BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause and generating performance incentive factor.	DOCKET NO. 010001-EI ORDER NO. PSC-01-2516-FOF-EI ISSUED: December 26, 2001

The following Commissioners participated in the disposition of this matter:

E. LEON JACOBS, JR., Chairman
J. TERRY DEASON
LILA A. JABER
BRAULIO L. BAEZ
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APPEARANCES:

JAMES A. MCGEE, ESQUIRE, Florida Power Corporation, P. O. Box 14042, St. Petersburg, Florida 33733-4042
On behalf of Florida Power Corporation (FPC).

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On behalf of Florida Power & Light Company (FPL).

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On behalf of Gulf Power Company (Gulf).

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

TOM CLOUD, ESQUIRE, Gray, Harris and Robinson, P. A., 201 S. Bronough Street, Suite 600, Tallahassee, Florida 32301
On behalf of Publix Super Markets, Inc. (Publix).

JOHN W. MCWHIRTER, JR., ESQUIRE, and VICKI GORDON KAUFMAN, ESQUIRE, McWhirter Reeves McGlothlin Davidson Decker Kaufman Arnold & Steen, P. A., McWhirter Reeves McGlothlin Davidson Decker Kaufman Arnold & Steen, P. A., 117 South Gadsden Street, Tallahassee, Florida 32301
On behalf of Florida Industrial Power Users Group (FIPUG).

ROBERT D. VANDIVER, ESQUIRE, Associate Public Counsel, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida (OPC).

WM. COCHRAN KEATING, IV, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Commission Staff (Staff).

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

As part of this Commission's continuing fuel and purchased power cost recovery and generating performance incentive factor proceedings, a hearing was held on November 20-21, 2001, in this docket. The hearing addressed the issues set out in the Prehearing Order for this docket. Several of the positions on these issues were stipulated by the parties and presented to us for approval, but some contested issues remained for our consideration. As set forth fully below, we approve each of the stipulated positions presented. Our rulings on the remaining contested issues are also discussed below.

We have jurisdiction over this subject matter pursuant to the provisions of Chapter 366, Florida Statutes, including Sections 366.04, 366.05, and 366.06, Florida Statutes.

I. GENERIC FUEL COST RECOVERY ISSUES

A. Shareholder Incentive Benchmarks

The parties stipulated that the estimated benchmark levels for calendar year 2001 for gains on non-separated wholesale energy sales eligible for a shareholder incentive pursuant to Order No. PSC-00-1744-PAA-EI, in Docket No. 991779-EI are as follows:

FPC:	$11,880,954
FPL:	$52,953,147
GULF:	$886,926
TECO:	$4,768,644

Based on the evidence in the record, we approve this stipulation as reasonable.

The parties also stipulated that the estimated benchmark levels for calendar year 2002 for gains on non-separated wholesale energy sales eligible for a shareholder incentive pursuant to Order No. PSC-00-1744-PAA-EI, in Docket No. 991779-EI are as follows:

FPC:	$11,354,219
FPL:	$37,870,079
GULF:	$1,208,241
TECO:	$2,289,019

Based on the evidence in the record, we approve this stipulation as reasonable.

B. Regulatory Treatment of Capital Projects Expected to Reduce Long-Term Fuel Costs

The parties stipulated that the appropriate regulatory treatment for capital projects with an in-service date on or after January 1, 2002, that are expected to reduce long-term fuel costs is the treatment prescribed by this Commission in Order No. 14546 in Docket No. 850001-EI-B where we listed the types of costs that are recoverable through the Fuel Cost Recovery Clause. Item No. 10 in that Order states:

> Fossil fuel-related costs normally recovered through base rates but which were not recognized or anticipated in the

> cost levels used to determine current base rates and which, if expended, will result in fuel savings to customers. Recovery of such costs should be made on a case by case basis after Commission approval.

In addition, the parties stipulated that the appropriate rate of return on the unamortized balance of capital projects with an in-service date on or after January 1, 2002, is the utility's cost of capital based on the midpoint of its authorized return on equity. We approve these stipulations as reasonable.

C. Recovery of Incremental Power Plant Security Costs

In this proceeding, FPL requests approval to recover incremental power plant security costs, related to recent national security concerns, through the fuel and purchased power cost recovery clause ("fuel clause"). Based on the evidence in the record, we approve FPL's request. We find that recovery of this incremental cost through the fuel clause is appropriate in this instance because there is a nexus between protection of FPL's nuclear generation facilities and the fuel cost savings that result from the continued operation of those facilities. Further, we believe that this type of cost is a potentially volatile cost, making it appropriate for recovery through a cost recovery clause. We are comforted that the true-up mechanism inherent in the fuel clause will ensure that ratepayers pay no more than the actual costs incurred. In addition, we find that recovery of this cost through the fuel clause provides a good match between the timing of the incurrence and recovery of the cost.

We believe that approving recovery of this incremental power plant security cost through the fuel clause sends an appropriate message to Florida's investor-owned electric utilities that we encourage them to protect their generation assets in extraordinary, emergency conditions as currently exist. FPL is the only utility seeking recovery of this cost in this proceeding. By our decision, we do not intend to require other investor-owned electric utilities to seek similar recovery at this time, given the unique circumstances of each utility. In addition, recognizing that these costs are not now clearly defined, we do not foreclose our ability to consider an alternative recovery mechanism for these costs at a later time.

D. Use of Updated Energy, Demand, and Price Forecasts

On August 31, 2001, FPL filed its petition for approval of fuel cost recovery factors and capacity cost recovery factors based, in part, on its forecast of sales for 2002. On November 5, 2001, FPL filed a petition for approval of revised fuel cost recovery factors and capacity cost recovery factors based on a reduction in its sales forecast for 2002. In support of this petition, witness Green testified that the impact of the September 11, 2001, attacks on the United States changed Florida's economic outlook for 2002 and, thus, warrants a revision to FPL's sales forecast. Witness Green testified that the performance of Florida's economy determines electricity usage per customer and the level of customer growth. He further testified that the growth of both of these factors is forecast to decline from the levels forecast prior to September 11, 2001, resulting in lower forecast electricity sales in FPL's service territory.

We believe that the use of FPL's revised 2002 sales forecast in establishing its 2002 fuel cost recovery factors and capacity cost recovery factors is appropriate. The factors that we approve for FPL in this Order, below, are based on FPL's revised sales forecast. We do not, however, require other investor-owned electric utilities to base their fuel and capacity cost recovery factors on updated sales forecasts at this time. We note that this matter was addressed in Order No. 13694, issued September 20, 1984, which requires utilities to inform this Commission of material and significant changes in the basic assumptions underlying their fuel and capacity cost recovery factors. The Order indicates that these cost recovery factors should be revised if changed assumptions would result in an anticipated overrecovery or underrecovery in excess of ten percent. No evidence was presented in this proceeding to suggest that FPC, Gulf, or TECO's proposed fuel and capacity cost recovery factors would result in this threshold variance.

II. COMPANY-SPECIFIC FUEL COST RECOVERY ISSUES

A. Florida Power & Light Company

The parties agree that FPL's aerial survey method of its coal inventory at Plant Scherer as stated in Audit Disclosure No. 1 of Audit Control No. 01-053-4-1 is not consistent with the method set forth in Order No. PSC-97-0359-FOF-EI, in Docket No. 970001-EI, issued March 31, 1997. Plant Scherer is located in Georgia and is operated by Georgia Power Company. The accounting procedures required of Georgia Power Company by the Georgia Public Service Commission are similar to those stated in Order No. PSC-97-0359-FOF-EI, with some differences. These different accounting procedures produce nearly identical coal inventory adjustments. However, FPL agrees to report aerial survey results and calculations of necessary coal inventory adjustments as soon as Georgia Power Company provides these adjustments to FPL. It is understood that this exception to the method specified in Order No. PSC-97-0359-FOF-EI is applicable to Plant Scherer only. The parties stipulated to this treatment. We approve this stipulation as reasonable.

The parties stipulated that FPL reasonably evaluated the costs associated with Florida Power & Light Company's purchase of 50 MW firm capacity and associated energy from Florida Power Corporation against the market price for similar capacity and energy and, thus, that these costs are reasonable. We approve this stipulation as reasonable.

The parties also stipulated FPL reasonably evaluated the costs associated with Florida Power & Light Company's purchase of approximately 1,000 MW of capacity and associated energy from Progress Energy Ventures, Reliant Energy Services, and Oleander Power Project L.P. against the market price for similar capacity and energy and, thus, that these costs are reasonable. We approve this stipulation as reasonable.

The parties stipulated that FPL should be permitted to recover through the fuel and capacity cost recovery clauses payments made to Cedar Bay resulting from litigation between FPL and Cedar Bay. In Order No. PSC-99-2512-FOF-EI, Docket No. 990001-EI, this Commission, by panel decision, allowed FPL to recover these costs as proposed through the fuel and capacity cost recovery clauses pending resolution of this issue by the full Commission. After our decision in December of 1999, Docket No. 991780-EG was opened so that the full Commission could address this issue. Waiting on completion of the appeals process, no schedule had been established in Docket No. 991780-EG. All appeals have now been exhausted and all payments have been made. Because the full Commission now hears this docket, we bring this issue to closure by approving the parties' stipulation as reasonable.

We find that the appropriate level of FPL 2002 incremental power plant security costs, related to recent increased national security concerns, allowed for recovery through the fuel clause is $1,860,000. As stated above, these amounts shall be subject to true-up to ensure that the ratepayers pay no more than the actual costs incurred in 2002.

B. Florida Power Corporation

The parties stipulated that FPC has confirmed the appropriateness of the "short-cut" methodology used to determine the equity component of Electric Fuels Corporation's capital structure for calendar year 2000. We approve this stipulation as reasonable.

The parties stipulated that FPC properly calculated the market price true-up for coal purchases from Powell Mountain in accordance with the market pricing methodology approved by this Commission in Docket No. 860001-EI-G. We approve this stipulation as reasonable.

The parties stipulated that FPC properly calculated the 2000 price for waterborne transportation services provided by Electric Fuels Corporation in accordance with the market pricing methodology approved by this Commission in Docket No. 930001-EI. We approve this stipulation as reasonable.

The parties stipulated that FPC's replacement fuel costs associated with the unplanned outage at Crystal River Unit 2, commencing on June 1, 2000, were reasonable. The record indicates that this outage began when a high voltage disconnect switch failed, which resulted in a high energy fault that caused significant damage to the generator rotor. The record also indicates that FPC could not have foreseen that the operation of this switch, which had been operated under similar circumstances many times, would lead to the damage that occurred. The parties agree that the resulting three-month outage to remove, repair, and reinstall the generator rotor was reasonable. Based on the evidence in the record, we approve this stipulation as reasonable.

The parties stipulated that payments made by FPC to Lake Cogen, Ltd. (Lake) pursuant to the outcome of contract litigation between FPL and Lake are appropriate for recovery through the fuel clause. Florida's Fifth District Court of Appeals ruled that FPC is required to pay Lake the firm energy rate for all hours that the avoided unit would operate and that the avoided unit would operate at all times other than periods for maintenance and repair. This ruling led to a stipulation requiring FPC to pay Lake $19,860,307 to resolve the historical energy pricing dispute. The stipulation also provides 45 days per year for maintenance periods during which Lake will be paid the as-available energy rate. The ruling by the court and subsequent stipulation results in costs over the life of the contract approximately $60 million (net present value) greater than the costs would have been under FPC's position in the litigation, but approximately $13.7 million (net present value) less than the costs would have been under Lake's position in the litigation. The parties also stipulated that the energy payments FPC is to make to Lake on a going forward basis are appropriate for recovery through the fuel clause. Based on the evidence in the record, we approve these stipulations as reasonable.

C. Florida Public Utilities Company

The record indicates that for the period October 2000 through September 2001, FPUC billed its GSD customers in the Marianna Division under the Street Lighting (SL) fuel cost recovery factor, which is lower than the GSD fuel cost recovery factor. The Commission-approved SL fuel cost recovery factor was 2.608 cents/kWh for the period October 2000 through December 2000, and 2.421 cents/kWh for the period January 2001 through September 2001. The Commission-approved GSD fuel cost recovery factor was 3.599 cents/kWh for the period October 2000 through December 2000, and 3.472 cents/kWh for the period January 2001 through September 2001. The parties stipulated to these facts.

The parties have also stipulated that the appropriate corrective action is for FPUC to backbill the affected customers for the shortfall through an adjustment on their future bill(s), pursuant to Rule 25-6.106(1), Florida Administrative Code. Under the provisions of this rule, FPUC shall allow the customers to pay for the unbilled service over the same length of time as the error occurred, or some other mutually agreeable time period. We approve these stipulations as reasonable.

D. Tampa Electric Company

Stipulated Matters

The parties stipulated that the appropriate 2000 waterborne coal transportation benchmark price for transportation services provided by TECO affiliates is $26.23 per ton. We approve this stipulation as reasonable.

The parties stipulated that TECO's actual costs associated with transportation service provided by TECO affiliates are below the 2000 waterborne transportation benchmark price. We approve this stipulation as reasonable.

The parties stipulated that TECO reasonably evaluated the lease of 39 portable generators to provide 70 MW of peaking capacity against the market price for similar capacity and energy and, thus, that TECO's lease of those generators was reasonable. We approve this stipulation as reasonable.

The parties stipulated that TECO's proposal to refund $6.37 million from 1999 earnings to its ratepayers from January 2002 to March 2002 is reasonable. Order No. PSC-01-0113-PAA-EI, issued in Docket No. 950379-EI, provides that TECO refund $6,102,126, plus interest, as of December 31, 2000 to the time the actual refund is completed. OPC protested this order and, at the time of our vote on this matter, OPC's protest had not been decided. Thus, we could not determine the final refund amount at the time of our vote. However, the parties agree that the amount will be at least $6.37 million. The parties stipulated that TECO has properly allocated this amount among its rate classes. Based on the evidence in the record, we approve these stipulations as reasonable.

TECO's Wholesale Transactions with Non-Afilliated Entities

For the reasons set forth below, we find that the evidence in the record shows that TECO's decisions concerning its wholesale energy purchases from and sales to non-affiliated entities were reasonable during the period January 1998 through December 2000.

The evidence indicates the following facts. TECO has not entered into any new long-term separated firm wholesale sales since 1995. The last new firm sale of any kind made by TECO was a nine month non-separated sale in 1998. TECO's reserve margins were estimated to be fifteen percent or greater over the planning horizon at the time each of the current firm contracts was signed. All of TECO's firm sales are cost-based, with FERC-approved pricing; none of the existing firm contracts are market-priced. Only one of TECO's separated sales is recallable. TECO has recalled this contract to serve firm load. These facts suggest that TECO appropriately entered into its current separated sales and is appropriately managing its current firm contracts. No evidence was presented to suggest otherwise. The evidence further indicates that TECO is currently entering only into new non-firm non-separated sales agreements, and TECO has a policy of recalling these sales if capacity is needed to serve both firm and non-firm retail load.

FIPUG's witness Collins stated that the issue at hand is not whether TECO's management of its wholesale sales was appropriate, but rather whether TECO's costs, including purchased power costs, are allocated appropriately to wholesale customers. We find that TECO has appropriately allocated its costs to wholesale customers.

First, capital and O&M costs for the generating plant necessary to make separated sales are allocated to wholesale customers. This reduces capital costs for retail customers when putting new plant in service for which total capacity is not immediately needed to serve retail load. A complete review of the effect of separated sales on retail customers must include the reduction in capital costs associated with serving separated wholesale customers.

Second, we agree with FIPUG's witnesses Collins and Pollock that fuel costs should be allocated to separated sales based on average system fuel cost. We also agree with FIPUG that average system fuel costs should include both generation and purchased power costs. Order No. PSC-97-0262-FOF-EI, issued March 11, 1997, in Docket No. 970001-EI, required that on a prospective basis, separated sales should be allocated average system fuel costs. The evidence indicates that TECO appears to be adhering to this policy. Only one of TECO's separated sales has fuel costs based on a specified unit. All other sales are based on average system fuel costs. TECO's only unit based sale was entered into in 1989, prior to issuance of Order No. PSC-97-0262-FOF-EI.

FIPUG witness Collins asserted that TECO's retail customers are being charged for 100 percent of TECO's purchased power costs. Witness Collins also asserted that separated wholesale customers are not paying for TECO's purchased power costs, but are charged rates based solely on fuel costs for "low-cost generation." We disagree with these assertions. Purchased power costs allocated to separated wholesale customers are included in the total fuel costs paid by separated customers included on line 29 of TECO's Schedules A-1 and E-1. A comparison of line 29 and 30 on TECO's E-1 schedule supports the position that on a going-forward basis, TECO expects the average fuel costs per MWH charged to separated wholesale customers to be approximately the same as that for retail customers.

We agree with FIPUG witness Pollock that non-separated sales should be charged incremental fuel costs, and that these costs should be used to determine the gains on these sales. We also agree with witness Pollock that incremental fuel costs can be either based on generation or purchased power costs. This is consistent with the treatment we approved in Order No. PSC-01-2371-FOF-EI, issued December 7, 2001, in Docket No. 010283-EI. TECO's policy of using incremental fuel costs, whether from generation or purchased power, to calculate the gains on non-separated sales appears to be consistent with our ruling in that Order. Given TECO's use of incremental fuel costs to calculate the gains, we disagree with FIPUG's assertion that retail customers receive little benefit from non-separated sales. Retail ratepayers receive 100% of the gains from these sales up to a benchmark based on past sales, after which gains are shared 80/20 between retail ratepayers and shareholders.

We find that the greater weight of the evidence shows that TECO is managing its wholesale purchases appropriately and allocating the costs from its purchases appropriately. TECO's new planned short-term firm purchases appear to be cost-effective.

We find that the greater weight of the evidence shows that TECO's purchases of buy-through power on behalf of interruptible retail customers were appropriate. Witnesses Collins and Pollock stated that the cost per kWh of buy-through power was increasing. The record indicates that no buy-through power was purchased by TECO from TECO affiliates. Therefore, there is no reason to believe that TECO has an incentive to purchase unreasonably high priced buy-through power.

TECO's Wholesale Transactions with Hardee Power Partners

We find that the evidence in the record shows that TECO's decisions concerning its wholesale energy purchases from and sales to Hardee Power Partners were reasonable during the period January 1998 through December 2000. No evidence was presented that indicated TECO is abusing the Hardee Power Partners contract or allocating the costs of this contract inappropriately. We do not believe that further study of this issue is warranted at this time.

The record indicates that TECO's contract with Hardee Power Partners is FERC-approved and cost-based. The original contract was appropriately compared to other available capacity and energy options. TECO's latest amendment to the contract compares favorably to the forwards energy market price, even if the capacity costs of the Hardee contract are included.

Further, TECO's separated sale of 145 megawatts to TECO Power Services from Hardee is TECO's only unit-based sale. This contract was signed in 1989 and expires on December 31, 2002. The record indicates that TECO has no plans to renegotiate this sale upon expiration of the contract. At the expiration of this contract, the capacity from TECO's Big Bend Unit 4 reserved for this contract will be available to serve TECO's retail ratepayers.

Allocation of TECO's Purchased Power Costs

We find that TECO does not allocate 100% of purchased power costs to retail customers. Purchased power costs include an energy and a capacity component. The evidence shows that a jurisdictional separation factor is applied to TECO's projected total system fuel and purchased power costs for 2002, which includes the cost of generated power and the energy component of purchased power. The evidence also shows that a jurisdictional demand separation factor is applied to TECO's total capacity payments for 2002. Applying energy and demand jurisdictional separation factors to TECO's total purchased power costs appropriately allocates a portion of TECO's purchased power costs to wholesale customers.

E. Gulf Power Company

The parties stipulated that Gulf's replacement fuel costs for the unplanned outage at Crist Unit 2, commencing on August 2, 2000, were reasonable. The record indicates that Gulf did not buy any additional fuel to specifically compensate for the unavailability of this peaking unit. Further, during the majority of this unplanned outage, Crist Unit 2 would not have been called upon in economic dispatch had it been available. We approve this stipulation as reasonable.

The parties agreed that Gulf inadvertently overstated the emission allowance costs related to Interchange Sales in August, 2000, which understated net recoverable fuel expense by $385,796 in 2000. Gulf made a correcting entry in July 2001 and has included this amount for recovery in this docket but is not requesting any back interest on the understated fuel expense. The parties stipulated that these corrective actions were appropriate. We approve this stipulation as reasonable.

III. APPROPRIATE PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR FUEL COST RECOVERY FACTORS

Based on the evidence in the record and the resolution of the generic and company-specific fuel cost recovery issues discussed above, we approve the following as the appropriate final fuel adjustment true-up amounts for the period of January 2000 through December 2000:

FPC:	$29,378,219 underrecovery
FPL:	$76,807,071 underrecovery
FPUC-Marianna:	$60,625 underrecovery
FPUC-Fernandina Beach:	$109,370 underrecovery
GULF:	$6,907,921 overrecovery
TECO:	$23,129,476 underrecovery

Based on the evidence in the record and the resolution of the generic and company-specific fuel cost recovery issues discussed above, we approve the following as the appropriate estimated/actual fuel adjustment true-up amounts for the period of January 2001 through December 2001:

FPC:	$33,346,822 overrecovery. Pending resolution of our review of FPC's risk management for natural gas purchases from March 1999 through March 2001, this Commission maintains jurisdiction over revenues credited and costs charged to the fuel and purchased power cost recovery clause.
FPL:	$13,794,067 overrecovery. Pending resolution of our review of FPL's risk management for natural gas purchases from March 1999 through March 2001, this Commission maintains jurisdiction over revenues credited and costs charged to the fuel and purchased power cost recovery clause.
FPUC-Marianna:	$1,548 underrecovery
FPUC-Fernandina Beach:	$92,507 overrecovery
GULF:	$17,609,612 underrecovery
TECO:	$65,543,259 underrecovery

Based on the evidence in the record and the resolution of the generic and company-specific fuel cost recovery issues discussed above, we approve the following as the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2002 through December 2002:

FPC:	$23,640,300 underrecovery. This amount includes the $27,608,904 underrecovery this Commission deferred for recovery until 2002. Pending resolution of our review of FPC's risk management for natural gas purchases from March 1999 through March 2001, this Commission maintains jurisdiction over revenues credited and costs charged to the fuel and purchased power cost recovery clause.
FPL:	$245,208,621 underrecovery. Pending resolution of our review of FPL's risk management for natural gas purchases from March 1999 through March 2001, this Commission maintains jurisdiction over revenues credited and costs charged to the fuel and purchased power cost recovery clause.
FPUC-Marianna:	$62,173 to be collected
FPUC-Fernandina Beach:	$16,863 to be collected

GULF:	$10,701,691 underrecovery
TECO:	$88,672,735 underrecovery.

Based on the evidence in the record and the resolution of the generic and company-specific fuel cost recovery issues discussed above, we approve the following as the appropriate levelized fuel cost recovery factors for the period January 2002 through December 2002:

FPC:	2.687¢/kWh
FPL:	2.860¢/kWh
FPUC-Marianna:	2.333¢/kWh
FPUC-Fernandina Beach:	2.095¢/kWh
GULF:	2.212¢/kWh
TECO:	3.301¢/kWh

Based on the evidence in the record and the resolution of the generic and company-specific fuel cost recovery issues discussed above, we approve the following as the appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class:

FPC:

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

FPL: The appropriate Fuel Cost Recovery Loss Multipliers are as provided on pages 17-18 of this Order.

FPUC:

Marianna	Multiplier
All Rate Schedules	1.0000
Fernandina Beach	
All Rate Schedules	1.0000

GULF: See table below:

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

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

TECO:

<u>Group</u>	<u>Multiplier</u>
Group A	1.0035
Group A1	n/a*
Group B	1.0009
Group C	0.9792

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

Based on the evidence in the record and the resolution of the generic and company-specific fuel cost recovery issues discussed above, we approve the following as the appropriate fuel recovery factors for each rate class/delivery voltage level class adjusted for line losses:

FPC:

Group	Delivery Voltage Level	Fuel Cost Factors (cents/kWh) Standard	Time Of Use On-Peak	Time Of Use Off-Peak
A.	Transmission	2.638	3.208	2.393
B.	Distribution Primary	2.665	3.241	2.417
C.	Distribution Secondary	2.692	3.273	2.442
D.	Lighting Service	2.597		

FPL:

GROUP	RATE SCHEDULE	AVERAGE FACTOR	FUEL RECOVERY LOSS MULTIPLIER	FUEL RECOVERY FACTOR
A	RS-1,GS-1,SL2	2.860	1.00210	2.866
A-1*	SL-1,OL-1,PL-1	2.799	1.00210	2.805
B	GSD-1	2.860	1.00202	2.865
C	GSLD-1 & CS-1	2.860	1.00078	2.862
D	GSLD-2,CS-2,OS-2 & MET	2.860	.99429	2.843
E	GSLD-3 & CS-3	2.860	.95233	2.723

GROUP	RATE SCHEDULE	AVERAGE FACTOR	FUEL RECOVERY LOSS MULTIPLIER	FUEL RECOVERY FACTOR
A	RST-1,GST-1			
	ON-PEAK	3.138	1.00210	3.145
	OFF-PEAK	2.735	1.00210	2.741
B	GSDT-1,CILC-1(G)			
	ON-PEAK	3.138	1.00202	3.144
	OFF-PEAK	2.735	1.00202	2.740
C	GSLDT-1 & CST-1			
	ON-PEAK	3.138	1.00078	3.140
	OFF-PEAK	2.735	1.00078	2.737
D	GSLDT-2 & CST-2			
	ON-PEAK	3.138	.99429	3.120
	OFF-PEAK	2.735	.99429	2.719
E	GSLDT-3,CST-3 CILC-1(T)&ISST-1(T)			
	ON-PEAK	3.138	.95233	2.988

	OFF-PEAK	2.735	.95233	2.604
F	CILC-1(D) & ISST-1(D)			
	ON-PEAK	3.138	.99331	3.117
	OFF-PEAK	2.735	.99331	2.717

*WEIGHTED AVERAGE 16% ON-PEAK AND 85% OFF-PEAK

FPUC: Marianna:

Rate Schedule	Adjustment
RS	$.04060
GS	$.04042
GSD	$.03654
GSLD	$.03492
OL	$.02529
SL	$.02526

Fernandina Beach:

Rate Schedule	Adjustment
RS	$.03983
GS	$.03732
GSD	$.03581
CSL	$.02591
OL	$.02591
SL	$.02591

GULF:

Group	Rate Schedules*	Fuel Cost Factors ¢/KWH		
		Standard	Time of Use	
			On-Peak	Off-Peak
A	RS, RSVP, GS, GSD, SBS, OSIII, OSIV	2.239	2.713	2.038
B	LP, LPT, SBS	2.170	2.629	1.975

C	PX, PXT, RTP, SBS	2.129	2.579	1.938
D	OSI, OSII	2.208	N/A	N/A

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

TECO:

Rate Schedule	Fuel Charge Factor (cents per kWh)	
Average Factor	3.301	
RS, GS and TS	3.313	
RST and GST	4.535	(on-peak)
	2.793	(off-peak)
SL-2, OL-1 and OL-3	3.054	
GSD, GSLD, and SBF	3.304	
GSDT, GSLDT, EV-X and SBFT	4.523	(on-peak)
	2.786	(off-peak)
IS-1, IS-3, SBI-1, SBI-3	3.232	
IST-1, IST-3, SBIT-1, SBIT-3	4.425	(on-peak)
	2.725	(off-peak)

We approve as reasonable the following stipulations as to the appropriate revenue tax factor to be applied in calculating each company's levelized fuel factor for the projection period January 2002 through December 2002:

FPC:	1.00072
FPL:	1.01597
FPUC-Fernandina Beach:	1.01597
FPUC-Marianna:	1.00072
GULF:	1.01597
TECO:	1.00072

IV. APPROPRIATE PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR CAPACITY COST RECOVERY FACTORS

We approve as reasonable the following stipulations as to the appropriate final capacity cost recovery true-up amounts for the period January 2000 through December 2000:

FPC:	$1,402,548 underrecovery
FPL:	$2,850,420 underrecovery
GULF:	$340,856 overrecovery
TECO:	$589,079 underrecovery

We approve as reasonable the following stipulations as to the appropriate estimated/actual capacity cost recovery true-up amounts for the period January 2001 through December 2001:

FPC:	$2,309,584 underrecovery
FPL:	$25,003,277 overrecovery
GULF:	$1,515,391 overrecovery
TECO:	$4,971,024 underrecovery

We approve as reasonable the following stipulations as to the appropriate total capacity cost recovery true-up amounts to be collected/refunded during the period January 2002 through December 2002:

FPC:	$3,712,132 to be collected
FPL:	$22,152,857 to be refunded
GULF:	$1,856,247 to be refunded
TECO:	$5,560,103 to be collected

We approve as reasonable the following stipulations as to the appropriate projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January 2002 through December 2002 are as follows:

FPC:	$343,015,424
FPL:	$573,968,082
GULF:	$2,346,103
TECO:	$52,600,466

We approve as reasonable the following stipulations as to the appropriate jurisdictional separation factors to be applied to determine the capacity costs to be recovered during the period January 2002 through December 2002:

FPC:	Base - 97.560%, Intermediate - 71.248%, Peaking - 76.267%.
FPL:	99.03598%
GULF:	96.50747%
TECO:	91.89189%

We approve as reasonable the following stipulations as to the appropriate projected capacity cost recovery factors for each rate class/delivery class for the period January 2002 through December 2002:

FPC:

Rate Class	Capacity Recovery Factor (cents/kWh)
Residential	1.132
General Service Non-demand - Secondary	0.849
@Primary Voltage	0.840
@Transmission Voltage	0.832
General Service 100% Load Factor	0.621
General Service Demand - Secondary	0.737
@Primary Voltage	0.730
@Transmission Voltage	0.722
Curtailable - Secondary	0.526
@Primary Voltage	0.520
@Transmission Voltage	0.515
Interruptible - Secondary	0.612
@Primary Voltage	0.606
@Transmission Voltage	0.599
Lighting	0.181

FPL:

Rate Class	Capacity Recovery Factor ($/kW)	Capacity Recovery Factor ($/kWh)
RS1	-	.00701
GS1	-	.00608
GSD1	2.34	-
OS2	-	.00310
GSLD1/CS1	2.40	-

GSLD2/CS2	2.38	-
GSLD3/CS3	2.49	-
CILCD/CILCG	2.51	-
CILCT	2.53	-
MET	2.55	-
OL1/SL1/PL-1	-	.00182
SL2	-	.00445

Rate Class	Capacity Recovery Factor (Reservation Demand Charge) ($/kW)	Capacity Recovery Factor (Sum of Daily Demand Charge) ($/kW)
ISST1D	.31	.15
SST1T	.29	.14
SST1D	.30	.14

GULF:

Rate Class	Capacity Recovery Factor (cents/kWh)
RS, RST, RSVP	.027
GS, GST	.027
GSD, GSDT	.021
LP, LPT	.018
PX, PXT, RTP, SBS	.016
OS-I, OS-II	.003
OS-III	.016
OS-IV	.008

TECO:

Rate Class	Capacity Recovery Factor ($/kWh)
RS	.00379
GS, TS	.00350
GSD	.00269
GSLD, SBF	.00245
IS-1, IS-3, SBI-1, SBI-3	.00022
SL/OL	.00041

The parties stipulated to the following:

The appropriate adjustment to Gulf's total recoverable capacity payments to reflect the former capacity transactions (credit) embedded in Gulf's base rates, as reflected on line 8 of Schedule CCE-1 should be based on the time period from January 1, 2002, up to the date Gulf's new base rates become effective. According to information provided for Gulf's rate case synopsis, the effective date of new base rates is expected to be June 6, 2002. The adjustment to recoverable capacity payments to reflect the capacity embedded in base rates should cover the period from January 1, 2002, through June 5, 2002, a period of 156 days. The amount of the adjustment should be $706,060 ($1,652,000 / 365 days x 156 days). If the effective date of Gulf's new base rates varies from June 6, 2002, the amount of the adjustment should be revised, with an appropriate adjustment to the true-up amount to reflect the revised amount.

Gulf's current base rate increase request, as filed, reflects adjustments to remove capacity transactions consistent with the calculations currently being made for the purchased capacity cost recovery clause. It is Gulf's position that if the partial year adjustment is made to the PPCC as described above, a corresponding adjustment should be made to Gulf's base rate increase request. This will ensure that the new base rates resulting from Docket No. 010949-EI and the PPCC factors established in this docket are calculated on a consistent basis. The adjustment to Gulf's base rate increase request is appropriately addressed in Docket No. 010949-EI.

We approve this stipulation as reasonable.

V. GENERATING PERFORMANCE INCENTIVE FACTOR (GPIF) ISSUES

The parties stipulated that the appropriate Generation Performance Incentive Factor (GPIF) rewards/penalties for performance achieved during the period January 2000 through December 2000 are those set forth in Attachment A to this Order, which is incorporated by reference herein. We approve these stipulations as reasonable.

The parties stipulated that the appropriate GPIF targets/ranges for the period January 2002 through December 2002 are those set forth in Attachment A to this Order, which is incorporated by reference herein. We approve these stipulations as reasonable.

The parties stipulated that the actual 2000 heat rates for TECO's Big Bend Units #1 and #2 should be adjusted for the flue gas desulfurization's (FGD) impact on Tampa Electric's 2000 reward/penalty. We approved similar adjustments to the actual data for Big Bend Unit 3 from July 1995 to March 1998, when TECO initiated flue gas desulfurization for that unit. In the next three fuel adjustment hearings, these adjustments will be necessary for the actual heat rate data for the years 2001, 2002, and 2003. We approve this stipulation as reasonable.

The parties stipulated that the heat rate targets for the year 2002 for TECO's Big Bend Units #1 and #2 should be adjusted for the FGD's impact on Tampa Electric's eventual 2002 reward/penalty. Adjustments to the heat rates for these units ensures comparability between heat rate targets, which are modeled using historical data, and the actual data for the same periods. These adjustments will also be necessary for the heat rate targets for the year 2003, which will be addressed in Docket No. 020001-EI. We approve this stipulation as reasonable.

VI. OTHER MATTERS

The parties stipulated that the new fuel adjustment charge and capacity cost recovery factors approved in this Order should be effective beginning with the first billing cycle for January 2002 and thereafter through the last billing cycle for December 2002. The parties also stipulated that the first billing cycle may start before January 1, 2002, and the last billing cycle may end after December 31, 2002, so long as each customer is billed for twelve months regardless of when the factors became effective. We approve these stipulations as reasonable.

Based on the foregoing, it is

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

ORDERED that Florida Power & Light Company, Florida Power Corporation, Tampa Electric Company, Gulf Power Company, and Florida Public Utilities Company are hereby authorized to apply the fuel cost recovery factors set forth herein during the period of January 2001 through December 2001. It is further

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

ORDERED that Florida Power & Light Company, Florida Power Corporation, Gulf Power Company, and Tampa Electric Company are hereby authorized to apply the capacity cost recovery factors as set forth herein during the period January 2001 through December 2001. It is further

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

By ORDER of the Florida Public Service Commission this 26th day of December, 2001.

BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

Paul Nichols, Chief
Administrative Services

(S E A L)

WCK/KNE

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of the Commission Clerk and Administrative Services 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.

Attachment A

Page 1 of 4

GPIF REWARDS/PENALTIES

January 2000 to December 2000

Utility	Amount	Reward/Penalty
Florida Power Corporation	$ 266,919	Reward
Florida Power and Light Company	$ 9,004,713	Reward
Gulf Power Company	$ 379,732	Reward
Tampa Electric Company	$ 1,095,745	Reward

Utility/ Plant/Unit	EAF		Heat Rate	
FPC	Target	Adjusted Actual	Target	Adjusted Actual
Anclote 1	92.4	84.5	10,022	10,177
Anclote 2	83.9	86.7	10,025	10,085
Crystal River 1	90.3	89.1	9,851	9,840
Crystal River 2	75.3	53.4	9,851	9,735
Crystal River 3	93.4	96.8	10,357	10,333
Crystal River 4	75.7	77.1	9,422	9,308
Crystal River 5	94.0	91.2	9,394	9,313
Bartow 3	82.8	80.9	10,140	10,201
Tiger Bay	79.1	81.0	7,590	7,695
FPL	Target	Adjusted Actual	Target	Adjusted Actual
Cape Canaveral 1	92.4	90.8	9,511	9,541
Cape Canaveral 2	78.2	77.2	9,690	9,764
Fort Lauderdale 4	93.5	91.3	7,349	7,334
Fort Lauderdale 5	93.5	89.9	7,358	7,303
Fort Myers 2	92.7	88.9	9,321	9,442
Manatee 2	71.7	81.1	10,162	10,131
Martin 3	94.2	95.3	6,996	6,770
Martin 4	91.6	95.3	6,906	6,685
Port Everglades 3	95.8	94.6	9,748	9,631
Port Everglades 4	88.2	83.7	9,664	9,647
Putnam 1	91.2	92.9	8,937	8,934
Sanford 4	92.3	90.8	10,016	10,522
Sanford 5	89.3	91.8	10,290	10,247
Turkey Point 3	84.6	90.1	11,066	11,095
Turkey Point 4	84.6	89.2	11,093	11,088
St. Lucie 1	93.6	100.0	10,854	10,805
St. Lucie 2	84.6	90.3	10,872	10,837
Scherer 4	94.2	98.0	9,989	10,036

Attachment A

GPIF REWARDS/PENALTIES

January 2000 to December 2000

Utility/ Plant/Unit	EAF		Heat Rate	
Gulf	Target	Adjusted Actual	Target	Adjusted Actual
Crist 6	84.3	73.5	10,629	10,515
Crist 7	77.3	79.2	10,236	10,241
Smith 1	90.6	92.6	10,332	10,227
Smith 2	89.2	91.5	10,137	10,143
Daniel 1	75.3	80.0	10,237	10,267
Daniel 2	74.5	81.3	10,105	10,046
TECO	Target	Adjusted Actual	Target	Adjusted Actual
Big Bend 1	78.1	74.3	10,127	10,091
Big Bend 2	80.6	83.2	10,061	9,811
Big Bend 3	76.3	79.6	10,197	9,841
Big Bend 4	84.4	86.1	9,976	9,799
Gannon 5	75.3	57.2	10,562	10,766
Gannon 6	72.2	28.2	10,507	10,529

Attachment A

GPIF TARGETS

January 2002 to December 2002

Utility/ Plant/Unit	EAF			Heat Rate
FPC	EAF	POF	EUOF	
Anclote 1	91.7	0.0	8.3	10,183
Anclote 2	81.7	13.2	5.2	10,090
Bartow 3	80.1	11.5	8.4	10,053
Crystal River 1	86.8	0.0	13.3	9,750
Crystal River 2	65.1	20.6	14.3	9,619
Crystal River 3	96.2	0.0	3.8	10,283
Crystal River 4	76.5	20.0	3.5	9,413
Crystal River 5	94.5	0.0	5.5	9,376
Tiger Bay	80.3	13.4	6.3	8,267
FPL	EAF	POF	EUOF	
Cape Canaveral 1	90.3	0.0	9.7	9,163
Cape Canaveral 2	88.2	3.8	7.7	9,209
Ft Lauderdale 4	91.8	2.7	5.5	7,351
Ft Lauderdale 5	91.9	2.7	5.4	7,303
Manatee 1	81.5	7.7	10.8	9,861
Manatee 2	85.4	7.9	6.4	10,054
Martin 1	89.2	4.1	6.4	9,147
Martin 2	90.8	4.1	4.8	8,884
Martin 3	94.9	0.0	5.1	6,828
Martin 4	87.9	4.2	5.4	6,734
Port Everglades 3	94.3	0.0	5.7	9,355
Port Everglades 4	86.0	7.9	5.8	9,192
Putnam 1	84.7	4.8	5.7	8,679
Riviera 3	84.4	0.0	15.6	9,809
Riviera 4	93.1	0.0	6.9	9,797
Turkey Point 1	85.4	7.4	6.9	8,960
Turkey Point 2	94.3	0.0	5.7	9,410
Turkey Point 3	93.6	0.0	6.4	11,137
Turkey Point 4	86.0	8.2	5.8	11,079
St Lucie 1	86.0	8.2	5.8	10,793
St Lucie 2	93.6	0.0	6.4	10,826
Scherer 4	84.4	11.8	3.6	10,098

Attachment A

GPIF TARGETS

January 2002 to December 2002

Utility/ Plant/Unit	EAF			Heat Rate
Gulf	EAF	POF	EUOF	
Crist 4	90.9	6.3	2.8	10,499
Crist 6	77.3	15.9	6.8	10,546
Crist 7	79.7	10.1	10.2	10,196
Smith 1	90.7	6.8	2.5	10,054
Smith 2	86.6	10.7	2.7	10,050
Daniel 1	88.0	2.5	9.5	10,191
Daniel 2	70.7	21.6	7.7	9,906
TECO	EAF	POF	EUOF	
Big Bend 1	77.3	3.8	18.9	10,111
Big Bend 2	66.7	19.2	14.1	9,815
Big Bend 3	67.5	15.3	17.2	10,036
Big Bend 4	82.6	5.8	11.6	10,089
Gannon 5	56.7	15.3	27.9	10,716
Gannon 6	63.9	18.1	18.0	10,704
Polk 1	78.0	7.7	14.3	10,087