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June 27, 1994

IN REPLY REFER TO:

HAND DELIVERED

Tallahassee

Ms. Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
101 East Gaines Street
Tallahassee, Florida 32399-0850

ORIGINAL FILE COPY

Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor; FPSC Docket No. 940001-EI

Dear Ms. Bayo:

Enclosed for filing in the above docket, on behalf of Tampa Electric Company, are fifteen (15) copies of each of the following:

ACK ✓
AFA 3
APP
CAF
CMU
CTR
EAG Dudley
LEG Brown
LIN Orig + 4
OPC
RCH
SEC 1
WAS
OTH

1. Petition of Tampa Electric Company. 06358-94

2. Prepared Direct Testimony of Mary Jo Pennino and Exhibit (MJP-2) regarding Tampa Electric's projected Total Fuel and Purchased Power Cost Recovery Factors and Exhibit (MJP-3) regarding projected Capacity Cost Recovery Factors for the period October 1994 through March 1995. 06359-94

3. Prepared Direct Testimony of William N. Cantrell with Exhibit (WNC-1) titled Exhibit of William N. Cantrell. 06360-94

4. Prepared Direct Testimony of George A. Keselowsky with Exhibits (GAK-2) and (GAK-3) regarding Tampa Electric Company's projected performance under the Generating Performance Incentive Factor for the period October 1994 through March 1995. 06361-94

5. Prepared Direct Testimony of Elizabeth A. Townes and R. F. Tomczak with Exhibit (RFT/EAT-2) regarding Schedules Supporting the Oil Backout Cost Recovery Factor for the period October 1994 March 1995 and Exhibit (RFT/EAT-3) regarding the Gannon Conversion Project Comparison of Projected Payoff with Original Estimate as of May 1994. 06362-94

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FPSC-BUREAU OF RECORDS

Ms. Blanca S. Bayo
June 27, 1994
Page 2

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
encls.

cc: All Parties of Record (w/enc.)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY ~~that a true copy of th~~e foregoing testimony and exhibits, filed on behalf of Tampa Electric Company, has been furnished by U. S. Mail on this 27th day of June, 1994 to the following:

Ms. Martha C. Brown*
Ms. Donna L.Canzano
Division of Legal Services
Florida Public Service Commission
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276 Spring Run Circle
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[signature]

ATTORNEY

DOCKET NO. 940001-EI
TAMPA ELECTRIC COMPANY
SUBMITTED FOR FILING 06/27/94

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM N. CANTRELL

ORIGINAL FILE COPY

Q. Please state your name, address and occupation.

A. My name is William N. Cantrell. My business address is 702 North Franklin Street, Tampa, Florida 33602, and I am Vice President-Energy Resources Planning of Tampa Electric Company.

Q. Please state your educational background and business experience.

A. I was educated in the public schools of Tampa, Florida and received a Bachelor of Science degree in Electrical Engineering from the Georgia Institute of Technology in 1974. I am a registered Professional Engineer licensed in the State of Florida. I also received a Master of Business Administration degree in 1979 from the University of Tampa. I have been employed at Tampa Electric Company since June 1975 in a variety of engineering and administrative positions. My current responsibilities as Vice President-Energy Resources Planning include fuel acquisition and

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related fuel matters, environmental planning and resource planning for Tampa Electric Company.

Q. Have you previously testified before the Commission?

A. Yes. I have testified on the subjects of cogeneration, oil backout cost recovery and statewide annual planning. I also testified on various subjects on behalf of Tampa Electric in its rate proceeding in 1985, Docket No. 850050-EI. I testified in Docket No. 870001-EI-A, investigation into affiliated cost-plus fuel supply relationships of Tampa Electric Company and in the fuel adjustment dockets for the past several years.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to report to the Commission the actual 1993 costs of Tampa Electric's affiliated coal and coal transportation transactions compared to the benchmark prices calculated in accordance with Order No. 20298 (coal transportation) and Order No. PSC-93-0443-FOF-EI ("Order No. 93-0443") (coal). I conclude that the 1993 prices paid by Tampa Electric to its affiliates TECO Transport and Trade Company and Gatliff Coal are reasonable and prudent.

Q. Have you prepared an exhibit which you sponsor in this proceeding?

A. Yes. Exhibit No. (WNC-1) titled "Exhibit of William N. Cantrell", consisting of 4 documents, was prepared under my direction and supervision.

AFFILIATED COAL TRANSPORTATION PRICES

Q. Were Tampa Ele[illegible]tation prices for 1993 at or below the transportation benchmark?

A. Yes, they were. This is reflected in Document No. 1 of my exhibit.

AFFILIATED (GATLIFF) COAL PRICES

Q. Mr. Cantrell, [illegible]ric did not address the appropriateness of Tampa Electric's purchases of coal from Gatliff Coal Company during 1992.

A. On March 23, 1993 the Commission issued its Order No. 93-0443 in this docket. That order approved a Stipulation between Tampa Electric and the Office of Public Counsel which, in part, provided that the prices paid by Tampa

Electric to Gatliff through 1992 were appropriate for recovery through the fuel and purchased power cost recovery clause. Thus, the appropriateness of these purchases during 1992 has already been addressed and resolved with the approval of the Stipulation. A copy of this order is included as Document No. 4 of my exhibit.

Q. Were Tampa Electric's actual 1993 affiliated coal prices at or below the benchmark as established in Order No. 93-0443?

A. Yes, they were. This is reflected in Document No. 2 of my exhibit.

Q. Please summarize your testimony.

A. My testimony justifies the prices paid for coal and coal transportation by Tampa Electric Company in 1993 to its affiliated suppliers, Gatliff Coal and TECO Transport and Trade. I demonstrate that the average prices for the year 1993 for all coal and coal waterborne transportation services were at or below the appropriate benchmark calculations as directed by Order No. 20298 and Order No. 93-0443 of this Commission. Therefore, Tampa Electric should recover its payments for coal and coal transportation made during 1993.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT NO. ______
DOCKET NO. 940001-EI
TAMPA ELECTRIC COMPANY
(WNC-1)

TAMPA ELECTRIC COMPANY

EXHIBIT OF W. N. CANTRELL

EXHIBIT NO. ______
DOCKET NO. 940001-EI
TAMPA ELECTRIC COMPANY
(WNC-1)

INDEX

1993 TRANSPORTATION BENCHMARK CALCULATION

Average Rail Mileage to Tampa	1,070	Miles	(Note 1)
x Average of Lowest Two Publicly Available Florida Rail Rates	x 2.135	c/ton mile	(Note 2)
	$22.84		
+ Costs of Privately Owned Rail Cars	$ 1.75		(Note 3)
Transportation Benchmark for the Year Ended 12/31/93	$24.59		(Note 4)

Notes

1/ Weighted average domestic rail miles from all Tampa Electric waterborne coal supplies to plants. Rail miles for imported coal sources are measured from port of entry.

2/ Cents per ton-mile for publicly available Florida utility rail coal transportation rates including discounts for volume and private rail cars. The current publicly available rail rates to Florida utilities on a cents per ton-mile basis for 1993 are as follows:

JEA	2.12 ¢	*
Orlando	2.15 ¢	*
Lakeland	2.19 ¢	
Gainesville	2.51 ¢	

* Average of Lowest Two 2.13 ¢

3/ The cost of Private rail cars was approved in the original stipulation as $2.00 per ton. Subsequent negotiation between Tampa Electric and Public Service Commission Staff resulted in an agreed upon estimated cost of $1.75 per ton.

4/ Calculated by multiplying average domestic rail milage to Tampa by Florida rail coal market costs (cents per ton-mile), then adding the costs of privately-owned rail cars.

1993 TRANSPORTATION MARKET PRICE APPLICATION

Tampa Electric Weighted Average per ton Water Transportation Price from All Tampa Electric Coal Sources ($[redacted] divided by 5,598,533.05)		$[redacted]
Transportation Benchmark		$24.59
Over/(Under) Benchmark		[redacted]
Total Tons Transported in 1993		5,598,533
Total Transportation Cost in 1993	$	[redacted]
Total Amount Allowable for Recovery Using Benchmark ($24.59 x 5,598,533)	$	137,667,926
Total Cost Over/(Under) Benchmark - 1993	$	[redacted]
Prior Year's Cumulative Benefit (1988-1992)	$	[redacted]
Net Benefit for 1988-1993	$	[redacted]

MARKET BASED COAL CALCULATION - 1993

Base Price of Coal As of 12/31/92	$ 38.00
CPI-U Index Value at 12/31/92	141.9
CPI-U Index Value at 12/31/93	145.8
Percent Change in CPI-U From 12/31/92 to 12/31/93	2.7%
1993 Gatliff Coal Price Benchmark (38.00 x (1 + 0.027))	$ 39.03

EXHIBIT NO. ______
DOCKET NO. 940001-EI
TAMPA ELECTRIC COMPANY
(WNC-1)
DOCUMENT NO. 2
PAGE 2 OF 2

COAL MARKET PRICE APPLICATION - 1993

Tampa Electric Weighted Average per Ton Price of Coal Purchased	$
Coal Price Benchmark	$ 39.03
Over/(Under) Benchmark	$
Total Tons Purchased in 1993	$ 2,129,457.59
Total Cost in 1993	$
Total Amount Allowable for Recovery Using Benchmark (39.03 x 2,129,457.59)	$ 83,112,730
Total Cost Over/(Under) Benchmark - 1993	$

EXHIBIT NO. ________
DOCKET NO. 940001-EI
TAMPA ELECTRIC COMPANY
(WNC-1)
DOCUMENT NO. 3
PAGE 1 OF 24

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Investigation into affiliated cost-plus fuel supply relationships of Tampa Electric Company.	) DOCKET NO. 870001-EI-A) ORDER NO: 20298) ISSUED: 11-10-88

The following Commissioners participated in the disposition of this matter:

KATIE NICHOLS, Chairman
THOMAS M. BEARD
GERALD L. GUNTER
JOHN T. HERNDON
MICHAEL McK. WILSON

APPEARANCES:

LEE L. WILLIS, Esquire, and JAMES D. BEASLEY, Esquire, Ausley, McMullen, McGehee, Carothers and Proctor, P. O. Box 391, Tallahassee, Florida 32302
On behalf of Tampa Electric Company.

JACK SHREVE, Esquire, and STEPHEN C. REILLY, Esquire, Office of the Public Counsel, c/o Florida House of Representatives, The Capitol, Tallahassee, Florida 32399-1300
On behalf of the Citizens of the State of Florida.

JOSEPH McGLOTHLIN, Esquire, Lawson, McWhirter, Grandoff & Reeves, 522 E. Park Avenue, Suite 200, Tallahassee, Florida 32301
On behalf of Florida Industrial Powers Users Group.

MICHAEL B. TWOMEY, Esquire, Florida Public Service Commission, Division of Legal Services, 101 East Gaines Street, Tallahassee, Florida 32399-0863
On behalf of the Commission Staff.

PRENTICE P. PRUITT, Florida Public Service Commission, Office of General Counsel, 101 East Gaines Street, Tallahassee, Florida 32399-0862
Counsel to the Commissioners.

ORDER IMPOSING MARKET-BASED PRI[illegible]
FROM AN AFFILIATE AND ACCEPTING SETTLEMENT
AGREEMENT ON IMPLEMENTATION OF MARKET-BASED METHODOLOGY

BY THE COMMISSION:

SUMMARY

We have determined as a matter of policy that utilities seeking the recovery of the cost of coal purchased from an affiliate through their fuel and purchased power cost recovery clauses shall have their recovery limited by a "market price" standard, rather than under the "cost-plus" standard now in effect. We also have accepted a stipulation among the parties to this docket which provides a methodology for implementing the market pricing standard for not only the coal Tampa Electric Company (TECO) purchases from an affiliate, but the transportation and handling services it purchases from affiliates, as well.

BACKGROUND

In February, 1986, we ~~opened Docket~~ No. 860001-EI-G for the purpose of investigating the affiliated cost-plus fuel supply relationships between Florida Power Corporation (FPC) and TECO and their respective affiliated fuel supply corporations. Also in February, 1986, we had established Docket No. 860001-EI-F, Investigation Into Certain Fuel Transportation Costs Incurred By Florida Power Corporation in Order No. 15895 for the purpose of determining why FPC's costs to transport coal by its affiliated waterborne system exceeded its costs to transport coal by non-affiliate rail. In September, 1987, we issued Order No. 18122, which removed TECO from Docket No. 860001-EI-G, established this docket for hearing the TECO issues.

After considering the post-hearing briefs of the parties and our Staff's recommendations, we, at our September 6, 1988 Agenda Conference, determined that affiliated coal should be priced at market price for recovery through the utilities' fuel cost recovery clauses. We directed our Staff to conduct discussions amongst the affected parties for the purpose of determining how best to establish and implement market pricing mechanisms.

After extensive negotiations, the parties to this docket arrived at a stipulated agreement which provided a methodology for establishing "market" price proxies for all of TECO's affiliated fuel transactions. This Order describes the TECO hearing in this docket, as well as the stipulated agreement, which we accept and approve.

Before describing TECO's affiliated fuel and fuel transportation system, it is worth noting that TECO did not object to the adoption of a market pricing system so long as the system fairly represented the price received for comparable coal on the competitive market. TECO also took the position, as did all parties, that market pricing should cut both ways and that any lower of cost or market method or market price cap method should be rejected. While TECO took the position that cost-plus pricing has provided an effective means of ensuring that only reasonable and prudently incurred fuel costs have been passed on to its customers, it agreed that the cost-plus methodology was administratively costly and caused unnecessary regulatory tension because it left the lingering suspicion, even in the face of outstanding results, that it resulted in higher costs to customers than would have been available through arm's-length contracts. Consequently, as will be noted below, the hearing in this docket was not over whether a market pricing system should be adopted but, rather, how it should be adopted.

THE TECO AFFILIATE SYSTEM

There are two primary components to the TECO affiliate coal supply system:

1. The coal supply affiliate (Gatliff Coal Company); and

2. The waterborne transportation system (TECO Transport and Trade Corporation).

Gatliff Coal Company

Gatliff Coal Company (Gatliff) is a subsidiary of TECO Coal, Inc. which, like TECO, is a subsidiary of TECO Energy, Inc. The other subsidiary of TECO Coal, Inc., Rich Mountain Coal Company controls a handling facility with coal-sizing capability on the Norfolk Southern Railroad in Tennessee, but is not currently operational and supplies no coal to TECO.

According to TECO witness John R. Rowe, Jr., Assistant Vice-President of TECO, TECO's Gannon Station units were constructed in the 1950's and 1960's with wet bottom boilers designed to burn Western Kentucky No. 9 coal having a 3% to 4% sulfur content and low ash-fusion temperature characteristics. This high sulfur, low ash-fusion coal was in abundant supply adjacent to the inland waterway system and was, said Rowe, the most inexpensive coal that could be purchased. However, with the passage of the Clean Air Act in 1970 and the associated Florida State Implementation Plan, TECO found it necessary to burn coal at Gannon Station which produced an average of not more than 2.0 lbs. per million BTU of sulfur dioxide, with a maximum of 2.4 lbs. per million BTU of sulfur dioxide. The requirement for coal that met the combined low sulfur and low ash-fusion characteristics created a serious fuel supply problem for TECO at its Gannon Station because such coal was extremely rare according to Rowe.

To meet the applicable air quality regulations, TECO converted four of the six coal burning units at Gannon Station to low sulfur oil and began a worldwide search in 1971 for a source of low sulfur, low ash-fusion coal that would be suitable for its boilers. The search revealed that there were many foreign and domestic coals that were low sulfur, but few that also met the necessary ash-fusion and slagging characteristics required of the Gannon wet bottom boilers. Suitable seams of coal were found in the western United States, but the high cost and lack of dependability of available transportation were of great concern to TECO and, ultimately, made the use of these coals prohibitively expensive. Polish coal was used for a time but labor and other problems shut off the supply of this coal in 1979-80. Ultimately, suitable eastern coals were narrowed to the Blue Gem seam in eastern Kentucky, and test burns in 1973 revealed that it could successfully be burned in the two largest Gannon Station units.

Gatliff (then named Cal-Glo Coal, Inc.) mined the Blue Gem seam in large quantities in a market that was dominated by many small producers. TECO first began purchasing coal from Cal-Glo in early 1973. Subsequently, when Cal-Glo experienced financial problems, TECO made it a loan to keep it viable and finally purchased the entire operation by August of 1974. In 1980, the State of Florida modified its sulfur dioxide emission limits to permit Gannon Units Nos. 1-4 to burn Blue Gem coal. Since then, all six units at Gannon station have burned Blue Gem coal. Cal-Glo Coal, Inc.'s name was changed to Gatliff Coal Company in 1982.

TECO's initial 1974 contract with Gatliff called for the price of coal to be established by an independent consultant's survey of market prices. This practice was continued until 1978 when this Commission ordered a change to a cost-plus a return on equity pricing system. See Order No. 7987 in Docket No. 760846. On March 2, 1978, TECO signed a new contract with Gatliff, which provided that coal would be mined and supplied to TECO on a cost-plus basis with Gatliff being entitled to earn the same mid-point return on its invested equity as allowed to TECO by this Commission. This contract was approved by the Commission in Order No. 8278 and its term was extended through December 31, 1996.

In 1981 this Commission hired the consulting firm of Emory Ayers Associates, Inc. to conduct a study to determine if the cost-based price paid by TECO to Gatliff was in line with market prices. The Emory Ayers study concluded that the cost-based coal price was in line with the market for the long term supply of this type coal and the study established a reasonable market price for this coal as of 1981.

TECO submits that its control of a sizable reserve of the relatively scarce Blue Gem coal in the eastern United States is absolutely critical to the reliable operation of its Gannon Station in view of the remaining lives of the boilers. TECO, said Rowe, believes this coal provides a least-cost alternative, which is superior to other environmental compliance solutions and assures that the utility will have a source of environmentally acceptable coal for the remaining lives of the Gannon units.

TECO Transport and Trade

TECO Transport and Trade Corporation, is a subsidiary of TECO's parent company, TECO Energy, Inc. TECO Transport and Trade in turn, has five separate subsidiary operating companies which make up the water transportation system. Except for a small (less than ten percent or about 500,000 tons per year) share of TECO's requirements of Gatliff's sales, which are delivered to Gannon Station directly by rail, all of TECO's coal is delivered to Big Bend and Gannon Stations by barge under the direction of TECO Transport and Trade Corporation.

Mid-South Towing, which was established in 1959, owns or operates ten tow boats and over three hundred river barges. It transports coal from the coal fields near the Ohio River to the Electro-Coal Transfer facility some 40 miles down river from New Orleans.

The Electro-Coal Transfer facility is over 200 acres in size, provides on-ground storage for 4.5 million tons and controls over three miles of riverfront. It was established in the early 1960s and provides a location for river vessels to discharge coal and transfer it to ocean vessels or to ground storage. Bulk products hauled for others are also stored or transloaded by Electro-Coal.

Gulfcoast Transit was established in 1959 to carry coal from Electro-Coal to TECO's generating stations. It owns 11 ocean-going, tug-barge combinations ranging in size from 9,000 tons to 38,000 tons. According to Rowe, Gulfcoast pioneered the ocean-going, coal shuttle idea for coal to peninsular Florida. Gulfcoast hauls coal for TECO and backhauls phosphate and other bulk products for others. When Gulfcoast delivers the coal to Tampa, it is off-loaded by G. C. Service Company, TECO Transport and Trade's stevedoring and ship repair group. TECO Towing, the fifth component of TECO Transport and Trade, was formed to move ICC-regulated bulk commodities and is currently inactive. According to Rowe, the third party transactions have provided significant savings to TECO's ratepayers by spreading the fixed costs of affiliated operations over a larger tonnage base.

Mr. Rowe testified that the transportation system was formed to lower costs and provide reliable transportation of coal for the benefit of the utility's ratepayers. He said that when the system was first formed, rail rates to Florida from the Midwestern coal fields were so high that coal was not competitive with oil. Because TECO did not want to be held captive by excessive dependence on rail transportation and a reliable water system for coal delivery to Florida did not exist, TECO, said Rowe, took the initiative and developed a water transportation system beginning in 1959 with the formation of Gulfcoast and Mid-South. Initially joint ventures with Peabody Coal Company and Virginia-Carolina Chemical Company, these operations were wholly-owned by TECO by May of 1968.

From 1959 to 1965 the transfer of coal from river barges to ocean vessels was accomplished by "mid-streaming" (direct vessel-to-vessel transfer at anchor) between New Orleans and Baton Rouge. When the mid-streaming proved unsatisfactory for the long term, TECO and Peabody Coal Company first leased an existing transloading facility at Myrtle Grove and, then, in October, 1968, incorporated Electro-Coal for the purpose of building and operating a more modern transloading and storage facility at Davant, Louisianna, some two miles south of Myrtle Grove on the Mississippi. According to Rowe, the new Electro-Coal facility was finished in 1965 and survived Hurricane "Betsy," which virtually demolished the old Myrtle Grove terminal. By May, 1968, TECO had purchased Peabody's 50 percent ownership in Electro-Coal and, thereafter, wholly-owned all of the transportation companies.

Mr. William N. Cantrell, Vice-President for Regulatory Affairs for TECO, testified that the cost-plus pricing system should be modified because it had caused: (1) substantial regulatory concerns for the Commission; (2) a substantial commitment of resources by the utilities in complying with the Commission's regulatory needs; and (3) ratepayer doubts concerning the use of a cost-plus concept. He said that while

TECO believed that the cost-plus pricing system had been fair and reasonable from its ratepayers' prospective, the utility had undertaken a search for another acceptable pricing alternative, which would continue to provide an assured, reliable source of services and products from affiliates, at a competitive price, with far less regulatory tension.

Mr. Cantrell stated that the market price approach was attractive from a theoretical point of view because it should reflect the arm's-length value of the goods or services being transferred. To do this properly, he said, involved being able to identify the proper product and geographic markets in order to compute comparable market prices. He added that doing this was extremely difficult in the case of the waterborne transportation of coal to Tampa, as provided by TECO Transport Trade, and the supplying of low sulfur, low ash-fusion coal produced by Gatliff. Cantrell said that despite the lack of comparables for the waterborne transportation and the Blue Gem coal, it was still possible to develop a market-based approach by establishing a base price, using an analysis of the market, and then provide for indexing of the base price in the same manner as did many arm's-length contracts negotiated by independent parties. He said that TECO was proposing such contracts for both Gatliff Coal and TECO Transport and Trade.

As testified to by Cantrell, TECO proposed a new coal contract with a term of ten years and a minimum annual tonnage of 1.1 million tons. It would have a base price set for the 1.1 million minimum tonnage level and a lower price for supplemental tonnage above the minimum. According to Cantrell, the proposed base prices would ensure that TECO, at the inception of the contracts, would pay no more for coal than it did under the cost-plus pricing system. Beginning in 1989 the price would be adjusted quarterly based upon appropriate indices. During the fifth year of the contract, a price adjustment of plus or minus 10 percent could be made in the adjusted contract price if it differed from an assessment of what the market price of the coal would be. Thereafter, the new contract price would be adjusted on a quarterly basis by the use of indices. During the tenth contract year, TECO would again assess the marketplace and determine a market-based price for the coal needed at Gannon Station. Gatliff would have an opportunity to match the market price and, thereby, extend the contract or to decline and allow TECO to contract elsewhere.

Mr. Cantrell said that the base price under the proposed coal contract would be similar to the price paid under the current contract, which he said was at or below the market for coals of a quality that could be burned at Gannon Station. He said that the base coal contract price would be indexed by publicly reported indices related to "labor," "materials and supplies," and "maintenance and equipment."

According to Cantrell, the new transporation contracts would have terms of ten years with minimum annual tonnages of 1,750,000 tons for river transportation and 4,000,000 tons for the terminal and Gulf transportation. As with the proposed coal contract, the proposed transportation contracts would have base prices for the minimum tonnage levels and lower base prices for supplemental tonnages. Like the coal contract the transportation contracts would be indexed for their first five years with a market-price adjustment in the fifth year based upon an assessment of the market. In the tenth year, the market would again be reassessed with TECO Transport and Trade having the opportunity to match the new price.

Mr. Cantrell said the base price for the transportation contracts would be similar to the price paid under the cost-plus contract, which he said was, by all measures that TECO could find, below a market price for the transportation of coal. The transportation base prices would be indexed by publicly reported indices for "fuel" and "variable" components.

Mr. Cantrell closed by saying that the proposed contracts represented a market-based approach because they were similar to the base price, indexed contracts commonly entered into between arm's-length parties in the competitive market.

Ms. Roberta S. Bass, a Planning and Research Economist in the Fuel Procurement Bureau of the Commission's Division of Electric and Gas, provided an overview of the organizational structure of TECO Transport and Trade Corporation and TECO Coal Corporation. In addition to describing the organizational relationships discussed in Mr. Rowe's testimony, Ms. Bass described the contractual relationships between TECO and the various affiliates and the manner in which costs were allocated between TECO and non-utility business. Generally, TECO's affiliated goods and services have been provided at the cost of providing them, plus a return on invested equity at a rate equal to that of the mid-point on equity authorized to TECO by this Commission. Likewise, costs are allocated between TECO and third party business directly, where possible, and otherwise on a percentage-of-use basis.

Mr. Hugh Stewart, General Engineer at the Federal Energy Regulatory Commission, testified on behalf of the Staff of the Florida Public Service Commission. Mr. Stewart testified that TECO's affiliate coal program had generally been successful because it took the time to determine that the coal transportation and production services were cost-effective before it acquired an ownership interest in the facilities. In this regard, he cited a study prepared for TECO, by an independent consultant, before it committed to coal, showing that coal could be economically produced and shipped to the Gannon Station. In the same vein, Stewart said that it was only after contracting in the competitive market for coal supply and transportation services that TECO acquired its ownership interest in the barge operations and the transloading facility. Stewart also testified that TECO contracted with an independent coal mine engineering consultant to determine the cost of producing coal from the Gatliff reserves before acquiring an ownership interest in those reserves.

Mr. Stewart acknowledged that if the wet bottom boilers at TECO's Gannon Station were to operate at maximum efficiency, TECO not only had to obtain coal with low sulfur levels, but low ash-fusion characteristics too. He acknowledged that coal of this type is relatively scarce and said that, after an apparently extensive search, TECO discovered that coal of this type was being mined by Coal-Glo Coal, Inc. from the Blue Gem

Seam in eastern Kentucky. Stewart noted that TECO executed a ten year contract with Coal-Glo for the supply of coal and did not acquire an ownership interest in the mining company until after the mine experienced financial difficulties.

Mr. Stewart discussed the several expansions of annual throughput capacity that had been accomplished at the Electro-Coal Terminal and voiced the opinion that the 1969 expansion from 4.0 to 6.0 million tons per year was justified by TECO's Big Bend generating units, the first of which was scheduled to come on line in 1970. He said that it was his opinion that the subsequent expansions - to 12.0 million tons per year in 1982 and to 25.0 million tons per year in 1984 - were to meet expected export markets and that no allocation of these expansions should be made to TECO's utility business.

On cross-examination, Mr. Stewart acknowledged that he had developed a "sanity check," using the publicly reported rail coal rates paid by Florida municipally-owned utilities, which showed that the total transportation costs paid by TECO to its affiliate were less than the surrogate rail cost.

Mr. John Pyrdol, Energy Economist with the Energy and Fuels Analysis Branch of the Federal Energy Regulatory Commission, also testified on behalf of the Staff of the Florida Public Service Commission for the purpose of discussing the benefits of a market price cap for affiliated transactions and to calculate the market price for the coal TECO purchases from its affiliate, the Gatliff Coal Company.

Mr. Pyrdol stated that it was important to utilize a market price for the allowable cost of coal purchased from an affiliate because a market price attempted to replicate a price resulting from an arm's-length transaction, where a utility would have nothing to gain, and something to lose, by accepting a higher than market-competitive price. By contrast, he said, a utility's incentive to pay the lowest possible price for coal may be blunted or otherwise subordinated by a willingness to accept a higher price from an affiliate mining operation. Pyrdol contended that this willingness to accept a higher affiliate price could stem from either: (1) a desire to keep the affiliate "whole", even if the affiliate prices are excessive; or (2) to help the affiliate earn greater profits.

Mr. Pyrdol testified that cost-plus contracts of the type between TECO and its affiliates are used almost solely when a utility is buying coal from an affiliate supplier and almost never in arm's-length contracts. He said that the most common form of arm's-length contract in the utility coal business is the base price plus escalator contract. According to Pyrdol, the cost-plus contract allows the seller to recover all of its costs plus a guaranteed profit. This allows the utility to keep its affiliate supplier whole by paying all of its costs of production, while insuring its profit margin. In contrast to this type of contract, Pyrdol said the base price plus escalator contract does not give the supplier a guaranteed, full cost pass-through, plus guaranteed profit. Rather, he said, the base price plus escalator contract is set up to have the price reflect competitive market conditions, both when the base price is established and in any changes made to this price. In the base price plus escalator contract, a base price is established at the outset of the contract, and then the price is changed by a set of market-sensitive indices which can increase or decrease the price. These indices, which are a subject of contract negotiation, typically are publicly reported and reflect changes in the components of production such as labor, fuel, taxes and others. These contracts may also contain "market reopener" provisions, which, after a given number of years, allow the base price to be raised or lowered to meet the current market.

Pyrdol said that the risk of non-recovery of costs in the competitive, arm's-length coal transaction is borne by the seller, not the buyer. He said that, similarly, this risk should be borne by the affiliate mine and not by the ultimate buyer, the utility ratepayer. Pyrdol testified that it was his opinion that all of TECO's affiliate fuel-related contracts suffered from the same potential conflicts of interest that the coal contract was subject to, and that market-price caps should be established for the barge and transloading contracts as well. He added that he did not have the necessary information to construct the transportation-related market prices and was, therefore, testifying only to a market price cap for Gatliff coal. Mr. Pyrdol noted that the Federal Energy Regulatory Commission has used a market price test and cap for affiliated coal operations since 1981.

Mr. Pyrdol said that there are many unique characteristics found in different regional and local coal markets serving different utility power plants and that, therefore, the calculation of a market price must consider the particular circumstances of the coal market in question. He said that there are essentially three steps to be followed in determining a market price for a given coal. First, the product market must be identified. Second, the geographical boundaries of the market must be determined. Third, select transactions should be examined within the product and geographic markets in order to determine the market price.

In constructing his market price cap for Gatliff coal, Pyrdol testified that he accepted TECO's representations that the Gannon boilers required low sulfur coal with low ash-fusion characteristics and, therefore, limited his analysis to similar quality coal. He next determined this type coal was found in limited quantities in eastern Kentucky, parts of Alabama, Illinois, Tennessee, Virginia and in some western states. After further analyzing these coal sources, he determined to further limit his analysis to coal produced in the Blue Gem Stream in eastern Kentucky, where Gatliff is located.

In determining which transactions to include in his analysis, Pyrdol elected to eliminate transactions on the spot market and focus on transactions involving longer-term, larger-volume contracts because the Gatliff transaction is a contract arrangement. He further determined that, generally, eastern utilities do not utilize coal that is both low in sulfur and in ash-fusion temperature and, therefore, it was difficult to find price information to calculate a market price for the Gatliff coal. In lieu of the market price information of comparable coal, Pyrdol used a 1981 study commissioned by this Commission entitled "A Market Survey of Boiler Fuel for Tampa Electric Company's Gannon Plant." This study, which was conducted by Emory Ayers Associates, Inc. and filed with this Commission on June 1, 1981, identified a contract market price for Blue Gem coal of $40 per ton as of 1981. To arrive at an adjusted market price for Blue Gem coal for each year 1981-1987, Pyrdol said he adjusted the 1981 $40/ton price for the Gatliff coal by the average annual percentage change in prices experienced by all coal produced in Bureau of Mines District (BOM) No. 8. BOM No. 8 includes eastern Kentucky, southern West Virginia, and parts of Virginia and Tennessee, and, according to Pyrdol, is the source of the highest-quality, highest-priced coal produced in Appalachia. Mr. Pyrdol said that when he compared the adjusted market prices to the actual prices TECO paid to Gatliff, he concluded that the Gatliff prices had been in line with the market price from 1981 to 1985 but had been higher than the market in 1986 and 1987.

Mr. Pyrdol recommended that the Commission limit the recovery of Gatliff coal through TECO's fuel adjustment clause to the adjusted market price for all future sales of the Gatliff coal to TECO. In doing so, Pyrdol noted that only a portion of the so-called Gatliff coal is actually produced by the Gatliff mine. He said the rest is purchased from independent mines at a price ($28-$31/ton in 1984) significantly below the cost of coal to TECO, and averaged for cost purposes with the coal actually produced by Gatliff. Specifically, Pyrdol said that in 1986, Gatliff actually produced 689,000 tons of coal while it bought 860,000 tons from other producers. Mr. Pyrdol took the position that the adjusted market price resulting from his methodology should only apply to the coal actually produced by Gatliff, while the less expensive coal that Gatliff buys from independent mines and resells to TECO should reflect the actual purchase price to Gatliff and not the higher market price. He said that since the Gatliff/TECO coal contract required TECO to take only a minimum of 500,000 tons per year, TECO should minimize the take of Gatliff coal and maximize its take of the less expensive Blue Gem coal produced by independent suppliers.

On cross-examination, Mr. Pyrdol acknowledged that his adjusted market price was based upon the total sales of BOM No. 8 coal to utilities and that it did, in fact, include some sales under spot market contracts. He accepted the removal of the spot sales as being reasonable and acknowledged that their removal, plus a quality characteristics adjustment suggested by TECO's Mr. Cantrell would increase his 1987 adjusted market price for Gatliff coal from approximately $36.60/ton to about $39.60/ton.

Mr. Harry T. Shea, Chief of the Bureau of Fuel Procurement, Division of Electric and Gas, Florida Public Service Commission, testified on behalf of the Commission Staff. Mr. Shea testified that the Commission's fuel procurement guidelines contained in Order No. 12645 state that all purchases from affiliated companies should be priced at levels not to exceed those available on the competitive market and that contracts with affiliated companies should be administered in a manner identical to the administration of a contract with an independent company. Mr. Shea said the

Commission should evaluate the reasonableness of the cost of fuel-related goods and services obtained from affiliate companies by one of three methods.

Mr. Shea's first and preferred method, where possible, was to establish a "market test" or market price by comparison to the price of similar products or services purchased in competitive markets. His second preferred method was by comparison to a price calculated by allocating an affiliate's fixed and variable costs to utility operations and non-utility operations based upon tonnage or some other appropriate measurement. A return on invested equity could be set equal to the midpoint of the utility's allowed range or equal to that realized by other companies in the same type of business. Mr. Shea's third and least preferred methodology was essentially a cost-of-service methodology that would involve reviewing the affiliate's expenses and capital structure to determine what a reasonable price should be. Shea stressed that the last methodology should only be employed when the market test and cost allocation methodologies were not applicable.

Mr. Shea testified that he would recommend using the methodology presented by Mr. Pyrdol to evaluate a comparable market (F.O.B. mine) price for Gatliff Coal Company. He said that he agreed with Pyrdol that a market price evaluation would be preferable for TECO's transportation affiliates, but added that he could not recommend such a methodology because he was unable to identify a sufficient number of comparable transactions to define a market price for the services provided by these companies.

CONCLUSION

As a result of this hearing and the companion hearing in Docket No. 860001-EI-G concerning Florida Power Corporation, we have concluded that it is desirable, where possible, to gauge the reasonableness of fuel costs sought to be recovered through a utility's fuel adjustment clause by comparison to a standard that attempts to measure what a given product or service would cost had it been obtained in the competitive market through an arm's-length contract with an unaffiliated third party. We believe that limiting cost recovery in this manner will best serve the interests of TECO's customers by insuring that they are not required to pay more than a market price for the fuel component of their electricity because of an affiliation between their utility and a fuel supplier.

We note that no party to this docket has alleged that either TECO's Gatliff coal or its TECO Transport and Trade rates are unreasonable and should be disallowed. In fact, after accepting the adjustments urged by TECO, witness Pyrdol's adjusted market price for Gatliff coal was within a dollar of the actual price then being paid for that coal. Likewise, TECO's affiliated waterborne rate for the entire route was shown to be significantly lower than the comparable rail rate/ton/mile being paid by several Florida Municipal electrical systems, whose coal and transportation rates are publicly reported.

Irrespective of whether any imprudence or unreasonable expenses are found and disallowances made, we agree with the parties to this case that a change from cost-plus pricing is warranted. While we believe that the current system has been generally successful in allowing only reasonable and prudent costs to be passed through the utilities' fuel adjustment clauses, we concur with TECO's position that it has been administratively costly, caused unnecessary regulatory tension, and left the lingering suspicion that it has resulted in higher costs to a utility's customers.

Implicit in cost-plus pricing is the requirement that one is capable of conducting a cost-of-service analysis of a business to determine that its expenses are both necessary and reasonable. This is a methodology that is demanded for monopoly utility services, and which usually proves to be complex, expensive and time consuming. It is a methodology which requires a high degree of familiarity with the capital requirements and expenses necessitated by the operation of the business being reviewed. Cost-of-service analysis of affiliate operations places additional demands upon the regulatory agency in terms of time, expense and acquiring additional expertise. All come at some additional cost that must eventually be borne by the ratepayer, either in his role as a customer or as a taxpayer. Furthermore, there seems to be no end to the types of affiliated businesses that we are expected to become sufficiently familiar with so that we might judge the reasonableness of their costs on a cost-of-service basis.

Cost-of-service regulation for public utilities is necessitated by their monopoly status and the attendant lack of significant competition, if any, for their end product. Cost-of-service regulation exists as the proxy for competition to insure that utilities provide efficient, sufficient and adequate service and at a cost that includes only reasonable and necessary expenses. Cost-of-service regulation of some type is essential when there is no competitive market for the product or service being purchased; it is superfluous when such a competitive market exists.

There is another reason for switching to a market pricing system that was alluded to in TECO's statement that the current system, no matter how outstanding the results, left lingering suspicions that it resulted in higher costs. That this might be true may be seen by contrasting affiliated and non-affiliated contracts. The latter, with few exceptions, are characterized by arm's-length transactions entered into in the competitive marketplace. Typically, the contracts result from competitive bidding systems in which the contract is awarded to the qualified bidder submitting the lowest bid. In any event, the utility's negotiator has clearly defined loyalties and knows whose interests he or she is to protect. In contrast to this, the typical affiliate contract is let without the benefit of competitive bidding. Instead, confident that the contract will be given to the affiliate, representatives of the two companies negotiate the rate at which the product or service will be purchased.

Considering the many advantages offered by a market pricing system, we, as a policy matter, shall require its adoption for all affiliated fuel transactions for which comparable market prices may be found or constructed.

In concluding, we note the following caveats: (1) from the record in this case, we are convinced that market prices can be established for the affiliated coals; (2) market prices for the transporatation-related services should be established if possible, but if not, methodologies for reasonably allocating costs should be suggested; and (3) cost-of-service methodologies should be avoided, if possible

PROPOSED STIPULATION AGREEMENT

In accordance with our directions at our September 6, 1988 Agenda Conference, our Staff, the Office of Public Counsel and TECO met to discuss the methods by which market pricing could be adopted for the affiliated coal and coal transportation transactions between TECO and its affiliates. As a result of numerous and lengthy negotiations, the parties have arrived at a Stipulation (Attachment A to this Order) which they have submitted for our approval.

According to the Stipulation, TECO shall be free to negotiate its contracts with its affiliates in any manner it deems to be fair and reasonable. TECO agrees to prudently administer the provisions of its contracts. Furthermore, TECO agrees to report to the Commission the actual transfer prices paid by it to its affiliates under the contracts in the normal course of the fuel adjustment proceedings.

With respect to Gatliff Coal Company, the Stipulation provides a benchmark for regulatory review of the coal purchased by TECO from Gatliff by utilizing an initial market price for TECO's transactions with Gatliff of $39.44/ton F.O.B. Mine, as of December 31, 1987. For purposes of regulatory review, this base price will be escalated or de-escaluated by the annual percentage change in BOM District 8 Data for Coal Shipments as reported on Form 423 for the weighted average price per million BTU of contract transactions (excluding all spot transactions), which meet TECO's Gannon Station specifications for heat content, sulfur content, ash content, and content and pounds sulfur dioxide per million BTU. An example of the benchmark market price and calculation is shown on Attachment 1 to the Stipulation, as well as the Gannon Station coal specifications.

As described in Paragraph 7 of the Stipulation, a 5% zone of reasonableness will be established around the adjusted market price for purposes of regulatory review. TECO's actual transfer price paid to Gatliff, based upon the total average price of Gatliff produced coal and coal purchased and resold as Gatliff coal, would be the cost allowed for recovery through TECO's fuel adjustment clause so long as the transfer price fell within the described zone of reasonableness. If the actual transfer price exceeded the ceiling of the 5% zone of reasonableness, the excess would be disallowed for recovery unless TECO adequately justified the reasonableness and prudence of the excess. (See Appendix 2 to the Stipulation). If the actual transfer price fell below the floor of the 5% zone of reasonableness, TECO would recover through its fuel clause only the actual transfer price.

Pursuant to the Stipulation, the parties agreed that the record in this proceeding indicated that the prices currently paid by TECO to TECO Transport and Trade are reasonable. Notwithstanding this, TECO agrees to the establishment of a benchmark price for coal transportation services to be used prospectively for regulatory review purposes. While TECO stated that it will execute its new contracts with TECO Transport and Trade at approximately the currently existing rates, which are less than current rail rates between the same points, the reasonableness of its actual transfer price for all of the transportation and transportation-related services from mine to generating plant would be compared to a coal transportation benchmark price. As shown on Attachment 3 to the Stipulation, the transportation benchmark would be calculated by averaging the two lowest comparable publicly-available, rail rates (in cents per ton-mile) for coal to other utilities in Florida and then multiplying that average times the average rail miles from all of TECO's coal sources to TECO's generating plants. The product would then have added to it the costs of privately-owned rail cars on a per ton, per trip basis. The total would be the coal transportation benchmark price. The actual transportation transfer price paid by TECO to TECO Transport and Trade, pursuant to its contracts, would be recoverable through the fuel adjustment clause, as long as it was equal to or less than the benchmark price. Any excess above the benchmark would be disallowed for cost recovery unless justified by TECO.

Pursuant to its terms, the Stipulation would be effective upon Commission approval, which was provided at our October 18, 1988 Agenda Conference.

In his letter forwarding the Stipulation, counsel to TECO represented that he had supplied counsel to the Florida Industrial Power Users Group (FIPUG) [the only other party to the proceeding] with a copy of the Stipulation and had been advised that FIPUG had no objection to the Commission's final action on it.

We believe that the proposed Stipulation meets our policy guidance and is in the public interest and shall, therefore, approve it. Briefly, with respect to the coal, the initial price is consistent with witness Pyrdol's modified methodology for vintaging the 1981 cost determined by the Emory Ayers study. Likewise, the initial price is consistent with the price TECO has recently been paying for this coal, a price no party has sought disallowances for.

The initial coal benchmark price will be escalated or de-escalated by the average annual percentage change in a large number of contract coal transactions for coal mined in the same BOM District as the Gatliff coal. Only those contracts that meet or exceed TECO's Gannon Station quality specifications will be included. These factors, coupled with the fact that many of these contracts were executed at approximately the same time as the Gatliff contract, go a long way towards fulfilling the goal of replicating a comparable coal for market pricing purposes. We are confident that the changes indicated by this large group of contracts will adequately reflect changes in the "market."

If one considers the objective of coal transportation services to be the movement of the coal from the mine to the generating plant, then rail service and the total waterborne system are not only comparable, but competitive to a large degree, as well. We believe using the average of the two lowest publicly available rail rates for coal being shipped to Florida will provide a reasonable market price indication of the value being provided by TECO's affiliate waterborne system.

In view of the above, it is

ORDERED by the Florida Public Service Commission that market-based pricing for affiliate fuel and fuel transportation services shall be used for the purposes of fuel cost recovery where a market for the product or service is reasonably available. It is further

ORDERED that the Stipulation (Attachment A) of the parties to this docket detailing methodologies for calculating market prices for Gatliff coal and the coal transportation services of TECO Transport and Trade Corporation is approved.

By ORDER of the Florida Public Service Commission, this 10th day of NOVEMBER, 1988.

STEVE TRIBBLE, Director
Division of Records and Reporting

(S E A L)

MBT

by: Kay Flynn
Chief, Bureau of Records

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

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

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

ATTACHMENT A

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Investigation into Affiliated Cost-Plus Fuel Supply Relationships of Tampa Electric Company	DOCKET NO. 870001-EI-A Submitted for filing 10/13/88

STIPULATION

1. At the Commission's Agenda Conference on September 6, 1988, the Commission reviewed the affiliated cost-plus fuel supply relationships between Tampa Electric Company ("Tampa Electric") and its affiliates, Gatliff Coal Company ("Gatliff") and TECO Transport and Trade ("TTT"), and determined that cost-plus pricing should be replaced with market pricing for fuel supply relationships of Tampa Electric wherever possible.

2. In accordance with the Commission's direction, Staff, Office of Public Counsel ("OPC") and Tampa Electric have met to discuss the methods by which market pricing can be adopted for the affiliated coal and coal transportation transactions between Tampa Electric and its affiliates. As a result of these discussions, Staff, OPC and Tampa Electric agree as follows:

3. Public Counsel and Staff agree that the specific contract format, including the pricing indices which Tampa Electric may include in its contracts with its affiliates, are not subject to this proceeding and Tampa Electric may negotiate its contracts with its affiliates in any manner it deems to be fair and reasonable. Tampa Electric agrees to prudently administer the provisions of such contracts.

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4. The transfer prices paid by Tampa Electric under contracts with its affiliates shall be reported to this Commission in the normal course of the fuel adjustment proceeding.

Gatliff Coal Company

5. In order to provide a benchmark for regulatory review of the coal purchased by Tampa Electric from Gatliff, Staff, Public Counsel and Tampa Electric agree that the initial market price to be used for computing the regulatory benchmark for Tampa Electric's transactions with Gatliff should be $39.44/Ton FOB Mine as of December 31, 1987.

6. For purposes of regulatory review, this base price should be escalated/de-escalated by a market based index described in Attachment 1 to this Stipulation.

7. For purposes of regulatory review, the benchmark price shall be a band of 5% around the adjusted price determined as described in paragraph 6. The results of this calculation will be applied as follows:

a. The benchmark price will be used to evaluate the average purchased price of coal from Gatliff.

b. Prices paid above the benchmark would be disallowed for cost recovery, unless justified by Tampa Electric.

c. An example application of this methodology is shown in Attachment 2 to this Stipulation titled "Public Counsel's Market Price Application."

TECO Transport & Trade

8. The parties agree that the record in this proceeding indicates that the prices currently paid by Tampa Electric to TTT are reasonable.

9. Tampa Electric, however, agrees to the establishment of a benchmark price to be used prospectively for regulatory review purposes.

10. The coal transportation benchmark price will be the average of the two lowest comparable publicly available rail rates for coal to other utilities in Florida. This rail rate will be stated on a cents/ton-mile basis representing the comparable total elements (i.e., maintenance, train size, distance, ownership, etc.) for transportation. The average cents per ton-mile multiplied by the average rail miles from all coal sources to Tampa Electric's power plants yields a price per ton of transportation. The result will become the "benchmark price" as shown on Attachment 3.

a. The benchmark price will be used to evaluate water transportation of coal services provided by TTT to Tampa Electric.

b. The price paid for water transportation of coal by Tampa Electric above the benchmark price would be disallowed for cost recovery unless justified by Tampa Electric.

General Provisions

11. The approval of this Stipulation will completely resolve all of the issues pending in this matter.

12. This Stipulation is based on the unique factual circumstances of this case and shall have no precedential value in proceedings involving other utilities before this Commission. The parties to the Stipulation

reserve the right to assert different positions on any of the matters contained in this Stipulation if the Stipulation is not accepted by the Commission.

13. The parties hereto shall not unilaterally recommend or support the modification of this Stipulation or discourage its acceptance by the Commission.

14. The parties hereto shall not request reconsideration of or appeal the order which approves this Stipulation.

15. The parties urge that the Commission take final agency action at the earliest possible Agenda Conference approving this Stipulation.

16. This Stipulation shall be effective upon Commission approval. In the event that the Commission rejects or modifies the Stipulation, in whole or in part, the parties agree that this Stipulation is void unless otherwise ratified by the parties, and that each party may pursue its interests as those interests exist, and that no party will be bound to or make reference to this Stipulation before this Commission or any court.

17. While Staff for internal reasons prefers to signify its agreement with this Stipulation by writing a Staff memorandum recommending approval of the Stipulation, the Electric and Gas and Legal Staff of the Florida Public Service Commission has reviewed this Stipulation simultaneously with the signing; has given its approval of the specific language contained herein; and has committed to submit its recommendation requesting approval of this Stipulation by the Commission; and has committed not to unilaterally recommend or support the modification of this Stipulation or discourage its acceptance by the Commission.

ATTACHMENT A

DATED this 13th day of October, 1988.

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TAMPA ELECTRIC COMPANY
DOCKET NO. 870001-EI-A

EXAMPLE BENCHMARK MARKET BASED COAL CALCULATION

The base price of $39.44 as of December 31, 1987 shall be adjusted by the annual percentage change in BOM District 8 Data for Coal Shipments as reported on Form 423 for the weighted average price per million BTU of contract transactions (excluding all spot transactions) which meet Tampa Electric's Gannon Station specifications (Note 4) for heat content, sulfur content, ash content and pounds sulfur dioxide per million BTU.

Example:

$$39.44 \times \frac{192.200 \text{ (Note 1)}}{189.015 \text{ (Note 2)}} = \$40.10$$

Revised Benchmark 40.10 x 1.05 (Note 3) = $42.11

Notes

1/ Hypothetical index value for 1988.

2/ Actual index value for 1987.

3/ 5% zone of reasonableness.

4/ Specifications as follows:

Heat Content - 12,500 BTU/lb minimum
Sulfur Content - 1.5% maximum
Ash Content - 9.0% maximum
Sulfur Dioxide - 2.0 pounds per million BTU maximum

PUBLIC COUNSEL'S MARKET

PRICE APPLICATION

--Gatliff coal purchased [1]

FOB mine	$45/ton
Tons purchased	500,000
Total cost	$22,500,000

--Market Benchmark $40/ton

--Cost recovered through fuel clause

$40/ton x 500,000 = $20,000,000

--Cost disallowed recovery

$20,000,000 - $22,500,000 = $2,500,000*

* The company would have to provide justification before recovery of these cost would be allowed.

1. This would include the total average price of Gatliff produced coal and coal purchased and resold as Gatliff coal.

ATTACHMENT A

TAMPA ELECTRIC COMPANY
DOCKET NO. 870001-EI-A

EXAMPLE BENCHMARK TRANSPORTATION CALCULATION

Average Rail Mileage to Tampa	974 miles	(Note 1)
x Average of Lowest Two Publicly-Available Florida Rail Rates	x 1.98 ¢/ton-mile	(Note 2)
	$19.29	
+ Costs of Privately-Owned Rail Cars	+ 2.00	
= Transportation Benchmark	$21.29	(Note 3)

Notes

1/ Weighted average rail miles from all coal sources for Tampa Electric to plants. This is expected to be 974 miles for 1989.

2/ Cents per ton-mile for publicly available Florida utility rail coal transportation rates. For example, the current publicly available rail rates to Florida utilities on a cents per ton mile basis for 1988 are as follows:

JEA	1.92 ¢*
Orlando	2.03 ¢*
Lakeland	2.30 ¢
Gainesville	2.45 ¢
*Average of Lowest Two	1.98 ¢

3/ Calculated by multiplying average rail mileage to Tampa by Florida rail coal market cost (cents per ton-mile), then adding the costs of privately-owned rail cars. This benchmark will be compared to Tampa Electric's weighted average water transportation cost from all Tampa Electric coal sources.

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Regulatory Control

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor.	DOCKET NO. 930001-EI ORDER NO. PSC-93-0443-FOF-EI ISSUED: 03/23/93

The following Commissioners participated in the disposition of this matter:

THOMAS M. BEARD
SUSAN F. CLARK
J. TERRY DEASON

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

BY THE COMMISSION:

24

As part of this Commission's continuing fuel cost recovery, oil backout cost recovery, capacity cost recovery, conservation cost recovery, and purchased gas cost recovery proceedings, hearings are held in February and August of each year. Pursuant to notice, a hearing was held in this docket and in Dockets No. 930002-EG and 930003-GU on February 17, 1993. The utilities submitted testimony and exhibits in support of their proposed fuel adjustment true-up amounts, fuel cost recovery factors, generating performance incentive factors, oil backout true-up amounts, capacity cost recovery factors and related issues.

Fuel Adjustment Factors

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

FPC: $13,863,288 Underrecovery.

FPL: $13,545,567 Underrecovery.

FPUC: $170,987 Underrecovery. (Marianna)
$19,913 Overrecovery. (Fernandina Beach)

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GULF: $1,732,139 Underrecovery.

TECO: $3,689,497 Underrecovery.

The estimated fuel adjustment true-up amounts for the period October, 1992 through March, 1993 are as follows:

FPC: $815,209 Underrecovery.

FPL: $30,415,048 Underrecovery.

FPUC: $186,021 Underrecovery. (Marianna)
$5,813 Underrecovery. (Fernandina Beach)

GULF: $1,199,942 Underrecovery.

TECO: $441,934 Overrecovery.

The total true-up amounts to be collected during the period April, 1993 through September, 1993 are as follows:

FPC: $14,678,497 Underrecovery.

FPL: $43,960,615 Underrecovery.

FPUC: $357,008 Underrecovery. (Marianna)
$14,100 Overrecovery. (Fernandina Beach)

GULF: $2,932,081 Underrecovery.

TECO: $3,247,563 Underrecovery

Finally, the appropriate levelized fuel cost recovery factors for the period April, 1993 through September, 1993 are as follows:

FPC: 2.171 cents per KWh - Standard rates*
2.780 cents per KWh - TOU On-Peak rates*
1.854 cents per KWh - TOU Off-Peak rates*

*Before line loss adjustment.

EXHIBIT NO.
DOCKET NO. 940001-EI
TAMPA ELECTRIC COMPANY
(WNC 1)
DOCUMENT NO. 4
PAGE 1 OF 19

FPL: 2.259 cents/kwh is the levelized recovery charge for non-time differentiated rates and 2.431 cents/kwh and 2.172 cents/kwh are the levelized fuel recovery charges for the on-peak and off-peak periods, respectively, for the differentiated rates.

FPUC: 3.266 cents/kwh (Marianna).
4.422 cents/kwh (Fernandina Beach).

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

GULF: 2.216 cents per KWH.

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

For billing purposes, the new fuel adjustment charge, oil backout charge, conservation cost recovery charge and capacity cost recovery charge factors shall be effective beginning with the specified fuel cycle and thereafter for the period April, 1993 through September, 1993. Billing cycles may start before April 1, 1993, and the last cycle may be read after September 30, 1993, so that each customer is billed for six months regardless of when the adjustment factor became effective.

Each utility proposed fuel recovery loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class. Those multipliers are shown in Attachment A attached hereto. We find that the proposed multipliers are appropriate and should be approved. The utilities further proposed fuel cost recovery factors for each rate group, adjusted for line losses, which are also shown in Attachment A. We find that the proposed factors are appropriate and should be approved.

Florida Power and Light Company proposed that they change the frequency of coal inventory aerial surveys from quarterly to semi-annually. We considered the issue for all investor-owned electric utilities and we find the proposal to be reasonable. We therefore approve the change in the frequency of aerial coal inventory surveys from quarterly to semi-annually for a two-year period. We direct our staff to review the impact of the less frequent surveys on inventory adjustments to determine whether to recommend a permanent change.

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

Florida Power Corporation

Florida Power Corporation requested our permission to recover through the fuel adjustment clause the cost of its affiliate, Electric Fuels Corporation's, charge for a return on equity on EFC's investment in locomotives. We approve the request. Florida Power Corporation has projected that the purchase of the locomotives will result in a reduction in rail transportation costs. This reduction will provide savings to FPC's ratepayers in excess of EFC's charge for a return on equity on EFC's investment.

We also approve Florida Power Corporation request for permission to recover through the fuel adjustment clause the charges associated with gas transportation to FPC's University of Florida cogeneration project. The costs are reasonable gas transportation costs for FPC's University of Florida cogeneration project, and they are appropriately recoverable through the fuel adjustment clause.

The following issue has been deferred to the August, 1993, fuel proceeding:

> Should Florida Power Corporation be permitted to recover through the fuel adjustment clause $972,000 in payments to the Department of Energy (DOE) for costs of the decontamination and decommissioning of the DOE's uranium enrichment plants?

For this period we will permit FPC to recover its payments to DOE for the costs of the decontamination and decommissioning of the DOE's uranium enrichment plants, subject to refund pending our decision on the issue in August.

Florida Power and Light Company

Florida Power and Light Company requested that it be permitted to recover through the fuel adjustment clause $550,000. of Clean Air Act operating fees. We prefer to investigate and determine the appropriate recovery of compliance costs associated with the Clean Air Act Amendment in a generic docket, where we can fully consider the appropriate recovery for all types of compliance costs for all investor-owned utilities. We do not wish to make thi determination piecemeal. Therefore, we withhold approval of FPL's recovery of those fees at this time, pending our investigation in the generic docket.

The following issue, similar to the issue for Florida Power Corporation, has been deferred to the August, 1993 fuel proceeding:

> Should Florida Power and Light Company be permitted to recover through the fuel adjustment clause $2,580,000 in payments to the Department of Energy (DOE) for costs of the decontamination and decommissioning of the DOE's uranium enrichment plants?

For this period we will permit FPL to recover its payments to DOE for the costs of the decontamination and decommissioning of the DOE's uranium enrichment plants, subject to refund pending our decision on the issue in August.

Florida Power and Light Company also requested that it be permitted to recover through the fuel adjustment clause $4,087,634 in litigation costs associated with the IMC contract arbitration. We find that the litigation costs incurred in the IMC contract dispute were reasonably related to the cost of fuel, reasonably expected to result in reduced fuel cost for the retail ratepayers, and thus appropriate for recovery through the fuel clause.

<u>Tampa Electric Company</u>

In August 1992, we deferred the following issues to this proceeding:

> What is the appropriate 1991 benchmark price for coal Tampa Electric Company purchased from its affiliate, Gatliff Coal Company, and;
>
> Has Tampa Electric Company adequately justified any costs associated with the purchase of coal from Gatliff coal Company that are in excess of the 1991 benchmark price?

At Public Counsel's request, the following issue was also scheduled to be heard in this proceeding;

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> Should TECO be ordered to refund the excess cost of Gatliff coal above the 1991 benchmark?

These issues relate to the market-based pricing methodology we established in Order No. 20298 (Docket No. 870001-EI-A) to measure the appropriate cost of coal TECO purchases from its affiliate, Gatliff Coal Company. The methodology we established at that time was developed by stipulation between TECO and the Office of Public Counsel.

The day before the hearing in this proceeding, TECO and the Office of Public Counsel submitted a new stipulation that revised the methodology by which the appropriateness of TECO's Gatliff coal purchases will be measured from 1993 to 1999. The new stipulation resolves all outstanding issues related to the pricing of TECO's coal purchases from Gatliff through 1992, and it provides that TECO will reduce its recoverable fuel expense by $10 million and credit that amount to its ratepayers. The adjustment will be made over the 12-month period from April, 1993 through March, 1994. Interest will be included.

The revised methodology developed by TECO and Public Counsel establishes a beginning base price of $38.00 per ton FOB Mine as of December 31, 1992. That base price will be escalated or de-escalated by the annual percentage change in the Consumer Price Index, All Urban Consumers (CPI-U). The stipulation provides that the weighted average annual price TECO pays to Gatliff will be disallowed for fuel cost recovery purposes if that price exceeds the price established by the methodology described above.

We approve the new stipulation revising the method to determine the appropriateness of the cost of TECO's coal purchases from its affiliate. The details of the revised methodology are provided in paragraphs 12 -14 of the stipulation attached to this order as Attachment B.

<u>Generating Performance Incentive Factor (GPIF)</u>

There was no controversy among the parties at this hearing as to either the appropriate GPIF reward or penalty for past performance or the proposed GPIF targets and ranges for performance in the upcoming period. The parties agreed to, and we approve, the following GPIF rewards for the period April, 1992 through September, 1992.

FPC: $1,211,009 reward.

FPL: $2,020,173 reward.

GULF: Reward $322,504.

TECO: Reward of $318,938.

The parties also agreed to targets and ranges for the period April, 1993 through September, 1993, which are shown on Attachment C to this order. We approve those targets and ranges.

Oil Backout Cost Recovery Factor

In accordance with the agreement of the parties, we find the proper final oil backout true-up amount for the period April, 1992 through September, 1992 period to be:

FPL: $3,636 Overrecovery.

TECO: $1,301,825 Overrecovery.

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The estimated oil backup true-up amount for the period October, 1992 through March, 1993, is:

FPL: $185,325 Overrecovery.

TECO: $988,475 Overrecovery.

The total oil backout true-up amount to be collected or refunded during the period April, 1993 through September, 1993, is:

FPL: $188,961 Overrecovery.

TECO: $1,580,247 Overrecovery.

Finally, we find the proper projected oil backout cost recovery factor for the period April, 1993 through September, 1993, is:

FPL: .013 cents/kwh.

TECO: .065 cents/kwh.

Capacity Cost Recovery Factor

We approve the following the final capacity cost recovery true-up amounts for the April, 1992 through September, 1992 period:

FPC: None.

FPL: $5,781,688 Underrecovery.

GULF: None. Gulf's initial implementation of a purchased power capacity cost recovery factor occurred during the October 1992 through March 1993 recovery period. As a result, Gulf does not have a true-up amount for any periods prior to October 1992.

TECO: None. Since Tampa Electric did not have a capacity cost recovery factor in effect for the period April 1992 - September 1992, there is no true-up to consider.

We approve the following estimated capacity cost recovery true-up amounts for the period October, 1992 through March, 1993

FPC: $1,662,838 Underrecovery.

FPL: $29,006,869 Overrecovery.

GULF: $1,711,114 Underrecovery.

TECO: $2,940,455 Underrecovery.

We approve the following total capacity cost recovery true-up amounts to be collected during the period April, 1993 through September, 1993

FPC: $1,662,838 Underrecovery.

FPL: $23,225,181 Overrecovery.

GULF: $1,711,114 Underrecovery.

TECO: $2,940,455 Underrecovery.

We approve the following appropriate projected net purchased power capacity cost amount to be included in the recovery factor for the period April, 1993 through September, 1993.

FPC: $32,570,136 jurisdictional.

FPL: $152,333,871 jurisdictional.

GULF: $1,801,898 jurisdictional.

TECO: $11,536,772 jurisdictional.

We approve the following projected capacity cost recovery factors for the period April, 1993 through September, 1993.

FPC:	RS	0.289	cents per kwh
	GS-Transmission	0.196	"
	GS-Primary	0.199	"
	GS-Secondary	0.202	"
	GS-100% Load Factor	0.152	"
	GSD-Transmission	0.140	"
	GSD-Primary	0.176	"
	GSD-Secondary	0.179	"
	CS-Curtailable	0.138	"
	IS-Transmission	0.145	"
	IS-Primary	0.147	"
	LS-Lighting Service	0.057	"

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FPL:	RS1	0.442	cents per kwh
	GS1	0.412	"
	GSD1	0.377	"
	OS2	0.365	"
	GSLD1/CS1	0.384	"
	GSLD2/CS2	0.317	"
	GSLD3/CS3	0.300	"
	ISST1D	0.261	"
	SST1T	0.237	"
	SST1D	0.242	"
	CILCD	0.264	"
	CILCT	0.243	"
	MET	0.337	"
	OL1/SL1	0.203	"
	SL2	0.279	"
	TOTAL	0.405	"

GULF: See table below:

RATE CLASS	CAPACITY COST RECOVERY FACTORS ¢/KWH
RS, RST	0.048
GS, GST	0.048
GSD, GSDT	0.036
LP, LPT	0.032
PX, PXT	0.027
OSI, OSII	0.005
OSIII	0.029
OSIV	0.003
SS	0.026

TECO:	RS	.217 cents per KWH
	GS, TS	.179 cents per KWH
	GSD	.149 cents per KWH
	GSLD, SBF	.133 cents per KWH
	IS-1 & 3, SBI-1 & 3	.012 cents per KWH
	SL, OL	.012 cents per KWH

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

Company-Specific Capacity Cost Recovery Issues

Florida Power and Light Company

Florida Power and Light Company requested recovery through the capacity clause the capacity payments associated with the 1988 Unit Power Sales Agreement (UPS) with the Southern Companies. We approve recovery. The 1988 UPS Agreement is a reasonable, prudent and necessary expense that benefits FPL's customers and is not being recovered in any other manner.

In consideration of the above, it is

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

ORDERED that investor-owned electric utilities subject to our jurisdiction are hereby authorized to apply the fuel cost recovery factors set forth herein during the period of April through September, 1993, and until such factors are modified by subsequent Order. Florida Power Corporation is authorized to apply its fuel cost recovery factors on the same date as any rate adjustment ordered in Docket No. 910890-EI. It is further

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

ORDERED that the Generating Performance Incentive Factor rewards and penalty stated in the body of this Order shall be applied to the projected levelized fuel adjustment factors for the period of April through September, 1993. It is further

ORDERED that the targets and ranges for the Generating Performance Incentive Factors set forth herein are hereby adopted for the period of April through September, 1993. It is further

ORDERED that the estimated true-up amounts included in the above Oil Backout Cost Recovery Factors are hereby authorized subject to final true-up, and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that the investor-owned electric utilities are hereby authorized to apply the capacity cost recovery factors set forth herein during the period of April through September, 1993, and until such factors are modified by subsequent Order. It is further

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

By ORDER of the Florida Public Service Commission this 23rd day of March, 1993.

Steve Tribble

STEVE TRIBBLE, Director
Division of Records and Reporting

(S E A L)
MCB:bmi

Commissioner Deason Dissents in Part from the decision in this Docket as follows:

I dissent from the Commission's decision to require Gulf Power to reflect the capacity revenues associated with Gulf Power's long - term non-firm schedule E contract with Florida Power Corporation in the capacity cost recovery clause. As I expressed at the time the clause was created, I have serious reservations about adding new costs/revenues to the factor if those costs/revenues are not currently included in the fuel adjustment clause. I believe that a rate case is the best time to make the determination about whether previously unrecognized items should be recovered through the CCRC.

In my view the setting of rates in a rate case recognizes that a balance is achieved between costs, investment and revenues. Once the Commission has engaged in such a balancing and set rates, these rates are deemed valid until changed. It is only when these rate making components are shown by the company or other party to be out of balance is there a need to address, either in a full - blown rate case or a more limited proceeding, a company's cost recovery. The difficulty facing the Commission in this case only underscores my belief that a rate case is the better place to undertake the comprehensive analysis that is needed.

I am only agreeing with the result reached by the majority of Commissioners with respect to denial of recovery of the IIC payments. I believe this same analysis set out above applies to those payments and would preclude recovery through the CCRC prior to a full rate case.

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.

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

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COMPANY	RATE SCHEDULE	RECOVERY FACTOR (CENTS PER KWH)
FPL	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
FPC	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
TECO	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
GULF	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]

FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE [illegible]
PAGE [illegible]

ESTIMATED FOR THE PERIOD: April – September [illegible]

FLORIDA POWER & LIGHT COMPANY

CLASSIFICATION	Classification Annualized $	Classification Annualized KWH	Classification Annualized Cents/KWH
1 Fuel Cost of System Net Generation (E3)	[illegible]	[illegible]	[illegible]
2 Spent NUC Fuel Disposal Cost (E2)	[illegible]	[illegible] (a)	[illegible]
2a DOE Decontamination & Decommissioning Costs	[illegible]	0	[illegible]
3 Coal Car Investment	[illegible]	0	[illegible]
5 Natural Gas Pipeline Enhancement	[illegible]	0	[illegible]
4a Fuel Cost of Sales to FKEC	[illegible]	[illegible]	[illegible]
5 TOTAL COST OF GENERATED POWER	[illegible]	[illegible]	[illegible]
6 Fuel Cost of Purchased Power – Firm (E8)	[illegible]	[illegible]	[illegible]
7 Energy Cost of Sch C,X Economy Purchases (Broker) (E9)	[illegible]	[illegible]	[illegible]
8 Energy Cost of Economy Purchases (Non-Broker) (E9)	[illegible]	[illegible]	[illegible]
9 Energy Cost of Sch E Purchases (E9)	0	0	[illegible]
10 Capacity Cost of Sch E Economy Purchases (E2)	0	0	[illegible]
11 Payments to Qualifying Facilities (E8A)	[illegible]	[illegible]	[illegible]
12 TOTAL COST OF PURCHASED POWER	[illegible]	[illegible]	[illegible]
13 TOTAL AVAILABLE KWH		[illegible]	
14 Fuel Cost of Economy Sales (E7)	[illegible]	[illegible]	[illegible]
15 Gain on Economy Sales – 80% (E7A)	[illegible]	[illegible] (a)	[illegible]
16 Fuel Cost of Unit Power Sales (SL2 Partpts) (E7)	[illegible]	[illegible]	[illegible]
17 Fuel Cost of Other Power Sales (E7)	[illegible]	[illegible]	[illegible]
18 TOTAL FUEL COST AND GAINS OF POWER SALES	[illegible]	[illegible]	[illegible]
19 Net Inadvertent Interchange (E4)	0	0	[illegible]
20 TOTAL FUEL AND NET POWER TRANSACTIONS	[illegible]	[illegible]	[illegible]
21 Net Unbilled (E4)	[illegible]	[illegible]	[illegible]
22 Company Use (E4)	[illegible] (a)	[illegible]	[illegible]
23 T & D Losses (E4)	[illegible] (a)	[illegible]	[illegible]
24 Adjusted System KWH Sales	[illegible]	[illegible]	[illegible]
25 Wholesale KWH Sales	[illegible]	[illegible]	[illegible]
26 JURISDICTIONAL KWH SALES	[illegible]	[illegible]	[illegible]
27 Jurisdictional KWH Sales Adjusted for Line Loss – 1.00036	[illegible]	[illegible]	[illegible]
28 True-up * (derived in Attachment C)	[illegible]	[illegible]	[illegible]
29 TOTAL JURISDICTIONAL FUEL COST	[illegible]	[illegible]	[illegible]
30 Revenue Tax Factor			[illegible]
31 Fuel Cost Adjusted for Taxes			[illegible]
32 GPIF *	[illegible]	[illegible]	[illegible]
33 Total fuel cost including GPIF	[illegible]	[illegible]	[illegible]
34 TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH			2.219

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

FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE [illegible]
PAGE [illegible]

ESTIMATED FOR THE PERIOD: April – September [illegible]

FLORIDA POWER CORPORATION

CLASSIFICATION	Classification Annualized $	Classification Annualized KWH	Classification Annualized cents/KWH
1 Fuel Cost of System Net Generation (E3)	[illegible]	[illegible]	[illegible]
2 Spent NUC Fuel Disposal Cost (E2a)	[illegible]	[illegible] (a)	[illegible]
3 Coal Car Investment	0	0	[illegible]
4 Adjustments to Fuel Cost	[illegible]	0	[illegible]
5 TOTAL COST OF GENERATED POWER	[illegible]	[illegible]	[illegible]
6 Energy Cost of Purchased Power – Firm (E8)	[illegible]	[illegible]	[illegible]
7 Energy Cost of Sch C,X Economy Purchases (Broker) (E9)	[illegible]	[illegible]	[illegible]
8 Energy Cost of Economy Purchases (Non-Broker) (E9)	[illegible]	[illegible]	[illegible]
9 Energy Cost of Sch E Purchases (E9)	[illegible]	[illegible]	[illegible]
10 Capacity Cost of Sch E Economy Purchases (E9)	0	0 (a)	[illegible]
11 Payments to Qualifying Facilities (E8A)	[illegible]	[illegible]	[illegible]
12 TOTAL COST OF PURCHASED POWER	[illegible]	[illegible]	[illegible]
13 TOTAL AVAILABLE KWH		[illegible]	
14 Fuel Cost of Economy Sales (E7)	[illegible]	[illegible]	[illegible]
14a Gain on Economy Sales – 80% (E7A)	[illegible]	[illegible] (a)	[illegible]
15 Fuel Cost of Other Power Sales (E7)	0	0	[illegible]
15a Gain on Other Power Sales (E6)	0	0 (a)	[illegible]
16 Fuel Cost of Seminole Backup Sales (E7)	0	0	[illegible]
16a Gain on Seminole Back-up Sales (E7B)	0	0 (a)	[illegible]
17 Fuel Cost of Seminole Supplemental Sales (E7)	[illegible]	[illegible]	[illegible]
18 TOTAL FUEL COST AND GAINS OF POWER SALES	[illegible]	[illegible]	[illegible]
19 Net Inadvertent Interchange (E4)	0	0	
20 TOTAL FUEL AND NET POWER TRANSACTIONS	[illegible]	[illegible]	[illegible]
21 Net Unbilled (E4)	[illegible] (a)	[illegible]	[illegible]
22 Company Use (E4)	[illegible] (a)	[illegible]	[illegible]
23 T & D Losses (E4)	[illegible] (a)	[illegible]	[illegible]
24 Adjusted System KWH Sales	[illegible]	[illegible]	[illegible]
25 Wholesale KWH Sales (Excluding Seminole Supplemental)	[illegible]	[illegible]	[illegible]
26 JURISDICTIONAL KWH SALES	[illegible]	[illegible]	[illegible]
27 Jurisdictional KWH Sales Adjusted for Line Loss – 1.0012	[illegible]	[illegible]	[illegible]
28 Net Period True-Up *	[illegible]	[illegible]	[illegible]
28a Miscellaneous True-Up	0	[illegible]	[illegible]
29 TOTAL JURISDICTIONAL FUEL COST	[illegible]	[illegible]	[illegible]
30 Revenue Tax Factor			[illegible]
31 Fuel Cost Adjusted for Taxes			[illegible]
32 GPIF *	[illegible]	[illegible]	[illegible]
33 Total fuel cost including GPIF	[illegible]	[illegible]	[illegible]
34 TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH			2.171

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

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FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE
PAGE OF 10

ESTIMATED FOR THE PERIOD April - September 1993

TAMPA ELECTRIC COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1 Fuel Cost of System Net Generation (E3)	[illegible]	[illegible]	[illegible]
2 Spent NUC Fuel Disposal Cost (E2A)	0	0 (a)	[illegible]
3 Coal Car Investment	0	0	[illegible]
4 Adjustments to Fuel Cost	0	0	[illegible]
5 TOTAL COST OF GENERATED POWER	[illegible]	[illegible]	[illegible]
11 TOTAL COST OF PURCHASED POWER	[illegible]	[illegible]	[illegible]
12 TOTAL AVAILABLE KWH		[illegible]	
21 TOTAL FUEL COST AND GAINS OF POWER SALES	[illegible]	[illegible]	[illegible]
25 TOTAL FUEL AND NET POWER TRANSACTIONS	[illegible]	[illegible]	[illegible]
30 JURISDICTIONAL KWH SALES	[illegible]	[illegible]	[illegible]
33 TOTAL JURISDICTIONAL FUEL COST	[illegible]	[illegible]	[illegible]
37 TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH			[illegible]

(a) Included for informational purposes only

FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE
PAGE 7 OF 10

ESTIMATED FOR THE PERIOD April - September 1993

GULF POWER COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1 Fuel Cost of System Net Generation (E3)	[illegible]	[illegible]	[illegible]
2 Spent NUC Fuel Disposal Cost (E13)	0	0	[illegible]
3 Adjustments to Fuel Cost	0	0	[illegible]
4 TOTAL COST OF GENERATED POWER	[illegible]	[illegible]	[illegible]
11 TOTAL COST OF PURCHASED POWER	[illegible]	[illegible]	[illegible]
12 TOTAL AVAILABLE KWH (line 4 + line 11)		[illegible]	
17 TOTAL FUEL COST AND GAINS OF POWER SALES	[illegible]	[illegible]	[illegible]
19 TOTAL FUEL AND NET POWER TRANSACTIONS	[illegible]	[illegible]	[illegible]
24 JURISDICTIONAL KWH SALES	[illegible]	[illegible]	[illegible]
34 TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH			[illegible]

(a) Included for informational purposes only

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE [illegible]
PAGE [illegible] OF [illegible]

ESTIMATED FOR THE PERIOD: April - September 1993

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)	[illegible]	[illegible]	[illegible]
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)	[illegible]	[illegible] (x)	[illegible]
10a Demand Costs of Purchased Power	[illegible] (x)		
10b Non-Fuel Energy & Customer Costs of Purchased Power	[illegible] (x)		
11 Energy Payments to Qualifying Facilities (E8A)	0	0	[illegible]
12 TOTAL COST OF PURCHASED POWER	[illegible]	[illegible]	[illegible]
13 TOTAL AVAILABLE KWH	[illegible]	[illegible]	[illegible]
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 Inadvertent Interchange (E4)	0	0	
20 TOTAL FUEL AND NET POWER TRANSACTIONS	[illegible]	[illegible]	[illegible]
21 Net Unbilled (E4)	[illegible] (x)	[illegible]	[illegible]
22 Company Use (E4)	[illegible] (x)	[illegible]	[illegible]
23 T & D Losses (E4)	[illegible] (x)	[illegible]	[illegible]
24 ADJUSTED SYSTEM KWH SALES	[illegible]	[illegible]	[illegible]
25 Less Total Demand Cost Recovery	[illegible]		
26 JURISDICTIONAL KWH SALES	[illegible]	[illegible]	[illegible]
27 Jurisdictional KWH Sales Adjusted for Line Loss - 1.00	[illegible]	[illegible]	[illegible]
28 True-up*	[illegible]	[illegible]	[illegible]
29 TOTAL JURISDICTIONAL FUEL COST	[illegible]	[illegible]	[illegible]
30 Revenue Tax Factor			[illegible]
31 Fuel Cost Adjusted for Taxes	[illegible]	0	[illegible]
32 GPIF*	0	[illegible]	[illegible]
33 Total Fuel Cost including GPIF	[illegible]	[illegible]	[illegible]
34 TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH			3.266

*Based on Jurisdictional Sales

(x) Included for informational purposes only

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FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE [illegible]
PAGE [illegible] OF [illegible]

ESTIMATED FOR THE PERIOD: April - September 1993

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 (E3)	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)	[illegible]	[illegible]	[illegible]
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	[illegible]	[illegible]	[illegible]
10a Demand Costs of Purchased Power (E2)	[illegible] (x)		
10b Non Fuel Energy and Customer Costs of Purchased Power (E2)	[illegible] (x)		
11 Energy Payments to Qualifying Facilities (E8A)	[illegible]	[illegible]	[illegible]
12 TOTAL COST OF PURCHASED POWER	[illegible]	[illegible]	[illegible]
13 TOTAL AVAILABLE KWH	[illegible]	[illegible]	[illegible]
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 Inadvertent Interchange (E4)			
20 TOTAL FUEL AND NET POWER TRANSACTIONS	[illegible]	[illegible]	[illegible]
21 Net Unbilled (E4)	[illegible] (x)	[illegible]	[illegible]
22 Company Use (E4)	[illegible] (x)	[illegible]	[illegible]
23 T & D Losses (E4)	[illegible] (x)	[illegible]	[illegible]
24 Adjusted System KWH Sales	[illegible]	[illegible]	[illegible]
25 Wholesale KWH Sales	0	0	[illegible]
26 JURISDICTIONAL KWH SALES	[illegible]	[illegible]	[illegible]
27 Jurisdictional KWH Sales Adjusted for Line Loss - 1.00	[illegible]	[illegible]	[illegible]
27a GSLD KWH Sales (E11)		[illegible]	
27b Other Classes KWH Sales (E11)		[illegible]	
27c GSLD CP KW		[illegible] (x)	
28 GPIF			
29 True-up*	[illegible]	[illegible]	[illegible]
30 TOTAL JURISDICTIONAL FUEL COST	[illegible]	[illegible]	[illegible]

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FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE [illegible]
PAGE [illegible] OF [illegible]

ESTIMATED FOR THE PERIOD: April - September 1993

FLORIDA PUBLIC UTILITIES - FERNANDINA

CLASSIFICATION	Classification Amount $	Classification Amount KWH	Classification Amount [illegible]
30a Demand Purchased Power Costs (line 10a)	2,917,000 (a)		
30b Non - Demand Purchased Power Costs (lines 6 + 10b + 11)	4,414,000 (a)		
30c True - up Over/Under Recovery (line 29)	(14,100)(a)		
APPORTIONMENT OF DEMAND COSTS			
31 Total Demand Costs	2,917,000		
32 G.S.L.D Portion of Demand Costs Including line losses (line 31a * [illegible])	612,360	100,000 KW	[illegible]
33 Balance to Other Customers	1,444,640	118,368,000	[illegible]
APPORTIONMENT OF NON - DEMAND COSTS			
34 Total Non - Demand Costs (line 30b)	4,414,000		
35 Total KWH Purchased (line 12)		144,278,000	
36 Average Cost per KWH Purchased			[illegible]
37 Avg. Cost Adjusted for Transmission line losses (line 36 * 1.01)			[illegible]
38 G.S.L.D Non - Demand Costs (line 37a * line 37)	1,324,343	37,200,000	[illegible]
39 Balance to Other Customers	3,091,462	118,368,000	[illegible]
G.S.L.D PURCHASED POWER COST RECOVERY FACTORS			
40a Total G.S.L.D Demand Costs (line 32)	612,360	100,000	[illegible]
40b Revenue Tax Factor			1.01609
40c G.S.L.D Demand Purchased Power factor adjusted for taxes and rounded			[illegible]
40d Total Current G.S.L.D Non - Demand Costs (line 38)	1,324,343	37,200,000	[illegible]
40e Total Non - Demand Costs including true - up	1,324,343	37,390,000	[illegible]
40f Revenue Tax Factor			1.01609
40g G.S.L.D Non - demand costs adjusted for taxes			[illegible]
OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a Total Demand and Non - Demand Purchased Power Costs of other classes (lines 33 + 39)	4,536,102	118,368,000	[illegible]
41b Less: Total Demand Cost Recovery	1,364,607 (a)		
41c Total Other Costs to be Recovered	3,171,495 (a)	118,368,000	[illegible]
41d Other Classes' Portion of True - up (line 30C)	(14,100)	118,368,000	-0.01190
41e Total Demand and Non - Demand Costs including True - up	3,157,395	118,368,000	[illegible]
42 Revenue tax factor			1.01609
			[illegible]
43 OTHER CLASSES PURCHASED POWER FACTOR ADJUSTED FOR TAXES ROUNDED TO THE NEAREST .001 CENTS PER KWH			4.422

*Based on [illegible]

(a) Included for informational purposes only

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor.	DOCKET NO. 930001-EI FILED: February 16, 1993

STIPULATION

This Stipulation is entered into by and between Tampa Electric Company ("Tampa Electric" or "the company") and the Office of Public Counsel ("Public Counsel") on this 16th day of February 1993 as follows:

<u>Purpose of this Stipulation</u>

This Stipulation has been entered into by Tampa Electric and Public Counsel to establish arrangements to dispose of a continuing controversy over a proper way to judge the reasonableness of prices paid by Tampa Electric to an affiliated coal supplier, Gatliff Coal Company ("Gatliff"). It is the objective of each party to this Stipulation to establish arrangements under which fair and reasonable coal costs are reflected in prices to electric consumers. With the Commission's encouragement that parties attempt to resolve disputes amicably, Tampa Electric and Public Counsel have engaged in extensive and protracted efforts to establish arrangements consistent with that objective. The parties' focus has been to develop a means to evaluate the pricing of Gatliff coal in a way that fairly passes on the appropriate costs to Tampa Electric's Customers and at the same time provides greater understanding and certainty for the parties as to the appropriate way to proceed in the future. The proposed settlement embodied in this Stipulation, if approved by the Commission, will resolve a pending appeal in the Supreme Court of Florida, will resolve all issues related to the pricing of coal purchased by Tampa Electric from Gatliff through calendar year 1992 and will afford the Commission and the parties an agreed upon method for evaluating the reasonableness of the pricing of such purchases during 1993 through 1999. In addition, Tampa Electric's customers will receive the benefits of a $[illegible] million downward adjustment to Tampa Electric's recoverable fuel expenses, by virtue of a credit (as described in Paragraph 9 below) to billed fuel costs on their electric bills.

To effect the above results, Tampa Electric and Public Counsel stipulate and agree as follows:

Background

1. In 1988, in Tampa Electric's "cost plus" docket, the Commission approved the implementation of a market-based pricing and benchmark methodology to measure the appropriateness of Tampa Electric's coal purchase prices from an affiliate, Gatliff Coal Company. (Order No. 20298, Docket No. 870001-EI-A). In that docket the Commission approved a stipulation (the "1988 Stipulation") between Tampa Electric and the Office of Public Counsel describing a benchmark for evaluating the reasonableness of coal prices. The 1988 Stipulation established an initial market price of $39.44 per ton FOB Mine as of December 31, 1987 for coal

purchased from Gatliff. The 1988 Stipulation then provided that for purposes of regulatory review in the fuel docket, an adjusted price would be calculated by escalating or de-escalating the initial market price by the annual percentage change in Bureau of Mines District 8 data for coal, as reported on FERC Form 423, for the weighted average price per million BTU of contract transactions that meet agreed upon coal specifications. The adjusted price would be increased by 5% to arrive at a new benchmark price. For purposes of recovery through the fuel adjustment clause, Tampa Electric was required to justify the costs for Gatliff Coal that exceeded the market-based benchmark calculation.

2. While one of the objectives of the benchmark calculation was to reduce or eliminate controversy concerning the pricing of Gatliff coal, the determination of the regulatory benchmark price under the 1988 Stipulation has been controversial and has consumed considerable time and resources of the Commission and all of the parties to this issue.

3. In the August 1991 fuel hearings the Commission found that, while the actual per ton contract price for 1990 for Gatliff Coal exceeded the regulatory benchmark, the actual per ton contract price of Gatliff coal purchased by Tampa Electric had been justified and full recovery should be allowed. See Order No. 25148 (Commissioner Deason dissenting) issued October 1, 1991 and Order No. PSC-92-0015-FOF-EI issued on reconsideration on March 9, 1992 in Docket No. 920001-EI. These orders are currently pending on review in the Florida Supreme Court in Case No. 79,675 in a

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proceeding initiated by Public Counsel.

4. On January 10, 1992, Tampa Electric filed in Docket No. 920041-EI a Petition for Clarification and Guidance on the calculation of the market based pricing methodology under the 1988 Stipulation. This Petition sought review of the appropriate method to calculate the benchmark index used to examine the reasonableness of the price paid for coal purchased by Tampa Electric from Gatliff. The testimony at the hearings centered around the interpretation of comparable data from the FERC Form 423 reports as a measure of market change. The Commission on September 23, 1992 issued Order No. PSC-92-1048-FOF-EI which affirmed the continued use of the existing market based index calculation. The Commission further stated that it would be beneficial also to analyze the market data on a contract annual average quality basis as a "sanity check."

5. The appropriate level of recovery of prices paid by Tampa Electric to Gatliff for 1991 is now pending in Docket No. 930001-EI and scheduled for hearing on February 17-19, 1993. The determination of the level of recovery of prices paid by Tampa Electric to Gatliff in 1992 would normally be considered during the fuel adjustment hearings to be conducted in August of 1993.

6. Public Counsel and Tampa Electric have met to discuss methods by which the application of market pricing to the coal transactions between Tampa Electric and Gatliff can be improved. As a result of these discussions, Public Counsel and Tampa Electric have reached the agreement embodied in this Stipulation.

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7. The focus of this agreement is on the regulatory benchmark and approval methodology. The format or details of the specific contracts between Tampa Electric and its affiliates, including the pricing indices in the contracts, are not subject to this proceeding. Tampa Electric may negotiate the terms in contracts with its affiliates in any manner it deems to be fair and reasonable. Tampa Electric agrees to prudently administer the provisions of such contracts.

8. The actual prices paid by Tampa Electric to its affiliates shall be reported to this Commission in the normal course of the fuel adjustment proceedings.

<u>Gatliff Coal Company</u>

9. Tampa Electric agrees to make a $10 million downward adjustment to its recoverable fuel expense beginning in April 1993. The adjustment will be implemented through a credit on Customers' bills which shall be calculated by multiplying a levelized factor adjusted for line losses times the actual KWH usage during the period of the credit. The adjustment shall be spread over the 12-month period April 1993 through March 1994, plus interest on the unamortized amount of the adjustment. Such interest shall be at the thirty (30) day commercial paper rate for high grade unsecured notes sold through dealers by major corporations in multiples of $1,000 as regularly published in the <u>Wall Street Journal</u>. Any over- or undercollection associated with this downward adjustment will be handled as a true-up component in the normal course of fuel

cost recovery proceedings.

10. Public Counsel and Tampa Electric agree that, after the downward adjustment specified in Paragraph 9 is taken into account, the prices paid by Tampa Electric to Gatliff in 1990, 1991 and 1992 are appropriate for recovery through the fuel and purchased power cost recovery clause.

11. The parties further agree that Public Counsel's appeal of Orders Nos. 25148 and PSC-92-0015-FOF-EI, pending in Florida Supreme Court Case No. 79,675, shall be withdrawn and dismissed with prejudice forthwith on Commission approval of this Stipulation. To preserve the status quo pending the Commission's consideration of this Stipulation, Public Counsel and Tampa Electric agree to jointly file a motion with the Court, immediately after signing this Stipulation, asking the Court to stay such appeal pending the finality of the Commission's action resolving the parties' request for approval of this Stipulation.

12. In order to provide a simpler and less controversial prospective benchmark for regulatory review of the annual average price per ton paid by Tampa Electric for coal purchased from Gatliff, the new beginning benchmark price to be used for computing the benchmark for Tampa Electric's transactions with Gatliff shall be $38.00 per ton FOB Mine as of December 31, 1992.

13. For purposes of regulatory review, this base price of $38.00 per ton FOB Mine shall be escalated or de-escalated by the annual percentage change in the unadjusted all items category of the final published calculation for the Consumer Price Index, All

Urban Consumers (CPI-U), as described in Attachment A, page 1 of 2, to this Stipulation. In the event the weighted average annual price of Gatliff coal to Tampa Electric is increased by (a) the enactment or amendment of any law, regulation, order or other governmentally imposed requirement, or (b) any change in the application or enforcement of any law, regulation, order or other governmentally imposed requirement, the base price as escalated or de-escalated as provided in the first sentence of this Paragraph shall be further increased by the effect on Gatliff coal prices of matters described in (a) or (b) of this Paragraph, but only to the extent that the weighted average annual price of Gatliff coal to Tampa Electric exceeds the base price escalated or de-escalated by the CPI-U as provided in the first sentence of this Paragraph.

14. The weighted average annual price paid to Gatliff Coal Company by Tampa Electric above the price determined for purposes of regulatory review in Paragraph 13 above, shall be disallowed for fuel cost recovery purposes.

<u>TECO Transport & Trade</u>

15. The parties agree that the provisions for calculating the market price benchmark described in paragraphs 8, 9 and 10 and Attachment "3" of the 1988 Stipulation, relating to coal transportation cost, are hereby reaffirmed and shall remain in full force and effect.

General Provisions

16. The approval of this Stipulation and compliance with its provisions will completely resolve all of the issues concerning the prices paid by Tampa Electric to Gatliff for coal through December 31, 1992.

17. This Stipulation is based on the unique factual circumstances of this case and shall have no precedential value in any proceedings involving other utilities before this Commission. The parties to this Stipulation reserve the right to assert different positions on any of the matters contained in this Stipulation if this Stipulation is not accepted in its entirety by the Commission.

18. The parties hereto shall support the approval of this Stipulation by the Commission at the earliest possible time in order to facilitate the implementation of the downward adjustment to Tampa Electric's recoverable fuel expenses provided for herein beginning April 1, 1993. The parties hereto shall not seek reconsideration or judicial appeal of the Commission's approval of this Stipulation.

19. The parties urge that the Commission take final agency action at the earliest possible time approving this Stipulation.

20. This Stipulation shall be effective upon Commission approval. In the event that the Commission rejects or modifies the Stipulation, in whole or in part, the parties agree that this Stipulation is void unless otherwise ratified by the parties, and that each party may pursue its interests as those interests exist,

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and that no party will be bound to or make reference to this Stipulation before this Commission, any court, any other administrative forum or arbitration panel.

DATED this 16th day of February, 1993.

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ATTORNEYS FOR TAMPA ELECTRIC COMPANY

ATTACHMENT A
Page 1 of 2

TAMPA ELECTRIC COMPANY

BENCHMARK MARKET BASED COAL CALCULATION

The initial base price of $38.00 per ton shall be adjusted by the annual percentage change in the unadjusted all items category of the final published calculation for the Consumer Price Index, All Urban Consumers (CPI-U). The CPI-U adjusted base price for any given year will be the adjusted base price at the end of the immediately preceding year increased by the percentage change in the CPI-U for the given year.

EXAMPLE

Assumptions:

1. Base price at beginning of year one = $38.00
2. Hypothetical CPI-U percentage change from 1992 to 1993 = 3.0%, which is the percentage change in CPI-U from end of 1992 to end of 1993
3. Hypothetical CPI-U percentage change from 1993 to 1994 also equals 3.0 percent.

Calculation for first year:

$38.00 x .03 = $1.14 + $38.00 = $39.14 = benchmark price for all coal purchased in year one (1993). This calculation may be increased to the extent provided in the second sentence of Paragraph 13. -

Calculation for second year under same assumptions:

$39.14 x .03 = $1.17 + $39.14 = $40.31 = benchmark price for all coal purchased in year two (1994). This calculation may be increased to the extent provided in the second sentence of Paragraph 13.

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ATTACHMENT A
Page 2 of 2

PUBLIC COUNSEL'S MARKET

PRICE APPLICATION

-- Gatliff coal purchased[1]

FOB mine	$45/ton
Tons purchased	500,000
Total cost	$22,500,000

-- Market Benchmark $40/ton

-- Coal recovered through fuel clause

$40/ton x 500,000 = $20,000,000

-- Cost disallowed recovery

$20,000,000 - $22,500,000 = $2,500,000*

1. This would include the total average price of Gatliff produced coal and coal purchased and resold as Gatliff coal.

* The company would not be allowed to recover these costs under this Stipulation except to the extent provided in the second sentence of Paragraph 13.

ATTACHMENT C
ORDER NO. PSC-93-0443-FOF-EI
DOCKET NO. 930001-EI
PAGE 35

GPIF REWARDS/PENALTIES
April 1992 to September 1992

Page 1 of 2

Florida Power Corporation	$1,211,000	Reward
Florida Power and Light Company	$7,020,173	Reward
Gulf Power Company	$322,504	Reward
Tampa Electric Company	$318,938	Reward

Utility/ Plant/Unit	EAF		Heat Rate	
FPC	Target	Adj. Actual	Target	Adj. Actual
Anclote 1	90.4	93.8	9,345	9,335
Anclote 2	92.2	94.4	9,367	9,469
Crystal River 1	81.6	73.1	10,026	9,897
Crystal River 2	81.6	88.9	10,043	10,051
Crystal River 3	51.5	61.4	10,635	10,548
Crystal River 4	81.3	78.8	9,301	9,253
Crystal River 5	89.5	86.3	9,265	9,303
FPL	Target	Adj. Actual	Target	Adj. Actual
Cape Canaveral 2	92.0	95.5	9,117	9,017
Fort Myers 2	83.0	88.9	9,459	9,330
Manatee 1	61.8	61.8	9,740	9,721
Manatee 2	92.3	95.9	9,304	9,550
Martin 1	97.3	95.4	9,531	9,978
Martin 2	95.3	97.5	9,391	9,408
Port Everglades 2	95.5	92.2	9,033	9,308
Port Everglades 3	90.4	92.7	9,183	9,093
Port Everglades 4	71.6	75.8	9,186	9,169
Riviera 3	90.2	93.7	9,403	9,701
Riviera 4 *	88.3	92.2	9,749	9,431
Turkey Point 1	94.4	89.3	9,370	9,115
Turkey Point 2	94.0	87.3	9,421	9,198
Turkey Point 3	62.7	70.8	11,305	11,217
Turkey Point 4	76.2	87.0	11,230	11,[illegible]
St. Lucie 1	90.5	91.3	10,886	10,808
St. Lucie 2	58.2	50.8	10,885	10,718
GULF	Target	Adj. Actual	Target	Adj. Actual
Crist 6	80.2	82.1	10,377	10,088
Crist 7	77.5	72.7	10,180	9,[illegible]
Smith 1	85.7	84.5	10,283	10,070
Smith 2	88.4	85.6	10,273	10,051
Daniel 1	97.8	95.7	10,522	10,387
Daniel 2	97.5	99.1	10,492	10,138

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ORDER NO. PSC-93-0443-FOF-EI
DOCKET NO. 930001-EI
PAGE 36

GPIF REWARDS/PENALTIES
April 1992 to September 1992

Page 2 of 2

Utility/ Plant/Unit	EAF		Heat Rate	
TECO	Target	Adj. Actual	Target	Adj. Actual
Big Bend 1	67.2	66.0	10,032	10,105
Big Bend 2	78.6	84.0	10,014	10,025
Big Bend 3	72.2	84.6	9,693	9,635
Big Bend 4	87.7	88.1	10,279	10,214
Gannon 5	85.5	89.1	10,400	10,302
Gannon 6	82.9	84.9	10,267	10,273

GPIF TARGETS
April 1993 to September 1993

Utility/ Plant/Unit	Equivalent Availability				Heat Rate	
	Company			Staff	Company	Staff
FPC	EAF	POF	EUOF			
Anclote 1	83.4	11.5	5.1	Agree	9,763	Agree
Anclote 2	94.7	0.0	5.3	Agree	9,886	Agree
Crystal River 1	84.3	0.0	15.7	Agree	9,988	Agree
Crystal River 2	78.1	7.1	14.8	Agree	9,975	Agree
Crystal River 3	72.2	15.3	12.5	Agree	10,462	Agree
Crystal River 4	83.2	12.6	4.2	Agree	9,245	Agree
Crystal River 5	94.9	0.0	5.1	Agree	9,301	Agree
FPL	EAF	POF	EUOF			
Cape Canaveral 1	83.8	10.9	5.3	Agree	9,082	Agree
Cape Canaveral 2	79.5	15.3	5.2	Agree	9,202	Agree
Ft. Myers 2	91.9	0.0	8.1	Agree	9,414	Agree
Manatee 1	83.7	0.0	16.3	Agree	9,710	Agree
Manatee 2	95.4	0.0	4.6	Agree	9,521	Agree
Martin 1	90.7	0.0	9.3	Agree	9,172	Agree
Martin 2	96.0	0.0	4.0	Agree	9,138	Agree
Port Everglades 1	94.8	0.0	5.2	Agree	9,791	Agree
Port Everglades 2	91.0	0.0	9.0	Agree	9,713	Agree
Port Everglades 3	93.9	0.0	6.1	Agree	9,301	Agree
Port Everglades 4	95.4	0.0	4.6	Agree	9,353	Agree
St. Johns River 1	97.3	0.0	2.7	Agree	9,344	Agree
St. Johns River 2	98.0	0.0	2.0	Agree	9,258	Agree
Riviera 3	91.1	0.0	8.9	Agree	9,864	Agree
Riviera 4	58.3	35.1	6.5	Agree	9,776	Agree
Sanford 4	93.8	0.0	6.2	Agree	9,979	Agree
Turkey Point 1	74.1	19.1	6.8	Agree	9,324	Agree
Turkey Point 2	82.5	0.0	17.5	Agree	9,400	Agree
Turkey Point 3	90.7	0.0	9.3	Agree	11,258	Agree
Turkey Point 4	60.1	35.0	4.9	Agree	11,216	Agree
St. Lucie 1	62.5	32.2	5.3	Agree	10,813	Agree
St. Lucie 2	93.6	0.0	6.4	Agree	10,795	Agree
GULF	EAF	POF	EUOF			
Crist 6	87.8	0.0	12.2	Agree	10,247	Agree
Crist 7	62.0	25.3	12.7	Agree	9,989	Agree
Smith 1	84.8	9.1	6.1	Agree	10,178	Agree
Smith 2	91.8	2.2	6.0	Agree	10,227	Agree
Daniel 1	98.0	0.0	2.0	Agree	10,498	Agree
Daniel 2	97.8	0.0	2.2	Agree	10,408	Agree

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GPIF TARGETS
April 1993 to September 1993

Utility/ Plant/Unit	Equivalent Availability				Heat Rate	
	Company			Staff	Company	Staff
TECO	EAF	POF	EUOF			
Big Bend 1	81.0	2.8	15.2	Agree	9,994	Agree
Big Bend 2	84.0	1.1	14.9	Agree	9,984	Agree
Big Bend 3	72.6	16.4	11.0	Agree	9,634	Agree
Big Bend 4	87.0	0.0	13.0	Agree	9,914	Agree
Gannon 5	59.5	30.6	9.9	Agree	10,442	Agree
Gannon 6	81.8	0.0	18.2	Agree	10,268	Agree