BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of Fuel and Purchased Power Cost Recovery Clause with Generation Performance Incentive Factor	DOCKET NO. 950001-EI

FIRST DAY - MORNING SESSION

VOLUME 1

Pages 1 through 180

PROCEEDINGS: **HEARING**

BEFORE: COMMISSIONER J. TERRY DEASON
COMMISSIONER JULIA L. JOHNSON
COMMISSIONER DIANE K. KIESLING

DATE: **Wednesday, March 8, 1995**

TIME: Commenced at 10:00 a.m

PLACE: Fletcher Building
FPSC Hearing Room 106
101 East Gaines Street
Tallahassee, Florida

REPORTED BY: JOY KELLY, CSR, RPR
Chief, Bureau of Reporting
SYDNEY C. SILVA, CSR, RPR
ROWENA NASH HACKNEY
Official Commission Reporters

APPEARANCES:

JAMES A. McGEE, Post Office Box 14042, St. Petersburg, Florida 33733, Telephone No. (813) 866-5098, appearing on behalf of **Florida Power Corporation.**

MATTHEW M. CHILDS, P.A., Steel, Hector & Davis, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301, Telephone No. (904) 224-7595, appearing on behalf of **Florida Power and Light Company.**

JAMES D. BEASLEY, Macfarlane, Ausley, Ferguson and McMullen, P.O. Box 392, Tallahassee, Florida 33302, Telephone No. (904) 224-9115, appearing on behalf of **Tampa Electric Company.**

MARIAN B. RUSH, Salem, Saxon & Nielsen, P.C., Suite 3200, One Barnett Plaza, 101 East Kennedy Boulevard, P. O. Box 3399, Tampa, Florida 33601, Telephone No. (813) 224-9000, and

MICHAEL E. KAUFMANN, Brickfield, Burchette & Ritts, P.C., 1025 Thomas Jefferson Street, N.W., Eighth Floor - West Tower, Washington, D.C., 20005, Telephone No. (904) 342-0800, appearing on behalf of **Florida Steel Corporation.**

APPEARANCES CONTINUED:

JOHN McWHIRTER, McWhirter, Reeves, McGlothlin, Davidson and Bakas, 315 South Calhoun Street, Suite 716, Tallahassee, Florida 32301, Telephone No. (904) 222-2525, appearing on behalf of **Florida Industrial Power Users Group.**

JOHN ROGER HOWE, Office of Public Counsel, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, Telephone No. (904) 488-9330, appearing on behalf of the **Citizens of the State of Florida.**

MARTHA CARTER BROWN, Florida Public Service Commission, Division of Legal Services, 101 East Gaines Street, Tallahassee, Florida 32399-0863, Telephone No. (904) 487-2740, appearing 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, Telephone No. (904) 488-7463, **Counsel to the Commissioners.**

WITNESSES - VOLUME 1

WITNESSES CONTINUED:

ELIZABETH A. TOWNES

Prefiled Direct Testimony Inserted Into the Record by Stipulation	163

EXHIBITS - VOLUME 1

NUMBER		IDENTIFIED	ADMITTED
1	(Wieland) KWH-1	13	13
2	(Wieland) KHW-2	13	13
3	(Wieland) KHW-3	13	13
4	(Wieland) KHW-4	13	13
5	(Turner) LTG-1	13	13
6	(Turner) LTG-2	13	13
7	(Birkett) BTB-1	13	13
8	(Birkett) BTB-2	13	13
9	(Birkett) BTB-3	13	13
10	(Birkett) BTB-4	13	13
11	(Silva) RS-1	13	
12	(Birkett) BTB-5	13	
13	(Birkett) BTB-6	13	
14	(Birkett) BTB-7	13	13
15	(Birkett) BTB-8	13	13
16	(Silva) RS-2	13	13
17	(Silva) RS-3	13	13
18	(Birkett) BTB-9	13	
19	(Silva) RS-4	13	
20	(Silva) RS-5	13	
21	(Bachman) GMB-1	13	13
22	(Fietek) SMF-1	13	
23	(Gilchrist) MLG-1	13	13
24	(Gilchrist) MLG-2	13	13
25	(Howell) MWH-1	13	13
26	(Cranmer) SDC-1	13	13
27	(Cranmer) SDC-2	13	13
28	(Fontaine) GDF-2	13	13
29	(Pennino) MJP-1	13	13
30	(Pennino) MJP-2	13	13
31	(Pennino) MJP-3	13	13
32	(Pennino) MJP-4	13	13
33	(Keselowsky) GAK-1	13	13
34	(Keselowsky) GAK-2	13	13
35	(Keselowsky) GAK-3	13	13
36	(Cantrell & Townes)	13	13

EXHIBITS CONTINUED:

	WNC/EAT-1		
37	(Cantrell & Townes)	13	13
	WNC/EAT-2		
38	(Cantrell & Townes)	13	13
	WNC/EAT-3		

P R O C E E D I N G S

(Hearing convened at 10:00 a.m.)

COMMISSIONER DEASON: Call the hearing to order. We'll begin by having the notice read.

MS. BROWN: By notice issued February 10th, 1995, this time and place was set for a hearing in the following dockets: Docket 950001-EI, fuel and purchased power cost recovery clause; Docket 950002-EC, energy conservation cost recovery cause; Docket 950003-GU, purchased gas cost recovery clause; and Docket 950007-EI, environmental cost recovery clause.

The purpose of the hearing is described in the notice.

COMMISSIONER DEASON: We'll take appearances.

MR. CHILDS: Commissioners, my name is Matthew Childs of the firm of Steel, Hector and Davis. I'm appearing on behalf of Florida Power and Light Company in the 01 and 07 dockets.

MR. BEASLEY: Commissioners, I'm James D. Beasley of the law firm of Macfarlane, Ausley, Ferguson and McMullen, representing Tampa Electric Company in the 01 and 02 dockets.

MR. KAUFMANN: Commissioners, my name is Michael Kaufmann, of the firm of Brickfield, Burchette and Ritts, out of Washington, D.C., representing Florida

Steel in the 01 docket.

MS. RUSH: Commissioners, my name is Marian Rush, I'm with the firm of Salem, Saxon and Neilsen. I'm here with Mr. Kaufmann representing Florida Steel in the 01 docket.

MR. HOWE: Commissioners, I'm Roger Howe with the Office of Public Counsel, appearing on behalf of the citizens of the state of Florida in the 01, 02, 03 and 07 dockets.

MR. McWHIRTER: Mr. Chairman, my name is John McWhirter of the firm of McWhirter Reeves, appearing on behalf of the Florida Industrial Power Users Group in the 1, 2, 3 and 7 dockets.

MS. BROWN: Martha Carter Brown and Vicki D. Johnson representing the Florida Public Service Commission Staff in the 01 and 07.

MR. PRUITT: I'm Prentice Pruitt, counselor to the Commissioners.

COMMISSIONER DEASON: Okay. Very well.

MS. BROWN: Commissioner, may I mention something before we get started?

COMMISSIONER DEASON: Well, I have something to do with the appearances, something to say, and then we can get on --

MS. BROWN: Something to do with appearances?

COMMISSIONER DEASON: Yes. Yesterday, Jeffry Stone -- is that what you wanted to just mention? He called my office and spoke with Charles. Apparently, he has no issues or Gulf Power has no issues, and it was his desire to be excused from today's proceedings and I granted him that. And he did obviously participate in the prehearing process and went through that; and since there are no contested issues, there would be no need for him to appear here today.

MS. BROWN: Yes. I had one other matter on appearances, Commissioner Deason.

Ms. Rush is sponsoring Mr. Kaufmann in this proceeding. She filed notice of sponsorship this morning.

COMMISSIONER DEASON: Yes. I reviewed that, that filing; and without objection, that sponsorship will be recognized and we'd welcome Mr. Kaufmann to participate with us today.

MR. KAUFMANN: Thank you.

* * * * * *

MS. BROWN: Commissioner, we're ready to proceed with 01 if you are.

COMMISSIONER DEASON: Yes. We will proceed into the 01 docket at this time.

MS. BROWN: Commissioner, I have a couple of minor corrections to the Prehearing Order that was issued yesterday.

Let me first -- with respect to the witnesses, let me first mention that Mr. Birkett from Florida Power and Light and Mr. Silva filed rebuttal testimony in the case, and the Prehearing Order does not reflect that. Mr. Childs has proposed that they give their direct testimony and then give their rebuttal testimony at the appropriate time.

COMMISSIONER DEASON: And that was for witnesses Birkett and Silva?

MS. BROWN: Yes.

We have four outstanding company-specific issues to deal with. We have several company-specific issues that have been stipulated and I need to mention one of them.

Jim, what issue is that that I need to add?

Commissioner, if you would turn to Page 21, Issue 23B, when we were putting this final Prehearing Order together, the last sentence of the position, of the stipulated position in that issue was inadvertently dropped, and I would like to read that into the record now.

It is a separate paragraph, and it begins, "All of the revenues that result from interchange sales other than the firm Schedule D sales should continue to appear as credits in the appropriate adjustment clauses. The Company should notice the Commission's Division of Electric and Gas via a certified letter if (when) additional Schedule D sales are made."

That's part of the position that Staff and Tampa Electric Company reached agreement upon, and it just got left out; the computer ate it.

There is one other minor correction that I need to make, and that is with Issue 13.

Issue 13 is a stipulated Issue as well, and the Prehearing Order does not reflect that.

COMMISSIONER DEASON: So then the only issues remaining are 10A, B, C.

MS. BROWN: 23A.

COMMISSIONER DEASON: And 23A.

MS. BROWN: Yes. All of the other issues have been stipulated. There are generic issues that have been stipulated with the caveat that the number is subject to adjustment for certain companies pending resolution of the company-specific issues in the fallout issues. It's just a calculation that we'll make after the Commission makes its decision.

COMMISSIONER DEASON: Yes. Very well.

MS. BROWN: There is nothing further

preliminarily, and we're ready to proceed with the issues in dispute.

COMMISSIONER DEASON: Well, would it be more expeditious if we went ahead and identified all of those witnessess whose testimony will be inserted, and their exhibits and go ahead and have that portion of the record completed, and then we can move into the live testimony of the other witnesses.

MS. BROWN: Yes. Yes, you're right, Commissioner, it would be.

COMMISSIONER DEASON: Okay.

MS. BROWN: Starting on Page 5 of the Prehearing Order the witnesses whose testimony has been stipulated to be inserted into the record as though read, all appear with an asterisk next to their names. And likewise the exhibits they have sponsored have been identified with an asterisk next to their name.

COMMISSIONER DEASON: First of all, let's take care of the testimony.

I'm going to ask all of the parties to look at the Prehearing Order and make sure that those witnesses that do have a asterisk by their names, that it is appropriate for their testimony to be inserted into the record and cross examination be waived.

I take it now you're moving that all of those witnesses who are so designated, that at this point their testimony be inserted into the record.

MS. BROWN: Yes, Commissioner.

COMMISSIONER DEASON: Without objection, showing no objection, show that the testimony for those witnesses so designated will have their testimony inserted into the record.

Now let's proceed to the exhibits for those particular witnesses. And what page is that on?

MS. BROWN: That's a Pages 22 through 24, or 25 rather.

MS. BROWN: Yes, Commissioner.

COMMISSIONER DEASON: First of all what I'm going to do, for ease of administration, I'm going to number for identification purposes all exhibits which have been identified in the Prehearing Order, I'm going to number those consecutively as Exhibits 1 through 38. All of those exhibits will be identified in order as they appear in the Prehearing Order, and they will be identified as Exhibits 1 through 38.

Now, I take it you have designated those exhibits with an asterisk that may be admitted at this point, and there would be no cross examination on those exhibits.

MS. BROWN: That's correct.

COMMISSIONER DEASON: Okay. Here again I'm going to ask all parties to review that quickly and make sure that is the case. And I take it then you are moving those so designated exhibits into the record at this time.

MS. BROWN: Yes, Commissioner.

COMMISSIONER DEASON: Without objection, show those exhibits so designated being admitted. And I believe that would leave Exhibits 11, 12, 13 that would not yet be admitted; 18, 19, 20 not yet admitted; 22 not yet admitted, and I believe that's all.

MS. BROWN: That is it.

(Exhibit Nos. 1 through 38 marked for identification and Exhibit Nos. 1 through 10, 14 through 17, 21 and 23 through 38 received in evidence.)

FLORIDA POWER CORPORATION

DOCKET NO. 940001-EI

Re: Fuel and Capacity Cost Recovery
Final True-up Amounts for
April through September 1994

DIRECT TESTIMONY OF
KARL H. WIELAND

Q. Please state your name and business address.

A. My name is Karl H. Wieland. My business address is P. O. Box 14042, St. Petersburg, Florida 33733.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power Corporation as Director of Business Planning.

Q. Have the responsibilities of your position with the Company remained the same since you last testified in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Company's Fuel Cost Recovery Clause final true-up amount for the period of April through September 1994, and the Company's Capacity Cost Recovery Clause final true-up amount for the period of April through September 1994.

Q. Have you prepared exhibits to your testimony?

A. Yes, I have prepared a three-page true-up variance analysis which examines the difference between the estimated fuel true-up and the actual period-end fuel true-up. This variance analysis is attached to my prepared testimony and designated exhibit (KHW-1). Also attached to my prepared testimony and designated exhibit (KHW-2) are the Capacity Cost Recovery Clause true-up calculations for the April through September 1994 period. In addition, I will sponsor Schedules A1 through A12 for the month of September, 1994 (period-to-date), which have been previously filed with the Commission and are also attached to my prepared testimony for ease of reference.

Q. What is the source of the data which you will present by way of testimony or exhibits in this proceeding?

A. Unless otherwise indicated, the actual data is taken from the books and records of Company. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by this Commission.

FUEL COST RECOVERY

Q. What is the Company's final true-up amount for fuel cost recovery?

A. The fuel true-up balance as of September 30, 1994 is an under-recovery of $33,870,947. When the estimated under-recovery of $31,586,452 to be collected during the current period is taken into account, the final net true-up amount attributable to the April - September 1994 period is an under-recovery of $2,284,495.

Q. How was the final true-up amount determined?

A. The amount was determined in the manner set forth on Schedule A2 of the Commission's standard forms previously submitted by the Company on a monthly basis.

Q. What factors contributed to the period-ending under-recovery of $33.9 million?

A. The factors contributing to the under-recovery are summarized on Sheet 1 of my exhibit (KHW-1). It is the net result of changes in projected costs on one hand, and changes in projected revenues on the other. The total system cost of fuel and net power transactions for the period was $33.6 million higher than projected, which was the combined effect of a $29.5 million increase in jurisdictional costs and a $4.1 million increase in wholesale costs. Jurisdictional fuel revenues were $1.4 million higher than projected due to higher than projected sales. The combination of significantly higher jurisdictional costs and slightly higher jurisdictional revenues resulted in an under-recovery of $28.2 million attributable to the April - September 1994 period. Other variances not directly attributable to the period, including an interest provision of $0.6 million, result in the total true-up under-recovery of $33.9 million, as of September 30, 1994.

Q. Please explain the components shown on Sheet 2 of your exhibit which produced the $33.6 million system variance from the projected cost of fuel and net power transactions.

A. Sheet 2 of my exhibit (KWH-1) shows an analysis of this system variance for each energy source in terms of three interrelated components: (1) changes in the amount (MWh's) of energy required; (2) changes in the heat rate, or efficiency, of generated energy (BTU's per kWh); and (3) changes in the unit price of either fuel consumed for generation ($ per million BTU) or energy purchases and sales (cents per kWh).

Q. What effect did these components have on the system fuel and net power variance for the true-up period?

A. As can be seen from Sheet 2, variances in the amount of MWh requirements from each energy source (column B) combined to produce a cost increase of $4.6 million. I will discuss this component of the variance analysis in greater detail below.

The heat rate variance for each source of generated energy (column C) produced a net cost increase of $5.1 million. Higher than anticipated heat rates for oil generating units were the largest component of the cost variance. On the Company's Schedule A3, all BTU's for light oil are included in the light oil heat rate computation. However since no kWh generation is associated with light oil consumed at steam plants, the resulting heat rate shown on A3 is distorted. In order to compute the true heat rate variance, light oil consumed at steam units is shown separately on line 23 of Sheet 2.

A cost increase of $23.9 million resulted from the price variance (column D), which was caused by a number of factors detailed on lines 1 through 26 of Sheet 2. The main factors were higher than projected prices for oil ($12.4 million) and purchased power ($11.0 million).

Q. What is the purpose of the analysis captioned "Reconciliation of Variances in MWh Requirements," shown on Sheet 3 of your exhibit?

A. The analysis on Sheet 3 is an attempt to identify the effect that variances in the MWh requirements of certain energy sources have on the MWh variances of other energy sources. Although this interrelationship is generally understood to exist, it is not readily apparent from the individual variances contained in the A Schedules or in the analysis on Sheet 2. For example, an increase in the MWh requirements of nuclear generation shows up on Schedule A3 and on Sheet 2 of my exhibit as a cost increase. While this may be correct in isolation, the true effect of increased nuclear generation is obviously a corresponding decrease in the MWh requirements of a number of other more costly energy sources, primarily oil. The result is a lower net system cost even if total system MWh requirements remain unchanged.

In addition to this effect of variances in generation mix, the analysis also attempts to identify the independent effect of the <u>net</u> variance in total system MWh requirements from all energy sources combined. In this true-up period, for example, total system requirements were lower than the original forecast by 31,215 MWh. This would have led to lower net costs even if the mix of generation had not changed, since the lower system load decreases oil generation at a cost above the system average.

Q. Please explain how this analysis was performed.

A. The analysis on Sheet 3 is made in two steps. The first, captioned "MWh Reconciliation," allocates the MWh variances for the individual energy sources shown in column B among the primary causal variances in columns C through H. Since the causal variances identified in this analysis are not all inclusive, the amount of any residual over- or under-allocation is shown in column I, "Unallocated Variances." The second step, captioned "Cost Reconciliation," assigns a dollar value to the MWh variances identified in step 1. This is done by allocating the cost variances identified in column B of Sheet 2 for each energy source (and shown again in column B of Sheet 3) among the causal variances based on the MWh's allocated to each in step 1. As mentioned above, the allocation of individual MWh and cost variances to the various causes of those variances is not intended to be all inclusive or precise. It is intended to be a representative approximation of the exceedingly complex cause and effect relationship existing among the individual and total MWh variances and their related cost variances.

Q. What were the major contributors to the $4.6 million cost increase associated with the variance in MWh requirements?

A. Coal units had a higher availability than expected during the period, but actual generation was 482,000 MWh lower than forecast due to economic purchases of Southern UPS and purchases of non-dispatchable cogen capacity. This contributed $5.6 million to the variance. Lower than expected system requirements during the period resulted in a $0.9 million reduction to the cost variance. Higher than expected nuclear generation reduced overall costs by $2.1 million. Other factors combined to increase the variance by $2.0 million.

CAPACITY COST RECOVERY

Q. What is the Company's final true-up amount for capacity cost recovery?

A. Exhibit (KHW-2), sheet 1, entitled "Calculation of Final True-Up Amount" records the costs and revenues associated with the Capacity Cost Recovery Clause for the period April through September 1994. The capacity cost recovery true-up balance as of September 30, 1994 is an over-recovery of $6,943,182.

Q. Is this true-up calculation consistent with the true-up methodology used for the other cost recovery clauses?

A. Yes it is. The calculation of the true-up amount follows the procedures established by this Commission as set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision" for the Fuel Cost Recovery Clause.

Q. What factors contributed to the period-end over-recovery of $6,943,182?

A. Exhibit (KHW-2), sheet 1, entitled "Summary of Final True-Up Amount", compares the summary items from sheet 2 to the original forecast for the period. As can be seen from sheet 1, actual capacity cost revenues were $0.8 million higher than forecast due to higher kWh sales during the period. Jurisdictional capacity costs were $6.1 million lower than forecast. The major factors contributing to this variance were the failure of Royster Phosphate to come on-line in August as expected, reduced payments to Orlando Cogen, and lower than forecast payments to Lake and Pasco Cogens.

Q. What is the Company's net true-up amount for capacity cost recovery?

A. When the estimated over-recovery of $4,552,921 to be refunded during the current period is subtracted from the period-end true-up of $6,943,182, the final net true-up amount attributable to the April - September 1994 period is an over-recovery of $2,390,261.

Q. Does this conclude your testimony?

A. Yes, it does.

FLORIDA POWER CORPORATION

DOCKET NO. 950001-EI

Levelized Fuel and Capacity Cost Factors
April through September 1995

AMENDED DIRECT TESTIMONY OF
KARL H. WIELAND

Q. Please state your name and business address.

A. My name is Karl H. Wieland. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power Corporation as Director of Business Planning.

Q. Have the duties and responsibilities of your position with the Company remained the same since you last testified in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the Company's levelized fuel and capacity cost factors for the period of April through September 1995.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared an exhibit attached to my prepared testimony consisting of Parts A through D and the Commission's minimum filing requirements for these proceedings, Schedules E1 through E10 and H1, which contain the Company's levelized fuel cost factors and the supporting data. Parts A through C contain the assumptions which support the Company's cost projections, Part D contains the Company's capacity cost recovery factors and supporting data.

FUEL COST RECOVERY

Q. Please describe the levelized fuel cost factors calculated by the Company for the upcoming projection period.

A. Schedule E1, page 1 of the "E" Schedules in my exhibit, shows the calculation of the Company's basic fuel cost factor of 1.891 ¢/kWh (before line loss adjustment). The basic factor consists of a fuel cost for the projection period of 1.9500 ¢/kWh (adjusted for jurisdictional losses), a GPIF reward of .00644 ¢/kWh, and an estimated true-up credit of 0.0672 ¢/kWh.

Utilizing this basic factor, Schedule E1-D shows the calculation and supporting data for the Company's levelized fuel cost factors for secondary, primary, and transmission metering tariffs. To accomplish this calculation, effective jurisdictional sales at the secondary level are calculated by applying 1% and 2% metering reduction factors to primary and transmission sales (forecasted at meter level). This is consistent with the methodology being used in the development of the capacity cost recovery factors.

Schedule E1-E develops the TOU factors 1.280 ¢/kWh On-peak and 0.853 ¢/kWh Off-peak. The levelized fuel cost factors (by metering voltage) are then multiplied by the TOU factors, which results in the final fuel factors to be applied to customer bills during the projection period. The final fuel cost factor for residential service is 1.894 ¢/kWh.

Q. What is included in Schedule E1, line 4, "Adjustments to Fuel Cost"?

A. Line 4 includes an estimate of Florida Power's liability for an annual payment to the US Department of Energy for funding of the decommissioning and decontamination of their nuclear fuel enrichment facilities ($1,259,000 in April), and an estimate of the University of Florida project steam credits ($160,000 per month).

Q. What is included in Schedule E1, line 6, "Energy Cost of Purchased Power"?

A. Line 6 includes energy costs for the purchase of 50 MWs from Tampa Electric Company and the purchase of 200-407 MWs under a Unit Power Sales (UPS) agreement with the Southern Company. During October-December 1994, the Southern Company purchase consists of 200 MW of Schedule E and 202 MW of unit power. Beginning January 1995, the Schedule E contract ends and the

Company will begin to purchase 407 MW of unit power. The capacity payments associated with the UPS contract are based on the original contract of 400 MW. The additional 7 MW are the result of revised SERC ratings for the five units involved in the unit power purchase, providing a benefit to Florida Power Corporation in the form of reduced costs per kW. Both of these contracts have been in place and have been approved for cost recovery by the Commission. Capacity costs for these purchases are included in the capacity cost recovery factor.

Q. What is included in Schedule E1, line 8, "Energy Cost of Economy Purchases (Non-Broker)"?

A. Line 8 includes energy costs for purchases from Seminole Electric Cooperative (SECI) for load following, off-peak hydroelectric purchases from the Southeast Electric Power Agency (SEPA), and miscellaneous economy purchases from within or outside the state which are not made through the Florida Broker System. The SECI contract is an ongoing contract under which the Company purchases energy from SECI at 95% of its avoided fuel cost. Purchases from SEPA are on an as-available basis. There are no capacity payments associated with either of these purchases. Other purchases may have non-fuel charges, but since such purchases are made only if the total cost of the purchase is lower than the Company's cost to generate the energy, it is appropriate to recover the associated non-fuel costs through the fuel adjustment clause rather than the capacity cost recovery factor.

Q. Please explain the entry on Schedule E1, line 17, "Fuel Cost of Supplemental Sales."

A. The Company has a wholesale contract with Seminole for the sale of supplemental energy to supply the portion of their load in excess of 655 MW. The fuel costs charged to Seminole for these supplemental sales are calculated on a "stratified" basis, in a manner which recovers the higher cost of intermediate/peaking generation used to provide the energy. The Company also has wholesale contracts with the municipal utilities of Kissimmee and St. Cloud under which fuel costs are charged in a similar manner. Unlike interchange sales, the fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kWh for fuel adjustment purposes. However, since the fuel costs of the Supplemental sales are not recovered on an average cost basis, an adjustment has been made to remove these costs and the related kWh sales from the fuel adjustment calculation in the same manner that interchange sales are removed from the calculation. This adjustment is necessary to avoid an over-recovery by the Company which would result from the treatment of these fuel costs on an average cost basis in this proceeding, while actually recovering the costs from the Supplemental customers on a higher, stratified cost basis. The development of this adjustment is shown on Schedule E6.

Q. **How was the estimated true-up shown on line 28 of Schedule E1 developed?**

A. The total true-up amount was determined in two parts. First, a period-to-date actual under-recovery of $15,142,918 through November 1995 was obtained from Schedule A2, page 3 of 4, previously submitted for the month of November. This balance was projected to the end of March 1995, including interest estimated at the November ending rate of 0.4717% per month. Second, the total estimated over-recovery of $12,575,671 for the current period was combined with the prior period (April through September 1994) under-recovery of $33,870,947 and $31,586,452 being collected during the current period for a total over-recovery of $10,291,176 at the end of March 1995. This results in an estimated true-up credit on line 28 of Schedule E1 of 0.0672 ¢/kWh for application in the April through September 1995 projection period. The development of the estimated true-up amount for the current April through September 1995 period is shown on Schedule E1-B, Sheet 1.

Q. **What are the primary reasons for the projected March 1995 over-recovery of $4.6 million?**

A. The over-recovery is primarily a result of lower coal prices, and lower costs of power purchased from qualifying facilities.

Q. Please explain the procedure for forecasting the unit cost of nuclear fuel.

A. The cost per million BTU of the nuclear fuel which will be in the reactor during the projection period (primarily Cycle 10, following the 1994 refueling outage) was developed from the projected cost of fuel added during the current period's refueling outage and the unamortized investment cost of the fuel remaining in the reactor from the prior cycle (Cycle 9). Cycle 10 consists of several "batches," of fuel assemblies which are separately accounted for throughout their life in several fuel cycles. The cost for each batch is determined from the actual cost incurred by the Company, which is audited and reviewed by the Commission's field auditors. The expected available energy from each batch over its life is developed from an evaluation of various fuel management schemes and estimated fuel cycle lengths. From this information, a cost per unit of energy (cents per million BTU) is calculated for each batch. However, since the rate of energy consumption is not uniform among the individual fuel assemblies and batches within the reactor core, an estimate of consumption within each batch must be made to properly weigh the batch unit costs in calculating a composite unit cost for the overall fuel cycle.

Q. How was the rate of energy consumption for each batch within Cycle 10 estimated for the upcoming projection period?

A. The consumption rate of each batch has been estimated by utilizing a core physics computer program which simulates reactor operations over the projection period. When this consumption pattern is applied to the individual batch costs, the resultant composite Cycle 10 is \$0.38 per million BTU.

Q. Would you give a brief overview of the procedure used in developing the projected fuel cost data from which the Company's basic fuel cost recovery factor was calculated?

A. Yes. The process begins with the fuel price forecast and the system sales forecast. These forecasts are input into PROMOD, along with purchased power information, generating unit operating characteristics, maintenance schedules, and other pertinent data. PROMOD then computes system fuel consumption, replacement fuel costs, and energy purchases and costs. This data is input into a fuel inventory model, which calculates average inventory fuel costs. This information is the basis for the calculation of the Company's levelized fuel cost factors and supporting schedules.

Q. What is the source of the system sales forecast?

A. The system sales forecast is made by the Forecasting section of the Business Planning Department using the most recently available data. The forecast used for this projection period was prepared in June 1994.

Q. Is the methodology used to produce the sales forecast for this projection period the same as previously used by the Company in these proceedings?

A. The methodology employed to produce the forecast for the projection period is the same as used in the Company's most recent filings, and was developed with a hybrid econometric/end-use forecasting model. The forecast assumptions are shown in Part A of my exhibit.

Q. What is the source of the Company's fuel price forecast?

A. The fuel price forecast was made by the Fuel and Special Projects Department based on forecast assumptions for residual oil, #2 fuel oil, natural gas, and coal. The assumptions for the projection period are shown in Part B of my exhibit. The forecasted prices for each fuel type are shown in Part C.

CAPACITY COST RECOVERY

Q. How was the Capacity Cost Recovery factor developed?

A. The calculation of the capacity cost recovery factor (CCRF) is shown in Part D of my exhibit. The factor allocates capacity costs to rate classes in the same manner that they would be allocated if they were recovered in base rates. A brief explanation of the schedules in the exhibit follows.

Sheet 1: Projected Capacity Payments. This schedule contains system capacity payments for Schedule E, UPS, TECO and QF purchases. The retail portion of the capacity payments are calculated using separation factors consistent with the Company's rate case filing. Prior to the implementation of the CCRF, capacity costs for these kinds of purchases were included on Schedules E8A and E9 and thus became part of the Company's basic Fuel Cost Factor calculated on Schedule E1. The estimated recoverable capacity payments for the April through September 1995 period are $115,781,701.

Sheet 2: Estimated/Actual True-Up. This schedule presents the actual ending true-up balance after two months of the current period and re-forecasts the over/(under) recovery balances for the next four months to obtain an ending balance for the current period. This estimated/actual balance of $(2,908,435) is then carried forward to Sheet 1, to be collected during the April through September 1995 period.

Sheet 3: Development of Jurisdictional Loss Multipliers: The same delivery efficiencies and loss multipliers as presented on Schedule E1-F.

Sheet 4: Calculation of 12 CP and Annual Average Demand. The calculation of average 12 CP and annual average demand is based on 1994 load research data and the delivery efficiencies on Sheet 3.

Sheet 5: Calculation of Capacity Cost Recovery Factors. The total demand allocators in column (7) are computed by adding 12/13 of the 12 CP demand allocators to 1/13 of the annual average demand allocators. The CCRF for each secondary delivery rate class in cents per kWh is the product of total jurisdictional capacity costs (including revenue taxes) from Sheet 1, times the class demand allocation factor, divided by projected effective sales at the secondary level. The CCRF for primary and transmission rate classes reflect the application of metering reduction factors of 1% and 2% from the secondary CCRF.

Q. Please discuss the increase in capacity payments compared to the prior six-month period.

A. The increase in capacity payments from $103.6 million in the October 1994 through September 1995 period to $126.6 million for the April through September 1995 period is due to several factors. First, all contracts escalate to the 1995 payment schedule for the full projection period. Second, several contracts began during the prior period and will be in effect for the entire six months in the projection period. Third, two new contracts (Orange County and EcoPeat) begin operation during the projection period. Finally, the contract with Southern ("Miller contract") increases to 407 MW in January 1995 with the 200 MW schedule E expiring at the same time.

Q. Is the Company seeking to combine the capacity cost responsibilities of its RS and GS non-demand rate schedules?

A. Yes. As a matter of ratemaking policy, the base rate energy charges for Florida Power's RS and GS non-demand rate schedules have been set the same since February, 1983. This was implemented to avoid administrative problems of customers attempting to qualify for the lower of the two rate schedules' charges. Since costs recovered through the capacity cost recovery clause are a substitute or are similar to costs that are recovered in base rates, Florida Power believes that this cost should be recovered in a manner consistent with the policy established for base rates, *i.e.*, combining the cost responsibilities of RS and GS non-demand rate schedules to develop the same factor for both schedules.

Q. Does this conclude your testimony?

A. Yes.

FLORIDA POWER CORPORATION

DOCKET NO. 940001-EI

Re: GPIF Reward/Penalty Amount for April through September 1994

DIRECT TESTIMONY OF LARRY G. TURNER

Q. Please state your name and business address.

A. My name is Larry G. Turner. My business address is P. O. Box 14042, St. Petersburg, Florida 33733.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power Corporation as Performance Engineer in Energy Supply Services.

Q. What are your responsibilities as Performance Engineer?

A. As the Performance Engineer, I am responsible for compiling and reporting various operational statistics regarding the Company's generating system. In particular, my duties include the preparation of the information and material required by the Commission's GPIF mechanism.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor's Degree in Mechanical Engineering from the University of Florida in 1967. In 1984 I received my Professional Engineers License for the State of Florida. I have been employed by Florida Power Corporation since 1967, with the exception of a three-year period from 1975 to 1978 at which time I was employed by the Alachua County Abstract Company. From 1967 to 1975, I worked as a Test Engineer, Plant Engineer and Mechanical Design Engineer. From 1978 to 1987, I worked as an Instrument and Controls Engineer and since 1987 to the present, I have worked in the Company's Plant Performance Section preparing internal and regulatory reports.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of the Company's Generation Performance Incentive Factor (GPIF) amount for the period of April through September 1994. This was developed by comparing the actual performance of the Company's seven GPIF generating units to the approved targets set for these units prior to the period.

Q. Do you have an exhibit to your testimony in this proceeding?

A. Yes, under my direction an exhibit has been prepared consisting of the numbered sheets which are attached to my prepared testimony. The exhibit contains the schedules required by the

GPIF Implementation Manual, which support the development of the incentive amount. I have also included other data forms to supplement the required schedules.

Q. What GPIF incentive amount have you calculated for this period?

A. I have calculated the Company's GPIF incentive amount to be a reward of $986,547. This amount was developed in a manner consistent with the GPIF Implementation Manual. Sheet 1 of my exhibit shows the calculation of system GPIF points and the corresponding reward. The summary of weighted incentive points earned by each individual unit can be found on Sheet 3.

Q. How were the incentive points for equivalent availability and heat rate calculated for the individual GPIF units?

A. The calculation of incentive points is made by comparing the adjusted actual performance data for equivalent availability and heat rate to the target performance indicators for each unit. This comparison is shown on the Generating Performance Incentive Points Table found in my exhibit Sheets 8 through 14.

Q. Why is it necessary to make adjustments to the actual performance data for comparison with the targets?

A. Adjustments to the actual equivalent availability and heat rate data are necessary to allow their comparison with the "target" Point

Tables exactly as approved by the Commission prior to the period. These adjustments are described in the Implementation Manual and are further explained by a Staff memorandum, dated October 23, 1981, directed to the GPIF utilities. The adjustments to actual equivalent availability concern primarily the differences between target and actual planned outage hours, and are shown on Sheet 6 of my exhibit. The heat rate adjustments concern the differences between the target and actual Net Output Factor (NOF), and are shown on Sheet 7. The methodology for both the equivalent availability and heat rate adjustments are explained in the Staff memorandum.

Q. Have you provided the as-worked planned outage schedules for the Company's GPIF units to support your adjustments to actual equivalent availability?

A. Yes, Sheet 22 of my exhibit shows a comparison of target and actual planned outage hours in bar-chart form. Sheets 23 through 26 present as-worked critical path charts for each unit which experienced a planned outage during the period.

Q. Does this conclude your testimony?

A. Yes, it does.

FLORIDA POWER CORPORATION

DOCKET NO. 950001-EI

GPIF Targets and Ranges for April through September 1995

DIRECT TESTIMONY OF LARRY G. TURNER

Q. Please state your name and business address.

A. My name is Larry G. Turner. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power Corporation as Senior Performance Engineer.

Q. Have the duties and responsibilities of your position with the Company remained the same since you last testified in this proceeding?

A. Yes, they have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the development of the Company's Generating Performance Incentive Factor (GPIF) targets and ranges for the period of April through September, 1995. This development includes the targets and improvement/degradation ranges for unit equivalent availability and unit average net operating heat rate in accordance with the Commission's Generating Performance Incentive Implementation Manual.

Q. Do you have an exhibit to your testimony?

A. Yes, I will sponsor an exhibit containing 73 pages, which consists of the GPIF standard form schedules prescribed in the Implementation Manual and supporting data, including unplanned outage rates, net operating heat rates, and computer analyses and graphs for each of the individual GPIF units, all of which are attached to my prepared testimony.

Q. Which of the Company's generating units have you included in the GPIF program for the upcoming projection period?

A. We have included the same units as were included for the current period, Crystal River Units 1 through 5 and Anclote Units 1 and 2.

Q. Have you determined the equivalent availability targets and improvement/degradation ranges for the Company's GPIF units?

A. Yes, I have. This information is included in the Target and Range Summary on page 3 of my exhibit.

Q. How were the equivalent availability targets developed?

A. The equivalent availability targets were developed using the methodology established for the Company's GPIF units, as set forth in Section 4 of the Implementation Manual. This method describes the formulation of graphs based on each unit's historic performance data for the four individual unplanned outage rates (i.e. forced, partial forced, maintenance and partial maintenance outage rates), which in combination constitute the unit's equivalent unplanned outage rate (EUOR). From operational data and these graphs, the individual target rates are determined by inspecting two years of twelve-month rolling averages and the scatter of monthly data points during the two-year period. The unit's four target rates are then used to calculate its unplanned outage hours for the projection period. When the unit's projected planned outage hours are taken into account, the hours calculated from these individual unplanned outage <u>rates</u> can then be converted into an overall equivalent unplanned outage <u>factor</u> (EUOF).

Because factors are additive (unlike rates), the unplanned and planned outage factors (EUOF and POF) when added to the equivalent availability factor (EAF) will always equal 100%. For example, an EUOF of 15% and a POF of 10% results in an EAF of 75%.

The supporting graphs and a summary table of all target and range rates are contained in the section of my exhibit entitled "Unplanned Outage Rate Tables and Graphs".

Q. What is the target equivalent availability factor for Crystal River 3?

A. The EAF target for Crystal River Unit 3 is 93.96%. The unit's EUOR target is 6.04, and the EUOF target is 6.04% because no mid-cycle outage is planned in 1995.

Q. Please describe the method utilized in the development of the improvement/degradation ranges for each GPIF unit's availability targets.

A. In general, the methodology described in the implementation manual was used. Ranges were first established for each of the four unplanned outage rates associated with each unit. From an analysis of the unplanned outage graphs, units with small historical variations in outage rates were assigned narrow ranges and units with large variations were assigned wider ranges. These individual ranges, expressed in terms of rates, were then converted into a single unit availability range, expressed in terms of a factor, using the same procedure described above for converting the availability targets from rates to factors.

Q. Have you determined the net operating heat rate targets and ranges for the Company's GPIF units?

A. Yes, I have. This information is included in the Target and Range Summary on Page 3 of my exhibit.

Q. How were these heat rate targets and ranges developed?

A. The development of the heat rate targets and ranges for the upcoming period utilized historical data from the past three comparable GPIF periods, as described in the Implementation Manual. A "least squares" computer program was used to curve-fit the heat rate data within ranges having a 90% confidence level of including all data. The computer analyses and data plots used to develop the heat rate targets and ranges for each of the GPIF units are contained in the section of my exhibit entitled "Average Net Operating Heat Rate Curves".

Q. **How were the GPIF incentive points developed for the unit availability and heat rate ranges?**

A. GPIF incentive points for availability and heat rate were developed by evenly spreading the positive and negative point values from the target to the maximum and minimum values in case of availability, and from the neutral band to the maximum and minimum values in the case of heat rate. The fuel savings (loss) dollars were evenly spread over the range in the same manner as described for the incentive points. The maximum savings (loss) dollars are the same as those used in the calculation of weighting factors.

Q. **How were the GPIF weighting factors determined?**

A. To determine the weighting factors for availability, a series of PROMOD simulations were made in which each unit's maximum equivalent availability was substituted for the target value to obtain a new system fuel cost. The differences in fuel costs between these cases and the target case determines the contribution of each unit's availability to fuel savings. Except for Crystal River 3, the heat rate contribution of each unit to fuel savings was determined by multiplying the BTU savings between the minimum and target heat rates (at constant generation) by the average cost per BTU for that unit. For Crystal River 3, the contribution of heat rate to fuel savings was developed in a manner similar to the fuel savings from availability, since an improvement in the nuclear unit's efficiency results in a corresponding increase in the unit's generating capacity. Weighting factors were then calculated by dividing each individual unit's fuel savings by total system fuel savings.

Q. What was the basis for determining the estimated maximum incentive amount?

A. The determination of the maximum reward or penalty was based upon monthly common equity projections obtained from a detailed financial simulation performed by the Company's Corporate Model.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF C. VILLARD

DOCKET NO. 950001-EI

January 17, 1995

Q. Please state your name and address.

A. My name is Claude Villard. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company (FPL) as Supervisor of Nuclear Fuel Procurement.

Q. Have you previously testified in this docket?

A. No, this is the first time I will be filing testimony in this docket.

Q. Briefly describe your educational background and employment history.

A. I am a graduate of Lowell Technological Institute, in Lowell, Massachusetts, with a Bachelor's Degree in Nuclear Engineering. I also hold a Master of Science Degree in Nuclear Engineering from the University of Lowell. From 1974 to 1979, I worked at Combustion Engineering (CE), a vendor and designer of nuclear reactors and nuclear fuel. There, I was involved in core neutronic performance calculations and in thermal hydraulic analyses of nuclear fuel assemblies and reactor internals, during both steady state and transient conditions. As Assistant Project Manager at CE, I managed the safety and licensing analyses required for the reload fuel, supplied by CE to a number of nuclear units. Subsequent to my employment at CE, I held a number of supervisory positions both at FPL and at Yankee Atomic Electric company, all related to fuel management and fuel procurement. In my current position as Supervisor of Nuclear Fuel Procurement, I am responsible for procurement and management of nuclear fuel contracts for uranium, conversion, enrichment services and the contract for spent fuel disposal with the Department of Energy. In addition, I am responsible for the development of new contracts for fuel fabrication services and nuclear fuel cost forecasting, inventory management and reporting.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain FPL's projections of nuclear fuel costs for the thermal energy (MMBTU) to be produced by our nuclear units and costs of disposal of spent nuclear fuel. Both of these costs were input values to POWRSYM for the calculation of the proposed fuel cost recovery factor for the period April 1995 through September 1995.

Q. What is the basis for FPL's projections of nuclear fuel costs?

A. FPL's nuclear fuel cost projections are developed using energy production at our nuclear units and their operating schedules, consistent with those assumed in POWRSYM, for the period April 1995 through September 1995.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period April 1995 through September 1995.

A. We estimate the nuclear units will produce 128,460,891 MBTU of energy at a cost of $0.427 per MMBTU, excluding spent fuel disposal costs for the period April 1995 through September 1995. Projections by nuclear unit and by month are provided on Schedule E-4 of Appendix II.

Q. Please provide FPL's projection for nuclear spent fuel disposal costs for the period April 1995 through September 1995 and what is the basis for FPL's projection.

A. FPL's projections for nuclear spent fuel disposal costs are provided on Schedule E-2 of Appendix II. These projections are based on FPL's contract with the DOE, which sets the spent fuel disposal fee at 1 mill per net Kwh generated minus transmission and distribution line losses.

In prior fuel cost recovery periods, FPL had received refunds from the DOE for past overpayment, when the utilities were required to pay on the basis of net generation without adjustments for transmission and distribution line losses. The last refund was received in October 1994 and therefore, there will be no further refund in future periods.

Q. Please provide FPL's projection for Decontamination and Decommissioning (D&D) costs to be paid in the period April 1995 through September 1995 and what is the basis for FPL's projection.

A. As indicated in prior testimony, The National Energy Policy Act of 1992 (The Act) requires FPL to make certain payments to a fund established at the U.S. Treasury, to cover the cost of decontamination and decommissioning DOE's enrichment facilities. D&D payments are in direct proportion to the amount of enrichment services purchased by FPL divided by the amount produced by the DOE through October 1992. Currently, FPL has contributed $14,534,395 into the D&D fund and expects to make deposits over a total period of fifteen years. Future deposits into the D&D fund are scheduled to be annually on the last day of October, therefore, FPL is not projecting D&D costs to be paid during this fuel cost recovery period.

Q. Are there currently any unresolved disputes under FPL's nuclear fuel contracts?

A. Yes. As reported in prior testimonies, there are two unresolved disputes.

The first dispute is under FPL's contract with the Department of Energy (DOE) for final disposal of spent nuclear fuel. FPL, along with a number of electric utilities, has filed suit against the DOE over DOE's denial of its obligation to accept spent nuclear fuel beginning in 1998. The suit requests that the court affirm DOE's legal obligation to begin accepting spent nuclear fuel in 1998. Further, the court is requested to direct the DOE to develop a program of acceptance of spent nuclear fuel on a timely basis and make regular periodic reports on its progress. In addition, the suit requests that, if appropriate, all or a portion of the utilities' Nuclear Waste Fund Fees be paid into an escrow account.

The Public Service Commission and the Florida Attorney General is participating in a similar suit with other states and public utility commissions.

Secondly, FPL is currently seeking to resolve a price dispute for uranium enrichment services purchased from the United States (US) government, after October 1, 1992.

Our contract for enrichment services with the US Government calls for pricing to be calculated in accordance with "Established DOE Pricing Policy". Such policy had always been one of cost recovery, which included costs related to the Decontamination and Decommissioning (D&D) of the DOE's enrichment facilities. However, the Energy Policy Act of 1992 (The Act) requires utilities to make separate payments to the US Treasury for D&D, starting in Fiscal 1993, as FPL has been doing. Therefore, D&D should not have been included in the price charged by DOE since then, and the price should have been reduced accordingly. FPL has written to DOE to request such refund. DOE's response so far has been to acknowledge our letter and to request clarifying information on the amount of our claim.

In addition, The Act created a new US Government corporation, the United States Enrichment Corporation (USEC). Effective July 1, 1993, The

Act transferred from the DOE to the USEC all US Government contracts, for the production and sales of enrichment services. Because of the transfer to the USEC, cost of producing enrichment services has decreased significantly. For example, the USEC no longer needs to account for the costs of D&D, because the Act requires that utilities make separate payments for D&D. However, the USEC has continued to charge the same price charged by DOE prior to the transfer.

FPL has filed three claims with the USEC's contracting officer, challenging the price for enrichment services. FPL believes that USEC's price should be based on recovery of its costs. At a minimum, FPL believes that the price must be lowered to reflect the separate payment it is making to cover D&D costs. USEC has not modified its price to date, and has rejected our claims. We are currently reviewing our next step with legal counsel. Meanwhile, FPL is paying the invoices submitted by the USEC, while objecting under a reservation of rights. The current price paid to the USEC is assumed in our projection. FPL will continue to keep the Commission informed on all aspects of this dispute with the USEC.

Q. Does this conclude your testimony?

A. **Yes, it does.**

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 950001-EI
CONTINUING SURVEILLANCE AND REVIEW OF
FUEL COST RECOVERY CLAUSES OF ELECTRIC UTILITIES

Direct Testimony of
George Bachman
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. George Bachman, 401 South Dixie Highway, West Palm Beach, FL 33401.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Have you previously testified in this Docket?

A. Yes.

Q. What is the purpose of your testimony at this time?

A. I will briefly describe the basis for the computations that were made in the preparation of the various Schedules that we have submitted in support of the April 1995 - September 1995 fuel cost recovery adjustments for our two electric divisions. In addition, I will advise the Commission of the projected differences between the revenues collected under the levelized fuel adjustment and the purchased power costs allowed in developing the levelized fuel adjustment for the period October 1994 - March 1995 and to establish a "true-up" amount to be collected or refunded during April 1995 - September 1995.

Q. Were the schedules filed by your Company completed under your direction?

A. Yes.

Q. Which of the Staff's set of schedules has your company completed and filed?
A. We have filed Schedules E1, E1A, E1-B, E1B-1, E2, E7, E8 and E10 for Marianna and Fernandina Beach. They are included in Composite Prehearing Identification Number GMB-1. These schedules support the calculation of the levelized fuel adjustment factor for April 1995 - September 1995. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period October 1994 - March 1995 based on 2 Months Actual and 4 Months Estimated data.
Q. In derivation of the projected cost factor for the April 1995 - September 1995 period, did you follow the same procedures that were used in the prior period filings?
A. Yes.
Q Why has the GSLD rate class for Fernandina Beach been excluded from these computations?
A. Demand and other purchased power costs are assigned to the GSLD rate class directly based on their actual CP KW and their actual KWH consumption. That procedure for the GSLD class has been in use for several years and has not been changed herein. Costs to be recovered from all other classes is determined after deducting from total purchased power costs those costs directly assigned to GSLD.
Q. How will the demand cost recovery factors for the other rate

classes be used?

A. The demand cost recovery factors for each of the RS, GS, GSD and OL-SL rate classes will become one element of the total cost recovery factor for those classes. All other costs of purchased power will be recovered by the use of the levelized factor that is the same for all those rate classes. Thus the total factor for each class will be the sum of the respective demand cost factor and the levelized factor for all other costs.

Q. What are the total cost recovery factors for those rate classes in Fernandina Beach beginning April 1, 1995 after adjustments for line losses multipliers and the revenue tax factor?

A. The factors are as follows:

RS	.05036 $/KWH
GS	.04770 $/KWH
GSD	.04581 $/KWH
OL & SL	.03996 $/KWH

Q. Please address the calculation of the total true-up amount to be collected or refunded during the April 1995 - September 1995 period.

A. We have determined that at the end of March 1995 based on two months actual and four months estimated, we will have under-recovered $143,938 in purchased power costs in our Marianna division. Based on estimated sales for the period April 1995 - September 1995, it will be necessary to add .10226¢ per KWH to collect this under-recovery.

In Fernandina Beach we will have over-recovered \$137,540 in purchased power costs. This amount will be refunded at .10812¢ per KWH during the April 1995 - September 1995 period. Page 3 and 12 of Composite Prehearing Identification Number GMB-1 provides a detail of the calculation of the true-up amounts.

Q. Looking back upon the April 1994 - September 1994 period, what were the actual End of Period - True-Up amounts for Marianna and Fernandina Beach, and their significance, if any?

A. The Marianna Division experienced an under-recovery of \$258,074 and Fernandina Beach Division over-recovered \$263,721. The amounts both represent fluctuations of less than 10% from the total fuel charges for the period and are not considered significant variances from projections.

Q. What are the final remaining true-up amounts for the period April 1994 through September 1994 for both divisions?

A. In Marianna the final remaining true-up amount was an under-recovery of \$230,486. The final remaining true-up amount for Fernandina Beach was an under-recovery of \$25,350.

Q. What are the estimated true-up amounts for the period of October 1994 through March 1995?

A. In Marianna, there is an estimated over-recovery of \$86,548. Fernandina Beach has an estimated over-recovery of \$162,890.

Q. What will the total fuel adjustment factor, excluding demand cost recovery, be for both divisions for the period April 1995

- September 1995?

A. In Marianna the total fuel adjustment factor as shown on Line 33, Schedule E1, is 3.221¢ per KWH. In Fernandina Beach the total fuel adjustment factor for "other classes", as shown on Line 43, Schedule E1, amounts to 3.584¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period April 1995 - September 1995 including base rates (which include revised conservation cost recovery factors) and fuel adjustment factor and after application of a line loss multiplier.

A. In Marianna a residential customer using 1,000 KWH will pay $73.97, an increase of $2.27 from the previous period. In Fernandina Beach a customer will pay $70.39, an increase of $.67 from the previous period.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
M. L. Gilchrist
Docket No. 940001-EI
Date of Filing: November 14, 1994

Q. Please state your name and business address.

A. My name is Malcolm Lane Gilchrist and my business address is 500 Bayfront Parkway, Post Office Box 1151, Pensacola, Florida 32520-0328.

Q. By whom are you employed and in what capacity?

A. I am the Manager of Fuel and Environmental Affairs for Gulf Power Company.

Q. Mr. Gilchrist, will you please describe your education and experience?

A. I graduated from Auburn University in 1958 with a Bachelor of Science Degree in Electrical Engineering. I joined Gulf Power Company in 1961 as a Field Engineer. Since then, I have held various positions with the Company, including Power Sales Engineer; Division Sales Supervisor; Division Engineer; Supervisor of Fuel Supply; Assistant Plant Manager, Crist Electric Generating Plant; and Manager of Interchange and Fuel Supply. I was promoted to my present position in June 1989.

Q. What are your duties as Manager of Fuel and Environmental Affairs?

A. I manage the fuel supply and environmental compliance activities of the Company. My responsibilities include fuel procurement, contract administration, and budgeting.

Q. Are you the same Malcolm Lane Gilchrist who has previously testified before this Commission on various fuel matters?

A. Yes.

Q. Mr. Gilchrist, what is the purpose of your testimony in this docket?

A. The purpose of my testimony is to summarize Gulf Power Company's fuel expenses and to certify that these expenses were properly incurred during the period April 1994 through September 1994. Also, it is my intent to be available to answer any questions that may arise among the parties to this docket concerning Gulf Power Company's fuel expenses.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. I have prepared an exhibit consisting of one Schedule.

Counsel: We ask that Mr. Gilchrist's exhibit consisting of 1 schedule be marked as Exhibit No. ______________ (MLG-1).

Q. During the period April 1, 1994 through September 30, 1994, how did Gulf's actual fuel expenses compare with the budget or projected expenses?

A. Gulf's actual fuel expense was $106,504,730 as compared with the projected amount of $111,171,243, or under our estimate by 4.20%. Gulf's total net system generation was 5,497,665 MWH compared to the projected generation of 5,957,220 MWH or 7.71% less than predicted. The resulting total fuel cost per KWH generated was 1.9373¢/KWH or 3.81% over the projected amount of 1.8662¢/KWH.

Q. How did the projected purchase cost of coal compare with the actual cost?

A. For the period, Gulf's average unit cost of coal purchased was 2.24% less than projected.

Q. Mr. Gilchrist, did Gulf Power make any significant changes in its fuel purchasing program during the twelve months ending September 1994?

A. Yes. Gulf Power completed negotiations with Peabody CoalSales concerning changes in Gulf's long term coal supply prompted by the requirements under Phase I of the Clean Air Act. Those negotiations resulted in termination of the old agreement with Peabody Coal Company and in a new agreement for a coal supply that will allow the Company to meet the requirements for Phase I. Peabody CoalSales will supply a blend of Venezuelan and Illinois coal sufficiently low in sulfur content to ensure compliance with Phase I of the Clean Air Act. The delivered cost of this new agreement coal is less than costs under the old agreement with Peabody Coal Company.

Gulf Power also amended the transportation contract with the Ohio River Company effective July 1, 1994, in order to achieve additional cost savings to the customers.

Q. What was the effect of the suspension agreement with Peabody Coal Company?

A. The agreement simply suspended the purchases/deliveries that would otherwise have been made during the period under the Company's long-term coal supply agreement with Peabody. During the suspension period, Gulf procured coal on the spot market to replace the suspended Peabody purchases/deliveries. Under the agreement, Gulf made a one-time payment of $16,389,423 to Peabody. Gulf calculated that this payment and the suspension agreement allowed the Company to achieve net fuel cost savings for its customers through the replacement of the suspended coal with coal purchased on the spot market.

Q. Are you in a position to address the total net savings achieved through the suspension agreement and the purchases of replacement coal?

A. Yes. We have now shipped and received all the replacement coal tonnage for the Peabody Suspension Agreement. The total net savings was $14,479,865. At the time the decision to enter into the Suspension Agreement was made, we projected savings of $12,358,227.

Q. What coal supply changes are taking place at Plant Daniel?

A. The current fuel supply program is called a seasonal Powder River Basin

(PRB) fuel program. During the off peak season, when full plant capacity is not normally needed, the plant will burn lower cost PRB coal. During the peak season, when full plant capacity is required, the plant will burn high Btu western coal. To date, the seasonal fuel program is working very well.

Q. Do you mean that Plant Daniel will operate below its rated capacity on PRB coal?

A. Yes. Plant Daniel is unable to reach its rated capacity while burning PRB coals. However, high Btu coal is being stockpiled so that the units can be changed over within 8-10 hours and achieve full capacity if needed. As the plant gains experience in burning the PRB coal, we expect the plant to increase its capacity. Plant Daniel has been transitioning to the seasonal PRB coal supply during 1994.

Q. How much spot coal did Gulf Power Company purchase during the period ending September 30, 1994?

A. Gulf purchased 1,307,270 tons or 53% of its supply from the spot coal market. My Schedule 1 of Exhibit No. 23 (MLG-1) consists of a list of contract and spot coal suppliers for the period ending September 30, 1994.

Q. How are coal prices determined under Gulf's long-term contracts?

A. Under all of Gulf's long-term coal contracts, Gulf pays a base price per ton plus cost escalations that have occurred since the coal contract began. The base price with cost escalations type contract is a long term agreement on quantity, quality, and escalation factors that provides the buyer with an assured source of coal of known quality. The price of coal supplied under this type of contract will not go up and down with current market conditions.

Q. Should Gulf's fuel purchase cost for the period be accepted as reasonable and prudent?

A. Yes. Gulf's coal purchases were primarily either from coal vendors with long term contracts subject to cost escalations or from a competitively bid spot purchase order. These coal vendors were selected by procedures designed to provide an assured quantity of coal of a known quality for a specific term at the lowest available delivered cost. Gulf has administered the provisions of these contracts and purchase orders appropriately. All of Gulf's oil purchases were from oil vendors selected by open bids to insure the most economical price of oil.

Q. Mr. Gilchrist, does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
M. L. Gilchrist
Docket No. 950001-EI
Date of Filing January 17, 1995

Q. Please state your name and business address.

A. My name is M. L. Gilchrist, and my business address is 500 Bayfront Parkway, Pensacola, Florida, 32520-0328.

Q. By whom are you employed and in what capacity?

A. I am Manager of Fuel and Environmental Affairs for Gulf Power Company.

Q. Mr. Gilchrist, will you please describe your education and experience?

A. I graduated from Auburn University in 1958 with a Bachelor of Science Degree in Electrical Engineering. I joined Gulf Power Company in 1961 as a Field Engineer. Since then, I have held various positions with the Company, including Power Sales Engineer, Division Sales Supervisor, Division Engineer, Supervisor of Fuel Supply, Assistant Plant Manager at Crist Electric Generating Plant, and Manager of Interchange and Fuel Supply. I was promoted to my present position June 1, 1989.

Q. What are your duties as Manager of Fuel and Environmental Affairs?

A. I manage the fuel supply and environmental compliance activities of the Company. My responsibilities include fuel procurement, fuel contract administration, and fuel budgeting.

Q. Are you the same Lane Gilchrist who has previously testified before this Commission on various fuel matters?

A. Yes.

Q. Mr. Gilchrist, what is the purpose of your testimony in this docket?

A. The purpose of my testimony is to support Gulf Power Company's projection of fuel expenses for the period April 1, 1995 to September 30, 1995 and to be available to answer any questions that may occur concerning the Company's fuel procurement

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. I have prepared an exhibit consisting of one schedule. Schedule 1 of my exhibit is a tabulation of projected and actual fuel cost for the past ten years. The purpose of this schedule is to illustrate the accuracy of our short term projections of fuel expenses.

COUNSEL: We ask that Mr. Gilchrist's exhibit, consisting of one schedule, be marked as Exhibit No. 24 (MLG-2).

Q. Has Gulf Power Company made any changes to its projection methods for this period?

A. No.

Q. Will there be any major changes in Gulf's fuel purchasing program during this period?

A. No.

Q. Has the Company included expenditures for emission allowances in its projection of fuel costs for this filing?

A. Yes. Phase I of the CAA became effective January 1, 1995, therefore, this projection does include an estimate of the cost of allowances to be expended during the period.

Q. How is the number of allowances expected to be used projected?

A. The same fuel budget model that predicts the coal burn also forecasts the number of tons of sulfur burned, which is readily converted to tons of SO_2. The nominal percent sulfur in the coal is simply multiplied by the tons of coal burned.

Q. How was the cost of allowances to be expended determined for the forecast?

A. The projected cost of allowances was determined by a method very similar to fuel inventory as specified by FERC procedures. In other words, allowances are held "in stock" at cost and are "issued" at the projected cost of allowances which is based on anticipated allowances granted net of allowance sales, purchases, and transfers.

Q. How much spot market coal does Gulf Power project it will purchase during April 1995 through September 1995?

A. We are projecting the purchase of approximately 470,000 tons. This represents approximately 33% of our projected purchase requirements.

Q. Mr. Gilchrist, does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 940001-EI
Date of Filing: November 14, 1994

Q. Please state your name, business address and occupation.

A. My name is M. W. Howell, and my business address is 500 Bayfront Parkway, Pensacola, Florida 32501. I am Manager of Transmission and System Control for Gulf Power Company.

Q. Have you previously testified before this Commission?

A. Yes. I have testified in various rate case, cogeneration, territorial dispute, planning hearing, fuel clause adjustment, and purchased power capacity cost recovery dockets.

Q. Please summarize your educational and professional background.

A. I graduated from the University of Florida in 1966 with a Bachelor of Science Degree in Electrical Engineering. I received my Masters Degree in Electrical Engineering from the University of Florida in 1967, and then joined Gulf Power Company as a Distribution Engineer. I have since served as Relay Engineer, Manager of Transmission, Manager of System Planning, Manager of Fuel and System Planning, and Manager of Transmission and System Control. My experience with the Company has included all areas of distribution operation, maintenance, and construction; transmission operation, maintenance, and construction; relaying and protection of the generation, transmission, and distribution systems; planning the generation, transmission, and distribution system additions in the future; bulk power interchange administration; overall management of fuel planning and procurement; and operation of the system dispatch center.

I have served as a member of the Engineering Committee and the Operating Committee of the Southeastern Electric Reliability Council, chairman of the Generation Subcommittee and member of the Edison Electric Institute System Planning Committee, and chairman or member of a number of various technical committees and task forces within the Southern electric system and the Florida Electric Power Coordinating Group, regarding a variety of technical issues including system operations, bulk power contracts, generation expansion, transmission expansion, transmission interconnection requirements, central dispatch, transmission system operation, transient stability, underfrequency operation, generator underfrequency protection, system production costing, computer modeling, and others.

Q. What is the purpose of your testimony in this proceeding?

A. I will summarize Gulf Power Company's purchased power fuel costs for energy purchases and sales that were incurred during the April 1, 1994 through September 30, 1994 recovery period. I will then compare these actual costs to their projected levels for the period and discuss the primary reasons for the differences.

I will also summarize the actual capacity expenses and revenues that were incurred during the recovery period, compare these figures to their projected levels, and discuss the reasons for the differences.

Q. During the period April 1, 1994 through September 30, 1994, what was Gulf's actual purchased power fuel cost for energy purchases and how did it compare with the projected amount?

A. Gulf's actual total purchased power fuel cost for energy purchases, as shown on line 11 of Schedule A-1, was $19,806,789 as compared to the projected amount of

$5,822,000. This resulted in a variance above budget of $13,984,789, or 240%. The actual fuel cost per KWH purchased was 1.8403 ¢/KWH as compared to 1.8380 ¢/KWH, or 0.1% above the projection.

Q. What were the events that influenced Gulf's purchase of energy?

A. Gulf was able to purchase significantly more economy power through the Southern electric power pool to meet its load than was forecasted for the period due to the availability of lower cost pool energy. Gulf purchased 1,076,290,940 KWH, shown on line 11 of Schedule A-1, as compared to the estimate of 316,750,000 KWH, or 240% more. The actual average cost was 1.8403 ¢/KWH as compared to the estimate of 1.8380 ¢/KWH, a very slight increase of 0.0023 ¢/KWH over budget.

This average actual fuel cost of purchases of 1.8403 ¢/KWH was actually 5% less per KWH than Gulf's actual average fuel cost of system generation, shown on line 4, which was 1.9373 ¢/KWH. Gulf's system net generation was 5,497,665,000 KWH, or 8% under our estimate, but was over budget in unit cost by 4%.

Q. During the period April 1, 1994 through September 30, 1994, what was Gulf's actual purchased power fuel cost for energy sales and how did it compare with the projected amount?

A. Gulf's actual total purchased power fuel cost for energy sales, as shown on line 17 of Schedule A-1, was \$29,469,775 as compared to the projected amount of \$22,775,400. This resulted in a variance above budget of \$6,694,375, or 29%. The actual fuel cost per KWH sold was 1.8039 ¢/KWH as compared to 1.8596 ¢/KWH, or 3% below the projection.

Q. What were the events that influenced Gulf's sale of energy?

A. Gulf's off-system sales, shown on line 17, were 1,633,709,618 KWH, or 33% over the projection for the period. These off-system sales were over the projection due to Gulf's increased sale of energy to the Southern electric system power pool to meet the pool's obligation for these sales. The lower cost of energy available from Gulf's resources compared with the cost of energy generated by the other pool members allowed Gulf to sell more energy than budgeted to the pool for off-system obligations.

Q. How are Gulf's net purchased power fuel costs affected by Southern electric system energy sales?

A. As a member of the Southern electric system power pool, Gulf Power participates in these sales. Gulf's generating units are economically dispatched to meet the needs of its territorial customers, the system, and off-system customers.

Therefore, Southern system energy sales provide a market for Gulf's surplus energy and generally improve unit load factors. The cost of fuel used to make these sales is credited against, and therefore reduces, Gulf's fuel and purchased power costs.

Q. During the period April 1, 1994 through September 30, 1994, how did Gulf's actual net purchased power capacity transactions compare with the net projected transactions?

A. In a previous cost recovery proceeding in Docket No. 940001-EI, I testified that the projected net purchased power capacity cost for the April 1, 1994 through September 30, 1994 recovery period was $494,906. The actual net capacity cost was $622,607. This represents an increase in cost of $127,701, or 26% more than projected.

The projected net IIC capacity cost for the

75

April 1, 1994 through September 30, 1994 recovery period was $1,094,906. The actual net IIC capacity cost for the filing period was $1,204,135, or 10% more than projected.

The projected Florida Power Corporation Schedule E capacity revenue for the period was $600,000. The actual Schedule E capacity revenue for the recovery period was $581,528, or 3% less than projected.

Q. Please explain the reasons for this difference.

A. First, Gulf's actual net IIC capacity cost was higher than budget because there was more actual system capacity to be equalized because of higher demand side program capacity and a lower actual system load.

Therefore, Gulf was responsible for sharing a percentage of an increased level of system capacity and the company had a slightly increased IIC capacity cost.

Second, Gulf's actual FPC Schedule E capacity revenue was below budget because the Southern electric system was required to give FPC capacity charge credits due to reduced capacity transfer capabilities on the Southern / Florida transmission interface caused by Tropical Storm Alberto.

Q. Does this conclude your testimony?
A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 950001-EI
Date of Filing: January 17, 1995

Q. Please state your name, business address and occupation.
A. My name is M. W. Howell, and my business address is 500 Bayfront Parkway, Pensacola, Florida 32501. I am Manager of Transmission and System Control for Gulf Power Company.

Q. Have you previously testified before this Commission?
A. Yes. I have testified in various rate case, cogeneration, territorial dispute, planning hearing, fuel clause adjustment, and purchased power capacity cost recovery dockets.

Q. Please summarize your educational and professional background.
A. I graduated from the University of Florida in 1966 with a Bachelor of Science Degree in Electrical Engineering. I received my Masters Degree in Electrical Engineering from the University of Florida in 1967, and then joined Gulf Power Company as a Distribution Engineer. I have since served as Relay Engineer, Manager of Transmission,

Manager of System Planning, Manager of Fuel and System Planning, and Manager of Transmission and System Control. My experience with the Company has included all areas of distribution operation, maintenance, and construction; transmission operation, maintenance, and construction; relaying and protection of the generation, transmission, and distribution systems; planning the generation, transmission, and distribution system additions in the future; bulk power interchange administration; overall management of fuel planning and procurement; and operation of the system dispatch center.

I have served as a member of the Engineering Committee and the Operating Committee of the Southeastern Electric Reliability Council, chairman of the Generation Subcommittee and member of the Edison Electric Institute System Planning Committee, and chairman or member of a number of various technical committees and task forces within the Southern electric system and the Florida Electric Power Coordinating Group, regarding a variety of technical issues including system operations, bulk power contracts, generation expansion, transmission expansion, transmission interconnection requirements, central dispatch, transmission system operation, transient stability, underfrequency operation, generator underfrequency protection, system production costing, computer modeling, and others.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support Gulf Power Company's projection of purchased power fuel costs for energy purchases and sales and its projection of purchased power capacity costs for the period April, 1995 - September, 1995.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. My exhibit consists of one schedule to which I will refer. This schedule was prepared under my supervision and direction.

Counsel: We ask that Mr. Howell's Exhibit, comprised of one Schedule, be marked for identification as Exhibit 25 (MWH-1).

00

Q. What are Gulf's projected purchased power recoverable costs for energy purchases and sales for the April, 1995 - September, 1995 recovery period?

A. Gulf's projected recoverable cost for energy purchases, shown on line 12 of Schedule E-1 of the fuel filing, is $10,212,000. The projected fuel cost for energy sales, shown on line 18 of Schedule E-1, is $17,870,200. These transactions result from Gulf's participation in the coordinated operation of the Southern electric system power pool. These amounts are used by Gulf's witness Susan Cranmer as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. What information is contained in your exhibit?

A. Schedule 1 of my exhibit lists the names of the power contracts which are included for capacity cost recovery, their associated megawatt amounts, and the resulting capacity dollar amounts.

Q. Which power contracts produce capacity transactions that are recovered through Gulf's purchased power capacity cost recovery factors?

A. In previous proceedings, the Commission has authorized the Company to include capacity transactions under the Southern electric system's Intercompany Interchange

Contract (IIC) and the Long-Term Non-Firm Contract (Schedule E) with Florida Power Corporation (FPC) for recovery through the purchased power capacity cost recovery factors. Because Schedule E capacity sales to FPC ended on December 31, 1994, Gulf will only have IIC capacity transactions during the April, 1995 - September, 1995 recovery period. In this case, the energy transactions under the contract are handled for cost recovery purposes through the fuel cost recovery factors. At this time, Gulf does not participate in any other power contracts that would produce capacity transactions during the relevant recovery period.

Q. Have there been any changes to the IIC with regard to capacity transactions since the last recovery factor adjustment proceedings?

A. No, there have not been any changes to the contract itself. However, on November 1, 1994, in accordance with both the contract and the requirements of the Federal Energy Regulatory Commission (FERC), the Southern electric system made its annual IIC informational filing with the FERC. The informational filing reflects updated historical load responsibility ratios, the expected system load, and the capacity amounts for 1995 that are used in the capacity equalization calculation performed pursuant to the IIC to determine the capacity transactions and costs for each operating company. These updates have increased Gulf's projected capacity payments for the April, 1995 - September, 1995 recovery period by $36,008 from what they otherwise would have been prior to the update.

Q. What are Gulf's IIC capacity transactions that are projected for the April, 1995 - September, 1995 recovery period?

A. As shown on Schedule 1 of my exhibit, capacity transactions under the IIC vary from month to month. IIC capacity purchases in the amount of $2,333,038 are projected for the period. IIC capacity sales during the same period are projected to be $337,070. The combination of these yields the Company's net capacity transactions under the IIC for the period, which are net purchases amounting to $1,995,968. This compares to net purchases of $5,425,921 that were projected for the period October, 1994 - March, 1995.

Q. What are Gulf's total projected net capacity transactions for the April, 1995 - September, 1995 recovery period?

A. As shown on Schedule 1 of my exhibit, the net purchases under the IIC will cause Gulf to have a projected net capacity cost of $1,995,968. Because Schedule E sales to FPC have ended, this IIC capacity cost is Gulf's total net cost to be included for recovery. This figure is used by Ms. Cranmer as one of the inputs in the calculation of the total capacity transactions to be recovered through the purchased power capacity cost recovery factors to be applied in the recovery period.

Q. Does this conclude your testimony?
A. Yes.

GULF POWER COMPANY
Before the Florida Public Service Commission
Prepared Direct Testimony of
Susan D. Cranmer
Docket No. 940001-EI
Date of Filing: November 14, 1994

Q. Please state your name, business address, and occupation.

A. My name is Susan Cranmer. My business address is 500 Bayfront Parkway, Post Office Box 1151, Pensacola, Florida, 32520-1151. I hold the position of Supervisor of Rate Services.

Q. Please briefly describe your educational background and business experience.

A. I graduated from Wake Forest University in Winston-Salem, North Carolina in 1981 with a Bachelor of Science Degree in Business and from the University of West Florida in 1982 with a Bachelor of Arts Degree in Accounting. I am also a Certified Public Accountant licensed in the State of Florida. I joined Gulf Power Company in 1983 as a Financial Analyst. I have held various positions with Gulf including Computer Modeling Analyst and Senior Financial Analyst. In 1991, I assumed the position of Supervisor of Rate Services and presently serve in that capacity.

My responsibilities include supervision of tariff administration, cost of service, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters Department.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have.

Counsel: We ask that Ms. Cranmer's Exhibit consisting of four schedules be marked as Exhibit No. ___ (SDC-1).

Q. Are you familiar with the Fuel and Purchased Power (Energy) True-up Calculation and the Purchased Power Capacity Cost True-Up Calculation for the period of April 1994 through September 1994 set forth in your exhibit?

A. Yes. These documents were prepared under my supervision.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have.

Q. What is the amount to be refunded or collected through the fuel cost recovery factor in the period April 1995 through September 1995?

A. An amount to be collected of $2,394,382 was calculated as shown in Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $2,393,795 was calculated by taking the difference in the estimated April 1994 through September 1994 under-recovery of $1,969,504 as approved in Order No. PSC-94-1092-FOF-EI, dated September 6, 1994 and the actual under-recovery of $4,363,886 which is the sum of lines 7, 8, and 12 shown on Schedule A-2, page 3 of 4, Period-to-date of the monthly filing for September 1994.

Q. Ms. Cranmer, you stated earlier that you are responsible for the Purchased Power Capacity Cost True-up Calculation. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedules CCA-1, CCA-2, and CCA-3 of my exhibit relate to the Purchased Power Capacity Cost True-up Calculation for the period April 1994 through September 1994.

Q. What is the amount to be refunded or collected in the period April 1995 through September 1995?

A. An amount to be refunded of $221,434 was calculated as shown in Schedule CCA-1 of my exhibit.

Q. How was this amount calculated?

A. The $221,434 was calculated by taking the difference in the estimated April 1994 through September 1994 over-recovery of $56,118 as approved in Order No. PSC-94-1092-FOF-EI, dated September 6, 1994 and the actual over-recovery of $277,552 which is the sum of lines 11 and 12 under the total column on Schedule CCA-2.

Q. Please describe Schedules CCA-2 and CCA-3 of your exhibit.

A. Schedule CCA-2 shows the calculation of the actual over-recovery of purchased power capacity costs for the period April 1994 through September 1994. Schedule CCA-3 of my exhibit is the calculation of the interest provision on the over-recovery. This is the same method of calculating interest that is used in the Fuel and Purchased Power (Energy) Cost Recovery Clause and the Environmental Cost Recovery Clause.

Q. Ms. Cranmer, does this complete your testimony?

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Susan D. Cranmer
Docket No. 950001-EI
Fuel and Purchased Power Capacity Cost Recovery
Date of Filing: January 17, 1995

Q. Please state your name, business address and occupation.

A. My name is Susan Cranmer. My business address is 500 Bayfront Parkway, Pensacola, Florida 32501. I hold the position of Supervisor of Rate Services for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from Wake Forest University in Winston-Salem, North Carolina in 1981 with a Bachelor of Science Degree in Business and from the University of West Florida in 1982 with a Bachelor of Arts Degree in Accounting. I am also a Certified Public Accountant licensed in the State of Florida. I joined Gulf Power Company in 1983 as a Financial Analyst. I have held various positions with Gulf including Computer Modeling Analyst and Senior Financial Analyst. In 1991, I assumed the position of Supervisor of Rate Services and presently serve in that capacity.

My responsibilities include supervision of tariff administration, cost of service, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters Department.

Q. Have your previously filed testimony before this Commission in Docket No. 950001-EI?
A. Yes, I have.

Q. What is the purpose of your testimony?
A. The purpose of my testimony is to discuss the calculation of Gulf Power's fuel cost recovery factors for the period April 1995 through September 1995. I will also discuss the calculation of the purchased power capacity cost recovery factors for that period.

Q. Are you familiar with the Fuel and Purchased Power Cost Recovery Clause Calculation for the period of April 1995 through September 1995?
A. Yes, these documents were prepared under my supervision.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?
A. Yes, I have.

Counsel: We ask that Ms. Cranmer's Exhibit consisting of fifteen schedules, along with Schedules A1 through A12 previously filed with the Commission for the months of June, July, August, September, October, and November 1994, be marked as Exhibit No. 27 (SDC-2).

Q. Ms. Cranmer, what has Gulf calculated as the true-up to be applied in the period April 1995 through September 1995?

A. The true-up for this period is an increase of .064¢/kwh. This includes a final true-up under-recovery of $2,394,382. As shown on Schedule E-1A, it also includes an estimated true-up under-recovery of $556,052 for the current period. The resulting under-recovery is $2,950,434.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of April 1994 through September 1994?

A. This is shown on Line 32b of Schedule E-1 as an increase of .0005¢/kwh, thereby rewarding Gulf by $22,931.

Q. Ms. Cranmer, what is the levelized projected fuel factor for the period April 1995 through September 1995?

A. Gulf has proposed a levelized fuel factor of 2.314¢/kwh. It includes projected fuel and purchased power energy expenses for April 1995 through September 1995 and projected kwh sales for the same period, as well as the true-up and GPIF reward. The proposed levelized fuel factor also includes the special recovery amount associated with the Air Products special contract. The calculation of the special recovery amount is presented on Schedule E-12 of my exhibit. The levelized fuel factor has not been adjusted for line losses.

Q. Ms. Cranmer, how were the line loss multipliers used on Schedule E-1E calculated?

A. They were calculated in accordance with procedures approved in prior filings and were based on Gulf's latest mwh Load Flow Allocators.

Q. Ms. Cranmer, what fuel factor does Gulf propose for its largest group of customers (Group A), those on Rate Schedules RS, GS, GSD, OSIII, and OSIV?

A. Gulf proposes a standard fuel factor, adjusted for line losses, of 2.342¢/kwh for Group A. Fuel factors for

Groups A, B, C, and D are shown on Schedule E-1E. These factors have also been adjusted for line losses.

Q. Ms. Cranmer, how were the time-of-use fuel factors calculated?

A. These were calculated based on projected loads and system lambdas for the period April 1995 through September 1995. These factors included the GPIF, true-up, and special contract recovery cost amounts and were adjusted for line losses. These time-of-use fuel factors are also shown on Schedule E-1E.

Q. How does the proposed fuel factor for Rate Schedule RS compare with the factor applicable to March and how will the change affect the cost of 1000 kwh on Gulf's residential rate RS?

A. The current fuel factor applicable to March 1995 is 2.206¢/kwh compared with the proposed factor of 2.342¢/kwh. For a residential customer who uses 1000 kwh in April 1995, the fuel portion of the bill will increase from $22.06 to $23.42.

Q. Ms. Cranmer, has Gulf updated its estimates of the as-available avoided energy costs to be shown on COG1 as required by Order No. 13247 issued May 1, 1984 in Docket

No. 830377-EI and Order No. 19548 issued June 21, 1988 in Docket No. 880001-EI?

A. Yes. A tabulation of these costs is set forth in Schedule E-11 of my Exhibit SDC-2. These costs represent the estimates for the period from April 1995 through March 1997.

Q. Ms. Cranmer, you stated earlier that you are responsible for the calculation of the purchased power capacity cost recovery factors. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedule CCE-1, including CCE-1a and CCE-1b, and Schedule CCE-2 of my exhibit relate to the calculation of the purchased power capacity cost recovery factors for the period April 1995 through September 1995.

Q. Please describe Schedule CCE-1 of your exhibit.

A. Schedule CCE-1 shows the calculation of the amount of capacity payments to be recovered through the Purchased Power Capacity Cost Recovery Clause. Mr. Howell has provided me with Gulf's projected purchased power capacity transactions under the Southern Company Intercompany Interchange Contract (IIC). Gulf's projected capacity payments for the period April 1995 through September 1995 are purchases of $1,995,968. The jurisdictional amount is $1,924,085. For the period, Gulf's requested recovery before true-up is the difference between the jurisdictional projected purchased power capacity costs and the approved adjustment for former capacity transactions embedded in current base rates. This adjustment amount was fixed in Order No. PSC-93-0047-FOF-EI, dated January 12, 1993, as an embedded credit of $839,290, or $826,000 net of revenue taxes. Thus, the projected recovery amount to be collected through the purchased power capacity cost recovery factors in the period April 1995 through September 1995 is $2,750,085. This amount is added to the total true-up amount to determine the total purchased power capacity transactions to be recovered through the factors to be applied in the period.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period April 1995 through September 1995?

A. The true-up for this period is a decrease of $120,011 as shown on Schedule CCE-1a. This includes a final capacity cost true-up over-recovery of $221,434. It also includes an estimated under-recovery of $101,423 for the period October 1994 through March 1995, as calculated on Schedule CCE-1b.

Q. What methodology was used to allocate the capacity payments to rate class?

A. As required by Commission Order No. 25773 in Docket No. 910794-EQ, the revenue requirements have been allocated using the cost of service methodology used in Gulf's last full requirements rate case and approved by the Commission in Order No. 23573 issued October 3, 1990 in Docket No. 891345-EI. Although the capacity payments in that cost of service study were allocated to rate class using the demand allocator based on the twelve monthly coincident peaks projected for the test year, for purposes of the purchased power capacity cost recovery clause, Gulf has allocated the net purchased power capacity costs to rate class with 12/13th on demand and 1/13th on energy. This allocation is consistent with the treatment accorded to production plant in the cost of service study used in Gulf's last rate case.

Q. How were the allocation factors calculated for use in the Purchased Power Capacity Cost Recovery Clause?

A. The allocation factors used in the Purchased Power Capacity Cost Recovery Clause have been calculated using the 1993 load data filed with the Commission in accordance with FPSC Rule 25-6.0437. The calculations of the allocation factors are shown in columns A through I on page 1 of Schedule CCE-2.

Q. Please describe the calculation of the cents/kwh factors by rate class used to recover purchased power capacity costs.

A. As shown in columns A through D on page 2 of Schedule CCE-2, 12/13th of the jurisdictional capacity cost to be recovered is allocated to rate class based on the demand allocator, with the remaining 1/13th allocated based on energy. The total revenue requirement assigned to each rate class shown in column E is then divided by that class's projected kwh sales for the six-month period to calculate the purchased power capacity cost recovery factor. This factor will be applied to each customer's total kwh to calculate the amount to be billed each month.

Q. What is the amount related to purchased power capacity costs recovered through this factor that will be included on a residential customer's bill for 1000 kwh?

A. The purchased power capacity costs recovered through the clause for a residential customer who uses 1000 kwh will be $.70.

Q. When does Gulf propose to collect these new fuel charges and purchased power capacity charges?

A. These factors will apply to April 1995 through September 1995 billings beginning with Cycle 1 meter readings scheduled on March 30, 1995 and ending with meter readings scheduled on September 27, 1995.

Q. Ms. Cranmer, does this complete your testimony?

A. Yes, it does.

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony of
G. D. Fontaine
Docket No. 940001-EI
Date of Filing November 14, 1994

Q. Please state your name, address and occupation.

A. My name is George D. Fontaine, my business address is Post Office Box 1151, Pensacola, Florida 32520, and my position is Performance Test Specialist for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Mechanical Engineering Degree from Auburn University in 1980. Following graduation, I joined Gulf Power Company as an Associate Engineer at the Scholz Electric Generating Plant, and as I previously stated, my current position is Performance Test Specialist. I am also a registered Professional Engineer in the State of Florida.

Q. Mr. Fontaine, have you previously testified in this Docket?

A. Yes, sir.

Q. Mr. Fontaine, what is the purpose of your testimony in this proceeding?
A. The purpose of my testimony is to present GPIF results for Gulf Power Company for the period of April 1, 1994, through September 30, 1994.

Q. Mr. Fontaine, have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes, Sir, I have prepared an exhibit consisting of five schedules.

Q. Mr. Fontaine, was this exhibit prepared by you or under your direction and supervision?
A. Yes, it was.

Counsel: We ask that Mr. Fontaine's exhibit be marked for identification as exhibit 28 (GDF-1).

Q. Mr. Fontaine, before reviewing the GPIF Results for Gulf's units, is there any information which has been supplied to the Commission pertaining to this GPIF period which requires amendment?
A. Yes, some corrections need to be made to the actual unit performance data which was submitted monthly to

the Commission during this period. These corrections are based on discoveries made during our final review to determine the accuracy of this information prior to this proceeding. The Actual Unit Performance Data tables on pages 14 to 19 of Schedule 5 incorporate these changes. The data contained on these tables is the data upon which the GPIF calculation was made.

Q. Mr. Fontaine, would you now review the Company's equivalent availability results for the period?

A. Actual equivalent availability and adjusted actual equivalent availability figures for each of the Company's GPIF units are shown on page 13 of Schedule 5. Pages 3 through 8 of Schedule 2 contain the calculations for the adjusted actual equivalent availabilities.

A calculation of GPIF availability points based on these availabilities and the targets established by Commission Order PSC-94-0390-FOF-EI is on page 9 of Schedule 2. The results are: Crist 6, -5.50 points; Crist 7, +10.00 points; Smith 1, +10.00 points; Smith 2, +10.00 points; Daniel 1, -10.00 points, and Daniel 2, +10.00 points.

Q. Mr. Fontaine, what were the heat rate results for the period?

A. The detailed calculation of the actual average net operating heat rates for the Company's GPIF units is on pages 2 through 7 of Schedule 3. These heat rate figures have not at this point been adjusted in accordance with GPIF procedures for load and other factors to the bases of their targets.

As was done for the prior GPIF periods, and as indicated on pages 8 through 13 of Schedule 3, the target setting equations were used to adjust actual results to the target bases. These equations, submitted in January 1994, are shown on page 15 of Schedule 3.

As calculated on page 16 of Schedule 3, the adjusted actual average net operating heat rates correspond to GPIF unit heat rate points of: -5.15 for Crist 6, -1.51 for Crist 7; 0.00 for Smith 1, -6.67 for Smith 2; +3.07 for Daniel 1; and +2.32 for Daniel 2.

Q. Mr. Fontaine, what number of Company points were achieved during the period, and what reward or penalty is indicated by these points according to the GPIF procedure?

A. Using the unit equivalent availability and heat rate points previously mentioned, along with the appropriate weighting factors, the Company points would be +0.28 as indicated on page 2 of Schedule 4. This calculated to a reward in the amount of $22,931.

Q. Mr. Fontaine, would you please summarize your testimony?

A. Yes, Sir. In view of the adjusted actual equivalent availabilities, as shown on page 9 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 16 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a reward in the amount of $22,931 as provided for by the GPIF plan.

Q. Mr. Fontaine, does this conclude your testimony?

A. Yes, Sir.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

W. N. CANTRELL

Q. Please state your name, address and occupation.

A. My name is William N. Cantrell. My mailing address is P. O. Box 111, Tampa, Florida 33601, and my business address is 6820 South Tamiami Trail, North Ruskin, Florida 33570. I am Vice President-Energy Supply of Tampa Electric Company.

Q. Please furnish a brief outline of 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. Since that time I have served as Manager of Generation Planning, Assistant Director, Budgets and

Director of Fuels. In 1987, I was elected Vice President of the company. In 1994, I was elected to my current position as Vice President-Energy Supply.

Q. Will you describe some of the responsibilities of your present position?

A. As Vice President - Energy Supply, I am responsible for the engineering, operation, maintenance, and construction of the power production facilities including safety of personnel and equipment, security, training, control of costs, and various personnel and administrative functions. I am also responsible for environmental matters and fuel procurement.

Q. Mr. Cantrell, what is the objective of your testimony?

A. The objective of my testimony is to present the cost associated with the conversion of four of Tampa Electric Company's generating units from oil to coal. In addition, I will sponsor the calculation of the operation and maintenance expense differential and the determination of fuel savings for the projection period and the projected payoff period.

Q. How does your testimony relate to the testimony of other witnesses in this proceeding?

A. Ms. Elizabeth Townes is sponsoring the overall calculation of the company's Oil Backout Cost Recovery Factor for the period April 1995 - September 1995, as well as the estimated payoff period for the total project. In these calculations, Ms. Townes develops the basic revenue requirements of the project using the actual cost of the conversion assets, and my projection of the operation and maintenance expense differential and the fuel savings resulting from the conversion. Kilowatt-hour sales and fuel costs are consistent with those used in the company's fuel adjustment filing.

Q. Have you prepared documents in support of your testimony?

A. Yes. I have prepared portions of documents which are included in a composite Exhibit No. (WNC/EAT-2) titled "Schedules Supporting Oil Backout Cost Recovery Factor" and Exhibit No. (WNC/EAT-3) titled "Comparison of Projected Payoff with Original Estimate, as of November 1994." These exhibits are being jointly sponsored by Ms. Townes and me.

Q. What is the status of the project?

REVISED 02/09/95

A. The conversion of Gannon units 1 through 4 from oil to coal is complete. The units were placed into commercial service as follows:

Unit 1	October 6, 1985
Unit 2	May 23, 1985
Unit 3	July 12, 1984
Unit 4	November 7, 1983

Q. What is the cost of the Oil Backout assets which are included in the cost recovery computation in this proceeding?

A. The total cost of the conversion project to be recovered through the Clause is \$140.5 million. No additional expenditures are anticipated.

Q. What are the projected fuel savings which will occur as a result of the operation of the converted Gannon units during the projection period?

A. As shown on Line 4 of Document 1, total fuel savings resulting from the project for the period April 1995 - September 1995 are expected to be \$266,530. This amount is based upon the difference in fuel expenses from production

REVISED 02/09/95

costing runs which simulate dispatch of all generating units with and without the conversion of the Gannon units. The assumptions for sales, unit ratings, heat rates, coal and No. 6 oil prices and availability factors are consistent with those used by the company in its fuel adjustment filing in this docket.

Q. Have you calculated the projected operating and maintenance expense differential of the project for April 1995 - September 1995?

A. Yes, I have calculated the operation and maintenance expense differential for this period to be $2,057,435 as shown on line 9 of Document 1.

Q. Please explain how the operation and maintenance expense differential was calculated.

A. The operation and maintenance differential consists of the oil/non-oil operating expense differential and other projected costs resulting from the Oil Backout project. This differential was calculated by applying a percentage representing the increased operation and maintenance costs associated with coal-firing to total projected operation and maintenance expenses pertaining to the converted Gannon units. The percentage was derived by comparing historical operation and maintenance costs for Gannon units 1-4 as oil-fired to historical operation and maintenance costs for Gannon units 5 and 6 as coal-fired. Specifically identifiable costs to be incurred to comply with the Oil Backout Cost Recovery Rule were added to the operating expense differential to derive the total operation and maintenance differential.

The operation and maintenance differential as shown on Exhibit No. (WNC/EAT-3) "Comparison of Projected Payoff with Original Estimate, as of November 1994," is now higher than the original estimate since the original estimate did not include maintaining the assets required for dual firing capability. In addition, the current estimate is based on more detailed engineering estimates and actual experience associated with the converted units.

Q. Mr. Cantrell, please explain the decrease in fuel savings indicated on the projected payoff exhibit.

A. The reduction in fuel savings is due to a decrease in the projected differential between the price of oil and the price of coal, and a decrease in the projected system energy requirements. The current estimate of fuel savings units. The percentage was derived by comparing historical operation and maintenance costs for Gannon units 1-4 as oil-fired to historical operation and maintenance costs for Gannon units 5 and 6 as coal-fired. Specifically identifiable costs to be incurred to comply with the Oil Backout Cost Recovery Rule were added to the operating expense differential to derive the total operation and maintenance differential.

The operation and maintenance differential as shown on Exhibit No. (WNC/EAT-3) "Comparison of Projected Payoff with Original Estimate, as of November 1994," is now higher than the original estimate since the original estimate did not include maintaining the assets required for dual firing capability. In addition, the current estimate is based on more detailed engineering estimates and actual experience associated with the converted units.

Q. Mr. Cantrell, please explain the decrease in fuel savings indicated on the projected payoff exhibit.

A. The reduction in fuel savings is due to a decrease in the projected differential between the price of oil and the price of coal, and a decrease in the projected system energy requirements. The current estimate of fuel savings is based on long-term fuel price and energy projections prepared in conjunction with this current fuel adjustment clause filing.

Q. Does this conclude your testimony?

A. Yes.

DOCKET NO. 940001-EI
TAMPA ELECTRIC COMPANY
SUBMITTED FOR FILING 11/14/94
(TRUE UP)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GEORGE A. KESELOWSKY

Q. Will you please state your name, business address, and employer?

A. My name is George A. Keselowsky and my business address is Post Office Box 111, Tampa, Florida 33601. I am employed by Tampa Electric Company.

Q. Please furnish us with a brief outline of your educational background and business experience.

A. I graduated in 1972 from the University of South Florida with a Bachelor of Science Degree in Mechanical Engineering. I have been employed by Tampa Electric Company in various engineering positions since that time. My curent position is that of Senior Consulting Engineer - Production Engineering.

Q. What are your current responsibilities?

A. I am responsible for testing and reporting unit performance, and the compilation and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. My testimony presents the actual performance results from unit equivalent availability and station heat rate used to determine the Generating Performance Incentive Factor (GPIF) for the period April 1994 through September 1994. I will also compare these results to the targets established prior to the beginning of the period.

Q. Have you prepared an exhibit with the results for this six month period?

A. Yes. Under my direction and supervision an exhibit has been prepared entitled, "Tampa Electric Company, April 1994 - September 1994, Generating Performance Incentive Factor Results" consisting of 28 pages that was filed with this testimony (Have identified as Exhibit GAK-1).

Q. Have you calculated the results of Tampa Electric Company for its performance under the GPIF during this period?

A. Yes I have. This is shown on page 4 of my exhibit. Based upon +0.788 GPIF points, the result is a reward amount of $146,321 for the period.

Q. Please proceed with your review of the actual results for the April 1994 - September 1994 period.

A. On page 3 of my exhibit, the actual average common equity for the period is shown on line 8 as $918,569,094. This produces the maximum penalty or reward figure of $1,856,865 as shown on line 15, page 3, and also on page 2 of my exhibit.

Q. Would you please explain how you arrived at the actual equivalent availability results for the six units included within the GPIF?

A. Yes I will. Operating data on each of our operating units is filed monthly with the Florida Public Service Commission on the Actual Unit Performance data form. Additionally, outage information is reported to the Commission on a monthly basis. A summary of this data for the six months provides the basis for the GPIF.

Q. Are the equivalent availability results shown on page 6, column 2, directly applicable to the GPIF table?

A. Not exactly. Adjustments to equivalent availability may be required as noted in section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown on page 6 of my exhibit.

The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J.H. Hoffsis of the Commission's Staff. The adjustments for each unit are as follows:

Gannon Unit No. 5

On this unit, 192 planned outage hours were originally scheduled to fall within the Summer 1994 period. The actual planned outage activities required 120.6 hours. Consequently, the actual equivalent availability of 85.4% is adjusted to 83.9% as shown on page 7 of my exhibit.

Gannon Unit No. 6

This unit was not scheduled to have a planned outage during the Summer 1994 period, and did not in fact have one. Consequently, the actual equivalent availability of 90.7% requires no adjustment, as shown on page 8 of my exhibit.

Big Bend Unit No. 1

On this unit, 1,344 planned outage hours were originally scheduled to fall within the Summer 1994 period. The actual planned outage activities required 1,342.6 hours. Since the actual hours were nearly identical to the planned hours, the adjustment process produced a change only beyond the first decimal point. Consequently, the actual equivalent availability of 59.1% remains 59.1% after adjustment as shown on page 9 of my exhibit.

Big Bend Unit No. 2

This unit was not scheduled to have a planned outage during the Summer 1994 period, and did not in fact have one. Consequently, the actual equivalent availability of 79.2% requires no adjustment as shown on page 10 of my exhibit.

Big Bend Unit No. 3

This unit was not scheduled to have a planned outage during the Summer 1994 period, and did not in fact have one. Consequently, the actual equivalent availability of 90.9% requires no adjustment as shown on page 11 of my exhibit.

Big Bend Unit No. 4

This unit was not scheduled to have a planned outage the Summer 1994 period, and did not in fact have one. Consequently, the actual equivalent availability of 92.6% requires no adjustment as shown on page 12 of my exhibit.

Q. How did you arrive at the applicable equivalent availability points for each unit?

A. The final adjusted equivalent availabilities for each unit are shown on page 6, column 4, of my exhibit. This number is entered into the respective Generating Performance Incentive Point (GPIP) Table for each particular unit on pages 21 through 26. Page 4 of my exhibit summarizes the equivalent availability points to be awarded or penalized.

Q. Would you please explain the heat rate results relative to the GPIF?

A. The actual heat rate and adjusted actual heat rate for Gannon and Big Bend Station are shown on page 6 of my exhibit. The adjustment was developed based on the guidelines of section 4.3.6 of the GPIF Manual. This procedure is further defined by a letter dated October 23, 1981, from Mr. J.H. Hoffsis of the FPSC Staff. The final adjusted actual heat rates are also shown on page 5 of my exhibit. This heat rate number is entered into the respective GPIP table for the particular unit, shown on pages 21 through 26. Page 4 of my exhibit summarizes the weighted heat rate and equivalent availability points to be awarded.

Q. What is the overall GPIP for Tampa Electric Company during this six month period?

A. This is shown on page 28 of my exhibit. Essentially, the weighing factors shown on page 4, column 3, plus the equivalent availability points and the heat rate points shown on page 4, column 4, are substituted within the equation. This resultant value, +0.788, is then entered into the GPIF table on page 2. Using linear interpolation, a reward amount of $146,321 is calculated.

Q. Does this conclude your testimony?

A. Yes, it does.

Dy Fr

117

DOCKET NO. 950001-EI
TAMPA ELECTRIC COMPANY
SUBMITTED FOR FILING 1/17/95
(PROJECTION)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GEORGE A. KESELOWSKY

Q. Will you please state your name, business address, and employer?

A. My name is George A. Keselowsky and my business address is Post Office Box 111, Tampa, Florida 33601. I am employed by Tampa Electric Company.

Q. Please furnish us with a brief outline of your educational background and business experience.

A. I graduated in 1972 from the University of South Florida with a Bachelor of Science Degree in Mechanical Engineering. I have been employed by Tampa Electric Company in various engineering positions since that time. My current position is that of Senior Consulting Engineer - Production Engineering.

Q. What are your current responsibilities?

A. I am responsible for testing and reporting unit performance, and the compilation and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. My testimony presents Tampa Electric Company's methodology for determining the various factors required to compute the Generating Performance Incentive Factor (GPIF) as ordered by this Commission.

Q. Have you prepared an exhibit showing the various elements of the derivation of Tampa Electric Company's GPIF formula?

A. Yes, I have prepared, under my direction and supervision, an exhibit entitled "Tampa Electric Company, Generating Performance Incentive Factor" April 1995 - September 1995, consisting of 35 pages filed with the Commission on January 17, 1994. (Have identified as Exhibit GAK-2). The data prepared within this exhibit is consistent with the GPIF Implementation Manual previously approved by this Commission.

Q. Which generating units on Tampa Electric Company's system are included in the determination of your GPIF?

A. Six of our coal-fired units are included. These are: Gannon Station Units 5 and

6; and Big Bend Station Units 1, 2, 3, and 4.

Q. Will you describe how Tampa Electric Company evolved the various factors associated with the GPIF as ordered by this Commission?

A. Yes. First, the two factors to be used, as set forth by the Commission Staff, are unit availability and station heat rate.

Q. Please continue.

A. A target was established for equivalent availability for each unit considered for this period. Heat rate targets were also established for each unit. A range of potential improvement and degradation was determined for each of these parameters.

Q. Would you describe how the target values for unit availability were determined?

A. Yes I will. The Planned Outage Factor (POF) and the Equivalent Unplanned Outage Factor (EUOF) were subtracted from 100% to determine the target equivalent availability. The factors for each of the 6 units included within the GPIF are shown on page 5 of my exhibit. For example, the projected EUOF for Gannon Unit Six is 14.1%. The Planned Outage Factor for this same unit during this period is 5.5%. Therefore, the target equivalent availability for this unit equals:

$$100\% - [(14.1\% + 5.5\%)] = 80.4\%$$

This is shown on page 4, column 3 of my exhibit.

Q. How was the potential for unit availability improvement determined?

A. Maximum equivalent availability is arrived at using the following formula.

Equivalent Availability Maximum

$$EAF_{MAX} = 100\% - [0.8\ (EUOF_T) + 0.95\ (POF_T)]$$

The factors included in the above equations are the same factors that determine target equivalent availability. To attain the maximum incentive points, a 20% reduction in Forced Outage and Maintenance Outage Factors (EUOF), plus a 5% reduction in the Planned Outage Factor (POF) will be necessary. Continuing with our example on Gannon Unit Six:

$$EAF_{MAX} = 100\% - [0.8\ (14.1\%) + 0.95\ (5.5\%)] = 83.5\%$$

This is shown on page 4, column 4 of my exhibit.

Q. How was the potential for unit availability degradation determined?

A. The potential for unit availability degradation is significantly greater than is the potential for unit availability improvement. This concept was discussed extensively and approved in earlier hearings before this Commission. Tampa

Electric Company's approach to incorporating this skewed effect into the unit availability tables is to use a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is arrived at via the following formula:

<u>Equivalent Availability Minimum</u>

$$EAF_{MIN} = 100\% - [1.4\ (EUOF_T) + 1.10\ (POF_T)]$$

Again, continuing with our example of Gannon Unit Five,

$$EAF_{MIN} = 100\% - [1.4\ (14.1\%) + 1.1\ (5.5\%)] = 74.2\%$$

Equivalent availability MAX and MIN for the other five units is computed in a similar manner.

Q. How do you arrive at the Planned Outage, Maintenance Outage and Forced Outage Factors?

A. Our planned outages for this period are shown on page 19 of my exhibit. A Critical Path Method (C.P.M.) for each outage greater than two weeks which affects GPIF is included in my exhibit. For example, Big Bend Unit 3 is scheduled for a major unit inspection from April 5 to May 16, 1995. There are 1008 planned outage hours scheduled for the summer 1995 period, and a total of 4391 hours during this 6 month period. Consequently, the Planned Outage Factor for Unit 3 at Big Bend is 1008/4391 x 100% or 23.0%. This factor is shown on pages 5 and 17 of my exhibit. Big Bend Units 2 and 4, as well as Gannon Unit 5 have planned outage factors of zero. Gannon Unit 6 has a planned outage factor of 5.5% and Big Bend Unit 1 has a planned outage factor of 1.1%.

Q. How did you arrive at the Forced Outage and Maintenance Outage Factors on each unit?

A. Graphs of both of these factors (adjusted for planned outages) vs. time are prepared. Both monthly data and 12 month moving average data are recorded. For each unit the most current, September 1994, 12 month ending value was used as a basis for the projection. This value was adjusted up or down by analyzing trends and causes for recent forced and maintenance outages. All projected factors are based upon historical unit performance, engineering judgment, time since last planned outage, and equipment performance resulting in a forced or maintenance outage. These target factors are additive and result in a EUOF of 11.3% for Gannon Unit Five. The Equivalent Unplanned Outage Factor (EUOF) for Gannon Unit Five is verified by the data shown on page 13, lines 3, 5, 10 and 11 of my exhibit and calculated using the formula:

$$EUOF = \frac{(FOH + EFOH + MOH + EMOH)}{\text{Period Hours}} \times 100$$

or

$$EUOF = \frac{(439 + 57)}{4391} \times 100 = 11.3\%$$

Relative to Gannon Unit Five, the EUOF of 11.3% forms the basis of our

Equivalent Availability target development as shown on sheets 4 and 5 of my exhibit.

Q. Please continue with your review of the remaining units.

Big Bend Unit One

A. The projected EUOF for this unit is 15.5% during this period. This unit will have a planned outage which is scheduled to end early in this period, and the Planned Outage Factor is 1.1%. This results in a target equivalent availability of 83.4% for the period.

Big Bend Unit Two

The projected EUOF for this unit is 11.9%. This unit will not have a planned outage during this period and the Planned Outage Factor is 0.0%. Therefore, the target equivalent availability for this unit is 88.1%.

Big Bend Unit Three

The projected EUOF for this unit is 9.9% during this period. This unit will have a planned outage this period and the Planned Outage Factor is 23.0%. Therefore, the target equivalent availability for this unit is 67.1%.

Big Bend Unit Four

The projected EUOF for this unit is 9.4%. This unit will not have a planned outage during this period and the Planned Outage Factor is 0.0%. This results in a target equivalent availability of 90.6% for the period.

Gannon Unit Five

The projected EUOF for this unit is 11.3%. This unit will not have a planned outage during this period and the Planned Outage Factor is 0.0%. Therefore, the target equivalent availability for this unit is 88.7%.

Gannon Unit Six

The projected EUOF for this unit is 14.1%. This unit will have a planned outage during this period and the Planned Outage Factor is 5.5%. Therefore, the target equivalent availability for this unit is 80.4%.

Q. Would you summarize your testimony regarding Equivalent Availability Factor (EAF), Equivalent Unplanned Outage Factor (EUOF) and Equivalent Unplanned Outage Rate (EUOR)?

A. Yes I will. Please note on page 5 that the GPIF system weighted Equivalent Availability Factor (EAF) equals 82.3%. This target compares very favorably to previous GPIF periods in that it is better than three of the five previous periods, as well as the five period average EAF. The system weighted Equivalent Unplanned Outage Rate (EUOR) equals 12.9%. This target is also worthy of note. It is within 0.4% of being better or equal to the EUOR of four of the five previous periods. These targets represent an outstanding level of performance for our system.

Q. As you graph and monitor Forced and Maintenance Outage Factors, why are they adjusted for planned outage hours?

A. This adjustment makes these factors more accurate and comparable. Obviously, a unit in a planned outage stage or reserve shutdown stage will not incur a forced or maintenance outage. Since our units are usually base loaded, reserve shutdown is generally not a factor. To demonstrate the effects of a planned outage, note the EUOR and EUOF for Gannon Unit Six on page 14. During the month of April and for June through September, EUOF and EUOR are equal. This is due to the fact that no planned outages are scheduled during these months. During the month of May, EUOR exceeds EUOF. The reason for this difference is the scheduling of a planned outage. The adjusted factors apply to the period hours after planned outage hours have been extracted.

Q. Does this mean that both rate and factor data are used in calculated data?

A. Yes it does. Rates provide a proper and accurate method of arriving at the unit parameters. These are then converted to factors since they are directly additive. That is, the Forced Outage Factor + Maintenance Outage Factor + Planned Outage Factor + Equivalent Availability = 100%. Since factors are additive, they are easier to work with and to understand.

Q. You previously stated that you had developed a CPM for your unit outages. How do you use the CPM in conjunction with your planned outages?

A. The CPM's included in this exhibit are preliminary and include only the major work activities we expect to accomplish during the planned outage. Planned outages are very complex and are anticipated months in advance. The actual CPM's utilized in the execution of the planned outage are detailed for all major and minor work activities.

Since it is important to the company and beneficial to our Customers to control outage length, we have implemented a computerized outage management system. Essentially, this tool enables management to monitor outage progress, measure activity results against previously established milestones, and verify timely execution of all critical path events. This results in the shortest outage time possible and the maximum utilization of all resources. Any reduction in planned outage length directly improves unit equivalent availability.

Q. Has Tampa Electric Company prepared the necessary heat rate data required for the determination of the Generating Performance Incentive Factor?

A. Yes. Target heat rates as well as ranges of potential operation have been developed as required.

Q. On what basis were the heat rate targets determined?

A. Average net operating heat rates are determined and reported on a unit basis. Therefore, all heat rate data pertaining to the GPIF is calculated on this basis.

Q. How were these targets determined?

A. Net heat rate data for the three most recent winter periods, along with the PROMOD III program, formed the basis of our target development. Projections of unit performance were made with the aid of PROMOD III. The historical data and the target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations, or equipment modifications having material effect on heat rate can be taken into consideration.

Q. Have you developed the heat rate targets in accordance with GPIF guidelines?

A. Yes.

Q. How were the ranges of heat rate improvement and heat rate degradation determined?

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate vs. net output factor curves have been developed for each station. This information is shown on pages 27 through 32 of my exhibit.

Q. Would you elaborate on the analysis used in the determination of the ranges?

A. The net heat rate vs. net output factor curves are the results of a first order curve fit to historical data. The standard error of the estimate of this data was determined, and a factor was applied to produce a band of potential improvement and degradation. Both the curve fit and the standard error of the estimate were performed by computer program for each station. These curves are also used in post period adjustments to actual heat rates to account for unanticipated changes in unit dispatch.

Q. Can you summarize your heat rate projection for the summer 1995 period?

A. Yes. The heat rate target for Big Bend Unit 1 is 10,137 Btu/Net kwh. The range about this value, to allow for potential improvement or degradation, is ±314 Btu/Net kwh. The heat rate target for Big Bend Unit 2 is 10,055 Btu/Net kwh with a range of ±353 Btu/Net kwh. The heat rate target for Big Bend Unit 3 is 9,607 Btu/Net kwh, with a range of ±320 Btu/Net kwh. The heat rate target for Big Bend Unit 4 is 10,036 Btu/Net kwh with a range of ±279 Btu/Net kwh. The heat rate target for Gannon Unit 5 is 10,052 Btu/Net kwh with a range of ±326 Btu/Net kwh. The heat rate target for Gannon Unit 6 is 10,335 Btu/Net kwh with a range of ±412 Btu/Net kwh. A zone of tolerance of ± 75 Btu/Net kwh is included within the range for each target. This is shown on page 4, and pages 7 through 12 of my exhibit.

Q. Do you feel that the heat rate targets and ranges in your projection meet the criteria of the GPIF and the philosophy of this Commission?

A. Yes I do.

Q. After determining the target values and ranges for average net operating heat rate and equivalent availability, what is the next step in the GPIF?

A. The next step is to calculate the savings and weighing factor to be used for both average net operating heat rate and equivalent availability. This is shown on pages 7 through 12. Our PROMOD III cost simulation model was used to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $136,669,300 is shown on page 6 column 2.

The PROMOD III output was then used to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6 column 4. After all the individual savings are calculated, column 4 is totaled: $5,848,700 reflects the savings if all units operated at maximum improvement. A weighting factor for each parameter is then calculated by dividing individual savings by the total. For Big Bend Unit One, the weighting factor for equivalent availability is 8.22% as shown in the right hand column on page 6. Pages 7 thru 12 show the point table, the Fuel Savings/(Loss), and the equivalent availability or heat rate value.

The individual weighting factor is also shown. For example, on Big Bend Unit One, page 9, if the unit operates at 86.5% equivalent availability, fuel savings would equal $480,700 and 10 equivalent availability points would be awarded.

The Generating Performance Incentive Factor Reward/Penalty Table on page 2 is a summary of the tables on pages 7 through 12. The left hand column of this document shows the Tampa Electric Company's incentive points. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, $5,848,700. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How were the maximum allowed incentive dollars determined?

A. Referring to my exhibit on page 3, line 8, the estimated average common equity for the period April 1995 - September 1995 is shown to be $993,746,714. This produces the maximum allowed jurisdictional incentive dollars of $2,015,317 shown on line 15.

Q. Is there any other constraint set forth by this Commission regarding the magnitude of incentive dollars?

A. Yes. Incentive dollars are not to exceed fifty percent of fuel savings. Page 2 of my exhibit demonstrates that this constraint is met.

Q. Do you wish to summarize your testimony on the GPIF?

A. Yes. To the best of my knowledge and understanding, Tampa Electric Company has fully complied with the Commission's directions, philosophy, and methodology in our determination of Generating Performance Incentive Factor. The GPIF for Tampa Electric Company is expressed by the following formula for calculating Generating Performance Incentive Points (GPIP):

$$GPIP = (0.0285\ EAP_{GN5} + 0.0611\ EAP_{GN6} + 0.0822\ EAP_{BB1} + 0.0766\ EAP_{BB2} + 0.0785\ EAP_{BB3} + 0.0689\ EAP_{BB4} + 0.0570\ HRP_{GN5} + 0.1120\ HRP_{GN6} + 0.1096\ HRP_{BB1} + 0.1282\ HRP_{BB2} + 0.0902\ HRP_{BB3} + 0.1072\ HRP_{BB4})$$

Where:

GPIP = Generating performance incentive points.

EAP = Equivalent availability points awarded/deducted for Units 5 and 6 at Gannon and Units 1, 2, 3 and 4 at Big Bend.

HRP = Average net heat rate points awarded/deducted for Units 5 and 6 at Gannon and Units 1, 2, 3 and 4 at Big Bend.

Q. Have you prepared a document summarizing the GPIF targets for the April 1995 - September 1995 period?

A. Yes. The availability and heat rate targets for each unit are listed on attachment "A" to this testimony entitled "Tampa Electric Company GPIF Targets, April 1, 1995 - September 30, 1995".

Q. Do you wish to sponsor an exhibit consisting of estimated unit performance data supporting the fuel adjustment?

A. Yes I do. (Have identified as Exhibit GAK-3).

Q. Briefly describe this exhibit.

A. This exhibit consists of 22 pages. This data is Tampa Electric Company's estimate of the Unit Performance Data and Unit Outage Data for the April 1995 - September 1995 period.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 940001-EI
SUBMITTED FOR FILING 11/14/94

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

MARY JO PENNINO

Q. Please state your name, address, occupation and employer.

A. My name is Mary Jo Pennino. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am Administrator - Wholesale and Fuel in the Regulatory Affairs Department of Tampa Electric Company.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science Degree in Chemical Engineering from the University of South Florida, Tampa, Florida in 1985. Upon graduation, I began my career at Tampa Electric Company in the Production Department. My responsibilities included heat rate testing, support services for the Plant Chemical Engineers, and start-up assistance for Hookers Point Station. In 1991, I transferred to the Generation Planning Department where I was responsible for annual expansion planning analyses, alternative technology evaluation and several other business planning activities. In 1993, I was promoted to Administrator - Wholesale and Fuel in the Regulatory Affairs Department. My present responsibilities include the areas of fuel adjustment filings, capacity cost recovery filings, and rate design.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the net true-up amounts for the April 1994 through September 1994 period for both the Fuel Cost Recovery and the Capacity Cost Recovery Clauses.

FUEL COST RECOVERY CLAUSE

Q. What is the net true-up amount for the fuel cost recovery clause for the period April 1994 through September 1994.

A. An over/(under) - recovery of $3,968,565. The actual fuel cost over/(under) - recovery, including interest, is ($858,518) for the period April 1994 through September 1994 (Schedule A2, page 3 of 4, of September 1994 monthly filing, in Document No. 4, reflects an end of period total net true-up of $4,920,706. Subtracting the beginning of period deferred true-up of $5,779,224 yields the

($858,518). This ($858,518) amount, less the actual/estimated over/(under) - recovery approved in the August 1994 fuel hearings of ($4,827,083) results in a final over/(under) - recovery for the period of $3,968,565 (the estimated end of period total net true-up of $952,141 minus the above mentioned beginning of period deferred true-up of $5,779,224 yields the ($4,827,083)). This over/(under) - recovery amount of $3,968,565 will be carried over and applied in the calculation of the fuel recovery factor for the period April 1995 through September 1995.

Q. How much effect will this $3,968,565 over/(under) - recovery in the April 1994 through September 1994 period, have on the April 1995 through September 1995 period?

A. The $3,968,565 over/(under) - recovery will cause a 1,000 KWH residential bill to be approximately $0.52 lower.

Q. Have you prepared an Exhibit in this proceeding?

A. Yes. Exhibit No. (MJP-1, Fuel Cost Recovery and Capacity Cost Recovery) which contains four documents. Document No. 3 is used to explain the capacity cost recovery clause which is discussed later in my testimony. Document No. 4

contains Commission Schedules A-1 through A-12 for the months of April 1994 through September 1994. Included with the September 1994 monthly filing is a six months summary for each of Commission Schedules A7, A7A, A8, A8a, A9, and A10, for the period April 1994 through September 1994.

Q. Please explain Document No. 1.

A. Document No. 1, entitled "Tampa Electric Company Final Fuel Over/(Under) - Recovery for the period April 1994 through September 1994" shows the calculation of the final fuel over/(under) - recovery for the period of $3,968,565 which will be applied to jurisdictional sales during the period April 1995 through September 1995.

Line 1 shows the total company fuel costs of $186,559,148 for the period April 1994 through September 1994. The jurisdictional amount of total fuel costs is $185,225,297 as shown on line 2. This amount is compared to the jurisdictional fuel revenues applicable to the period on line 3 to obtain the actual over/(under) - recovered fuel costs for the period, shown on line 4. The resulting ($867,200) over/(under) - recovered fuel costs for the period, combined with $8,682 of interest shown on line 5, constitute the actual over/(under) - recovery of ($858,518) shown on line 6. The ($858,518) less the actual/estimated over/(under) - recovery of ($4,827,083) shown on line 7, which was approved in the August 1994 fuel hearings, results in the final over/(under) - recovery of $3,968,565 shown on line 8.

Fuel rates were adjusted down in July 1994 as a result of a mid course correction. Estimated over recovery without the mid course correction would have been approximately $16.5 million higher (3,920,633 MWH for July - September 1994 times the difference in the fuel cost factor - 2.894 less 2.473).

Q. What does Document No. 2 show?

A. Document No. 2, entitled "Tampa Electric Company Calculation of True-Up Amount Actual vs. Original Estimates for the period April 1994 through September 1994," shows the calculation of the actual over/(under) - recovery as compared to the original estimate for the same period.

Q. What was the variance in jurisdictional fuel revenues for the period April 1994 through September 1994?

A. As shown on line D1 of my Document No. 2, the company collected $929,561 or 0.5% more jurisdictional fuel revenues than originally estimated.

Q. What was the total fuel and net power transaction cost variance for the period April 1994 through September 1994?

A. As shown on line A7 of Document No. 2, the fuel and net power transactions cost variance is ($3,470,134) or (1.8%).

Q. What are the reasons for the total fuel and net power transactions cost being lower by ($3,470,134) or (1.8%)?

A. Although sales variance was 7,505,793 MWH minus 7,420,960 MWH, or up 84,833 MWH, unbilled sales, company use and T&D losses, as a group, were less than anticipated by (153,717) MWH or (25.8%). The combined result is that Net Energy for Load was down (68,884) MWH or (0.9%). This (0.9%), combined with the ¢/KWH cost for Total Fuel and Net Power Transaction being less than estimated by (1.0%), accounts for the (1.8%) variance.

CAPACITY COST RECOVERY CLAUSE

Q. What is the net true-up amount for the capacity cost recovery clause for the period April 1994 through September

1994?

A. An over/(under) - recovery of ($35,650). The actual capacity cost over/(under) - recovery, including interest, is $1,568,922 for the period April 1994 through September 1994 (Document No. 3, pages 2 and 3 of 5). This amount, less the actual/estimated over/(under) - recovery approved in the August 1994 fuel hearings of $1,604,572 results in a final over/(under) - recovery for the period of ($35,650) (Document No. 3, page 5 of 5). This over/(under) - recovery amount of ($35,650) will be carried over and applied in the calculation of the capacity cost recovery factor for the period April 1995 through September 1995.

Q. How much effect will this ($35,650) over/(under) - recovery in the April 1994 through September 1994 period, have on the April 1995 through September 1995 period?

A. The ($35,650) over/(under) - recovery will be less than a $.005 increase in a 1,000 KWH residential bill.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

MARY JO PENNINO

Q. Please state your name, address, occupation and employer.

A. My name is Mary Jo Pennino. My business address is 702 North Franklin Street, Tampa, Florida 33602. My title is Administrator - Wholesale and Fuel. I work in the Regulatory Affairs Department of Tampa Electric Company.

Q. Please provide a brief outline of your educational background and business experience.

A. I was educated in both public and private schools in Illinois and received a Bachelor of Science Degree in Chemical Engineering from the University of South Florida, Tampa, Florida in 1985. Upon graduation, I began my career with Tampa Electric in the Production Department. My responsibilities included heat rate testing, support service for the Plant Chemical Engineers, and start-up engineering for Hookers Point Station. In 1991, I transferred to the Generation Planning Department where I was responsible for annual expansion planning analyses, alternative technology evaluation and several other business planning activities. In 1993, I was promoted to my current position as Administrator in the Regulatory Affairs Department. My present responsibilities include the areas of fuel adjustment filings, capacity cost recovery filings, and rate design.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is twofold. First, I would like to present to the Commission the proposed Total Fuel and Purchased Power Cost Recovery factors for the period of April - September 1995, and the proposed Capacity Cost Recovery factors for the same period. Second, I would like to provide the Commission with a description of Tampa Electric's various types of off-system sales and an explanation of the treatment of the revenues received from wholesale sales. In addition, I will present reasons why this treatment is appropriate and fair to both retail ratepayers and Tampa Electric Company.

<u>Fuel and Purchased Power Cost Recovery Factors / Capacity Cost Recovery Clause</u>

Q. Did you review the projected data necessary to calculate period April - September 1995?

A. Yes.

Q. What is the proper value for the new period?

A. The proper value for the new period is 2.386 cents per kwh before the application of the factors that adjust for variations in line losses.

Q. Please describe the information provided on Schedule E-1C.

A. The GPIF and True-up factors are provided on Schedule E-1C. We propose that a GPIF reward of $146,321 be included in the projection period. The True-up amount for the October 1994 - March 1995 period is an overrecovery of $6,423,678. This overrecovery is comprised of a final True-up overrecovery amount of $3,968,565 for the April 1994 - September 1994 period and an estimated overrecovery in the amount of 2,455,113 for the October 1994 - March 1995 period.

Q. Please describe the information provided on Schedule E-1D.

A. Schedule E-1D presents the company's on-peak and off-peak fuel charge factors for the April - September 1995 period.

Q. What is the purpose of Schedule E-1E?

A. The purpose of Schedule E-1E is to present the standard, on-peak and off-peak fuel charge factors after adjusting for variations in line losses.

Q. Please recap the proposed Fuel and Purchased Power Cost Recovery factors for the April - September 1995 period.

A.

Rate Schedule	Fuel Charge Factor (cents per kwh)
Average Factor	2.386
RS, GS and TS	2.401
RST and GST	2.844 (on-peak)
	2.154 (off-peak)
SL-2, OL-1 and OL-3	2.258
GSD, GSLD and SBF	2.389
GSDT, GSLDT and SBFT	2.829 (on-peak)
	2.143 (off-peak)
IS-1, IS-3, SBI-1, SBI-3	2.319
IST-1, IST-3, SBIT-1, SBIT-3	2.747 (on-peak)
	2.080 (off-peak)

Q. How does Tampa Electric Company's proposed average fuel charge factor of 2.386 cents per kwh compare to the average fuel charge factor for the October 1994- March 1995 period?

A. The proposed fuel charge factor is 0.033 cents per kwh (or 33 cents per 1000 kwh) higher than the average fuel charge factor of 2.353 cents per kwh for the October 1994 - March 1995 period.

Q. Please explain.

A. The slight increase in fuel and purchased power expense is primarily due to Phase 1 compliance coal costs and increased heat rates and purchased power expense typically associated with the summer fuel adjustment period. The projected increase has been mitigated through the effective administration of both the Peabody and Gatliff coal contracts. Tampa Electric has negotiated significant changes in both of these contracts that provide significant benefits to its Customers. In the case of the Peabody contract, Tampa Electric has effected a buy-out of this agreement that will yield estimated net benefits to Customers of 2.5 million dollars in 1995 and 29 million dollars (present value) over the period 1995 - 2004. In the case of the Gatliff contract, Tampa Electric has negotiated, for 1995, a lower contract minimum (1.5 million tons) and a price reduction ($0.85 per ton reduction). Replacement coal for the Gatliff coal will be purchased at competitive spot prices. These changes are the result of significant efforts on the part of Tampa Electric to negotiate these changes and extensive test burn efforts at Tampa Electric's Gannon Station to find appropriate blend fuels to reduce our overall fuel costs.

Q. On December 23, 1994, a petition was filed with this Commission requesting recovery of buy-out costs associated with the buy-out of the Peabody Coalsales, Inc. contract. Are the costs and benefits associated with the Peabody buy-out included in the projected fuel charge factor for the April - September 1995 period?

A. Yes they are.

Q. Are the costs and benefits consistent with those filed in the supporting data included with the petition?

A. Yes they are.

Q. Please describe how the costs associated with the Peabody buy-out are allocated between wholesale and retail

Customers.

A. The costs associated with the Peabody buy-out have been allocated to the wholesale Requirements Customers through the inclusion of the costs in Total Net Fuel and Purchased Power Expense (prior to the jurisdictional separation). Buy-out costs have not been allocated to the separated Big Bend Unit Four sale and Schedule D Customers since those Customers do not receive the benefit of the lower fuel cost. Separated Schedule D Customers are unit power sales from Big Bend Units 1 through 4. The fuel charge for these sales is based on supplemental coal cost. The Peabody buy-out will only benefit those currently paying for contract coal in Big Bend Units 1 - 4. Buy-out costs have not been allocated to the sale of Big Bend Unit Four energy to Hardee Power Partners. Again, these Customers would not realize the benefit of lower fuel costs associated only with Big Bend Units 1 through 4.

Q. Please describe any compliance costs associated with the Clean Air Act Amendment that have been included in the calculation of the average fuel charge factor for the April - September 1995 period?

A. Only the costs associated with sulfur dioxide emission allowances have been included in the factor. In addition to the 86,485 allowances granted by EPA for 1995, 17,000 allowances were purchased for Phase 1 compliance at an average cost of $146 per allowance. The weighted average cost of all of the allowances is calculated as follows:

86,485 granted allowances @ $0 per allowance
17,000 purchased allowances @ $146.48 per allowance
103,485 total allowances @ $24.06 per allowance

In the month of May, proceeds from the 1995 auction will lower the average dollar per allowance to $22.55. In April, 5,802 tons of SO_2 are projected to be emitted and in the May - September 1995 period, 30,683 tons are projected to be emitted. Therefore, the dollars associated with allowances for this period are 5,802 times $24.06 plus 30,683 times $22.55 or $831,445 (rounding). This accounting treatment of allowances was established by the Federal Energy Regulatory Commission (FERC) in FERC Order No. 552.

Q. Why were additional allowances purchased?

A. The decision to purchase allowances was a strategic compliance decision based on Tampa Electric's best estimate of future levels of generation for affected units and the future differential in costs between high and low sulfur coal versus the cost to purchase allowances.

Q. How are projected allowance costs allocated among the various classes?

A. Allowance costs have been added on a dollar per ton basis to the cost of Big Bend Station coal. This methodology properly allocates allowance costs to all users of Big Bend Station. Allowance costs allocated to jurisdictional interchange sales and all separated sales with the exception of Requirements sales are included on Schedule E-6. The allocation to the Requirements Customers is accomplished by adding all remaining allowance costs to the retail fuel expense and then applying the jurisdictional separation factor to the combined total.

Q. Why is it appropriate to recover Clean Air Act Compliance costs through the Fuel and Purchased Power Cost Recovery Clause?

A. Since the only cost that Tampa Electric is seeking to recover at this time is the cost of SO_2 allowances, it is appropriate that the Customers who realize the benefit of lower fuel costs associated with the ability to burn higher sulfur coal are the same Customers who incur the costs associated with the allowances that enabled the use of coal with a higher sulfur content.

Q. Why has Tampa Electric chosen to recover these allowance costs through the Fuel and Purchased Power Cost Recovery Clause versus the Environmental Cost Recovery Clause?

A. While Tampa Electric recognizes the implementation of the Environmental Cost Recovery Clause to facilitate recovery of Clean Air Act Amendment Compliance costs, we feel that the administrative requirement associated with a separate filing for recovery of the relatively small expense would be in excess of any associated benefit. We are, however, willing to cooperate with the Commission should they desire a separate filing.

Q. Are you also requesting Commission approval of the projected Capacity Cost Recovery factors for the Company's various rate schedules?

A. Yes.

Q. Have you prepared or caused to be prepared under your direction or supervision an exhibit which supports this request?

A. Yes. It consists of five pages identified as Exhibit No. 31 MJP-3, Capacity Cost Recovery.

Q. What payments are included in Tampa Electric's capacity cost recovery factor?

A. Tampa Electric is requesting recovery, through the capacity cost recovery factor, of capacity payments made pursuant to cogeneration, small power production and purchased power agreements to which we are a party.

Q. Please re-cap the proposed Capacity Cost Recovery Clause factors for the April - September 1995 period.

A.

Rate Schedule	Capacity Cost Recovery Factor (cents per kwh)
RS	0.187
GS and TS	0.173
GSD	0.130
GSLD and SBF	0.119
IS-1, IS-3, SBI-1, SBI-3	0.011

SL-2, OL-1 and OL-3	0.029

These factors can be seen in Exhibit No. 31 (MJP-3), page 3 of 5.

Q. What is the composite effect of the above changes on a 1,000 kwh residential Customer?

A. A residential bill for 1,000 kwh will decrease $0.19. See following table.

Type of Charge	Oct. 94 thru Mar. 95	Apr. 95 thru Sep. 95
Customer	$ 8.50	$ 8.50
Energy	43.42	43.42
Conservation	1.85	1.54
Oil Backout	0.96	0.81
Fuel	23.68	24.01
Capacity	1.93	1.87
FGR Tax	2.06	2.06
TOTAL	$ 82.40	$ 82.21

Q. When should the new charges go into effect?

A. They should go into effect commensurate with the first billing cycle in April 1995.

Wholesale Revenue Recovery

Q. Please describe your reason for filing testimony regarding the appropriate treatment of revenues from wholesale sales.

A. Following the filing of testimony for the 1994 Winter Fuel Adjustment Docket No. 940001-EI, Staff raised the issue (25a):

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

The issue was deferred to this fuel hearing. Therefore, the purpose of my testimony is to provide the Commission and Commission Staff with the information they need on Tampa Electric's position on the appropriate treatment of wholesale sale revenues.

Q. Please describe the various types of off system sales in which your company engages and identify the retail regulatory treatment as stipulated to in Tampa Electric Company's last general rate case.

A. Exhibit No. 32 (MJP-4) describes the various types of sales in which Tampa Electric engages.

Tampa Electric primarily engages in emergency sales (Schedule A and B), economy sales (Schedule C and X), other interchange (Schedule D and J), the TPS Contract Sale, and Requirements Sales (AR-1). In TECO's last general rate case in 1992, revenues from the company's firm wholesale sales, including Requirements Sales, unit power sales (TPS Contract), and station power sales (firm Schedule D), were ordered to be separated from the retail jurisdiction. The intent of the Commission was to separate wholesale sales and those that "looked like" wholesale sales. Based on this determination, a portion of total rate base and expenses was allocated, for these sales, to the wholesale jurisdiction. The purpose of this separation was to isolate the revenues, rate base and expenses to be used in setting retail prices, based on the test years litigated in the case. The non-fuel revenues from non-firm off-system sales (other than economy) were ordered to be credited to retail ratepayers in the Capacity Cost Recovery Clause (CCRC) and the Fuel and Purchased Power Cost Recovery Clause (FPPCRC). The rate base and expenses for these sales were ordered to be treated as part of the retail jurisdiction. Likewise, revenues from these sales are credited to the retail jurisdiction in the CCRC and the FPPCRC.

Q. What characteristics are common exclusively to the sales that were ordered to be separated in Tampa Electric's last general rate case?

A. Tampa Electric's Requirements sales, the TPS Contract Sale, and firm Schedule D sales were ordered to be separated from the retail jurisdiction. The common characteristics which set these sales apart from the remaining, jurisdictional interchange sales are Tampa Electric's commitment to serve these classes and the Customer's commitment to a prescribed capacity payment. Agreements were signed and filed with the FERC with each Customer in these separated classes that established in advance a capacity commitment, comparable to the commitment to serve Tampa Electric's firm retail Customers, and an associated availability commitment in return for a firm capacity payment.

Q. Are all Schedule D Sales separated? Please explain.

A. There are two types of Schedule D sales. The sales that were ordered to be separated were the firm Schedule D sales. The other type of Schedule D sale is non-firm as-available service. Tampa Electric currently has an agreement with Seminole Electric Cooperative for the latter. This type of sale was ordered to be treated within the retail jurisdiction.

Q. Order No. PSC-93-0664-FOF-EI was an order issued by the Commission in Tampa Electric Company's last general rate case that dealt specifically with the issue of how the off-system sales should be treated in the FPPCRC and the CCRC. In this order, some of the specific types of sales were referenced by type of sale (TECO Power Services contracts), some were referenced by the Customers that were currently being served at the time of the jurisdictional separation study (City of Sebring), and still another carried both references (firm Schedule D sales (for the Cities . . .). Does your company believe that the intent of the order was to separate specific Customers or entities or specific types of sales?

A. Tampa Electric believes that the intent of this order was to separate specific types of sales into the retail and wholesale jurisdictions, but not to go so far as to separate sales to specific "entities". For instance, it is not of significance that requirements sales projected in the rate case were designated in the order as being to the City of Sebring (which they were when the projections were made) instead of to Florida Power Corporation (which the sales became after the order). This is not significant because all requirements sales are a separated type, or class, of Customers and once a class of Customers has been separated from the retail jurisdiction, that class should be treated as being separated until another jurisdictional separation is approved by the Commission in the next rate proceeding. At the time of Tampa Electric Company's last general rate case, revenues from requirements Customers were identified at a point in time as "Sebring sales" and separated based on our best knowledge of our projected level of requirements service. We do not believe that the intent of the order was to require Tampa Electric Company to flow back the non-fuel revenues now associated with the sale to Florida Power Corporation simply, for example, because Florida Power Corporation was not one of the "seven entities" identified in our last rate case. Nor do we believe that because the sales once projected to be made to Sebring are no longer to Sebring, that retail rates should be increased to reflect the loss of wholesale sales. Likewise, if Tampa Electric added a new requirements Customer between rate cases, as fellow utilities Florida Power Corporation and Florida Power and Light have done, we would treat that sale as a separated sale. Once again, requirements sales are a separated class of Customers.

Q. Why does Tampa Electric feel that their treatment of firm Schedule D sale revenues from the city of Ft. Meade and Kissimmee Utility Authority is fair to both retail ratepayers and Tampa Electric?

A. Like AR-1 sales, Firm Schedule D sales are also a separated class of Customers as ordered by the Commission in Tampa Electric Company's last rate case. The firm Schedule D sales projections utilized for purposes of establishing rates were estimated amounts based on prospective Customers and transactions. Tampa Electric asserts that specifically "who" the Customers are is insignificant. Since the time of the rate case, in some cases, the anticipated revenues from prospective firm off-system sales Customers have not materialized. During the same period, however, Tampa Electric has made increased levels of firm off-system sales to other Customers. This same phenomenon can occur within any class of Customers. The Commission recognizes that the future will always be different from the forecast and the effect of those differences in revenues is dealt with in surveillance by allowing a range in the earned return on equity for the allowed return. Upon ordering rate base and expenses associated with firm Schedule D sales to be removed from the retail jurisdiction for the purposes of setting prices based on the test year(s), the Commission effectively challenged the company to maintain the revenues to support the separated revenue requirements if it wishes to earn the allowed return. The firm Schedule D sale agreements to the city of Ft. Meade and Kissimmee Utility Authority made subsequent to the rate case separation study are identical to the other Schedule D sales that were separated in the last rate case.

Based on the foregoing, Tampa Electric's treatment of wholesale sales has been to apply revenues from all firm Schedule D sales along with the other separated sales to offset wholesale revenue requirements. Tampa Electric asserts that its treatment of off-system sales revenues is fair because it balances the risks associated with the "snapshot" rate case separation of revenues, rate base, and expenses of these sales with potential benefits to the company, while insulating the retail Customers from any risk associated with shortfalls in projected revenues.

Since the Commission's order effectively required that shareholders carry the entire risk of recovering the portion of rate base and expenses associated with firm Schedule D sales, Tampa Electric Company further asserts that it must retain the ability to acquire additional sales agreements to potentially cover the separated revenue requirements in the event that an existing agreement does not provide the level of revenue expected or the anticipated agreements do not materialize. Requiring the company to credit revenues from sales agreements obtained subsequent to the rate case projections to the retail ratepayers without a mechanism to recover from the retail Customer any lost revenues originally projected but not realized is inequitable and asymmetrical treatment. Tampa Electric should not be expected to carry the downside potential for lost sales without the upside potential of increased revenues. Retail ratepayers are held harmless in the event of wholesale revenue shortfalls and, therefore, should not receive the benefits from additional sales in the wholesale jurisdiction.

Q. Please summarize.

A. Retail base rates were established during Tampa Electric's last rate case by determining, at a "snapshot" point in time, the proper allocations of rate base and expenses to each class of Customer. Since firm Schedule D sales were separated to the wholesale jurisdiction in the last rate case, that treatment should remain consistent until another jurisdictional separation methodology is approved in the next general rate proceeding. Each projection used for the purposes of setting rates is subject to change (level of retail sales, expenses, rate base, return necessary etc.). To protect both the ratepayers and the company from significant, excessive variability in returns, an ROE range was established. Separated wholesale sales, like all elements of the price setting basis, are also subject to change. Tampa Electric was ordered to absorb all risks associated with varying levels of separated sales including the firm Schedule D sales in its last rate case. It follows that Tampa Electric should have the ability to seek out and engage in additional transactions to maintain the revenue requirement and to provide an upside potential to appropriately balance the downside risks.

It has become apparent to Tampa Electric that the letter of the order has the potential of being interpreted in a manner that we feel is inappropriate and asymmetrical with respect to risks and benefits. We would recommend that an appropriate interpretation of the order would be to clarify that the <u>firm Schedule D sales</u> are a separated class. All future <u>firm Schedule D sales</u> should also be separated between now and the time of the next general rate proceeding.

Q. Does this conclude your testimony?

A. Yes it does.

DOCKET NO. 950001-EI
TAMPA ELECTRIC COMPANY
SUBMITTED FOR FILING 01/17/95

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ELIZABETH A. TOWNES

Q. Please state your name, business address and occupation.

A. My name is Elizabeth A. Townes. My business address is 702 N. Franklin St., Tampa, Florida 33602. I am the assistant controller of Tampa Electric Company.

Q. Please describe you educational background and business experience.

A. I received a bachelor of business administration degree in accounting from Florida International University in 1978 and a Master of Business Administration degree from the University of Tampa in 1982. I am a Certified Public Accountant licensed in the state of Florida and a member of the Florida and the American Institute of CPA's. I am also currently a member of the Edison Electric Institute's Corporate Accounting Committee.

Prior to joining Tampa Electric Company in January 1982, I was employed by General Telephone Company of Florida in various accounting and regulatory functions. I was hired by Tampa Electric Company in January 1982 in the position of regulatory accountant. In September 1983, I was promoted to manager Regulatory Control and subsequently in February 1991, I was promoted to my current position as assistant controller.

My current responsibilities include accounting for fuel activities, conservation, oil backout and other regulatory accounting areas, the revenue and financial reporting functions, preparation of budgeted financial statements and the monthly surveillance report. I am also responsible for disbursements and bank reconciliation processes.

Q. Have you testified before this Commission in other proceedings?

A. Yes. I have provided written testimony in Docket No. 920001-EI, 930001-EI, and 940001-EI related to the company's oil backout cost recovery clause and in Docket No. 920324-EI which is Tampa Electric company's most recent full rate case. I also testified in the Docket No. 930987-EI , Investigation into Currently Authorized Return On Equity of Tampa Electric Company.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is discuss Tampa Electric Company's accounting treatment of long term firm Schedule D sales which were separated and treated as wholesale transactions during the company's last rate case.

Q. Have you testified on this issue previously?

A. Yes, in Docket No. 930987-EI I testified to our accounting treatment for off system sales and described the method we have used consistently on our surveillance report to allocate between wholesale and retail.

Q. Please discuss the treatment of these sales in the last case.

A. In the company's last rate case, the Commission very clearly established a philosophy which determines what types of sales were to be separated to the wholesale jurisdiction and which should be included in the retail jurisdiction. The company's rate case test years were projected for 1993 and 1994. The long term firm Schedule D sales utilized for purposes of establishing rates were estimated amounts based on prospective Customers and transactions, just as all other items of revenue, expense and rate base were estimated.

Since that time, new Customers were added and other contracts which were anticipated during the case did not materialize. This same phenomenon occurs within all classes of Customers. However, Tampa Electric company continues to treat all of this category of sales consistent with the treatment accorded during the rate case.

Q. How does this treatment impact the reporting of the company's earned return for surveillance purposes?

A. The Commission monitors Tampa Electric's earnings from retail sales through Tampa Electric's monthly surveillance report. Each month as the company calculates its earned return to equity, the actual expenses and the rate base amounts which are separated and allocated to wholesale Customers are adjusted up or down to reflect the actual level of wholesale sales. This treatment offers the Commission a valid current picture of the regulatory return being achieved in the retail jurisdiction.

Q. Could you describe your treatment in a little more detail?

A. The company's total actual rate base and expenses are allocated between retail and wholesale utilizing the same methodology as was ordered in our last rate case. We adjust the separation factors used in the last rate case by comparing the current demand and energy levels to the amounts earlier estimated in the 1993 separation study approved in Docket No. 920324-EI. Although this method does not contain as much detail as a full separation study, it does provide an appropriate and adequate estimate for purposes of tracking consistently the current retail return in the surveillance report.

Q. Is this the same treatment that other companies use?

A. It is my understanding that companies continue to treat separated sales the same between rate cases and do not flow revenues from new contract sales back to ratepayers. The methodology which Tampa Electric has adopted for reporting earnings on the surveillance report is different from that utilized by other companies. Most companies do not change separation factors between rate cases. Therefore, if the relationship between wholesale and retail changes significantly in between rate cases, no indication of that change is reported.

Q. Do you believe that Tampa Electric's treatment of these types of sales is fair and reasonable?

A. Yes, I do. The first reason I believe it is fair is that the Commission established a category or type of sale which they considered to be non-retail in nature. Therefore, in order for symmetry to work, the company cannot be expected to absorb any downside impacts without also benefitting from any upside impacts. The company's treatment of these sales maintains the symmetry of increases and decreases in our wholesale activities. Second, the surveillance report treatment affords the Commission a much clearer picture of the company's actual earnings position with respect to the retail contribution. Since the surveillance reporting procedure is identical for increases and decreases, again the symmetry is preserved. Third, I believe that this treatment is consistent with all other items which are considered in setting rates. Expenses and revenues go up and down in between rate cases. However, the company continues to report the earned return to the Commission utilizing the same treatment of revenues and expenses as was approved in the company's last rate case. In this way, the surveillance report properly reflects current business conditions, including changes which have taken place within each and every Customer class.

It should be noted that if separated wholesale transactions yield higher energy and demand than anticipated, retail ROE will be shown as being higher through our method of surveillance reporting. Thus, the efficiency and overall benefit gained though greater off system sales levels is reflected in the reported retail ROE. In effect, the proper signals are sent through this accounting treatment - increased wholesale sales lead to better utilization of the "total ratebase" (retail and wholesale) and thus tend to defer the timing of Tampa Electric's next retail rate case.

Q. Why would it not be fair to flow these revenues back through the fuel clause?

A. This treatment would penalize the company and would not provide the right incentives. Not only would Tampa Electric lose revenues from sales which do not materialize -- it would also forfeit revenues from additional sales which do occur. This is not a symmetrical treatment, nor would it be fair. Shareholders would absorb the impact of lost wholesale contracts and all other changes in revenues and expenses. However, ratepayers would benefit from new contracts while shareholders still absorb other changes in revenues and expense.

Q. Does this conclude your testimony?

A. Yes, it does.

DOCKET NO. 950001-EI
TAMPA ELECTRIC COMPANY
OIL BACKOUT
SUBMITTED FOR FILING 01/17/95

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ELIZABETH A. TOWNES

Q. Would you please state your name and address?

A. My name is Elizabeth A. Townes. My business address is 702 North Franklin Street, Tampa, Florida 33602.

Q. Please describe your educational background and experience.

A. I received a Bachelor of Business Administration degree in Accounting from Florida International University in 1978 and a Master of Business Administration from the University of Tampa in 1982. I am a Certified Public Accountant in the state of Florida and a Member of the Florida Institute of Certified Public Accountants and American Institute of Certified Public Accountants.

Prior to joining Tampa Electric Company in January 1982, I was employed by General Telephone Company of Florida. I joined Tampa Electric as a regulatory accountant. In September 1983, I was promoted to Manager-Regulatory Control and subsequently in February 1991, I was promoted to my current position as Assistant Controller.

My current responsibilities include accounting for fuel activities, conservation, oil backout and other regulatory accounting areas. I am also responsible for the revenue and financial reporting functions and accounts payable.

Q. Ms. Townes, what is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present a summary computation of the estimated Oil Backout Cost Recovery Factor to be collected during the six-month projection period beginning April 1995 and ending September 1995, including the estimated true-up adjustment required as of March 1995.

Q. Have you prepared documents in support of your testimony?

A. Yes. I have jointly prepared with Mr. Cantrell a composite exhibit titled "Schedules Supporting Oil Backout Cost Recovery Factor" indicated as Exhibit No. (WNC/EAT-2). This exhibit is a summary of the detailed computations, prepared under my supervision and direction, to derive the estimated Oil Backout Cost Recovery Factor. This exhibit consists of six documents and I will make references in my testimony to each of the documents and explain the development, or source, of each line item. I have also jointly prepared with Mr. Cantrell Exhibit No. (WNC/EAT-3) titled "Comparison of Projected Payoff with Original Estimate, as of November 1994." This exhibit provides a comparison of the estimated payback of the Gannon conversion project with the original projection submitted during the 1982 qualification hearings.

Q. Ms. Townes, would you first please summarize the key assumptions used in your derivation of the estimated factor?

A. Yes. The key assumptions involved with the determination of the factor for the projection period are the estimated fuel savings, the estimated revenue requirements associated with the converted Gannon Units and common facilities, the estimated energy sales, and the estimated true-up as of March 1995.

Q. What is the estimated Oil Backout Cost Recovery Factor which you have determined for the six-month projection period ended September 1995?

A. The factor which I have determined to be appropriate for the projection period is .081 cents per kilowatt hour. This factor is shown on line 19, of Document 1.

Q. Please explain the computations shown on Document 1.

A. The computations begin with the estimated energy sales during the projection period shown on line 1. These amounts are consistent with the company's fuel adjustment filing in this docket. Lines 2 through 4 reflect the estimated fuel savings supplied by Mr. Cantrell. Lines 5 through 10 reflect a computation of the estimated revenue requirements associated with the Gannon Oil Backout Project. Lines 11 through 13 reflect a computation of the estimated net savings and the amount available for additional depreciation under the Clause, as determined on a six-month basis. Lines 14 through 19 reflect the computation of the Oil Backout Cost Recovery Factor including the estimated net true-up adjustment required as of March 1995.

Q. Ms. Townes, please explain your computation of revenue requirements shown on lines 5 through 10.

A. The computation begins on line 5 with the estimated straight-line depreciation expense associated with the various components of the Plant in Service investment. The monthly provisions for depreciation reflected on line 5 are based on the currently approved depreciation rates for the various components of the Plant in Service investment. Line 6 reflects the estimated interest carrying cost of the Plant in Service investment. The projected monthly interest expense is determined based on the projected debt cost applied to the average debt balance for each month. Income tax expense, shown on line 7, is computed on Document 3. The estimated monthly property tax expense is shown as Taxes Other Than Income Taxes on line 8. The amounts shown on line 9 represent the operation and maintenance expense differential which was furnished by Mr. Cantrell. Total revenue requirements reflected on line 10 represent the sum of all revenue requirement components shown on lines 5 through 9.

Q. Ms. Townes, would you please explain Document 2 reflecting your computation of the Plant in Service investment?

A. Yes. Line 1 of Document 2 reflects the actual unrecovered investment in Plant in Service at the beginning of each month shown. Since no additional expenditures are currently anticipated, line 2 indicates no additions to Plant in Service. Line 5 reflects the provision for depreciation for the period. These are the same amounts shown on line 5 of Documents 1 and 5. Line 6 reflects the additional depreciation permitted under the Oil Backout Recovery Clause, equivalent to 2/3 of the estimated net savings which is shown on line 13 of Documents 1 and 5. Line 7 reflects the estimated net unrecovered investment in Plant in Service at the end of the month.

Q. Ms. Townes, would you please explain further the computation of income tax expense reflected on line 7 of Documents 1 and 5?

A. Yes. The computation of these amounts is shown on Document 3. Referring to Document 3, lines 1 through 5 agree with amounts shown as components of revenue requirements including those associated with additional depreciation, on lines 5, 6, 8, 9, 10 and 13 on Documents 1 and 5. Line 7 reflects the portion of depreciation on line 2 which represents depreciation of the equity portion of AFUDC capitalized during construction. As this amount is not tax deductible, it represents a "permanent" difference between book and tax basis of plant. Thus, this portion of depreciation expense for each month must be added back to book income to compute income before income taxes on line 8. Line 9 reflects the income tax expense before ratable amortization of investment tax credits using an effective income tax rate of 38.575%. Line 10 reflects the ratable amortization of investment tax credit consistent with the investment recovery via depreciation expense. Line 11 reflects the total income tax expense which agrees with amounts shown on line 7 of Documents 1 and 5.

Q. Ms. Townes, you indicated earlier that a key assumption in determining the factor for this projection period is the estimated true-up adjustment required for the six-month period ending March 1995. Please explain the calculation of the net true-up adjustment.

A. The projected cumulative net true-up adjustment as of March 1995 represents an overrecovery of $153,138 as shown on line 15 of Document 1. The true-up adjustment is calculated on Documents 4, 5 and 6.

The computation begins on Document 4 with the estimated tariff revenues to be billed under the Clause for each month in the period from October 1994 through March 1995, shown on Line 1. The Oil Backout Revenue applicable to this period is then reduced by the estimated/actual cost recovery under the Clause for each month in the period from October 1994 through March 1995. The amounts on Line 4 are calculated on Document 5. To this true-up provision shown on Line 5 by month, is added the beginning of the month true-up and interest provision, shown on Line 6 for a cumulative end of the period net true-up before interest, shown on Line 8. The resulting estimated true-up provision at March 1995, of $153,138 is shown on Line 10 of Document 4.

Q. What was the projected true-up amount for the six months ended September 1994 which was included in the Oil Backout cost recovery for the period October 1994 - March 1995?

A. In the filing dated June 27, 1994, the company projected a cumulative underrecovery of $(31,543) as of September 1994 which is currently being collected. The actual underrecovery at September 1994 was $(62,379), as reflected on line 6 of Document 4. The actual underrecovery at September 30, 1994, is due to higher than anticipated operating expense.

Q. What is the status of the estimated payback of the Gannon conversion project?

A. As shown on Exhibit No. (WNC/EAT-3), titled "Comparison of Projected Payoff with Original Estimate, as of November

1994," cost recovery is now projected for 2001. The delay in recovery from the original projection submitted during the 1982 qualification hearings is due primarily to reduced estimated fuel savings, as sponsored by Mr. Cantrell.

Q. Please explain any significant variances noted in the payoff comparison.

A. Actual straight-line depreciation is less than the original projection in 1982. This is due to the 1982 estimation of early retirement of existing plant.

Significant variances noted in the cost of capital and income tax components are due to the current estimate being based on the approved 100% debt financing; whereas, the original estimate was based on conventional financing, which included a combination of debt and equity. Since conventional financing included an equity component, income taxes were provided on the return associated with the equity component.

An estimate for taxes other than income taxes was not included in the original estimate. An estimate is now included since property taxes can be more reasonably determined.

In the original estimate, revenue taxes were included as part of the base revenue requirement (the sum of straight-line depreciation, cost of capital, income taxes, taxes other than income taxes, operation and maintenance differential, and revenue taxes). Revenue taxes are now excluded from the base revenue requirement. The Regulatory Assessment fee is included in the total to be billed by grossing up the Oil Backout factor.

The net result of the changes between the original and current estimate is a decrease in base revenue requirement. However, the expected additional depreciation has declined due to reduced fuel savings. Additional depreciation is computed as two-thirds of the excess of fuel savings over the base revenue requirement determined on a six-month filing period as required under the Oil Backout Clause.

Q. Ms. Townes, does this conclude your testimony?

A. Yes, it does.

(Transcript follows in sequence in Volume 2.)