996	NA	NA
	E	GSLD	N/A				4.799 (1) $6.18/CP KW		
Marianna	A	RS	5.086	NA	NA	1.01260	5.151	NA	NA
	B	GS	4.933	NA	NA	0.99630	4.915	NA	NA
	C	GSD	4.558	NA	NA	0.99630	4.541	NA	NA
	D	GLSD	4.397	NA	NA	0.99630	4.381	NA	NA
	E	OL, OL-2	3.221	NA	NA	1.01260	3.262	NA	NA
	F	SL-1, SL-2	3.221	NA	NA	0.98810	3.183	NA	NA

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

DIVISION OF ELECTRIC AND GAS
DATE: 02/20/95
PAGE 2 of 10

FOR THE PERIOD: April 1995 – September 1995

			WITHOUT LINE LOSS MULTIPLIER			LINE LOSS	WITH LINE LOSS MULTIPLIER		
COMPANY	GROUP	RATE SCHEDULES	Levelized	* On/Peak	Off/Peak	MULTIPLIER	Levelized	On/Peak	Off/Peak
FP&L	A	RS-1,RST-1,GST-1,GS-1,SL-2, CILC-G	1.744	1.800	1.716	1.00210	1.747	1.804	1.720
	A-1	SL-1,OL-1	1.730	NA	NA	1.00210	1.734	NA	NA
	B	GSD-1,GSDT-1	1.744	1.800	1.716	1.00204	1.747	1.804	1.720
	C	GSLD-1,GSLDT-1, CS-1, CST-1	1.744	1.800	1.716	1.00089	1.745	1.802	1.718
	D	GSLD-2,GSLDT-2, CS-2, CST-2	1.744	1.800	1.716	0.99443	1.734	1.790	1.707
	E	GSLD-3,GSLDT-3,CS-3,CST-3	1.744	1.800	1.716	0.96091	1.676	1.730	1.649
	F	CILC-1(D),ISST-1(D)	NA	1.800	1.716	0.99758	NA	1.796	1.712
FPC *	A	Distribution Secondary Delivery	1.894	2.425	1.616	1.00000	1.894	2.424	1.616
	A-1	OL-1,SL-1	1.767	NA	NA	1.00000	1.767	NA	NA
	B	Distribution Primary Delivery	1.894	2.425	1.616	0.99000	1.875	2.400	1.599
	C	Transmission Delivery	1.894	2.425	1.616	0.98000	1.856	2.376	1.583
TECO	A	RS,GS,TS	2.386	2.826	2.140	1.00640	2.401	2.844	2.154
	A-1	SL-1,2,3,OL-1,2	2.258	NA	NA	1.00000	2.258	NA	NA
	B	GSD,GSLD	2.386	2.826	2.140	1.00120	2.389	2.829	2.143
	C	IS-1,IS-3	2.386	2.826	2.140	0.97210	2.319	2.747	2.080
GULF	A	RS,GS,GSD,OS-III,OS-IV, SBS(100 to 500 kW)	2.315	2.533	2.211	1.01228	2.343	2.564	2.238
	B	LP, SBS(Contract Demand of 500 to 7499 kW)	2.315	2.533	2.211	0.98106	2.271	2.485	2.169
	C	PX, SBS(Contract Demand above 7499 kW)	2.315	2.533	2.211	0.96230	2.228	2.438	2.128
	D	OS-1,OS-2	2.240	NA	NA	1.01228	2.268	NA	NA
FPUC									
Fernandina	A	RS	5.036	NA	NA	1.00000	5.036	NA	NA
	B	GS	4.770	NA	NA	1.00000	4.770	NA	NA
	C	GSD	4.581	NA	NA	1.00000	4.581	NA	NA
	D	OL, OL-2, SL-2, SL-3, CSL	3.996	NA	NA	1.00000	3.996	NA	NA
	E	GSLD	N/A				4.799 (1)		
							$6.18/CP KW		
Marianna	A	RS	5.086	NA	NA	1.01260	5.151	NA	NA
	B	GS	4.933	NA	NA	0.99630	4.915	NA	NA
	C	GSD	4.558	NA	NA	0.99630	4.541	NA	NA
	D	GLSD	4.397	NA	NA	0.99630	4.381	NA	NA
	E	OL, OL-2	3.221	NA	NA	1.01260	3.262	NA	NA
	F	SL-1, SL-2	3.221	NA	NA	0.98810	3.183	NA	NA

ATTACHMENT A

PROPOSED CAPACITY COST RECOVERY FACTORS
For the Period: April 1995 – September 1995

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COMPANY	RATE SCHEDULE	RECOVERY FACTOR (CENTS PER KWH)	
FPL	RS1	0.415	
	GS1	0.367	
	OL1/SL1	0.109	
	SL2	0.261	
	OS2	0.229	
		RECOVERY FACTOR (DOLLARS PER KW)	
	GSD1	$1.36	
	GSLD1/CS1	$1.41	
	GSLD2/CS2	$1.43	
	GSLD3/CS3	$1.41	
	ISST1D = RDC/SDD	$0.18	$0.09
	SST1T = RDC/SDD	$0.17	$0.08
	SST1D = RDC/SDD	$0.18	$0.09
	CILCD,CILCG	$1.35	
	CILCT	$1.29	
	MET	$1.47	
		RECOVERY FACTOR (CENTS PER KWH)	
FPC	RS	0.918	
	GS–Transmission	0.714	
	GS–Primary	0.721	
	GS–Secondary	0.728	
	GS – 100% Load Factor	0.502	
	GSD–Transmission	0.598	
	GSD–Primary	0.604	
	GSD–Secondary	0.610	
	CS – Transmission	0.501	
	CS – Primary	0.506	
	CS – Secondary	0.511	
	IS–Transmission	0.502	
	IS–Primary	0.507	
	IS–Secondary	0.512	
	LS – Lighting Service	0.183	
TECO	RS	0.187	
	GS,TS	0.173	
	GSD	0.130	
	GSLD,SBF	0.119	
	IS–1 & 3,SBI–1 & 3	0.011	
	SL/OL	0.030	
GULF	RS,RST	0.070	
	GS,GST	0.068	
	GSD,GSDT	0.053	
	LP,LPT	0.046	
	PX,PXT	0.037	
	OS–1,OS–II	0.005	
	OS–III	0.041	
	OS–VI	0.005	

ATTACHMENT A

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
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ESTIMATED FOR THE PERIOD: April 1995 – September 1995

FLORIDA POWER & LIGHT COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated Cents/KWH
1.Fuel Cost of System Net Generation (E3)	544,755,274	35,853,147,000	1.51941
2.Spent NUC Fuel Disposal Cost (E2)	11,153,262	11,946,509,000 (a)	0.09336
3.Fuel Related Transactions	7,034,943	0	0.00000
4. Natural Gas Pipeline Enhancements	0	0	0.00000
4a. Fuel Cost of Sales to FKEC	(8,848,014)	(448,644,000)	1.97217
5.TOTAL COST OF GENERATED POWER	554,095,465	35,404,503,000	1.56504
6.Fuel Cost of Purchased Power – Firm (E8)	90,347,195	5,217,333,000	1.73167
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	9,068,200	779,060,000	1.16399
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	10,344,570	598,969,000	1.72706
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)	38,925,071	2,263,095,000	1.71999
12.TOTAL COST OF PURCHASED POWER	148,685,036	8,858,457,000	1.67845
13.TOTAL AVAILABLE KWH		44,262,960,000	
14.Fuel Cost of Economy Sales (E7)	(9,131,626)	(414,750,000)	2.20172
15.Gain on Economy Sales – 80% (E7A)	(2,202,510)	(414,750,000)(a)	0.53105
16.Fuel Cost of Unit Power Sales (SL2 Partpts) (E7)	(1,120,283)	(262,154,000)	0.42734
17.Fuel Cost of Other Power Sales (E7)	0	0	0.00000
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(12,454,419)	(676,904,000)	1.83991
19.Net Inadvertant Interchange (E4)	0	0	0.00000
20.TOTAL FUEL AND NET POWER TRANSACTIONS	690,326,082	43,586,056,000	1.58382
21.Net Unbilled (E4)	4,350,620 (a)	(1,000,153,000)	0.01100
22.Company Use (E4)	(2,055,280)(a)	(132,104,000)	−0.00519
23.T & D Losses (E4)	(45,079,110)(a)	(2,885,000,800)	−0.11393
24.Adjusted System KWH Sales	690,326,082	39,568,798,200	1.74462
25.Wholesale KWH Sales	3,877,976	(222,280,000)	1.74464
26.JURISDICTIONAL KWH SALES	686,448,106	39,346,518,200	1.74462
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00035	686,811,923	39,346,518,200	1.74555
28.True–up * (derived in Attachment C)	(14,614,552)	39,346,518,200	−0.03714
29.TOTAL JURISDICTIONAL FUEL COST	672,197,371	39,346,518,200	1.70840
30.Revenue Tax Factor			1.01609
31.Fuel Cost Adjusted for Taxes			1.73589
32.GPIF*	3,065,156	39,346,518,200	0.00779
33.Total fuel cost including GPIF	675,262,527	39,346,518,200	1.74368
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			1.744

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

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

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ESTIMATED FOR THE PERIOD: April 1995 – September 1995

FLORIDA POWER CORPORATION

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	201,690,909	12,617,244,000	1.59853
2.Spent NUC Fuel Disposal Cost (E3A)	2,948,649	3,153,635,000 (a)	0.09350
3.Coal Car Investment	0	0	0.00000
4.Adjustments to Fuel Cost	299,000	0	0.00000
5.TOTAL COST OF GENERATED POWER	204,938,558	12,617,244,000	1.62427
6.Energy Cost of Purchased Power – Firm (E8)	23,471,060	1,138,415,000	2.06173
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	19,807,800	770,000,000	2.57244
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	564,152	23,580,000	2.39250
9.Energy Cost of Sch.E Purchases (E9)	0	0	0.00000
10.Capacity Cost of Sch.E Economy Purchases (E9)	0	0 (a)	0.00000
11.Payments to Qualifying Facilities (E8A)	72,143,870	3,563,863,000	2.02432
12.TOTAL COST OF PURCHASED POWER	115,986,882	5,495,858,000	2.11044
13.TOTAL AVAILABLE KWH		18,113,102,000	
14.Fuel Cost of Economy Sales (E7)	(4,705,740)	(265,000,000)	1.77575
14a.Gain on Economy Sales –80% (E7A)	(524,000)	(265,000,000)(a)	0.19774
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)	(7,360,400)	(320,012,000)	2.30004
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(12,590,140)	(585,012,000)	2.15212
19.Net Inadvertant Interchange (E4)	0	0	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	308,335,300	17,528,090,000	1.75909
21.Net Unbilled (E4)	10,258,192 (a)	(583,150,000)	0.06479
22.Company Use (E4)	1,662,350 (a)	(94,500,000)	0.01050
23.T & D Losses (E4)	17,900,039 (a)	(1,017,568,000)	0.11306
24.Adjusted System KWH Sales	308,335,300	15,832,872,000	1.94744
25.Wholesale KWH Sales(Excluding Seminole Supplemental)	(10,051,165)	(516,042,000)	1.94774
26.JURISDICTIONAL KWH SALES	298,284,135	15,316,830,000	1.94743
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.0014	298,671,904	15,316,830,000	1.94996
28.Prior Period True–Up *	(10,291,176)	15,316,830,000	–0.06719
28a. Market Price Refund for 1992	0	0	0.00000
29.TOTAL JURISDICTIONAL FUEL COST	288,380,728	15,316,830,000	1.88277
30.Revenue Tax Factor			1.00083
31.Fuel Cost Adjusted for Taxes	288,620,084		1.88430
32.GPIF*	986,547	15,316,830,000	0.00640
33.Total fuel cost including GPIF	289,606,631	15,316,830,000	1.89070
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			1.891

*Based on Jurisdictional Sales

(a) Included for informational purposes only.

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

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ESTIMATED FOR THE PERIOD: April 1995 – September 1995

TAMPA ELECTRIC COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	195,434,704	8,992,142,000	2.17339
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	3,083,415	8,992,142,000	0.03429
5.TOTAL COST OF GENERATED POWER	198,518,119	8,992,142,000	2.20768
6.Fuel Cost of Purchased Power – Firm (E8)	5,520,500	150,153,000	3.67658
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	624,500	18,415,000	3.39126
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)	4,577,800	234,743,000	1.95013
12.TOTAL COST OF PURCHASED POWER	10,722,800	403,311,000	2.65869
13.TOTAL AVAILABLE KWH		9,395,453,000	
14.Fuel Cost of Economy Sales (E7)	13,059,300	797,767,000	1.63698
15.Gain on Economy Sales – 80% (E7A)	2,093,040	797,767,000 (a)	0.26236
16.Fuel Cost of Scedule D Sales (Jurisdictional)(E7)	399,200	24,657,000	1.61901
16a.Fuel Cost of Schedule G Sales (E7)	0	0	0.00000
17.Fuel Cost Schedule J Sales (E7)	581,700	33,359,000	1.74376
17a.Fuel Cost Schedule D TPS and Seperated Sales (E7)	4,107,800	257,993,000	1.59221
18.TOTAL FUEL COST AND GAINS OF POWER SALES	20,241,040	1,113,776,000	1.81733
19.Net Inadvertant Interchange (E4)	0	0	
19b.Interchange and Wheeling Losses	0	19,834,000	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	188,999,879	8,261,843,000	2.28762
21.Net Unbilled (E4)	3,627,868 (a)	158,587,000	0.04731
22.Company Use (E4)	384,320 (a)	16,800,000	0.00501
23.T & D Losses (E4)	9,570,647 (a)	418,367,000	0.12481
24.Adjusted System KWH Sales	188,999,879	7,668,089,000	2.46476
25.Wholesale KWH Sales	(798,126)	(32,759,000)	2.43636
26.JURISDICTIONAL KWH SALES	188,201,753	7,635,330,000	2.46488
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00005	188,295,854	7,635,330,000	2.46611
28.True–up * (derived in Attachment C)	(6,423,678)	7,635,330,000	–0.08413
29.Pyramid Coal Contract Buyout Adjustment	0	7,635,330,000	0.00000
30.TOTAL JURISDICTIONAL FUEL COST	181,872,176	7,635,330,000	2.38198
31.Revenue Tax Factor			1.00083
32.Fuel Cost Adjusted for Taxes	182,023,130		2.38396
33.GPIF * (Already adjusted for taxes)	146,321	7,635,330,000	0.00192
34.Total Fuel Cost including GPIF	182,169,451	7,635,330,000	2.38588
35.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			**2.386**

*Based on Jurisdictional Sales

Effective date for billing purposes:

(a) Included for informational purposes only.

ATTACHMENT A

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)	113,193,885	5,533,480,000	2.0456
2.Net Cost of Emission Allowances	0	0	0.0000
3.Adjustments to Fuel Cost	0	0	0.0000
4.TOTAL COST OF GENERATED POWER	113,193,885	5,533,480,000	2.0456
5.Fuel Cost of Purchased Power – Firm (E8)	0	0	0.0000
6.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	10,212,000	562,780,000	ERR
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	10,212,000	562,780,000	1.8146
12.TOTAL AVAILABLE KWH (line 4 + line 11)		6,096,260,000	
13.Fuel Cost of Economy Sales (E7)	(654,000)	(22,790,000)	2.8697
14.Gain on Economy Sales – 80% (E7A)	(55,200)	0 (a)	0.0000
15.Fuel Cost of Unit Power Sales (E7)	(12,115,000)	(688,200,000)	1.7604
16.Fuel Cost of Other Power Sales (E7)	(5,046,000)	(247,167,000)	2.0415
17.TOTAL FUEL COST AND GAINS OF POWER SALES	(17,870,200)	(958,157,000)	1.8651
18.Net Inadvertant Interchange (E4)	0		
19.TOTAL FUEL AND NET POWER TRANSACTIONS	105,535,685	5,138,103,000	2.0540
20.Net Unbilled (E4)	0	0	0.0000
21.Company Use (E4)	20,255,805 (a)	9,865,000	205.3300
22.T & D Losses (E4)	7,143,422 (a)	347,781,000	2.0540
23.Adjusted System KWH Sales	105,535,685	4,780,457,000	2.2076
24.Wholesale KWH Sales	3,774,554	170,980,000	2.2076
25.JURISDICTIONAL KWH SALES	101,761,131	4,609,477,000	2.2077
26.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00140	101,903,596	4,609,477,000	2.2107
27.True–up *	2,971,655	4,609,477,000	0.0645
28.Total Jurisdictional Fuel Cost	104,875,251	4,609,477,000	2.2752
29.Revenue Tax Factor			1.01609
30.Fuel Cost Adjusted for Taxes			2.3118
31.Special Contract Recovery Cost	121,472	4,609,477,000	0.0026
32.GPIF *	22,931	4,609,477,000	0.0005
33.Total Fuel Cost including GPIF	104,898,182	4,609,477,000	2.3149
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			**2.315**

*Based on Jurisdictional Sales
Effective date for billing purposes:

(a) included for informational purposes only.

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

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ESTIMATED FOR THE PERIOD: April 1995 – September 1995

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)	3,239,841	151,682,000	2.13594
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	0	0	0.00000
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	0	0	0.00000
9.Energy Cost of Sch.E Purchases (E9)	0	0	0.00000
10.Demand & Non Fuel Cost of Purchased Power (E2)	3,336,279	151,682,000 (a)	2.19952
10a.Demand Costs of Purchased Power	2,287,890 (a)		
10b.Non–Fuel Energy & Customer Costs of Purchased Power	1,048,389 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	0	0	0.00000
12.TOTAL COST OF PURCHASED POWER	6,576,120	151,682,000	4.33546
13.TOTAL AVAILABLE KWH	6,576,120	151,682,000	4.33546
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	6,576,120	151,682,000	4.33546
21.Net Unbilled (E4)	205,544 (a)	4,741,000	0.14603
22.Company Use (E4)	4,986 (a)	115,000	0.00354
23.T & D Losses (E4)	263,032 (a)	6,067,000	0.18687
24.ADJUSTED SYSTEM KWH SALES	6,576,120	140,759,000	4.67190
25.Less Total Demand Cost Recovery	2,190,354		
26.JURISDICTIONAL KWH SALES	4,385,766	140,759,000	3.11580
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00	4,385,766	140,759,000	3.11580
28.True–up *	143,938	140,759,000	0.10226
29.TOTAL JURISDICTIONAL FUEL COST	4,529,704	140,759,000	3.21806
30.Revenue Tax Factor			1.00083
31.Fuel Cost Adjusted for Taxes	3,499,562	0	3.22073
32.GPIF *	0	140,759,000	0.00000
33.Total Fuel Cost including GPIF	4,529,704	140,759,000	3.22073
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			3.221

*Based on Jurisdictional Sales

(a) included for informational purposes only.

ATTACHMENT A

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
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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)	3,038,247	174,083,000	1.74529
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	0	0	0.00000
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	0		
9.Energy Cost of Sch.E Purchases (E9)	0	0	0.00000
10.Demand & Non Fuel Cost of Purchased Power	5,253,018	174,083,000	3.01754
10a.Demand Costs of Purchased Power (E2)	2,388,000 (a)		
10b.Non Fuel Energy and Customer Costs of Purchased Power (E2)	2,865,018 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	0	0	0.00000
12.TOTAL COST OF PURCHASED POWER	8,291,265	174,083,000	4.76282
13.TOTAL AVAILABLE KWH	8,291,265	174,083,000	4.76282
14.Fuel Cost of Economy Sales (E7)	0	0	0.00000
15.Gain on Economy Sales – 80% (E7A)	0	0	0.00000
16.Fuel Cost of Unit Power Sales (E7)	0	0	0.00000
17.Fuel Cost of Other Power Sales (E7)	0	0	0.00000
18.TOTAL FUEL COST AND GAINS OF POWER SALES	0	0	0.00000
19.Net Inadvertant Interchange (E4)			
20.TOTAL FUEL AND NET POWER TRANSACTIONS	8,291,265	174,083,000	4.76282
21.Net Unbilled (E4)	10,288 (a)	216,000	0.00630
22.Company Use (E4)	9,811 (a)	206,000	0.00601
23.T & D Losses (E4)	497,477 (a)	10,445,000	0.30480
24.Adjusted System KWH Sales	8,291,265	163,216,000	5.07993
25.Wholesale KWH Sales	0	0	0.00000
26.JURISDICTIONAL KWH SALES	8,291,265	163,216,000	5.07993
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00	8,291,265	163,216,000	5.07993
27a.GSLD KWH Sales (E11)		36,000,000	
27b.Other Classes KWH Sales (E11)		127,216,000	
27c.GSLD CP KW		132,000 (a)	
28. GPIF			
29.True–up *	(137,540)	163,216,000	–0.08427
30.TOTAL JURISDICTIONAL FUEL COST	8,153,725	163,216,000	4.99567

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 02/20/95
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ESTIMATED FOR THE PERIOD: April 1995 – September 1995

FLORIDA PUBLIC UTILITIES–FERNANDINA

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
30a.Demand Purchased Power Costs (line 10a)	2,388,000 (a)		
30b.Non–Demand Purchased Power Costs (lines 6+10b+11)	5,903,265 (a)		
30c.True–up Over/Under Recovery (line 29)	(137,540)(a)		
APPORTIONMENT OF DEMAND COSTS			
31.Total Demand Costs	2,388,000		
32.GSLD Portion of Demand Costs Including line losses (line 27c * $3.708)	815,760	132,000 KW	$6.18
33.Balance to Other Customers	1,572,240	127,216,000	1.23588
APPORTIONMENT OF NON–DEMAND COSTS			
34.Total Non–Demand Costs (line 30b)	5,903,265		
35.Total KWH Purchased (line 12)		174,083,000	
36.Average Cost per KWH Purchased			3.39106
37.Avg. Cost Adjusted for Transmission line losses (line 36 * 1.03)			3.49280
38.GSLD Non–Demand Costs (line 27a * line 37)	1,257,303	36,000,000	0.03493
39.Balance to Other Customers	4,645,962	127,216,000	3.65203
GSLD PURCHASED POWER COST RECOVERY FACTORS			
40a.Total GSLD Demand Costs (Line 32)	815,760	132,000	$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)	1,257,303	36,000,000	3.49251
40e.Total Non–Demand Costs including true–up	1,257,303	36,000,000	3.49251
40f.Revenue Tax Factor			1.01609
40g.GSLD Non–demand costs adjusted for taxes			3.549
OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a.Total Demand and Non–Demand Purchased Power Costs of other classes (lines 33 + 39)	6,218,202	127,216,000	4.88791
41b.Less: Total Demand Cost Recovery	1,593,378 (a)		
41c.Total Other Costs to be Recovered	4,624,824 (a)	127,216,000	3.63541
41d.Other Classes' Portion of True–up (line 30 C)	(137,540)	127,216,000	–0.10812
41e.Total Demand and Non–Demand Costs including True–up	4,487,284	127,216,000	3.52730
42.Revenue tax factor			1.01609
			3.58405
43.OTHER CLASSES PURCHASED POWER FACTOR ADJUSTED FOR TAXES ROUNDED TO THE NEAREST .001 CENTS PER KWH:			**3.584**

*Based on Jurisdictional Sales

(a) included for informational purposes only.