BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of : DOCKET NO. 970001-EI

Fuel and purchased power cost recovery clause and generating performance incentive factor.

VOLUME 3

Pages 292 through 466

PROCEEDINGS: **HEARING**

BEFORE: CHAIRMAN JULIA L. JOHNSON
COMMISSIONER SUSAN F. CLARK
COMMISSIONER JOE GARCIA

DATE: **Thursday, August 14, 1997**

TIME: Commenced at 9:30 a.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: JOY KELLY CSR, RPR
Chief, Bureau of Reporting
H. RUTHE POTAMI, CSR, RPR
Official Commission Reporters

APPEARANCES:

(As heretofore noted.)

INDEX

MISCELLANEOUS

WITNESSES

WITNESSES

P R O C E E D I N G S

(Transcript follows in sequence from Volume 2.)

CHAIRMAN JOHNSON: Did we move into the record the testimony for the stipulated items?

MS. PAUGH: Not yet. We need to do that.

Staff requests that all of the testimony for stipulated items and the exhibits be moved into the record.

CHAIRMAN JOHNSON: Is there a motion?

COMMISSIONER CLARK: So moved.

COMMISSIONER GARCIA: Second.

CHAIRMAN JOHNSON: There's a motion and a second. Show it so moved without objection.

Florida Power Corporation

Docket No. 970001-EI

Fuel and Capacity Cost Recovery
Final True-up Amounts for
October 1996 through March 1997

DIRECT TESTIMONY OF
JOHN SCARDINO, JR.

Q. Please state your name and business address.

A. My name is John Scardino, Jr. 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 (Florida Power or the Company) in the capacity of Vice President and Controller. In addition, I also hold the position of Vice President and Controller of Florida Progress Corporation, the holding company of Florida Power Corporation.

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 describe the Company's Fuel Cost Recovery Clause final true-up amount for the period of October 1996 through March 1997, and the Company's Capacity Cost Recovery Clause final true-up amount for the same period.

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 No. 14 (JS-1). Also attached to my prepared testimony and designated Exhibit No. 15 (JS-2) are the Capacity Cost Recovery Clause true-up calculations for the October 1996 through March 1997 period. Also, I will sponsor the applicable Schedules A1 through A9 for the period to date through March 1997, which have been previously filed with the Commission and are also attached to my prepared testimony for ease of reference and designated as Exhibit No. 16 (JS-3).

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 the 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 jurisdictional ending balance as of March 31, 1997 for fuel cost recovery?

A. The actual ending balance as of March 31, 1997 for true-up purposes is an underrecovery of $89,565,627

Q. How does this amount compare to the Company's estimated ending balance included in the April 1997 through September 1997 period?

A. When the estimated underrecovery of $88,684,203 to be collected during the period of April 1997 through September 1997 is taken into account, the final true-up attributable to the six-month period ended March 31, 1997 is an underrecovery of $881,424.

Q. How was the final true-up ending balance 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 but adjusted to remove the recoverable costs incurred by Florida Power associated with the recalculation of the firm energy price to Lake Cogen Limited which amounted to $5.4 million on a retail basis and is subject to approval in Docket 961477.

Q. What factors contributed to the period-ending jurisdictional underrecovery of $89.6 million as shown on your Exhibit No. 14 (JS-1)?

A. The primary reason for the fuel cost underrecovery was the unavailability of the Crystal River 3 nuclear plant (CR3). This and other factors contributing to the underrecovery are summarized on Sheet 1 of 3. The actual jurisdictional kwh sales were lower than the original estimate by 278,531,661 KWH. This decrease in KWH sales, attributable to abnormally mild weather, resulted in lower jurisdictional fuel revenues of $5.2 million, and lower fuel expense. The $68.5 million unfavorable variance in jurisdictional fuel and purchased power expense was primarily attributable to the replacement fuel cost resulting from the extended CR3 outage and the settlement energy payment made to Pasco Cogen.

When the differences in jurisdictional revenues and jurisdictional fuel expenses are combined, the net result is an underrecovery of $75.3 million related to the October 1996 through March 1997 time period. Other variances not directly related to the period include $12.2 million underrecovery of prior period costs and $2.1 million in interest. This results in the actual ending underrecovery balance of $89.6. million, as of March 31, 1997.

Q. **Please explain the components shown on Exhibit No. 14 (JS-1), Sheet 2 of 3 which produced the $72.3 million unfavorable system variance from the projected cost of fuel and net purchased power transactions.**

A. Sheet 2 of 3 shows an analysis of the 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 of 3, variances in the amount of MWH requirements from each energy source (column B) combined to produce a cost increase of $58.8 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) did not produce a material variance.

A cost increase of $13.5 million resulted from the price variance (column D), which was caused by a number of factors detailed on lines 1 through 17 of Sheet 2 of 3, of exhibit (JS-1). The most significant factors contributing to the unfavorable variance were increased oil and gas prices. Increased oil prices resulted from increased market demand for oil to replenish the industry's low inventories. Increased gas prices were attributable to the unusually cold winter in the northern United States. A favorable variance of $3 million resulted from avoiding spent nuclear fuel disposal payments due to the extended outage of CR3. Another factor contributing to the variance was the energy price true-up for the period of August 1994 through September 1996 in the

Pasco Cogen QF contract interpretation settlement. This produced a $5.4 million unfavorable impact during this period. This change in the energy calculation methodology was approved in Docket 961407-EQ.

Q. Please explain the analysis shown on Sheet 3 of 3 of your Exhibit No. 14 (JS-1).

A. The analysis on Sheet 3 of 3 attempts to identify the effect that generation mix has on total net system fuel and purchased power cost. Although this interrelationship is generally understood to exist, it is not readily apparent from the individual variances contained in the Commission "A" Schedules or in the analysis presented on Sheet 2 of 3. For example, a decrease in the MWH requirements of nuclear generation shows up on Schedule A3 and on Sheet 2 of my exhibit as a cost decrease of $11.1 million. While this may be correct in isolation, the true effect of decreased nuclear generation is obviously a corresponding increase in the MWH requirements of a number of other more costly energy sources. As seen on Sheet 3 of 3 Column D, the result is a higher net system cost of $60.7 million even if total system MWH requirements remain unchanged.

In addition to the effect of variances in generation mix, this analysis also attempts to identify the independent effect of the <u>net</u> variance in total system MWH requirements from all energy sources combined (internal and external). In this true-up period, for example, total system requirements were lower than the original forecast by 340,184 MWH.

This led to lower net costs of $6.8 million 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 of 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 $58.8 million cost increase associated with the variance in MWH requirements?

A. Lower than expected system requirements during the period contributed to reduce the unfavorable variance by $6.8 million. The remaining $65.6 million unfavorable increase is primarily caused by the use of higher cost generation and purchased power primarily to replace nuclear generation which resulted in approximately $60.7 million of the total.

Q. Has Florida Power performed a more rigorous analysis to quantify the actual replacement power costs attributable to the current extended outage of CR3 for the October 1996 through March 1997 true-up period?

A. Yes. CR3's replacement power costs were calculated for the true-up period using PROMOD IV, the production costing model widely used throughout the industry. Unlike the more typical PROMOD projections, this analysis simulated the operation of the Florida Power system using only actual data to determine replacement power costs, including actual loads, plant maintenance, power purchases and sales, and fuel prices. The methodology employed is identical to that used in previous replacement power cost calculation performed by the Company and accepted by this Commission. This analysis resulted in replacement power costs for the true-up period of $60.8 million, which is coincidently close to the amount determined by the less rigorous employed for variance analysis purposes.

Q. Has Florida Power provided the Commission with information regarding the cause and expected duration of the current extended outage of CR3?

A. Yes. Following the February 1997 hearings in this docket, the Commission directed that a separate spin-off docket be established to review the current outage of CR3 (Docket No. 970261-EI). Shortly thereafter on March 19, 1997, Florida Power filed a three-volume Preliminary Report and appendices describing the cause of the outage that began on September 2, 1996 and the circumstances that led to the decision in October 1996 to extend the outage in order to make certain equipment modifications in CR3's Engineered Safeguards systems necessary to increase the unit's safety margins. The Preliminary Report also described other outage activities that would take place while these modifications are being performed, as well as an estimated time line for CR3's return to service by the end of 1997. At a workshop held on March 26, 1997, Florida Power made an oral presentation on the Preliminary Report and responded to questions by Staff. On April 14, 1997, Florida Power filed the prepared direct testimony of five witnesses who further elaborated on the cause of the extended outage and various related issues, with additional rebuttal testimony to be filed on May 27, 1997. During this period Florida Power has also responded to numerous interrogatories propounded by Staff and Public Counsel and has submitted over 100,000 pages of documents requested by the parties. Hearings have been scheduled in the spin-off docket for June 26 and 27, 1997, at which time the testimony and exhibits of the parties will be presented to the Commission.

Q. Does this six-month period's ending balance include any noteworthy adjustments to fuel expense as shown on exhibit (JS-3), Schedule A2, page 1 of 4, footnote to line 6b?

A. Yes, Exhibit No. 16 (JS-3) shows other jurisdictional adjustments to fuel expense. Noteworthy adjustment include recovery of the Company's Intercession City Gas Conversion Projects and the pass through of Emission Allowance expense transactions.

Q. Did ratepayers benefit from the investment in the Intercession City Gas Conversion projects previously approved by the Commission?

A. Yes. For this period, the estimated system fuel savings related to the conversion of Units 7 & 9 are $1,602,525. The total system depreciation and return was $320,031 resulting in a net system benefit to ratepayers of $1,282,494. The estimated system fuel savings related to the conversion of Units 8 & 10 are $1,176,469. The system depreciation and return was $228,865 resulting in a net system benefit to ratepayers at $947,604.

Q. Has the Company passed any sulfur dioxide emission allowance transactions through the current or prior periods fuel adjustment clause?

A. Yes, in prior six-month fuel adjustment clause periods, the Company has passed through $749,499 of proceeds from the mandated EPA Sulfur Dioxide Emission Allowance Auction as a credit to fuel expense. This amount represents the auction proceeds for the years 1993 through 1996. Under the provisions of the Clean Air Act Amendments (CAAA) of 1990 a percentage of Florida Power's allowances are withheld each year to populate a pool of allowances which EPA offers for sale at auction. Anyone can purchase but the real intent of the allowance pool was to ensure that allowances would be available for new units or new entrants to the energy market. Once these allowances are sold, proceeds are returned to the company which provided the allowances.

In the current six-month fuel adjustment clause period, the Company included $743,750 of expense for the purchase of 8,500 EPA Sulfur Dioxide Emission Allowances. See (JS-3) Schedule A2, Page 1 of 4, Footnote to Line 6b. Florida Power looked ahead to the 2000 and beyond time period when we would need to hold sufficient allowances to cover our emissions. Projecting a deficit, Florida Power entered the SO2 market and purchased allowances at a price considerably below the cost of other compliance options. To fund the purchase Florida Power used the proceeds from the sale of allowances withheld. In the future Florida Power may purchase additional allowances depending on market conditions and the Company's SO2 compliance status.

Q. Were there any other unusual costs included in the current true-up period?

A. Yes. In December 1996, Florida Power paid Procter and Gamble Paper Products Company $583,000 to assume approximately 6,000 Mcf per day of firm natural gas transportation capacity via the Southern Natural Gas and South Georgia Natural Gas interstate pipeline systems, effective January 1, 1997. This amount was included in the cost of gas to the Suwannee Plant in December.

Q. What was Florida Power's rationale for terminating the Southern & South Georgia Natural Gas contracts?

A. Florida Power owned a total of approximately 10,000 Mcf per day of firm transportation with fixed costs of approximately $1,750,000 per year for the Suwannee Plant. Based on current price and fuel availability forecasts, Florida Power could lower its fuel costs by terminating the contracts. 4,000 Mcf per day of the Southern and South Georgia Natural Gas contract was swapped with the City of Tallahassee for Florida Gas Transmission firm transportation, where it may be more fully utilized. 6,000 Mcf was sold to Procter and Gamble. Florida Power expects to save approximately $600,000 during 1997 by terminating the contracts, of which approximately $216,000 has been achieved during this true-up period. Additional savings are expected annually beyond 1997.

Q. Has Florida Power confirmed the validity of using the "short cut" method of determining the equity component of EFC's capital structure for calendar year 1996?

A. Yes. Florida Power's Audit Services department has reviewed the analysis performed by Electric Fuels Corporation (EFC). The revenue requirements under a full utility-type regulatory treatment methodology using the actual weighted average cost of debt and equity required to support Florida Power business was compared to revenues billed using equity based on 55% of net long term assets (short cut method). The analysis showed that for 1996, the short cut method resulted in revenues of $273.1 million which were $.3 million or .1% lower than revenues under the full utility-type regulatory treatment methodology. Florida Power continues to believe that this analysis confirms the appropriateness of the short cut method.

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of March 31, 1997 for capacity cost recovery?

A. The actual ending balance as of March 31, 1997 for true-up purposes is an underrecovery of $2,826,552.

Q. How does this amount compare to the Company's estimated ending balance to be included in the April 1997 through September 1997 period?

A. When the estimated overrecovery of $1,247,824. to be refunded during the period of April through September 1997 is taken into account, the final true-up attributable to the six month period ended March 1997 period is an underrecovery of $4,074,376.

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

A. Yes. The calculation of the final net 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 but adjusted to remove the recoverable costs incurred by Florida Power relating to the change in capacity rates and the buyout payments to Lake Cogen Limited which amounted to $4.5 million which is subject to approval in Docket 961477.

Q. What factors contributed to the actual period-end underrecovery of $3 million?

A. Exhibit No. 15 (JS-2), sheet 1 of 3, entitled "Capacity Cost Recovery Clause Summary of Actual True-Up Amount", compares the summary items from sheet 2 of 3 to the original forecast for the period. As can be seen from sheet 1, the actual jurisdictional capacity cost revenues were $157,268 higher than forecast due to the kwh usage mix during the period being different then estimated. Net capacity expenses were $3.2 million higher due to settlement payment to Pasco Cogen Limited which were partially set-off by several cogenerators not meeting their contractual capacity factors.

Q. What was the impact of the settlement payments associated with Pasco Cogeneration Limited in the actuals for the true-up period?

A. The Company has included the costs associated with the Pasco Cogen Limited settlement agreement of $4 million in actual results for the true-up period. This resulted from a change in the methodology in the calculation of capacity payments and the buyout of the last 67 months of the QF contract. The transaction was recorded in compliance with the Commission's order in Docket 961407-EQ

Q. Does this conclude your testimony?

A. Yes, it does

FLORIDA POWER CORPORATION

DOCKET NO. 970001-EI

Re: GPIF Reward/Penalty Amount for
October 1996 through March 1997

DIRECT TESTIMONY OF
DARIO B. ZULOAGA

Q. Please state your name and business address.

A. My name is Dario B. Zuloaga. 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 a Principal Engineer in Energy Supply, Performance Services.

Q. What are your responsibilities as Principal Engineer?

A. As a Principal 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. 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 October 1996 through March 1997. 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 (DBZ-1) 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 penalty of $255,522.00. 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 23 of my exhibit shows a comparison of target and actual planned outage hours in bar-chart form. Sheets 24 and 29 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.

FLORIDA POWER CORPORATION

DOCKET NO. 970001-EI

GPIF Targets and Ranges for October 1997 through March 1998

DIRECT TESTIMONY OF DARIO B. ZULOAGA

Q. Please state your name and business address.

A. My name is Dario B. Zuloaga. 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 a Principal Engineer in Energy Supply, Performance Services.

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 October 1997 through March 1998. 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 78 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, 2, 4 and 5 and Anclote Units 1 and 2. The Crystal River 3 Nuclear Unit is scheduled to be available for service starting January 1, 1998. Therefore, we have reinstated Crystal River 3 as part of the GPIF units.

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 rates can then be converted into an overall equivalent unplanned outage factor (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 91.37%. Since no planned outages are scheduled for the upcoming winter period, the unit's EUOR and EUOF targets are both 8.63%.

The availability targets for the current period were developed after removing from the historical data base, all forced outage hours associated with the voluntary shutdown of the unit to address several design issues related to backup safety systems, including the emergency diesel generator.

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. 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. 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 PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF R. SILVA

DOCKET NO. 970001-EI

MAY 20, 1997

Q. **Please state your name and business address.**

A. My name is Rene Silva and my business address is 9250 W. Flagler Street, Miami, Florida 33174.

Q. **Mr. Silva, would you please state your present position with Florida Power and Light Company (FPL).**

A. I am the Manager of Forecasting and Regulatory Response for the Power Generation Business Unit of FPL.

Q. **Mr. Silva, have you previously presented testimony in this docket?**

A. Yes, I have.

Q. **Mr. Silva, what is the purpose of your testimony?**

A. The purpose of my testimony is to report the actual performance for the Equivalent Availability Factor (EAF) and Average Net Operating Heat Rate (ANOHR) for the nineteen (19) generating units used to determine the Generating Performance Incentive Factor (GPIF). I have compared the actual performance of each unit to the targets that were approved in Commission Order No. PSC-96-0353-FOF-EI issued March 13, 1996, for the period April through September, 1996, and have performed the calculations prescribed by the GPIF Rule based on this comparison. My testimony presents the result of my calculations which is an incentive reward for the period.

Q. **Have you prepared, or caused to have prepared under your direction, supervision or control, an exhibit in this proceeding?**

A. Yes, I have. It consists of one document. Page 1 of that document is an index to the contents of the document.

Q. **What is the incentive amount you have calculated for the period April, 1996 through September, 1996?**

A. I have calculated a GPIF reward incentive of $ 5,801,940.

Q. **Please explain how the reward amount is calculated?**

A. The steps involved in making this calculation are provided in Document No. 1. Page 2 of Document No. 1 provides the GPIF Reward/Penalty Table (Actual) which shows an overall GPIF performance point value of +6.2364 corresponding to a GPIF reward of $5,801,940. Page 3 provides the calculation of the maximum allowed incentive dollars. The calculation of the system actual GPIF performance points is shown on page 4. This page lists each unit, the performance indicators (ANOHR and EAF), the weighing factors and the associated GPIF points.

Page 5 is the actual EAF and adjustments summary. This page lists each of the nineteen (19) units, the actual outage factors and the actual EAF in columns 1 through 5. Column 6 is the adjustment for planned outage variation. Column 7 is the adjusted actual EAF, which is calculated on page 6, and Column 8 is the target EAF. Column 9 contains the Generating Performance Incentive Points for availability as determined from the tables submitted to and approved by the Commission prior to the start of the period. These tables are shown on pages 8 through 26.

Page 7 shows the adjustments to ANOHR. For each of the nineteen (19) units, it shows the target heat rate formula, the actual Net Output Factor (NOF) and the actual ANOHR in columns 1 through 4. Since heat rate varies with NOF, it is necessary to determine both the target and actual heat rates at the same NOF. This adjustment is to provide a common basis for comparison purposes and is shown numerically for each GPIF unit in columns 5 through 8. Column 9 contains the Generating Performance Incentive Points that have been determined from the table submitted for each unit and approved by the Commission prior to the begining of the period. These tables are also shown on pages 8 through 26.

Q. Are there any changes to the targets approved through Commission Order No. PSC-96-0353-FOF-EI ?

A. No, the approved targets have not changed.

Q. Please explain the primary reason or reasons why FPL will be rewarded under the GPIF for the April 1996, through September, 1996 period ?

A. The primary reason that FPL will receive a reward for the period was that Turkey Point Nuclear Units 3 and 4 and St. Lucie Nuclear Units 1 and 2 achieved better availability than was targeted.

Q. Please summarize the effect of FPL's nuclear unit availability on the GPIF reward?

A. Turkey Point Unit 3 operated at an adjusted actual EAF of 97.0%, compared to its target of 93.6%. This results in a +10.00 point reward, which corresponds to a GPIF reward of $1,096,668.

Turkey Point Unit 4 operated at an adjusted actual EAF of 85.5%, compared to its target of 82.4%. This results in a +10.00 point reward, which corresponds to a GPIF reward of $965,585.

St. Lucie Unit 1 operated at an adjusted actual EAF of 61.1%, compared to its target of 53.1%. This results in a +10.00 point reward, which corresponds to a GPIF reward of $1,393,907.

St. Lucie Unit 2 operated at an adjusted actual EAF of 93.8%, compared to its target of 84.2%. This results in a +10.00 point reward, which corresponds to a GPIF reward of $1,716,637.

The total GPIF reward due to the nuclear units' actual availability performance is $5,172,796.

Q. **Please summarize each nuclear unit's performance as it relates to the ANOHR of the units.**

A. Turkey Point Unit 3 operated with an adjusted actual ANOHR of 11,115 BTU/KWH. This ANOHR is within the ± 75 BTU/KWH deadband around the projected target, therefore there is no GPIF reward or penalty.

Turkey Point Unit 4 operated with an adjusted actual ANOHR of 11,290 BTU/KWH, which is 94 BTU/KWH higher than the projected target. This results in a -2.71 point penalty, which corresponds to a GPIF penalty of $77,124.

St. Lucie Unit 1 operated with an adjusted actual ANOHR of 10,887 BTU/KWH. This ANOHR is within the ± 75 BTU/KWH deadband around the projected target, therefore there is no GPIF reward or penalty.

St. Lucie Unit 2 operated with an adjusted actual ANOHR of 10,907 BTU/KWH, which was 88 BTU/KWH better than projected. This results in a +1.49 point reward which corresponds to a GPIF reward of $26,328.

In total, the nuclear units' heat rate performance results in a GPIF penalty of $50,796.

Q. **What is the total GPIF incentive reward for FPL's nuclear units?**

A. $5,122,000.

Q. **Mr. Silva, would you summarize the performance of FPL's fossil units?**

A. Yes ten (10) of the fifteen (15) generating units performed better than their availability targets, while the remaining five (5) units performed worse than their targets. The combined fossil unit availability performance results in a GPIF reward of $796,975

Two (2) of the units operated with ANOHR's that were better than their projected targets and six (6) units operated with ANOHR's that were worse than their projected targets. The remaining seven (7) units operated with ANOHR's that were within the +/- 75 BTU/KWH deadband around the projected targets and they will receive no incentive reward or penalty. In total, the combined fossil unit heat rate performance results in a GPIF penalty of $117,035.

In total, the GPIF incentive reward for FPL's fossil units for the period of April through September, 1996 is $679,940.

Q. **Does this conclude your testimony?**

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENE SILVA

DOCKET NO. 970001-EI

June 23, 1997

Q **Please state your name and address.**

A. My name is Rene Silva. My business address is 9250 W. Flagler Street, Miami, Florida 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as Manager of Forecasting and Regulatory Response in the Power Generation Business Unit.

Q. **Have you previously testified in this docket?**

A. Yes.

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is to present and explain FPL's projections for (1) dispatch costs of heavy fuel oil, light fuel oil, coal and natural gas, (2) availability of natural gas to FPL, (3) generating unit heat rates and availabilities, and (4) quantities and costs of interchange and other power transactions. These projected values were used as input values to POWRSYM in the calculation of the proposed fuel cost recovery factor for the period April through September,1997. In addition, my testimony describes the circumstances regarding FPL's request to begin recovery, through the Capacity Cost Recovery Clause, of approximately $4.7 million per year associated with capacity payments to be made to Jacksonville Electric Authority (JEA) during the "St. Johns River Power Park energy suspension period".

Q. Have you prepared or caused to be prepared under your supervision, direction and control an Exhibit in this proceeding?

A. Yes, I have. It consists of pages 1 through 7 of Appendix I of this filing.

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the October, 1997 through March, 1998 period?

A. The key factors are (1) demand for crude oil and petroleum products (including heavy fuel oil), (2) non-OPEC crude oil production, (3) the extent to which OPEC production matches actual demand for OPEC crude oil, (4) the price relationship between heavy fuel oil and crude oil, and (5) the terms of FPL's heavy fuel oil supply and transportation contracts.

In general, world demand for crude oil and petroleum products is projected to continue to increase at a moderate rate through 1998 as a result of continued economic growth in the Pacific Rim countries.

On the supply side, total non-OPEC crude oil production is projected to rise slightly through 1998 due to increases in the North Sea and Latin America. The balance of the projected increase in crude oil demand is projected to be adequately met by a moderate increase in OPEC production, in part due to the resumption of small quantities of Iraqi exports .

Based on these factors crude oil prices, and consequently heavy fuel oil prices, for the October, 1997 through March, 1998 period will be only slightly higher than at present.

Q. **What is the projected relationship between heavy fuel oil and crude oil prices during the October, 1997 through March, 1998**

period?

A. The price of heavy fuel oil on the U. S. Gulf Coast (1.0% sulfur) is projected to be approximately 72% of the price of West Texas Intermediate (WTI) crude oil.

Q. **Please provide FPL's projection for the dispatch cost of heavy fuel oil for the October, 1997 through March, 1998 period.**

A. FPL's projection for the system average dispatch cost of heavy fuel oil, by sulfur grade, by month, is provided on page 3 of Appendix I in dollars per barrel.

Q. **What are the key factors that could affect the price of light fuel oil?**

A. The key factors that affect the price of light fuel oil are similar to those described above for heavy fuel oil.

Q. **Please provide FPL's projection for the dispatch cost of light fuel oil for the period from October, 1997 through March, 1998.**

A. FPL's projection for the average dispatch cost of light oil, by sulfur grade, by month, is shown on page 4 of Appendix I.

Q. What is the basis for FPL's projections of the dispatch cost of coal?

A. FPL's projected dispatch cost of coal is based on FPL's price projection of spot coal delivered to its coal plants.

For St. Johns River Power Park (SJRPP), annual coal volumes delivered under long-term contracts are fixed on October 1st of the previous year. For Scherer Plant, the annual volume of coal delivered under long-term contracts is set by the terms of the contracts. Therefore, the price of coal delivered under long-term contracts does not affect the daily dispatch decision. The dispatch price of coal for each coal plant is based on the variable component of the coal cost, the projected spot coal price.

In the case of SJRPP, FPL began to blend petroleum coke with the coal in order to reduce fuel costs, beginning in the spring of 1997. It is anticipated that petroleum coke will represent 15% of the fuel blend at SJRPP. The lower price of petroleum coke is reflected in the weighted average price of fuel delivered to SJRPP.

Q. Please provide FPL's projection for the dispatch cost of coal for

the October, 1997 through March, 1998 period.

A. FPL's projected system average dispatch cost of coal, shown on page 5 of Appendix I, is about $1.53 per million BTU, delivered to plant.

Q. What are the factors that can affect FPL's natural gas prices during the October, 1997 through March, 1998 period?

A. In general, the key factors are (1) domestic natural gas demand and supply, (2) natural gas imports, (3) heavy fuel oil prices and (4) the terms of FPL's gas supply and transportation contracts.

Every year, between the months of April and October, natural gas market inventories are built up as a reserve in preparation for peak winter gas demand The quantity of natural gas in inventory in April, 1997 - the start of the gas "injection" season - while lower than average, was significantly higher than in April, 1996.

It is projected that by the end of October the inventory level will be adequate to meet winter (1997-1998) demand for natural gas. Consequently, gas prices for the October, 1997 through March, 1998 period are projected to be lower than during the same period a year earlier.

Q. What are the factors that affect the availability of natural gas to FPL during the October, 1997 through March, 1998 period?

A. The key factors are (1) the existing capacity of natural gas transportation facilities into Florida, (2) the portion of that capacity that is contractually allocated to FPL on a firm, "guaranteed" basis each month and (3) the natural gas demand in the State of Florida.

The current capacity of natural gas transportation facilities into the State of Florida is 1,455,000 million BTU per day (including FPL's firm allocation of 455,000 to 480,000 million BTU per day during this period, depending on the month). Total demand for natural gas in the State during the period (including FPL's firm allocation) is projected to be between 245,000 and 255,000 million BTU per day below the pipeline's total capacity. This projected available pipeline capacity could enable FPL to acquire and deliver additional natural gas, beyond FPL's 455,000 to 480,000 million BTU per day of firm, "guaranteed" allocation, should it be economically attractive, relative to other energy choices.

Q. Please provide FPL's projections for the dispatch cost and availability (to FPL) of natural gas for the October, 1997 through

March, 1998 period.

A. FPL's projections of the system average dispatch cost and availability of natural gas are provided on page 6 of Appendix I.

Q. Please describe how you have developed the projected unit Average Net Operating Heat Rates shown on Schedule E4 of Appendix II.

A. The projected Average Net Operating Heat Rates were calculated by the POWRSYM model. The current heat rate equations and efficiency factors for FPL's generating units, which present heat rate as a function of unit power level, were used as inputs to POWRSYM for this calculation. The heat rate equations and efficiency factors are updated as appropriate, based on historical unit performance and projected changes due to plant upgrades, fuel grade changes, or results of performance tests.

Q. Are you providing the outage factors projected for the period October, 1997 through March, 1998?

A. Yes. This data is shown on page 7 of Appendix I.

Q. How were the outage factors for this period developed?

A. The unplanned outage factors were developed using the actual historical full and partial outage event data for each of the units. The historical unplanned outage factor of each generating unit was adjusted, as necessary, to eliminate non-recurring events and recognize the effect of planned outages to arrive at the projected factor for the October, 1997 through March, 1998 period.

Q. Please describe significant planned outages for the October, 1997 through March, 1998 period.

A. Planned outages at our nuclear units are the most significant in relation to Fuel Cost Recovery. Turkey Point Unit No.4 is scheduled to be out of service for refueling beginning on September 8, 1997 and until October 18, 1997, or eighteen days during the projected period. St. Lucie Unit No.1 will be out of service for refueling beginning on October 20, 1997 and until January 3, 1998, or seventy-five days during the projected period. There are no other significant planned outages during the projected period.

Q. Are any changes to FPL's generation capacity planned during the April through September, 1997 period?

A. Yes. Net Summer Continuous Capability (NSCC) at Pt. Everglades

Unit No.4 will increase by 21 MW, from 385 MW to 406 MW, while its Summer Peaking Capability (SPC) will increase by 16 MW, from 395 MW to 411 MW. This change had been previously projected to occur during the April through September, 1997 period.

Q. **Are you providing the projected interchange and purchased power transactions forecasted for October, 1997 to March, 1998?**

A. Yes. This data is shown on Schedules E6, E7, E8, and E9 of Appendix II of this filing.

Q. **In what types of interchange transactions does FPL engage?**

A. FPL purchases interchange power from others under several types of interchange transactions which have been previously described in this docket: Emergency - Schedule A; Short Term Firm - Schedule B; Economy - Schedule C; Extended Economy - Schedule X; Opportunity Sales - Schedule OS; UPS Replacement Energy - Schedule R and Economic Energy Participation - Schedule EP.

For services provided by FPL to other utilities, FPL has developed amended Interchange Service Schedules, including AF (Emergency), BF (Scheduled Maintenance), CF (Economy), DF (Outage), and XF (Extended Economy). These amended schedules replace and supersede existing Interchange Service Schedules A, B, C, D, and X for services provided by FPL.

Q. Does FPL have arrangements other than interchange agreements for the purchase of electric power and energy which are included in your projections?

A. Yes. FPL purchases coal-by-wire electrical energy under the 1988 Unit Power Sales Agreement (UPS) with the Southern Companies. FPL has contracts to purchase nuclear energy under the St. Lucie Plant Nuclear Reliability Exchange Agreements with Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA). FPL also purchases energy from JEA's portion of the SJRPP Units, as stated above. Additionally, FPL purchases energy and capacity from Qualifying Facilities under existing tariffs and contracts.

Q. Please provide the projected energy costs to be recovered through the Fuel Cost Recovery Clause for the power purchases referred to above during the October, 1997 to March, 1998 period.

A. Under the UPS agreement FPL's capacity entitlement during the projected period is 913 MW from October, 1997 through March, 1998. Based upon the alternate and supplemental energy provisions of UPS, an availability factor of 100% is applied to these capacity entitlements to project energy purchases. The projected UPS energy (unit) cost for this period, used as input to POWRSYM, is based on data provided by the Southern Companies. For the period, FPL projects the purchase of 1,561,795 MWH of UPS Energy at a cost of $29,129,990. In addition, we project the purchase of 1.088,327 MWH of UPS Replacement energy (Schedule R) at a cost of $17,915,970. The total UPS Energy plus Schedule R projections are presented on Schedule E7 of Appendix II.

Energy purchases from the JEA-owned portion of the St. Johns River Power Park generation are projected to be 1,388,436 MWH for the period at an energy cost of $20,691,410. FPL's cost for energy purchases under the St. Lucie Plant Reliability Exchange Agreements is a function of the operation of St. Lucie Unit 2 and the fuel costs to the owners. For the period, we project purchases of 261,495 MWH at a cost of $958,900. These projections are shown on Schedule E7 of Appendix II.

In addition, as shown on Schedule E8 of Appendix II, we project that purchases from Qualifying Facilities for the period will provide

3,625,783 MWH at a cost to FPL of $66,825,038

Q. **How were energy costs related to purchases from Qualifying Facilities developed?**

A. For those contracts that entitle FPL to purchase "as-available" energy we used FPL's fuel price forecasts as inputs to the POWRSYM model to project FPL's avoided energy cost that is used to set the price of these energy purchases each month. For those contracts that enable FPL to purchase firm capacity and energy, the applicable Unit Energy Cost mechanism prescribed in the contract is used to project monthly energy costs.

Q. **Have you projected Schedule A/AF - Emergency Interchange Transactions?**

A. No purchases or sales under Schedule A/AF have been projected since it is not practical to estimate emergency transactions.

Q. **Have you projected Schedule B/BF - Short-Term Firm Interchange Transactions?**

A. No commitment for such transactions had been made when projections were developed. Therefore, we have estimated that no Schedule BF sales or Schedule B purchases would be made in the projected period.

Q. **Please describe the method used to forecast the Economy Transactions.**

A. The quantity of economy sales and purchase transactions are projected based upon historic transaction levels, adjusted to remove non-recurring factors.

Q. **What are the forecasted amounts and costs of Economy energy sales?**

A. We have projected 814,436 MWH of Economy energy sales for the period. The projected fuel cost related to these sales is $19,169,883. The projected transaction revenue from the sales is $24,235,826. Eighty percent of the gain for Schedule C is $4,052,754 and is credited to our customers.

Q. **In what document are the fuel costs of economy energy sales transactions reported?**

A. Schedule E6 of Appendix II provides the total MWH of energy and total dollars for fuel adjustment. The 80% of gain is also provided on

Schedule E6 of Appendix II.

Q. What are the forecasted amounts and costs of Economy energy purchases for the October, 1997 to March, 1998 period?

A. The costs of these purchases are shown on Schedule E9 of Appendix II. For the period FPL projects it will purchase a total of 2,392,872 MWH at a cost of $45,368,580. If generated, we estimate that this energy would cost $52,804,756. Therefore, these purchases are projected to result in savings of $7,436,176.

Q. What are the forecasted amounts and cost of energy being sold under the St. Lucie Plant Reliability Exchange Agreement?

A. We project the sale of 153,043 MWH of energy at a cost of $621,700. These projections are shown on Schedule E6 of Appendix II.

Q. Are you presenting testimony related to the Capacity Cost Recovery clause?

A. Yes. Ms. Korel M. Dubin has filed testimony in which she addresses FPL's request that it be authorized to collect, during the next seventeen (17) years, approximately $4.7 million per year associated with future capacity payments to be made to JEA during the SJRPP energy suspension period. My testimony describes the circumstances that underlie FPL's request.

Q, Why does FPL propose to recover, between 1998 and 2014, capacity costs to be paid to JEA between 2015 and 2020?

A. Because there is a mismatch between the period over which FPL currently anticipates it will continue to receive energy from JEA's ownership share of SJRPP, and the period over which FPL is contractually required to make annual capacity payments to JEA.

Q. Please explain this mismatch between capacity and energy under the contract with JEA.

A. FPL makes capacity payments to JEA at a rate necessary to pay off, by the year 2020, bonds issued by JEA to finance SJRPP. The magnitude of the annual capacity payment is not related to the quantity of energy FPL receives each year. In fact, since SJRPP provides a low-cost source of energy, the plant runs as much as possible, and FPL takes as much of the plant's energy as it can each year, while the capacity payment remains unaffected.

Q. Why does this mismatch create a concern?

A. Because the total quantity of energy FPL can take from JEA's ownership share of SJRPP through the year 2020 is limited to 80,534,332 MWh. FPL is taking as much SJRPP energy as possible currently, and we project that the energy limit will be reached in 2015. Thereafter FPL will, consistent with the contract, continue making capacity payments through 2020, but would receive no energy from JEA's share of SJRPP ("SJRPP energy suspension").

Q. How was this energy limit established?

A. An Internal Revenue Service (IRS) ruling, which established the tax-exempt status of the municipal bonds used to finance JEA's ownership interest in SJRPP, stipulates that FPL shall not receive more than twenty-five percent (25%) of the namplate capacity of JEA's ownership share of the plant over the life of the bonds. Under FPL's contract with JEA, FPL will purchase 37.5% of energy produced by JEA's share of the plant, based on a projected plant capacity factor of approximately 67%. This is equivalent to 25% of the plant's total capability.

Q. Has SJRPP operated at the assumed 67% capacity factor?

A. The plant has operated at a 88.2% capacity factor and as a result FPL has received more low-cost energy during the first ten years of operation than had been originally estimated. We project that the plant will operate at an average capacity factor of 92% between 1998 and 2014. At that rate, the energy limit of 80,534,332 MWh imposed by the IRS ruling will be reached in 2015.

Q. Why doesn't FPL reduce the quantity of energy purchased from JEA's share of SJRPP so that the energy limit would not be reached until the bonds are paid?

A. Because we would have to replace the energy not taken from SJRPP with more expensive purchases or FPL generation, and as a result our customers' costs would increase. In fact, our analysis shows that operating SJRPP at a 67% capacity factor in order to reduce the annual quantity of SJRPP energy purchases would increase energy costs by about $128 million on a net present value basis between 1998 and 2020. The net present value of the amount FPL is requesting to collect is approximately $40 million.

Q. Would you please summarize your testimony?

A. Yes. In my testimony I have presented FPL's fuel price projections for the fuel cost recovery period of October, 1997 through March,

1998. In addition, I have presented FPL's projections for generating unit heat rates and availabilities, and the quantities and costs of interchange and other power transactions for the same period. These projections were based on the best information available to FPL, and were used as inputs to POWRSYM in developing the projected Fuel Cost Recovery Factor for the October, 1997 through March, 1998 period.

My testimony also describes the circumstances underlying FPL's request to begin to recover currently about $4.7 million per year in future SJRPP capacity costs through the Capacity Clause

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF R. SILVA

DOCKET NO. 970001-EI

JUNE 23, 1997

Q. **Please state your name and business address.**

A. My name is Rene Silva and my business address is 9250 W. Flagler Street, Miami, Florida 33174.

Q. **Mr. Silva, would you please state your present position with Florida Power and Light Company (FPL).**

A. I am the Manager of Forecasting and Regulatory Response for the Power Generation Business Unit of FPL.

Q. **Mr. Silva, have you previously had testimony presented in this docket?**

A. Yes, I have.

Q. **Mr. Silva, what is the purpose of your testimony?**

A. The purpose of my testimony is to present the target unit average net operating heat rates and target unit equivalent availabilities for the period October, 1997 through September, 1998, for use in determining the Generating Performance Incentive Factor (GPIF). The improvement and degradation range for each performance indicator is also presented in this testimony.

Q. **Mr. Silva could you please summarize what the FPL system targets are for Equivalent Availability Factor (EAF) and Average Net Operating Heat Rate (ANOHR).**

A. FPL projects a weighted system equivalent planned outage factor of 6.0% and a weighted system equivalent unplanned outage factor of 6.1% which yield a weighted system equivalent availability of 87.9%. This target includes the refueling of two nuclear units during the October, 1997 through September, 1998 period. FPL also projects a weighted system average net operating heat rate of 9277 BTU/KWH. As discussed later in this testimony, these targets represent fair and reasonable values when compared to historical data . FPL therefore requests that the targets for these performance indicators and the respective improvement/degradation ranges in my testimony be approved by the Commission .

Q. **Have you prepared, or caused to have prepared under your direction, supervision or control, an exhibit in this proceeding?**

A. Yes, I have. It consists of one document. The first page of this document is an index to the contents of the document. All other pages are numbered according to the latest revisions of the GPIF Manual as approved by the Commission.

Q. **Have you established target levels of performance for the units to be considered in establishing the GPIF for FPL?**

A. Yes, I have. Document No. 1, pages 6 and 7 contain the information summarizing the targets and ranges for unit equivalent availability and average net operating heat rates for the sixteen (16) generating units which FPL proposes to have considered. These sheets were prepared in accordance with the latest revisions of the GPIF Manual, except that, for consistency with previous GPIF filings, it is necessary to divide the format of Sheet 3.505 of the GPIF Manual into two sheets. All of these targets have been derived utilizing methodologies as adopted in Section 4, Subsection 2.3 of the GPIF Manual.

Q. **Please summarize FPL's methodology for determining equivalent availability targets?**

A. The GPIF Manual requires that the equivalent availability target for each unit be determined as the difference between 100% and the sum of the Planned Outage Factor (POF) and the Unplanned Outage Factor (UOF). The POF for each unit is determined by the length of the planned outage during the projected period. The GPIF Manual also requires that the sum of the most recent twelve month ending average forced outage factor (FOF) and maintenance outage factor (MOF) be used as the starting value for the determination of the target unplanned outage factor (UOF). The UOF is then adjusted to reflect recent monthly performance and known modifications or changes in equipment.

For most units in the GPIF this adjustment is usually done for units which had or are forecast to have planned outages. When a unit is in a planned outage state the unit cannot incur an unplanned outage. For this reason, when historical data, which contains a planned outage, is used for developing targets, the UOF will be lower than if the unit had operated the entire period. To account for this, the historical UOF is increased in proportion to the planned outage duration for that period. Similarly, if a unit is forecast to have a planned outage in the projection period the adjusted historical UOF will be higher than it should because it will not be exposed to unplanned outages for the entire period. In this case the UOF is reduced in proportion to the forecast planned outage duration.

Q. **Mr. Silva, were the EAF targets for the GPIF units determined using the methodology as described in the GPIF Operating Manual?**

A. Yes.

Q. **How did you select the units to be considered when establishing the GPIF for FPL?**

A. The sixteen (16) units which FPL proposes to use represent the top 81.0% of the forecast system net generation for the October, 1997 through September, 1998 period. These units were selected in accordance with the GPIF Manual Section 3.1 using the estimated net generation for each unit taken from the production costing simulation program, POWRSYM, which forms the basis for the projected levelized fuel cost recovery factor for the period.

Q. **Mr. Silva, from the heat rate targets and equivalent availability range projections, do FPL's generation performance targets represent a reasonable level of efficiency?**

A. Yes. To fully appreciate why these targets are reasonable, and in some cases ambitious, it would be necessary to discuss the development of both the heat rate and availability targets for each of the sixteen (16) units in the GPIF. However, a less rigorous approach of comparing weighted system values of these targets to actual values for prior periods will provide a valuable insight into the appropriateness of the targets.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF R. L. WADE

DOCKET NO. 970001-EI

June 23, 1997

Q. Please state your name and address.

A. My name is Robert L. Wade. 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 Director, Business Services in the Nuclear Business Unit.

Q. Have you previously testified in this docket?

A. Yes, I have.

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 October 1997 through March 1998.

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 October 1997 through March 1998.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period October 1997 through March 1998.

A. FPL projects the nuclear units will produce 114,468,963 MBTU of energy at a cost of $0.333 per MMBTU, excluding spent fuel disposal costs for the period October 1997 through March 1998. Projections by nuclear unit and by month are provided on Schedule E-4 of Appendix II.

Q. Please provide FPL's projections for nuclear spent fuel disposal costs for the period October 1997 through March 1998 and what is the basis for FPL's projections.

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 U.S. Department of Energy (DOE), which sets the spent fuel disposal fee at 1 mill per net Kwh generated minus transmission and distribution line losses.

Q. Please provide FPL's projection for Decontamination and Decommissioning (D&D) costs to be paid in the period October 1997 through March 1998 and what is the basis for FPL's projection.

A. FPL's projection of $5.42M for D&D costs to be paid during the period October 1997 through March 1998 is included on Schedule E-2 of Appendix II.

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 DOE for final disposal of spent nuclear fuel. FPL, along with a number of electric utilities, has filed suit against DOE over DOE's denial of its obligation to accept spent nuclear fuel beginning in 1998. A July 23, 1996, ruling by the U.S. Court of Appeals for the District of Columbia said that DOE is required by the Nuclear Waste Policy Act to take title and dispose of spent nuclear fuel from nuclear power plants beginning on January 31, 1998. DOE declined to seek further review of the decision, which was remanded to DOE for further proceedings. On December 17, 1996, DOE advised the electric utilities that it would not begin to dispose of spent nuclear fuel by the unconditional deadline.

In response to DOE's letter, FPL, other electric utilities, and state utility commissions filed suit on January 31, 1997 in the U.S. Court of Appeals for the District of Columbia requesting that the court authorize the utilities to suspend payments into the Nuclear Waste Fund (NWF) until DOE performs on its unconditional obligation to take title to and dispose of spent nuclear fuel.

On May 7, 1997, the utilities filed a petition for a writ of mandamus that (1) DOE comply with its statutory obligation and begin disposing of spent nuclear fuel by January 31, 1998 or in the alternative, direct DOE to develop a program that will enable the agency to begin disposing of spent nuclear fuel by January 31, 1998; (2) declaring that the utilities are relieved of the obligation to pay into the NWF and are authorized to place NWF collections into escrow until DOE disposes of the spent nuclear fuel; (3) prohibiting DOE from suspending the contracts with the utilities or from taking any other adverse action under the contracts; and (4) declaring that the suspension of fee payments will not adversely affect the utilities as to timing, manner, or further cost disposal entitlements by reason of such suspension of fee payments. DOE must file a response to the petition on June 6, 1997. The utilities may then reply to DOE's response ten days thereafter.

Secondly, FPL is currently seeking to resolve a price dispute for uranium enrichment services purchased from the United States (U.S.) Government, prior to July 1, 1993. FPL's contract for enrichment services with the U.S. 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 DOE's enrichment facilities. However, the Energy Policy Act of 1992 (The Act) requires utilities to make separate payments to the U.S. Treasury for D&D, starting in Fiscal Year 1993. FPL has been making such payments. Therefore, D&D should not have been included in the price charged by DOE for deliveries during Fiscal Year 1993, and the price should have been reduced accordingly. FPL filed a claim with the DOE Contracting Officer on July 14, 1995, for a refund for such deliveries. On October 13, 1995, the DOE Contracting Officer officially rejected FPL's claim. On October 11, 1996, FPL, along with five other U.S. utilities and one foreign entity, appealed DOE's rejection of the Fiscal Year 1993 overcharge claim with the U.S. Court of Federal Claims.

On December 12, 1996, the Court of Federal Claims granted the unopposed motion of all parties to suspend the overcharge proceeding pending the outcome of an appeal to the U.S. Court of Appeals for the Federal Circuit in Barseback Kraft AB v. United States, where the appellants are seeking to recover overcharges for uranium enrichment services under identical contract provisions to those at issue in FPL's overcharge claim. Oral argument was held in the Barseback case on May 7, 1997, and a decision could be issued during the summer of 1997. FPL will reevaluate the validity of its overcharge claim upon issuance of a final decision in the Barseback case.

Meanwhile, in a related case, Yankee Atomic Electric Company had been challenging the legality of the United States to impose the D&D fees. On May 6, 1997, a panel of the U.S. Court of Appeals for the Federal Circuit held that the D&D special assessment was lawful under the Energy Policy Act. United States v. Yankee Atomic Electric Co. A lower court had ruled that the D&D special assessment was unlawful. Yankee has until June 20, 1997 to determine whether to seek review from the full panel of the Federal Circuit. FPL will continue to follow this case and will take actions, as appropriate, consistent with the outcome of the appeal.

Q. **Does this conclude your testimony?**

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 970001-EI

May 20, 1997

Q. Please state your name, business address, employer and position.

A. My name is Korel M. Dubin, and my business address is 9250 West Flagler Street, Miami, Florida, 33174. I am employed by Florida Power & Light Company (FPL) as a Principal Rate Analyst in the Rates and Tariff Administration Department.

Q. Please state your education and business experience.

A. I received a Bachelor of Arts in Political Science from Emory University in 1980 and in 1982 I received a Master of Business Administration from Barry University. In June 1982, I joined Florida Power & Light Company's Fossil Fuel Section of the Fuel Resources Department. My responsibilities included administration of fuel supply and operations contracts, development of procurement procedures and research and analysis of transportation options and by-product sales.

After holding positions of increasing responsibility in the Fuel Resources Department (1982-1985) and Rates and Research Department (1985 -1991), I joined the Regulatory Affairs Department as a Coordinator in July 1991 where I was primarily responsible for the coordination of the Company's Fuel, Oil Backout, Capacity, Environmental Cost Recovery Clause and Generating Performance Incentive Factor (GPIF) filings.

In April 1997 I became Principal Rate Analyst in the Rates and Tariff Administration Department where I am primarily responsible for the development and support of the Company's Fuel, Capacity and Environmental Cost Recovery Clause and GPIF Filings.

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

A. The purpose of my testimony is to present the schedules necessary to support the actual Fuel Cost Recovery Clause (FCR) Net True-Up amount for the period October 1996 through March 1997. The Net True-Up for FCR is an overrecovery, including interest, of $13,141,163. I am requesting Commission approval to include this true-up amount in the calculation of the FCR factor for the period October 1997 through March 1998.

Q. Have you prepared or caused to be prepared under your direction, supervision or control an exhibit in this proceeding?

A. Yes, I have. It consists of Appendix I which contains the FCR related schedules. FCR Schedules A-1 through A-13 for the October 1996 through March 1997 period have been filed monthly with the Commission, are served on all parties and are incorporated herein by 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 FPL. The books and records are kept in the regular course of our business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by this Commission.

Q. Please explain the calculation of the Net True-up Amount.

A. Appendix I, page 3, entitled "Summary of Net True-Up Amount" shows the calculation of the Net True-Up for the six-month period October 1996 through March 1997, an overrecovery of $13,141,163, which I am requesting be included in the calculation of the Fuel Cost Recovery Factor for the period October 1997 through March 1998. The calculation of the true-up amount for the period follows the procedures established by this Commission as set forth on

Commission Schedule A-2 "Calculation of True-Up and Interest Provision".

The actual End-of-Period underrecovery for the six-month period October 1996 through March 1997 of $50,449,989 shown on line 1, less the estimated/actual End-of-Period underrecovery for the same period of $63,591,152 shown on line 2 that was included in the calculation of the Fuel Cost Recovery Factor for the period April 1997 through September 1997, results in the Net True-Up for the six-month period October 1996 through March 1997 shown on line 3, an overrecovery of $13,141,163.

Q. Have you provided a schedule showing the variances between actuals and estimated/actuals?

A. Yes. Appendix I, page 4, entitled "Calculation of Final True-up Variances" shows the actual fuel costs and revenues compared to the estimated/actuals for the period October 1996 through March 1997.

Q. What was the variance in fuel costs?

A. As shown on Appendix I, page 4, line A7, actual fuel costs on a Total Company basis were $7.1 million lower than the estimated/actual projection. The Fuel Cost of Power Sales are $13.2 million lower than projected. This variance is offset by a $3.6 million decrease in the Fuel Cost of System Net Generation, a $1.9 million decrease in the

Fuel Cost of Purchased Power, an $8.4 million decrease in the Energy Payments to Qualifying Facilities and a $5.8 million decrease in Energy Cost of Economy Purchases.

The decrease in the Fuel Cost of Power Sold was primarily due to lower than projected opportunity sales due to mild weather. The decrease in the Fuel Cost of System Net Generation was primarily due to a decrease in natural gas prices due to warmer than anticipated weather and higher gas inventory levels throughout the winter. The decrease in the Fuel Cost of Purchased Power was due to lower than projected UPS purchases from Southern Company due to mild weather. The decrease in Energy Payments to Qualifying Facilities was due to lower than expected deliveries from Indiantown Cogeneration Limited (ICL), Cedar Bay and Florida Crushed Stone contracts. The decrease in Energy Cost of Economy Purchases was due to reduced availability of low cost economy energy due to cold weather in the southeast region.

Q. **What was the variance in retail (jurisdictional) Fuel Cost Recovery revenues?**

A. As shown on line D1, actual jurisdictional Fuel Cost Recovery revenues, net of revenue taxes, were $5.9 million higher than the estimated/actual projection. This increase was due to higher jurisdictional kWh sales. Jurisdictional sales were 257,001,059 kWh

(0.7%) higher than the estimated/actual projection.

Q. How is Real Time Pricing (RTP) reflected in the calculation of the Net True-up Amount?

A. In the determination of Jurisdictional kWh sales, only kWh sales associated with RTP baseline load are included, consistent with projections (Appendix 1, page 4, Line C3). In the determination of Jurisdictional Fuel Costs, revenues associated with RTP incremental kWh sales are included as 100% Retail (Appendix 1, page 4, Line D4c) in order to offset incremental fuel used to generate these kWh sales.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 970001-EI

June 23, 1997

Q. Please state your name and address.

A. My name is Korel M. Dubin and my business address is 9250 West Flagler Street, Miami, Florida 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as Principal Rate Analyst in the Rates and Tariff Administration Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the fuel factors for the Company's rate schedules for the period October 1997 through March 1998 and the capacity payment factors for the Company's rate schedules for the period October 1997 through September 1998. The calculation of the fuel factors is based on projected fuel cost and operational data as set forth in Commission

Schedules E1 through E10, H1 and other exhibits filed in this proceeding and data previously approved by the Commission. I am also providing projections of avoided energy costs for purchases from small power producers and cogenerators and an updated ten year projection of Florida Power & Light Company's annual generation mix and fuel prices.

In addition, my testimony presents the schedules necessary to support the calculation of the Estimated/Actual True-up amounts for the Fuel Cost Recovery Clause (FCR) for the period April 1997 through September 1997 and the Capacity Cost Recovery Clause(CCR) for the period October 1996 through September 1997.

Q. Have you prepared or caused to be prepared under your direction, supervision or control an exhibit in this proceeding?

A. Yes, I have. It consists of various schedules included in Appendices II and III. Appendix II contains the FCR related schedules and Appendix III contains the CCR related schedules.

FCR Schedules A-1 through A-13 for April 1997 and May 1997 have been filed monthly with the Commission, are served on all parties and are incorporated herein by 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 FPL. The books and records are kept in the regular course of our 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 CLAUSE

Q. What is the proposed levelized fuel factor for which the Company requests approval?

A. 1.643¢ per kWh. Schedule El, Page 3 of Appendix II shows the calculation of this six-month levelized fuel factor. Schedule E2, Page 10 of Appendix II indicates the monthly fuel factors for October 1997 through March 1998 and also the six-month levelized fuel factor for the period.

Q. Has the Company developed a six-month levelized fuel factor for its Time of Use rates?

A. Yes. Schedule E1-D, Page 8 of Appendix II provides a six-month levelized fuel factor of 1.734¢ per kWh on-peak and 1.607¢ per kWh off-peak for our Time of Use rate schedules.

Q. Were these calculations made in accordance with the procedures

previously approved in this Docket?

A. Yes, they were.

Q. What adjustments are included in the calculation of the six-month levelized fuel factor shown on Schedule E1, Page 3 of Appendix II?

A. As shown on line 29 of Schedule E1, Page 3, of Appendix II the estimated/actual fuel cost overrecovery for the April 1997 through September 1997 period amounts to $14,618,648. This estimated/actual overrecovery for the April 1997 through September 1997 period plus the final overrecovery of $13,141,163 for the October 1996 through March 1997 period results in a total overrecovery of $27,759,811. This amount, divided by the projected retail sales of 37,770,170 MWH for October 1997 through March 1998 results in a decrease of 0.0735¢ per kWh before applicable revenue taxes. In his testimony for the Generating Performance Incentive Factor, FPL Witness R. Silva calculated a reward of $5,801,940 for the period ending September 1996, one half ($2,900,970) of which is being applied to the October 1997 through March 1998 period. This $2,900,970 divided by the projected retail sales of 37,770,170 MWH during the projected period, results in an increase of 0.0077¢ per kWh, as shown on line 33 of Schedule E1, Page 3 of Appendix II.

Q. Please explain the calculation of the FCR Estimated/Actual True-

up amount you are requesting this Commission to approve.

A. Schedule E1-B, Page 5 of Appendix II shows the calculation of the FCR Estimated/Actual True-up amount. The calculation of the estimated/actual true-up amount for the period April 1997 through September 1997 is an overrecovery, including interest, of $14,618,648 (Column 7, lines C7 plus C8). This amount, when combined with the Final True-up overrecovery of $13,141,163 (Column 7, line C9a) deferred from the period October 1996 through March 1997, presented in my Final True-up testimony filed on May 20, 1997, results in the End of Period overrecovery of $27,759,811 (Column 7, line C11).

This schedule also provides a summary of the Fuel and Net Power Transactions (lines A1 through A7), kWh Sales (lines B1 through B3), Jurisdictional Fuel Revenues (line C1 through C3), the True-up and Interest Provision (lines C4 through C10) for this period, and the End of Period True-up amount (line C11).

The data for April 1997 and May 1997, columns (1) and (2) reflects the actual results of operations and the data for June 1997 through September 1997, columns (3) through (6), are based on updated estimates.

The variance calculation of the Estimated/Actual data compared to the original projections for the April 1997 through September 1997 period is provided in Schedule E1-B-1, Page 6 of Appendix II.

As shown on line A5, the variance in Total Fuel Costs and Net Power Transactions is $26.4 million or a 3.1% decrease. This variance is mainly due to an approximate $12.0 million decrease in the Fuel Cost of System Net Generation as shown on line A1a and an approximate $12 million decrease in Energy Payments to Qualifying Facilities as shown on line A3b.

The decrease in the Fuel Cost of System Net Generation was primarily due to a reduction in natural gas and heavy oil prices due to milder than anticipated weather. The decrease in Energy Payments to Qualifying Facilities was primarily due to lower than expected deliveries from Indiantown Cogeneration Limited (ICL), Cedar Bay and Florida Crushed Stone contracts.

The true-up calculations follow the procedures established by this Commission as set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision" filed monthly with the Commission.

Q. Several issues were raised at the Prehearing Conference on February 5, 1997, and deferred by Order No. PSC-97-0180-PHO-EI, in connection with FERC's Order 888 requirement that investor

owned utilities include the cost of transmission when making Schedule C sales. How should these transmission costs be recovered?

A. FPL proposes to include the transmission costs of Schedule C in the calculation of the Fuel Cost Recovery Clause. These costs are to be included in the calculation of Economy Sales as reported monthly on Schedules A6 and A6a. This issue is addressed in greater detail in the testimony of FPL witness, Mario Villar.

CAPACITY PAYMENT RECOVERY CLAUSE

Q. Please describe Page 3 of Appendix III.

A. Page 3 of Appendix III provides a summary of the requested capacity payments for the projected period of October 1997 through September 1998. Total recoverable capacity payments amount to $480,405,069 (line 12), and include payments of $207,724,137 to non-cogenerators (line1), payments of $345,135,975 to cogenerators (line 2), $3,467,177 of Mission Settlement payments (line 3) and $4,700,000 relating to the St. John's River Power Park (SJRPP) Energy Suspension Accrual (line 4a) which is explained later in my testimony. This amount is offset by revenues from capacity sales of $4,946,711 (line 4), $290,998 of return requirements on Energy Suspension payments (line 4b) which is explained later in my testimony and $56,945,592 of jurisdictional capacity related payments included in base rates (line 8) plus a net overrecovery of $10,479,736 (line 9). The net overrecovery of $10,479,736 reflects actual costs for January 1997 through May 1997 and revised estimates for June 1997 through September 1997. Actual costs for the period October 1996 through December 1996 were included in the CCR midcourse correction filed on January 16, 1997 and approved by the Commission in Order No. PSC-97-0359-FOF-EI issued on March 31, 1997.

Q. Is FPL requesting recovery of any additional costs through the CCR?

A. Yes. FPL is requesting that it be authorized to collect, during the next seventeen (17) years, approximately $4.7 million per year associated with future capacity payments to be made to Jacksonville Electric Authority (JEA). FPL is requesting to collect this annual amount, because there is a mismatch between the period over which FPL currently anticipates it will continue to receive energy from JEA's ownership share of SJRPP, and the period over which FPL is contractually required to make annual capacity payments to JEA. Mr. Rene Silva's testimony describes the circumstances that underlie FPL's request.

Q. Please explain the SJRPP energy suspension issue.

A. An Internal Revenue Service (IRS) ruling, which established the tax exempt status of the municipal bonds used to finance JEA's ownership interests in SJRPP stipulates that FPL shall not receive more than twenty-five (25%) of the nameplate capacity of JEA's ownership share of the plant over the life of the bonds. According to FPL's contract with JEA, FPL agreed to purchase 37.5% of energy produced by JEA's share of the plant, based on a projected plant capacity factor of approximately 67%. This is equivalent to 25% of the plant's total capability. Since commercial operation in 1987, the plant has run at a higher capacity factor than projected and, therefore, FPL's customers have received more energy from SJRPP in the early years than originally anticipated. When FPL reaches the 25% limit, which has been calculated to be 80,534,332 mWh, based on the nameplate rating times the life of the bonds, FPL will be suspended from taking energy until the bonds are paid off. FPL is taking as much SJRPP energy as possible currently, and we project that the energy limit will be reached in 2015. Thereafter FPL will, consistent with the contract, continue making capacity payments through 2020, but would receive no energy from JEA's share of SJRPP ("SJRPP energy suspension").

Q. **How was the $4.7 million per year amount to be recovered through the CCR determined?**

A. Municipal bonds are used to finance JEA's ownership share of SJRPP. FPL makes capacity payments based on debt service amortization over the life of the bonds. When FPL reaches the 25% limit, which has been calculated to be 80,534,332 mWh, based on the nameplate rating times the life of the bonds, FPL will be suspended from taking energy until the bonds are paid off. Based on the average capacity factor for the last five years, FPL has projected that the 80,534,332 mWh limit will be reached in 2015. Based on FPL's debt service forecast, from 2015 through 2020, FPL is obligated to pay $80 million in capacity payments. An annual accrual of $4.7 million collected through the Capacity Cost Recovery Clause over the 17 year period, from 1998 through 2015, results in the recovery of the $80 million needed to make the capacity payments to JEA during the energy suspension period from 2015 through 2020. FPL proposes to update the debt service forecast as well as the five year average capacity factor each year in FPL's Capacity Cost Recovery filing, therefore, the accrual amount will change each year.

The $4.7 million annual payment for the SJRPP energy suspension payments will be recorded as a liability on FPL books when received from the customers. FPL proposes to pay the customers a return on the liability until all amounts are paid to JEA during the suspension period. The methodology used to calculate the return requirements to the customer is the same that is being used in determining the return on assets in the Fuel Cost Recovery Clause. For the 12 month period ending September

30, 1998, expenses recoverable through the CCR will be reduced by approximately $291,000, to reflect the return requirements on the suspension payments received during the same period (Appendix III, page 3, line 4b).

Q. What is the basis for requesting recovery of costs associated with this issue through the Capacity Cost Recovery Clause now?

A. FPL is requesting that $4.7 million annually associated with the SJRPP energy suspension be recovered through the CCR beginning in 1998 because there is a mismatch between the period over which FPL currently anticipates it will continue to receive energy from JEA's ownership share of SJRPP, and the period over which FPL is contractually required to make annual capacity payments to JEA. FPL is requesting to collect this annual amount from 1998 through 2014 so that in the years 2015 through 2020, when FPL will receive no energy from JEA's ownership share of SJRPP, FPL's customers would not pay capacity charges.

For these reasons, FPL believes that it is appropriate to bring this issue forward for Commission consideration and approval at this time.

Q. Please describe Page 4 of Appendix III.

A. Page 4 of Appendix III calculates the allocation factors for demand and energy at generation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate contributes to total kWh sales, as adjusted for losses, for each rate class.

Q. Please describe Page 5 of Appendix III.

A. Page 5 of Appendix III presents the calculation of the proposed Capacity Payment Recovery Clause (CCR) factors by rate class.

Q. Please explain the calculation of the CCR Estimated/Actual True-up amount you are requesting this Commission to approve.

A. The Estimated/Actual True-up for the period October 1996 through September 1997 is an overrecovery, including interest, of $10,479,736 (Appendix III, page 6, line 7). Appendix III, pages 6 and 7 show the calculation supporting the CCR Estimated/Actual True-up amount.

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.

The resulting overrecovery of $10,479,736 has been included in the calculation of the Capacity Cost Recovery factor for the period October 1997 through September 1998.

Q. Please explain the calculation of the Interest Provision.

A. Appendix III, pages 9 and 10, show the calculation of the interest provision and follows the same methodology used in calculating the interest provision for the other cost recovery clauses, as previously approved by this Commission.

The interest provision is the result of multiplying the monthly average true-up amount (line 4) times the monthly average interest rate (line 9). The average interest rate for the months reflecting actual data is developed using the 30 day commercial paper rate as published in the Wall Street Journal on the first business day of the current and subsequent months. The average interest rate for the projected months is the actual rate as of the first business day in June 1997.

Q. Have you provided a schedule showing the variances between the Estimated/Actuals and the Original Projections?

A. Yes. Appendix III, page 11, shows the Estimated/Actual capacity charges and applicable revenues compared to the original projections for the period.

Q. What is the variance related to capacity charges?

A. As shown in Appendix III, page 11, line 5, the variance related to capacity charges is a $2.0 million decrease. This variance is primarily due to a $2.8 million decrease in Cypress Settlement payments and a $0.6 million decrease in projected revenues from capacity sales. The decrease in Cypress Settlement payments was primarily due to differences in the timing of payments. The decrease in expected revenues from capacity sales is primarily due to the original projections being adjusted to reflect more current market trends.

Q. What is the variance in Capacity Cost Recovery revenues?

A. As shown on line 10, Capacity Cost Recovery revenues, net of revenue taxes, are now estimated to be $3.5 million higher than originally projected.

Q. What effective date is the Company requesting for the new factors?

A. The Company is requesting that the new FCR factors become effective with customer billings on cycle day 3 of October 1997 and continue through Customer billings on cycle day 2 of March 1998 and that the new CCR factors become effective with customer billings on cycle day 3 of October 1997 and continue through cycle day 2 of September 1998. This will provide for 6 months of billing on the FCR factors and 12 months of billing on the CCR factors for all our customers.

Q. What will be the charge for a Residential customer using 1,000 kWh effective October 1997?

A. The total residential bill, excluding taxes and franchise fees, for 1,000 kWh will be $74.34. The base bill for 1,000 residential kWh is $47.46, the fuel cost recovery charge from Schedule E1-E, Page 9 of Appendix II for a residential customer is $16.46, the Conservation charge is $2.62, the Capacity Cost Recovery charge is $6.74, the Environmental Cost Recovery charge is $.31 and the Gross Receipts Tax is $.75. A Residential Bill Comparison (1,000 kWh) is presented in Schedule E10, Page 40 of Appendix II.

Q. Does this conclude your testimony.

A. Yes, it does.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 970001-EI
CONTINUING SURVEILLANCE AND REVIEW OF
FUEL COST RECOVERY CLAUSES OF ELECTRIC UTILITIES

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

Q. Please state your name and business address.

A. George M. 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 October 1997 - March 1998 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 April 1997 - September 1997 and to establish a "true-up" amount to be collected or refunded during October 1997 - March 1998.

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-3.

These schedules support the calculation of the levelized fuel adjustment factor for October 1997 - March 1998. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period April 1997 - September 1997 based on 2 Months Actual and 4 Months Estimated data.

Q. In derivation of the projected cost factor for the October 1997 - March 1998 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. Please address the calculation of the total true-up amount to be collected or refunded during the October 1997 - March 1998.

A. We have determined that at the end of September 1997 based on two months actual and four months estimated, we will have under-recovered $10,203 in purchased power costs in our Marianna division. Based on estimated sales for the period October 1997 - March 1998, it will be necessary to add .007834¢ per KWH to collect this under-recovery.

In Fernandina Beach we will have under-recovered $65,586 in purchased power costs. This amount will be collected at .04134¢ per KWH during the October 1997 - March 1998 period. Page 3 and 12 of Composite Prehearing Identification Number GMB-3 provides a detail of the calculation of the true-up amounts.

Q. Looking back upon the October 1996 - March 1997 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 over-recovery of $359,886 and Fernandina Beach Division over-recovered $145,789. 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 October 1996 - March 1997 for both divisions?

A. In Marianna the final remaining true-up amount was an over-recovery of $132,028. The final remaining true-up amount for Fernandina Beach was an over-recovery of $46,124.

Q. What are the estimated true-up amounts for the period of April 1997 - September 1997?

A. In Marianna, there is an estimated under-recovery of $142,231. Fernandina Beach has an estimated under-recovery of $111,710.

Q. What will the total fuel adjustment factor, excluding demand cost recovery, be for both divisions for the period October 1997 - March 1998?

A. In Marianna the total fuel adjustment factor as shown on Line 33, Schedule E1, is 2.402¢ per KWH. In Fernandina Beach the total fuel adjustment factor for "other classes", as shown on Line 43, Schedule E1, amounts to 2.685¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period October 1997 - March 1998 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 $67.08, an increase of $2.38 from the previous period. In Fernandina Beach a customer will pay $65.20, a decrease of $.15 from the previous period.

Q. Does this conclude your testimony?

A. Yes.

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GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Michael F. Oaks
Docket No. 970001-EI
Date of Filing: May 20, 1997

Q. Please state your name and business address.

A. My name is Michael F. Oaks 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 Compliance and Fuel Supply Supervisor at Gulf Power Company.

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

A. I graduated from Belhaven College in Jackson, Mississippi, in 1977 with a Bachelor of Science Degree in Chemistry. I joined Gulf Power Company in 1977 as a Chemist. Since then, I have held various positions with the Company, including Water Chemistry Specialist, Water Quality Specialist, Environmental Affairs Specialist, Environmental Audit Administrator, and Compliance Administrator. I was promoted to my present position in May 1996.

Q. What are your duties as Fuel Supply Supervisor?

A. I supervise and administer the Company's fuel procurement, transportation, budgeting, contract administration, and quality control to ensure the generating plants are provided high quality fuel supply at the lowest practical cost.

Q. Mr. Oaks, have you previously testified before this Commission?
A. Yes. I have presented testimony to this Commission.

Q. Mr. Oaks, 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 October 1996 through March 1997. 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. Oak's exhibit consisting of one schedule be marked as Exhibit No. 26 (MFO-1).

Q. During the period October 1, 1996, through March 31, 1997, how did Gulf's actual fuel expenses compare with the budget or projected expenses?
A. Gulf's actual fuel expense was $94,997,793 as compared with the projected amount of $97,740,994, or under our estimate by 2.81%. Gulf's total net system generation was 4,672,294 MWH compared to the

projected generation of 5,069,150 MWH or 7.83% less than predicted. The resulting total fuel cost per KWH generated was 2.0332¢/KWH or 5.45% over the projected amount of 1.9282¢/KWH.

Q. How much spot coal did Gulf Power Company purchase during the period ending March 31, 1997?

A. Gulf purchased 791,205 tons or 39% of its supply from the spot coal market. My Schedule 1 of Exhibit No. 26 (MFO-1) consists of a list of contract and spot coal suppliers for the period ending March 31, 1997.

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

A. For the period, Gulf's total cost of coal purchased was 2.7% higher than projected.

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

A. Yes. Gulf's coal purchases were either from long term contracts or the competitive spot market. Coal vendors are selected by procedures designed to asssure a deliverable quantity of acceptable quality coal 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 ensure the most economical price of oil.

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

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 970001-EI

Before me the undersigned authority, personally appeared Michael F. Oaks, who being first duly sworn, deposes, and says that he is the Compliance and Fuel Supply Supervisor at Gulf Power Company, a Maine corporation, and that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

Michael F. Oaks
Compliance and Fuel Supply Supervisor

Sworn to and subscribed before me this 13th day of May 1997.

Rollanda R. Cothran
Notary Public, State of Florida at Large

Commission Number:

Commission Expires:

ROLLANDA R. COTHRAN
MY COMMISSION EXPIRES
FEBRUARY 26, 1998
#CC 346358
Bonded thru
Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Michael F. Oaks
Docket No. 970001-EI
Date of Filing: June 18, 1997

Q. Please state your name and business address.

A. My name is Michael F. Oaks and my business address is 500 Bayfront Parkway, 500 Bayfront Parkway, Pensacola, Florida 32520-0328.

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

A. I am the Compliance and Fuel Supply Supervisor at Gulf Power Company.

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

A. I graduated from Belhaven College in Jackson, Mississippi, in 1977 with a Bachelor of Science Degree in Chemistry. I joined Gulf Power Company in 1977 as a Chemist. Since then, I have held various positions with the Company, including Water Chemistry Specialist, Water Quality Specialist, Environmental Affairs Specialist, Environmental Audit Administrator, and Compliance Administrator. I was promoted to my present position in May 1996.

Q. What are your duties as Fuel Supply Supervisor?

A. I supervise and administer the Company's fuel procurement, transportation, budgeting, contract administration, and quality control to ensure the generating plants are provided an adequate low cost fuel supply with minimal operational problems.

Q. Are you the same Michael F. Oaks who has previously submitted testimony in this proceeding?

A. Yes.

Q. Mr. Oaks, 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 October 1, 1997, tc March 31, 1998 and to be available to answer any questions that may occur concerning the Company's fuel procurement procedures.

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. Oaks' exhibit, consisting of one schedule, be marked as Exhibit No. 27 (MFO-2).

Q. Has Gulf Power Company made any changes to its methods in this period for projecting fuel cost?

A. No.

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

A. Yes. Gulf Power Company's long term contract with Peabody COALSALES is subject to a market review opener. Effective February 1, 1998, the contract price will either go to a market adjusted delivered price, or if COALSALES does not agree to the matching price, the contract will be terminated. If the contract is renewed, our annual obligation will resume at 1.9 million tons per year. If the contract is terminated, Gulf will be seeking a similar quantity of coal from other sources.

Q. How much spot market coal does Gulf Power project it will purchase during the October 1997 through March 1998 period?

A. We are projecting the purchase of approximately 408,095 tons on the spot market. This represents approximately 17% of our projected purchase requirements.

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

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 970001-EI

Before me the undersigned authority, personally appeared Michael F. Oaks, who being first duly sworn, deposes, and says that he is the Compliance and Fuel Supply Supervisor at Gulf Power Company, a Maine corporation, and that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

Michael F. Oaks
Compliance and Fuel Supply Supervisor

Sworn to and subscribed before me this 18th day of June 1997.

Rollanda R. Cothran
Notary Public, State of Florida at Large

Commission Number:

Commission Expires:

ROLLANDA R. COTHRAN
MY COMMISSION EXPIRES
FEBRUARY 26, 1998
#CC 346358
Bonded thru Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 970001-EI
Date of Filing: May 20, 1997

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 32520. I am Transmission and System Control Manager 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 Transmission and System Control Manager. 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; bulk power interchange administration; overall management of fuel planning and procurement; and operation of the system dispatch center.

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

Q. What is the purpose of your testimony in this proceeding?
A. I will summarize Gulf Power Company's purchased power recoverable costs for energy purchases and sales that were incurred during the October 1, 1996 through March 31, 1997 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 October 1, 1995 through September 30, 1996 recovery period, compare these figures to their projected levels, and discuss the reasons for the differences.

Q. During the period October 1, 1996 through March 31, 1997, what was Gulf's actual purchased power recoverable cost for energy purchases and how did it compare with the projected amount?
A. Gulf's actual total purchased power recoverable cost for energy purchases, as shown on line 12 of Schedule A-1,

was $8,942,360 for 578,612,017 KWH as compared to the projected amount of $5,499,969 for 314,210,000 KWH. The actual cost per KWH purchased was 1.5455 ¢/KWH as compared to the projected 1.7504 ¢/KWH, or 12% below the projection. This significantly lower price is why the amount of energy purchased was 84% over the projection amount.

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

A. During the recovery period, the availability of lower cost pool energy due to higher than budgeted nuclear and hydro generation on the Southern electric system allowed Gulf to purchase more energy at a significantly lower unit price than was forecasted in order to meet its load obligations.

Q. During the period October 1, 1996 through March 31, 1997, 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 18 of Schedule A-1, was $16,219,536 for 1,027,729,884 KWH as compared to the projected amount of $21,122,000 for 1,081,922,000 KWH.

This resulted in a variance below budget of $4,902,464, or 23%. The actual fuel cost per KWH sold was 1.5782 ¢/KWH as compared to 1.9523 ¢/KWH, or 19% below the projection.

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

A. The same higher availability of more lower cost pool energy that increased our purchases also supplanted some sales that Gulf was expected to make in the forecast. Therefore, Gulf sold less energy, and at a lower unit price.

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. Overall, Gulf's

Total Fuel and Net Power Transactions for the recovery period, as shown on line 20 of Schedule A-1, were only 7% over budget.

Q. During the period October 1, 1995 through September 30, 1996, how did Gulf's actual net purchased power capacity transactions compare with the net projected transactions?

A. The net projected purchased power capacity transactions for the October 1, 1995 through September 30, 1996 recovery period were established as a result of the hearings in Docket No. 950001-EI held in August 1995. I testified that the projected net purchased power capacity cost for the October 1, 1995 through September 30, 1996 recovery period was $10,499,074. The actual net capacity cost was $10,741,967. This represents an increase in cost of $242,893, or 2% more than projected.

Q. Please explain the reasons for this capacity cost difference.

A. This relatively small difference is basically due to a slight increase in Gulf's load responsibility component of the IIC capacity equalization calculation. This increase resulted in Gulf being responsible for sharing a slightly higher percentage of system reserves.

The capacity cost forecast for October 1, 1995 through September 30, 1996 called for IIC transactions only, but we actually purchased 19 Megawatts of capacity from the Monsanto Company beginning in June, 1996. This capacity, however, simply caused a reduction in IIC capacity purchases, so the purchase was not a factor in the slight overall capacity cost increase.

As I testified in Docket No. 960001-EI, the Monsanto capacity purchase, which amounts to $62,202 per month for 19 megawatts of capacity, was previously authorized for cost recovery by the Commission in Docket No. 921167-EU. This purchase was not included in my capacity cost projection for the October 1, 1995 through September 30, 1996 recovery period because the contract did not require a final commitment from Monsanto for the supply of this capacity until well past the August, 1995 hearing which established Gulf's capacity cost forecast. Of course, Monsanto did not begin receiving capacity payments until after it made a firm commitment to deliver capacity onto Gulf's system.

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

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 970001-EI

Before me the undersigned authority, personally appeared M. W. Howell, who being first duly sworn, deposes, and says that he is the Transmission and System Control Manager of Gulf Power Company, a Maine corporation, that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

M. W. Howell

M. W. Howell
Transmission and System Control Manager

Sworn to and subscribed before me this 16th day of May, 1997.

Linda C. Webb

Notary Public, State of Florida at Large

Commission No. CC 362703

My Commission Expires May 31, 1998

LINDA C. WEBB
Notary Public-State of FL
Comm. Exp: May 31,1998
Comm. No: CC 362703

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Susan D. Cranmer
Docket No. 970001-EI
Fuel and Purchased Power Capacity Cost Recovery
Date of Filing: May 20, 1997

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 Assistant Secretary and Assistant Treasurer of Gulf Power Company. In this position, I am responsible for supervising the Rates and Regulatory Matters Department.

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. Prior to assuming my current position, I have held various positions with Gulf including Computer Modeling Analyst, Senior Financial Analyst, and Supervisor of Rate Services.

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

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. 29 (SDC-1).

Q. Are you familiar with the Fuel and Purchased Power (Energy) True-up Calculation for the period of October 1996 through March 1997 and the Purchased Power Capacity Cost True-up Calculation for the period of October 1995 through September 1996 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 October 1997 through March 1998?
A. An amount to be collected of $3,165,271 was calculated as shown in Schedule 1 of my exhibit.

Q. How was this amount calculated?
A. The $3,165,271 was calculated by taking the difference in the estimated October 1996 through March 1997 under-recovery of $2,698,394 as approved in Order No. PSC-97-0359-FOF-EI, dated March 31, 1997 and the actual under-recovery of $5,863,665 which is the sum of lines 7 and 8 shown on Schedule A-2, page 2 of 3, Period-to-date of the monthly filing for March 1997.

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 October 1995 through September 1996.

Q. What is the amount to be refunded or collected in the period October 1997 through September 1998?

A. An amount to be collected of $201,368 was calculated as shown in Schedule CCA-1 of my exhibit.

Q. How was this amount calculated?

A. The $201,368 was calculated by taking the difference in the estimated October 1995 through September 1996 over-recovery of $374,156 as approved in Order No. PSC-96-1172-FOF-EI, dated September 19, 1996 and the actual over-recovery of $172,788 which is the sum of lines 11 and 12 under the total column of 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 October 1995 through September 1996. 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.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 970001-EI

Before me the undersigned authority, personally appeared Susan D Cranmer, who being first duly sworn, deposes, and says that she is the Assistant Secretary and Assistant Treasurer of Gulf Power Company, a Maine corporation, that the foregoing is true and correct to the best of her knowledge, information, and belief. She is personally known to me.

Susan D. Cranmer

Susan D. Cranmer
Assistant Secretary and Assistant Treasurer

Sworn to and subscribed before me this 16th day of May, 1997.

Linda C. Webb

Notary Public, State of Florida at Large

LINDA C. WEBB
Notary Public-State of FL
Comm. Exp: May 31,1998
Comm. No: CC 382703

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Susan D. Cranmer
Docket No. 970001-EI
Fuel and Purchased Power Cost Recovery
Date of Filing: June 23, 1997

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

A. My name is Susan Cranmer. My business address is 500 Bayfront Parkway, Pensacola, Florida 32520-0780. I hold the position of Assistant Secretary and Assistant Treasurer 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. Prior to assuming my current position, I have held various positions with Gulf including Computer Modeling Analyst, Senior Financial Analyst, and Supervisor of Rate Services.

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

Q. Have you previously filed testimony before this Commission in Docket No. 970001-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 October 1997 through March 1998. I will also discuss the calculation of the purchased power capacity cost recovery factors for the period October 1997 through September 1998.

Q. Are you familiar with the Fuel and Purchased Power Cost Recovery Clause Calculation for the period of October 1997 through March 1998?
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, be marked as Exhibit No. 30 (SDC-2).

Q. Ms. Cranmer, what has Gulf calculated as the true-up to be applied in the period October 1997 through March 1998?
A. The true-up for this period is an increase of .0994¢/kwh. This includes a final true-up under-recovery for the October 1996 through March 1997 period of $3,165,271. As shown on Schedule E-1A, it also includes an estimated true-up under-recovery of $857,475 for the current period. The resulting under-recovery is $4,022,746.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of October 1996 through March 1997?
A. This is shown on Line 32b of Schedule E-1 as an increase of .0003¢/kwh, thereby rewarding Gulf by $11,349.

Q. Ms. Cranmer, what is the levelized projected fuel factor for the period October 1997 through March 1998?

A. Gulf has proposed a levelized fuel factor of 2.131¢/kwh. It includes projected fuel and purchased power energy expenses for October 1997 through March 1998 and projected kwh sales for the same period, as well as the true-up and GPIF amount. 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 2.157¢/kwh 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 October 1997 through March 1998. 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 September and how will the change affect the cost of 1000 kwh on Gulf's residential rate RS?

A. The current fuel factor for Rate Schedule RS applicable to September 1997 is 2.180¢/kwh compared with the proposed factor of 2.157¢/kwh. For a residential customer who uses 1000 kwh in October 1997, the fuel portion of the bill will decrease from $21.80 to $21.57.

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 estimated averages for the period from October 1997 through September 1999.

Q. Ms. Cranmer, you stated earlier that you are responsible for the calculation of the purchased power capacity cost (PPCC) 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 PPCC recovery factors for the period October 1997 through September 1998.

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 PPCC 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 contract with Monsanto Chemical Company, and certain short-term market capacity transactions. Gulf's total projected capacity payments for the period

October 1997 through September 1998 are purchases of $1,841,669. The jurisdictional amount is $1,773,874. 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 $1,678,580, or $1,652,000 net of revenue taxes. Thus, the projected recovery amount to be collected through the PPCC recovery factors in the period October 1997 through September 1998 is $3,425,874. 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 October 1996 through September 1997?

A. The true-up for this period is an increase of $523,967 as shown on Schedule CCE-1a. This includes $0 final capacity cost true-up amount for October 1995 through September 1996 because the actual over-recovery for that period was incorporated into the mid-course correction filed November 21, 1996. It includes an estimated over-recovery of $2,791,701 for the period October 1996 through September 1997, less $3,315,668 estimated over-recovery related to the same period but already reflected in the factors approved in the mid-course correction which was effective January 1, 1997.

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 PPCC 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 PPCC Recovery Clause?

A. The allocation factors used in the Purchased Power Capacity Cost Recovery Clause have been calculated using the 1995 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, the 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 twelve-month period to calculate the PPCC 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 would be $.54.

Q. When does Gulf propose to collect these new fuel charges and purchased power capacity charges?
A. The fuel factors will apply to October 1997 through March 1998 billings beginning with Cycle 1 meter readings scheduled on October 1, 1997 and ending with meter readings scheduled on March 31, 1998. The capacity factors will apply to October 1997 through September 1998 billings beginning with Cycle 1 meter readings scheduled on October 1, 1997 and ending with meter readings scheduled on September 29, 1998.

Q. Ms. Cranmer, does this complete your testimony?
A. Yes, it does.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No 970001-EI

Before me the undersigned authority, personally appeared Susan D Cranmer, who being first duly sworn, deposes, and says that she is the Assistant Secretary and Assistant Treasurer of Gulf Power Company, a Maine corporation, that the foregoing is true and correct to the best of her knowledge, information, and belief She is personally known to me.

Susan D Cranmer

Susan D. Cranmer
Assistant Secretary and Assistant Treasurer

Sworn to and subscribed before me this 20th day of June, 1997.

Linda C. Webb

Notary Public, State of Florida at Large

NOTARY PUBLIC STATE OF FLORIDA

LINDA C. WEBB
Notary Public-State of FL
Comm. Exp: May 31,1998
Comm. No: CC 382703

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony of
G. D. Fontaine
Docket No. 970001-EI
Date of Filing May 20, 1997

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 October 1, 1996, through March 31, 1997.

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 31 (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-96-1172-FOF-EI is on page 9 of Schedule 2. The results are: Crist 6, -10.00 points; Crist 7, +3.75 points; Smith 1, +7.78 points; Smith 2, +10.00 points; Daniel 1, +10.00 points, and Daniel 2, +7.37 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 June 1996, 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: +3.54 for Crist 6, +5.00 for Crist 7, +5.71 for Smith 1, +9.58 for Smith 2, -8.90 for Daniel 1, and -10.00 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 adjusted weighting factors, the Company points would be +0.13 as indicated on page 2 of Schedule 4. This calculates to a reward in the amount of $11,349.

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 $11,349 as provided for by the GPIF plan.

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

A. Yes, Sir.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 970001-EI

Before me the undersigned authority, personally appeared George D. Fontaine, who being first duly sworn, deposes, and says that he is the Performance Test Specialist of Gulf Power Company, a Maine Corporation, and that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

George D. Fontaine
Performance Test Specialist

Sworn to and subscribed before me this 15th day of May, 1997.

Rollanda R. Cothran
Notary Public, State of Florida at Large

ROLLANDA R. COTHRAN
MY COMMISSION EXPIRES FEBRUARY 26, 1998
#CC 346358
Bonded thru Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony of
G. D. Fontaine
Docket No. 970001-EI
Date of Filing June 23, 1997

Q. Please state your name, address and occupation.

A. My name is George D. Fontaine, my business address is 500 Bayfront Parkway, 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. Have you previously testified in this Docket?

A. Yes. I have presented testimony regarding the Generating Performance Incentive Factor (GPIF) periodically for the past several years.

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

A. The purpose of my testimony today is to present GPIF targets for Gulf Power Company for the period of October 1, 1997 through March 31, 1998.

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 three schedules.

Q. 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 32 (GDF-2).

Q. Which units does Gulf propose to include under the GPIF for the subject period?

A. We propose that Crist Units 6 and 7, Smith Units 1 and 2, and Daniel Units 1 and 2 continue to be the Company's GPIF units.

Q. What are the target heat rates Gulf proposes to use in the GPIF for these units for the performance period October 1, 1997 through March 31, 1998?

A. I would like to refer you to Page 32 of Schedule 1 of my exhibit where these targets are listed.

Q. How were these proposed target heat rates determined?

A. In every case they were determined according to the GPIF implementation manual procedures for Gulf. Page 2 of Schedule 1 shows the target average net operating heat rate equations for the proposed GPIF units, and pages 4 through 29 of Schedule 1 contain the weekly historical data used for the statistical development of these equations. Pages 30 and 31 of Schedule 1 present the calculations which provide the unit target heat rates from the target equations.

Q. Were the maximum and minimum attainable heat rates for each proposed GPIF unit, indicated on page 32 of Schedule 1, calculated according to the appropriate GPIF implementation manual procedures?

A. Yes.

Q. What are the proposed target, maximum and minimum, equivalent availabilities for Gulf's units?
A. The target equivalent availabilities and their ranges are listed on page 4 of Schedule 2.

Q. How are these target equivalent availabilities determined?
A. The target equivalent availabilities were determined according to the standard GPIF implementation manual procedures for Gulf, and are presented on page 2 of Schedule 2.

Q. How were the maximum and minimum attainable equivalent availabilities determined for each unit?
A. The maximum and minimum attainable equivalent availabilities, which are presented along with their respective target availabilities on page 4 of Schedule 2, were determined per GPIF manual procedures for Gulf.

Q. Mr. Fontaine, has Gulf completed the GPIF minimum filing requirements data package?
A. Yes, we have completed the required data. Schedule 3 of my exhibit contains this information.

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

A. Yes. Gulf asks that the Commission accept:

1. Crist Units 6 and 7, Smith Units 1 and 2 and Daniel Units 1 and 2, for inclusion under the GPIF for the period of October 1, 1997 through March 31, 1998.

2. The target, maximum attainable, and minimum attainable average net operating heat rates, as proposed by the Company and as shown on page 32 of Schedule 1 and also page 5 of Schedule 3 of my exhibit.

3. The target, maximum attainable, and minimum attainable equivalent availabilities, as proposed by the Company and as shown on Page 4 of Schedule 2 and also page 5 of Schedule 3 of my exhibit.

4. The weekly average net operating heat rate least squares regression equations, shown on page 2 of Schedule 1 and also pages 18 through 23 of Schedule 3 of my exhibit, for use in adjusting the six-month actual unit heat rates to target conditions.

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

A. Yes, Sir.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 970001-EI

Before me the undersigned authority, personally appeared George D. Fontaine, who being first duly sworn, deposes, and says that he is the Performance Test Specialist of Gulf Power Company, a Maine Corporation, and that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

George D. Fontaine
Performance Test Specialist

Sworn to and subscribed before me this 16th day of June, 1997.

Rollanda R. Cothran
Notary Public, State of Florida at Large

ROLLANDA R. COTHRAN
MY COMMISSION EXPIRES FEBRUARY 26, 1998
#CC 346356
Bonded thru Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

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 the actual performance results from unit equivalent availability and station heat rate used to determine the Generating Performance Incentive Factor (GPIF) for the period October 1996 through March 1997. 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, October 1996 - March 1997, 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 + 0.512 GPIF points, the result is a reward amount of $96,660 for the period.

Q. Please proceed with your review of the actual results for the October 1996 - March 1997 period.

A. On page 3 of my exhibit, the actual average common equity for the period is shown on line 8 as $1,118,087,092. This produces the maximum penalty or reward figure of $2,258,102 as shown on line 15, page 3, and also 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:

<u>Gannon Unit No. 5</u>

On this unit, 336 planned outage hours were originally scheduled to fall within the Winter 1996 period. Due to a revision of the outage schedule 604.9 planned outage hours were accomplished within the Winter 1996 period. Consequently, the actual equivalent availability of 63.8% is adjusted to 68.3%, as shown on page 7 of my exhibit.

<u>Gannon Unit No. 6</u>

On this unit, 336 planned outage hours were originally scheduled to fall within the Winter 1996 period. Actual planned outage activities required 413.2 hours. Consequently, the actual equivalent availability of 79.1%

is adjusted to 80.6%, as shown on page 8 of my exhibit.

Big Bend Unit No. 1

On this unit 600 planned outage hours were originally scheduled to fall within the Winter 1996 period. Due to a revision of the outage schedule 404.8 planned outage hours were required. Consequently, the actual equivalent availability of 75.0% is adjusted to 71.3% as shown on page 9 of my exhibit.

Big Bend Unit No. 2

On this unit 505 planned outage hours were originally scheduled to fall within the Winter 1996 period. Actual planned outage activities required 460.3 hours. Consequently, the actual equivalent availability of 79.5% is adjusted to 79.6% as shown on page 10 of my exhibit.

Big Bend Unit No. 3

On this unit 744 planned outage hours were originally scheduled to fall within the Winter 1996 period. Due to a revision of the outage schedule, the outage was moved to begin after the end of the period, and no planned outage hours fell within the period. Consequently, the actual equivalent availability of 83.5% is adjusted to 69.2% as shown on page 11 of my exhibit.

Big Bend Unit No. 4

This unit was not scheduled to have a planned outage during the Winter 1996 period. Due to a revision of the outage schedule, a planned outage was moved forward and was accomplished within the period. Consequently, the actual equivalent availability of 82.7% was adjusted to 93.7% 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. Were any additional adjustments to heat rate required?

A. In order to assure compatability of data, Big Bend Unit 3 heat rates have been calculated in the standard fashion, without scrubber power. This methodology has been reviewed and approved by the PSC staff, to be employed until there is sufficient operational history with the scrubber to meet target preparation guidelines.

Q. Does this assure that the Big Bend 3 heat rate for the period is appropriate for comparison to its target and meets GPIF criteria?

A. Yes.

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 weighting 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, +0.512, is then entered into the GPIF table on page 2. Using linear interpolation, a reward amount of $96,660 is calculated.

Q. Does this conclude your testimony?

A. Yes, it does.

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 - Energy Supply 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" October 1997 - March 1998, consisting of 34 pages filed with the Commission on June 23, 1997. (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 Big Bend Unit One is 13.0%. The Planned Outage Factor for this same unit during this period is 7.7%. Therefore, the target equivalent availability for this unit equals:

$$100\% - [(13.0\% + 7.7\%)] = 79.3\%$$

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 Big Bend Unit One:

$$EAF_{MAX} = 100\% - [0.8\ (13.0\%) + 0.95\ (7.7\%)] = 82.3\%$$

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:

Equivalent Availability Minimum

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

Again, continuing with our example of Big Bend Unit One,

$EAF_{MIN} = 100\% - [1.4\ (13.0\%) + 1.1\ (7.7\%)] = 73.3\%$

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 major planned outage which affects GPIF is included in my exhibit. For example, Big Bend Unit 3 is scheduled for an annual maintenance outage November 1 to November 21, 1997. There are 504 planned outage hours scheduled for the winter 1997 period, and a total of 4369 hours during this 6 month period. Consequently, the Planned Outage Factor for Unit 3 at Big Bend is 504/4369 x 100% or 11.5%. This factor is shown on pages 5 and 17 of my exhibit. Big Bend Unit 1 has a planned outage factor of 7.7% as does Big Bend Unit 2. Big Bend Units 3 and 4 have planned outage factors of 11.5%, as does Gannon Unit 5. Gannon Unit 6 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, March 1997, 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 13.0% for Big Bend Unit One. The Equivalent Unplanned Outage Factor (EUOF) for Big Bend Unit One is verified by the data shown on page 15, 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

$$EUOF = \frac{(400 + 168)}{4369} \times 100 = 13.0\%$$

Relative to Big Bend Unit One, the EUOF of 13.0% 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 13.0% during this period. This unit will have a planned outage this period and the Planned Outage Factor is 7.7%. This results in a target equivalent availability of 79.3% for the period.

Big Bend Unit Two

The projected EUOF for this unit is 12.6%. This unit will have a planned outage during this period and the Planned Outage Factor is 7.7%. Therefore, the target equivalent availability for this unit is 79.7%.

Big Bend Unit Three

The projected EUOF for this unit is 14.4%. This unit will have a planned outage this period and the Planned Outage Factor is 11.5%. Therefore, the target equivalent availability for this unit is 74.1%.

Big Bend Unit Four

The projected EUOF for this unit is 7.4%. This unit will have a planned outage during this period and the Planned Outage Factor is 11.5%. This results in a target equivalent availability of 81.1% for the period.

Gannon Unit Five

The projected EUOF for this unit is 11.1%. This unit will have a planned outage during this period and the Planned Outage Factor is 11.5%. Therefore, the target equivalent availability for this unit is 77.3%.

Gannon Unit Six

The projected EUOF for this unit is 10.5%. This unit will have a planned outage during this period and the Planned Outage Factor is 1.1%. Therefore, the target equivalent availability for this unit is 88.4%.

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 78.2%. This target compares very favorably to previous GPIF periods when compared on a common planned outage factor basis. 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 months of October through February, EUOF and EUOR are equal. This is due to the fact that no planned outages are scheduled during these months. During the month of March, 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. 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. 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. The accomplishment of scrubbing the flue gas from Big Bend Unit 3 requires an additional amount of station service power. How do you plan to address the associated effect to net heat rate for GPIF purposes?

A. The change in heat rate for this unit resulting from increased utilization of the Unit 4 scrubber can be quantified, but the operational history is short of GPIF guidelines. The target for Big Bend 3 has, therefore, been developed in the standard fashion using data without scrubber power. In order to assure compatability with this target, scrubber power will be removed prior to calculating Unit 3 heat rate for the subsequent True-Up process. This method has been reviewed and approved by the PSC Staff to be employed until there is sufficient history to meet target preparation guidelines. Successful implementation of this innovation to maximize the potential of existing plant equipment, represents a major cost savings and a significant benefit for our customers.

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 unit. This information is shown on pages 26 through 31 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 unit. 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 winter 1997 period?

A. Yes. The heat rate target for Big Bend Unit 1 is 10,084 Btu/Net kwh. The range about this value, to allow for potential improvement or degradation, is ±237 Btu/Net kwh. The heat rate target for Big Bend Unit 2 is 9,961 Btu/Net kwh with a range of ±345 Btu/Net kwh. The heat rate target for Big Bend Unit 3 is 9,680 Btu/Net kwh, with a range of ±362 Btu/Net kwh. The heat rate target for Big Bend Unit 4 is 10,025 Btu/Net kwh with a range of ±315 Btu/Net kwh. The heat rate target for Gannon Unit 5 is 10,378 Btu/Net kwh with a range of ±392 Btu/Net kwh. The heat rate target for Gannon Unit 6 is 10,692 Btu/Net kwh with a range of ±393 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 weighting 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 $114,813,500 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: $4,133,500 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 Two, the weighting factor for equivalent availability is 5.22% 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 Two, page 10, if the unit operates at 82.6% equivalent availability, fuel savings would equal $215,700 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, $4,133,500. 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 October 1997 - March 1998 is shown to be $1,157,214,571. This produces the maximum allowed jurisdictional incentive dollars of $2,351,688 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 the maximum allowed incentive dollars have been reduced to meet this constraint.

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):

$$GPIP = (0.0146\ EAP_{GN5} + 0.0101\ EAP_{GN6} + 0.0416\ EAP_{BB1} + 0.0522\ EAP_{BB2} + 0.0798\ EAP_{BB3} + 0.0398\ EAP_{BB4} + 0.0740\ HRP_{GN5} + 0.1185\ HRP_{GN6} + 0.1067\ HRP_{BB1} + 0.1614\ HRP_{BB2} + 0.1522\ HRP_{BB3} + 0.1491\ HRP_{BB4})$$

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 October 1997 - March 1998 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, October 1, 1997 - March 31, 1998".

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 23 pages. This data is Tampa Electric Company's estimate of the Unit Performance Data and Unit Outage Data for the October 1997 - March 1998 period.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CHARLES R. BLACK

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

A. My name is Charles R. Black. My mailing address is P.O. Box 111, Tampa, Florida 33601, and my business address is 702 North Franklin Street, Tampa, Florida 33602. I am Vice President-Energy Supply of Tampa Electric Company.

Q. Mr. Black, please furnish a brief outline of your educational background and business experience.

A. I graduated from the University of South Florida in August, 1973 with a Bachelor of Science degree in Engineering, majoring in Chemical Engineering. I am a registered Professional Engineer licensed in the State of Florida. I began my career with Tampa Electric Company in September 1973 as a staff engineer in the Production Department. Between 1973 and 1989, I held various engineering and management positions in the Production Department, Power Plant Engineering Department, and the Budget Department. In March of 1989, I joined our affiliated company, TECO

Power Services as Director of Engineering and Construction. In December of 1990, I was elected Vice President of Engineering and Construction. In December of 1991, I returned to Tampa Electric as Vice President of Project Management. In November of 1996, 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. Please state the purpose of your testimony.

A. The purpose of my testimony is to report to the Commission the actual 1996 costs of Tampa Electric's affiliated coal and coal transportation transactions compared to the benchmark prices calculated in accordance with Order No. 20298 (coal transportation) and Order No. PSC-93-0443-FOF-

EI ("Order No. 93-0443") (coal). I conclude that the 1996 prices paid by Tampa Electric to its affiliates TECO Transport and Trade and Gatliff Coal are reasonable and prudent.

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

A. Yes. Exhibit No. (CRB-1) titled "Exhibit of Charles R. Black", consisting of 2 documents, was prepared under my direction and supervision.

AFFILIATED COAL AND COAL TRANSPORTATION PRICES

Q. Were Tampa Electric's actual affiliated coal transportation prices for 1996 at or below the transportation benchmark?

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

Q. Were Tampa Electric's actual 1996 affiliated coal prices at or below the benchmark as established in Order No. 93-0443?

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

Q. Please summarize your testimony.

A. My testimony justifies the prices paid for coal and coal transportation by Tampa Electric Company in 1996 to its affiliated suppliers, Gatliff Coal and TECO Transport and Trade. I demonstrate that the average prices for the year 1996 for all coal and coal waterborne transportation services were at or below the appropriate benchmark calculations as directed by Order No. 20298 and Order No. 93-0443 of this Commission. Therefore, Tampa Electric should recover its payments for coal and coal transportation made during 1996.

Q. Does this conclude your testimony?

A. Yes, it does.

MS. PAUGH: One final matter. The briefing date has been set for September 19th, 1997, for briefs on Issues 9 through 12.

MR. WILLIS: Chairman Johnson, we had requested at the prehearing conference, and I renew that request today, that an opportunity be also provided to file a reply brief, which could be done a week after the filing of the initial brief.

And I think that that's important because it will help both the Commission and the Staff to frame the issue so that we make sure that we meet each other with our various arguments, and that something is not placed in the brief that cannot be responded to.

So I think that that would be a better procedure for us to follow in this proceeding. And it will help you clarify and sharpen the issues that you will be deciding, and it will be helpful to all of us.

CHAIRMAN JOHNSON: Okay. I don't remember that at the prehearing, but Staff, any comments?

MS. PAUGH: We don't object to reply briefs being filed.

CHAIRMAN JOHNSON: I think it would be helpful so we can -- what about the schedule? You're suggesting a week after --

MR. WILLIS: It could be done the next

Friday, the 26th.

MR. STONE: May I ask for leave to make that ten days filing because of the mailing so that -- if they are filed on Friday, we won't get ours until Monday. And that's our concern about that. So if we could make it ten days that would be the Monday -- ten days after the 19th. I guess the 29th.

MR. WILLIS: We could handle it that way or we could also agree to file the briefs by Federal Express overnight.

CHAIRMAN JOHNSON: Staff, what is your preference?

MS. PAUGH: Staff has no preference. It's up to the parties.

CHAIRMAN JOHNSON: Does anyone object to the ten days?

MR. WILLIS: We do not object to it. I just --

COMMISSIONER JOHNSON: We'll go with the ten days.

MR. WILLIS: Okay.

CHAIRMAN JOHNSON: Any other matters?

MS. PAUGH: None from Staff.

CHAIRMAN JOHNSON: Very well. This hearing is adjourned. Thank you very much.

(Thereupon, the hearing was recessed at 3:50 p.m., and reconvened at 4:05 p.m. Present were Chairman Johnson, Commissioner Clark, Commissioner Garcia, Leslie Paugh and Roberta Bass, and the following proceedings were had:)

CHAIRMAN JOHNSON: We're going to go back on the record.

There were several issues that were stipulated in the 01 docket.

MS. PAUGH: That is correct, Madam Chairman.

CHAIRMAN JOHNSON: Issue 1 through 8 and 14 through 23.

COMMISSIONER CLARK: I move we accept the stipulation.

CHAIRMAN JOHNSON: Is there a second?

COMMISSIONER GARCIA: I second.

CHAIRMAN JOHNSON: Show them then approved without objection. Are there any other matters to come before us?

MS. PAUGH: No, Madam Chairman.

CHAIRMAN JOHNSON: Okay. Then this hearing is adjourned. Thank you.

(Thereupon, the hearing concluded at 4:07 p.m.)

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STATE OF FLORIDA)
: CERTIFICATE OF REPORTERS
COUNTY OF LEON)

We, JOY KELLY, CSR, RPR, Chief, Bureau of Reporting, and RUTHE POTAMI, CSR, RPR, Official Reporters,

DO HEREBY CERTIFY that the Hearing in Docket No. 970001-EI was heard by the Florida Public Service Commission at the time and place herein stated; it is further

CERTIFIED that we stenographically reported the said proceedings; that the same has been transcribed under our direct supervision; and that this transcript, consisting of 465 pages, Volumes 1 through 3, constitutes a true transcription of our notes of said proceedings and the insertion of the prescribed prefiled testimony of the witness.

DATED this 20th day of August, 1997.

JOY KELLY, CSR, RPR
Chief, Bureau of Reporting
(904) 413-6732

H. RUTHE POTAMI, CSR, RPR
Official Commission Reporter
(904) 413-6732