BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

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

VOLUME - 1

Pages 1 through 179

PROCEEDINGS: **HEARING**

BEFORE: COMMISSIONER J. TERRY DEASON
COMMISSIONER JOE GARCIA
COMMISSIONER DIANE K. KIESLING

DATE: **Wednesday, August 9, 1995**

TIME: Commenced at 9:45 a.m.
Concluded at 10:50 a.m.

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

REPORTED BY: ROWENA NASH HACKNEY
Official Commission Reporter

APPEARANCES:

JAMES A. McGEE, Florida Power Corporation, 3201 34th Street South, Post Office Box 14042, St. Petersburg, Florida 33733-4042, Telephone No. (813) 866-5786, appearing on behalf of **Florida Power Corporation.**

MATTHEW M. CHILDS, Steel, Hector and Davis, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301, Telephone No. (904) 222-2300, appearing on behalf of **Florida Power & Light Company.**

NORMAN H. HORTON, JR., Messer, Vickers, Caparello, Madsen, Goldman & Metz, P. O. Box 1876, Tallahassee, Florida 32302-1876, Telephone No. (904) 222-0720, appearing on behalf of **Florida Public Utilities Company.**

JEFFREY A. STONE and **RUSSELL A. BADDERS**, Beggs & Lane, P. O. Box 12950, Pensacola, Florida 32576-2950, Telephone No. (904) 432-2451, appearing on behalf of **Gulf Power Company.**

JAMES D. BEASLEY, Macfarlane, Ausley, Ferguson and McMullen, P.O. Box 391, Tallahassee, Florida 33302, Telephone No. (904) 224-9115, appearing on behalf of **Tampa Electric Company.**

APPEARANCES CONTINUED:

VICKI GORDON KAUFMAN, McWhirter, Reeves, McGlothlin, Davidson Rief & Bakas, 117 South Gadsden Street, Tallahassee,Florida 32301, Telephone No. (904) 222-2525, appearing on behalf of **Florida Industrial Power Users Group.**

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

VICKI D. JOHNSON, Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Telephone No. (904) 413-6199, appearing on behalf of the **Commission Staff.**

PRENTICE P. PRUITT, Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Telephone No. (904) 413-6199, appearing as Counsel to the **Commissioners.**

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P R O C E E D I N G S

(Hearing convened at 9:45 a.m.)

COMMISSIONER DEASON: Call the hearing to order. Have the notice read, please.

MS. JOHNSON: By notice issued June 19, 1995, a hearing was set in Docket Nos. 950001-EI, Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor; in Docket No. 950007-EI, Environmental Cost Recovery Clause. The purpose of the hearing is set out in the notice.

COMMISSIONER DEASON: Okay. Now, as is evident from the Prehearing Orders that have been filed in these dockets, all issues have been stipulated.

MS. JOHNSON: That's correct.

COMMISSIONER DEASON: Okay. For purposes of appearances, I think it would just suffice to show that all the appearances that were taken at the prehearing conference would just be recognized for purposes of this hearing, realizing that the participants have been excused from actually making an appearance and presenting their witnesses; is that correct?

MS. JOHNSON: That's correct.

COMMISSIONER DEASON: I suppose the first order of business would be to identify all of the exhibits which have been preliminarily identified in the Prehearing Orders.

MS. JOHNSON: That's correct. I handed out this morning a revised Page 26, which should be inserted in the Prehearing Order for Docket No. 950001. One of the exhibits was inadvertently omitted. With that revision, there are 36 exhibits starting with DPD-1.

COMMISSIONER DEASON: Okay. And that would conclude with WNC-1 on Page 31 of the Prehearing Order; is that correct?

MS. JOHNSON: That's correct.

COMMISSIONER DEASON: So for purposes of identification, we'll show that those exhibits, which are identified in the Prehearing Order for Docket 950001, as being identified as Exhibits 1 through 36.

MS. JOHNSON: Staff would request that those exhibits be inserted into the record along with the testimony that was prefiled by the witnesses.

COMMISSIONER DEASON: The witnesses are identified on Pages 5 and 6 on the Prehearing Order, and Staff is now moving that the testimony of all of those witnesses, prefiled testimony, be inserted into the record. And without objection, that is done. All of that testimony has been stipulated.

And Staff is likewise moving that the exhibits which have just been identified as Exhibits 1 through 36, likewise be admitted. And those exhibits have been stipulated and show

FLORIDA POWER CORPORATION

DOCKET NO. 950001-EI

**Re: Fuel Cost Recovery and
Capacity Cost Recovery
Final True-up Amounts for
October 1994 through March 1995**

**DIRECT TESTIMONY OF
DAVID P. DEVELLE**

Q. Please state your name and business address.

A. My name is David P. Develle. My business address is P. O. Box 14042, St. Petersburg, Florida 33733.

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

A. I am employed by Florida Power Corporation as Director, Regulatory Accounting.

Q. Would you please describe your educational background and work experience?

A. I graduated from the University of South Florida in 1975 with a Bachelor's Degree in Business Administration, majoring in Accounting. In 1989, I graduated from the University of Tampa with a Master's Degree in Business Administration. I began my employment with Florida Power in 1975. In addition to various staff accounting positions within the Controllers department, I have held the following supervisory positions: Manager of Accounting Research and Analysis, Manager of Regulatory Accounting and Financial Reporting, and Director of Regulatory

Accounting. My responsibilities in these positions included maintenance of the general records of the Company, fuel accounting, plant and depreciation accounting, financial and regulatory reporting, and preparation and/or coordination of all accounting schedules required in the Company's base rate proceedings before the Florida Public Service Commission (FPSC) and the Federal Energy Regulatory Commission (FERC). I have attended a variety of courses on management and finance sponsored by the Company, the Edison Electric Institute and others. In addition, I currently serve on the Accounting Standards Committee of the Edison Electric Institute.

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 1994 through March 1995, 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 (DPD-1). Also attached to my prepared testimony and designated exhibit (DPD-2) are the Capacity Cost Recovery Clause true-up calculations for the October 1994 through March 1995 period. Also, I will sponsor the applicable Schedules A1 through A12 for the month of March 1995 (period-to-date), which have been previously filed with the Commission and are also attached to my prepared testimony for ease of reference and designated as exhibit (DPD-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, 1995 for fuel cost recovery?

A. The actual ending balance as of March 31, 1995 for true-up purposes is an over-recovery of $8,270,052.

Q. How does this amount compare to the Company's estimated ending balance to be included in the April through September 1995 period?

A. When the estimated over-recovery of $10,291,176 to be refunded during the period of April through September 1995 is taken into account, the final true-up ending balance attributable to the six month period ended March 1995 period is an under-recovery of $2,021,124.

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.

Q. What factors contributed to the period-ending jurisdictional over-recovery of $8.3 million as shown on exhibit (DPD-1)?

A. The factors contributing to the over-recovery are summarized on Sheet 1 of 3. The actual jurisdictional kwh sales were lower than the original estimate by 510,027,184 kwh. This decrease in kwh sales, attributable to mild weather, resulted in lower jurisdictional revenues of $11.5 million and also accounted for approximately $10 million of the total $22.3 million favorable variance in jurisdictional fuel and purchased power expense. The remaining $12.3 million favorable variance in fuel expense can be primarily attributable to price.

When these differences in jurisdictional revenues and jurisdictional fuel expenses are combined, the net result is a over-recovery of $10.8 million related to the October 1994 through March 1995 time period. Other variances not directly related to the period, including an interest provision of $.3 million, result in the actual ending balance over-recovery of $8.3 million, as of March 31, 1995.

Q. Please explain the components shown on exhibit (DPD-1), Sheet 2 of 3 which produced the $22.5 million favorable system variance from the projected cost of fuel and net purchased power transactions.

A. Sheet 2 of 3 of my exhibit (DPD-1) 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 decrease of $10.5 million. I will discuss this component of the variance analysis in greater detail below.

The heat rate variance for each source of generated energy (column C) produced a net cost increase of $2.4 million. Higher than anticipated heat rates for oil generating units were the largest component of the cost variance. On the Company's Schedule A3, exhibit (DPD-3), all BTU's for light oil are included in the light oil heat rate computation. However since no Kwh generation is associated with light oil consumed at steam plants, the resulting heat rate shown on A3 is distorted. In order to compute the true heat rate variance, light oil consumed at steam units is shown separately on line 23 of Sheet 2 of 3 of exhibit (DPD-1).

A cost decrease of $14.4 million resulted from the price variance (column D), which was caused by a number of factors detailed on lines 1 through 25 of Sheet 2 of 3, of exhibit(DPD-1). The most significant factors contributing to the favorable variance were a lower cost per mmbtu for coal and reduced energy payments to QF's partially offset by reduced prices for economy sales and supplemental sales.

Q. Please explain the analysis shown on Sheet 3 of 3 of your exhibit (DPD-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 FPSC "A" Schedules or in the analysis presented on Sheet 2 of 3. For example, an increase in the Mwh requirements of nuclear generation shows up on Schedule A3 and on Sheet 2 of my exhibit as a cost increase of $.5 million. While this may be correct in isolation, the true effect of increased nuclear generation is obviously a corresponding decrease in the MWH requirements of a number of other more costly energy sources, primarily coal and light oil. The result is a lower net system cost of $1.4 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 net 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 420,000 MWH. This would have led to lower net costs of $7.6 million even if the mix of generation had not changed, since the lower system load decreases coal 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 $10.5 million cost decrease associated with the variance in MWH requirements?

A. Lower than expected system requirements during the period accounted for $7.6 million of the favorable variance and the continued high capacity factor at Crystal River Unit No. 3 accounted for $1.4 million of the favorable variance.

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 1994?

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 1994, the short cut method resulted in revenues of $250,[illegible]7,419 which were $126,620 or .051% 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, 1995 for capacity cost recovery?

A. The actual ending balance as of March 31, 1995 for true-up purposes is an under-recovery of $4,061,575.

Q. How does this amount compare to the Company's estimated ending balance to be included in the April through September 1995 period?

A. When the estimated under-recovery of $3,572,022 to be recovered during the period of April through September 1995 is taken into account, the final true-up ending balance attributable to the six month period ended March 1995 period is an under-recovery of $489,553.

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 final net true-up amount follows the procedures established by this Commission as set forth on FPSC Schedule A2 "Calculation of True-Up and Interest Provision" for the Fuel Cost Recovery Clause.

Q. What factors contributed to the actual period-end under-recovery of $4.1 million?

A. Exhibit (DPD-2), sheet 1 of 3, entitled "Capacity Cost Recovery/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, actual jurisdictional capacity cost revenues were $1.1 million lower than forecast due to lower residential Kwh sales during the period. Jurisdictional capacity costs were $3.1 million higher than forecast. The major factor contributing to this variance was higher than forecast payments to Orlando Cogen.

Q. Does this conclude your testimony?

A. Yes, it does.

FLORIDA POWER CORPORATION

DOCKET NO. 950001-EI

Levelized Fuel and Capacity Cost Factors
October 1995 through March 1996

DIRECT TESTIMONY OF
KARL H. WIELAND

Q. Please state your name and business address.

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

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

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

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

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the Company's levelized fuel and capacity cost factors for the period of October 1995 through March 1996.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared an exhibit attached to my prepared testimony consisting of Parts A through D and the Commission's minimum filing requirements for these proceedings, Schedules E1 through E11 and H1, which contain the Company's levelized fuel cost factors and the supporting data. Parts A through C contain the assumptions which support the Company's cost projections, Part D contains the Company's capacity cost recovery factors and supporting data.

FUEL COST RECOVERY

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

A. Schedule E1 (Basic), page 1 of the "E" Schedules in my exhibit, shows the calculation of the Company's basic fuel cost factor of 1.783 ¢/kwh (before line loss adjustment). The basic factor consists of a fuel cost for the projection period of 1.7068 ¢/kwh (adjusted for jurisdictional losses), a GPIF reward of .00133 ¢/kwh, a coal market price true-up credit of 0.0036 ¢/kwh and an estimated prior period true-up charge of 0.0771 ¢/kwh.

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

Schedule E1-E (Final) develops the TOU multipliers 1.223 On-peak and 0.909 Off-peak. The levelized fuel cost factors (by metering voltage) are then multiplied by the TOU multipliers, which results in the final fuel factors to be applied to customer bills during the projection period. The final fuel cost factor for residential service is 1.786 ¢/kwh.

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

A. Line 4 shows costs for the conversion of two Intercession City combustion turbine units to burn natural gas instead of distillate fuel oil. The rationale for including these costs is presented later in my testimony.

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

A. Line 6 includes energy costs for the purchase of 50 MWs from Tampa Electric Company and the purchase of 407 MWs under a Unit Power Sales (UPS) agreement with the Southern Company. Capacity costs for these purchases are included in the capacity cost recovery factor. Both of these contracts have been in place and have been approved for cost recovery by the Commission.

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

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

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

A. The Company has a wholesale contract with Seminole for the sale of supplemental energy to supply the portion of their load in excess of 665 MW. The fuel costs charged to Seminole for these supplemental sales are calculated on a "stratified" basis, in a manner which recovers the higher cost of intermediate/peaking generation used to provide the energy. The Company also has wholesale contracts with the municipal utilities of Kissimmee and St. Cloud under which fuel costs are charged in a similar manner. Unlike interchange sales, the fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kwh for fuel adjustment purposes. However, since the fuel costs of the supplemental sales are not recovered on an average cost basis, an adjustment has been made to remove these costs and the related kwh sales from the fuel adjustment calculation in the same manner that interchange sales are removed from the calculation. This adjustment is necessary to avoid an over-recovery by the Company which would result from the treatment of these fuel costs on an average cost basis in this proceeding, while actually recovering the costs from the supplemental customers on a higher, stratified cost basis. The development of this adjustment is shown on Schedule E6.

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

A. The total true-up amount was determined in two parts. First, a period-to-date actual over-recovery of $13,441,514 through April 1995 was obtained from Schedule A2, page 3 of 4, previously submitted for the month of April. This balance was projected to the end of September 1995, including interest estimated at the April ending rate of 0.5058% per month. The development of the estimated true-up amount for the current April through September

1995 period is shown on Schedule E1B, Sheet 1. Second, the total estimated under-recovery of $8,628,315 for the current period was combined with the prior period (October 1994 through March 1995) over-recovery of $8,270,063 and $10,291,176 being refunded during the current period for a total under-recovery of $10,649,438 at the end of September 1995. This results in an estimated true-up charge on line 28 of Schedule E1 of 0.0771 ¢/kwh for application in the October 1995 through March 1996 projection period.

Q. What are the primary reasons for the projected September 1995 under-recovery of $10.6 million?

A. The under-recovery is primarily a result of higher oil prices, higher costs of purchased power, and significantly higher system requirements during the early months of the current period.

Q. How was the market price true-up for Powell Mountain coal purchases (Schedule E1, line 28a) calculated?

A. The calculation was performed in accordance with the market pricing methodology approved by the Commission for Powell Mountain coal purchases in Docket No. 860001-EI-G and has been made available for Staff review. The true-up is based on the difference between the previously recovered cost of Powell Mountain coal purchases during 1993, and a calculated cost using the market price index for compliance coal in BOM District 8 for 1994, as adopted in Order No. 22401. The true-up amount of $503,961 includes a correction from

1992 for a delivery not previously accounted for, and interest through April 1995.

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

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

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

A. The consumption rate of each batch has been estimated by utilizing a core physics computer program which simulates reactor operations over the projection period. When this consumption pattern is applied to the individual batch costs, the resultant composite Cycle 10 is $0.37 per million BTU.

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

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

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

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

1994. The forecasted sales are shown on Schedule E11, and contain the energy reductions expected to result from the energy conservation programs being implemented by the Company.

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

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

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

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

Q. Please explain the basis for requesting recovery of the cost of converting combustion turbine units 7 and 9 at the Intercession City site to burn natural gas.

A. In Docket No. 850001-EI-B, Order No. 14546 issued on July, 1985, the Commission addressed charges appropriate for recovery through the fuel clause:

> "Fossil fuel-related costs normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine current base rates and which, if expended, will result in fuel savings to customers. Recovery of such costs should be made on a case by case basis after Commission approval."

The gas conversion cost of $2.2 million was clearly not part of the cost of Intercession City units 7 and 9 when they were included in rate base as part of the 1993 test year. In addition, a one-time payment of $272,000 for gas metering costs is a transportation related cost which we believe is recoverable as a fuel expense. The anticipated fuel savings from the conversion are in excess of $20 million.

Q. How is FPC proposing to recover the conversion cost?

A. The Company proposes to amortize the $2.2 million conversion cost over a five year period beginning with the plant in-service date of July, 1995. The one-time metering expense will be recognized in the first month of amortization. The projected cost during the October 1995 through March 1996 period is $337,518 which consists of an amortization charge of $221,154 and a return (including income taxes) of $116,364 based on the Company's current cost of capital of 8.37%. The fuel savings for the same period are expected to be $1,077,438 resulting in a net benefit to customers of $739,920. During the July through September, 1995 period, costs (including the $272,000 metering charge) are $416,370 compared to savings of $611,983 for a net benefit of $195,613.

Q. Why is the Company proposing a five year amortization period rather than expensing the conversion cost or depreciating it over the life of the units?

A. The Company chose five years in order to align recovery of cost with anticipated benefits. The Company is relying on the availability of interruptible gas transportation for the delivery of gas to the site because firm (take or pay) contracts are not economical for a low capacity factor peaking site. Discussions with Florida Gas Transmission (FGT) indicate that they expect interruptible gas to be available in sufficient quantity to power the two units at the site for the next five years. The Company hopes that some gas will be available beyond that time which will yield additional savings, but we believe it more appropriate to recover costs during the time when the majority of benefits are expected to occur. Expensing the conversion cost would burden existing customers with costs that exceed benefits while amortizing the conversion over the life of the units could burden future customers with costs that do not have corresponding benefits.

Q. What is the Company proposing to do if expected fuel savings are not achieved?

A. The Company is willing to assume the risk for achieving fuel savings. If fuel savings during any six-month fuel recovery period are less than the amortization and return costs, we will limit cost recovery to fuel savings and defer recovery of the difference to future periods. In no case will the Company collect an amount greater than the fuel savings, making this a no-lose proposition for customers.

CAPACITY COST RECOVERY

Q. How was the Capacity Cost Recovery factor developed?

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

Sheet 1: Projected Capacity Payments. This schedule contains system capacity payments for UPS, TECO and QF purchases. The retail portion of the capacity payments are calculated using separation factors consistent with the Company's rate case filing. The estimated recoverable capacity payments for the October 1995 through March 1996 period are $122,003,909.

Sheet 2: Estimated/Actual True-Up. This schedule presents the actual ending true-up balance after one month of the current period and re-forecasts the over/(under) recovery balances for the next five months to obtain an ending balance for the current period. This estimated/actual balance of $(611,949) is then carried forward to Sheet 1, to be collected during the October 1995 through March 1996 period.

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

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

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

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

A. The increase in capacity payments from \$129.7 million in the April through September 1995 period to \$138.2 million for the October 1995 through March 1996 period is due to two factors. First, two contracts (Eco Peat and Orange Cogen) began during the April through September period, but will be in effect for the entire six months in the projection period. Second, the escalation provisions in most contracts take effect in January, 1996.

Q. What does line 19, Eco Peat lease credit, represent?

A. This credit is a result of negotiations between the Company and Eco Peat to allow the Eco Peat facility and its power sales contract to become part of the General Peat facility. The credit consists of two parts: a fixed payment of \$800,000 per year (paid monthly) which Eco peat would have paid in order to lease the Avon Park steam site, and a share of the actual profit for Eco Peat, estimated to \$150,000, payable in January of 1996. FPC feels that since customers are paying capacity charges for this contract, it is appropriate to reduce capacity charges by these credits.

Q. Does this conclude your testimony?

A. Yes.

FLORIDA POWER CORPORATION

DOCKET NO. 950001-EI

GPIF Targets and Ranges for October 1995 through March 1996

DIRECT TESTIMONY OF LARRY G. TURNER

Q. Please state your name and business address.

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

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

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

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

A. Yes, they have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the development of the Company's Generating Performance Incentive Factor (GPIF) targets and ranges for the period of October 1995 through March 1996. 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 76 pages, which consists of the GPIF standard form schedules prescribed in the Implementation Manual and supporting data, including unplanned outage rates, net operating heat rates, and computer analyses and graphs for each of the individual GPIF units, all of which are attached to my prepared testimony.

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

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

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

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

Q. How were the equivalent availability targets developed?

A. The equivalent availability targets were developed using the methodology established for the Company's GPIF units, as set forth in Section 4 of the Implementation Manual. This method describes the formulation of graphs based on each unit's historic performance data for the four individual unplanned outage rates (i.e. forced, partial forced, maintenance and partial maintenance outage rates), which in combination constitute the unit's equivalent unplanned outage rate (EUOR). From operational data and these graphs, the individual target rates are determined by inspecting two years of twelve-month rolling averages and the scatter of monthly data points during the two-year period. The unit's four target rates are then used to calculate its unplanned outage hours for the projection period. When the unit's projected planned outage hours are taken into account, the hours calculated from these individual unplanned outage <u>rates</u> can then be converted into an overall equivalent unplanned outage <u>factor</u> (EUOF). Because factors are additive (unlike rates), the unplanned and planned outage factors (EUOF and POF) when added to the equivalent availability factor (EAF) will always equal 100%. For example, an EUOF of 15% and a POF of 10% results in an EAF of 75%.

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

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

A. The EAF target for Crystal River Unit 3 is 79.79%. The unit's next mid-cycle outage is scheduled to begin February 20, and continue through April 15, resulting in a Winter period POF of 17.48%. The unit's EUOR target is 3.30, which results in an EUOF of 2.27% when planned outage hours are taken into account.

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

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

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

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

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

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

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

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

Q. How were the GPIF weighting factors determined?

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

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

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

Q. Does this conclude your testimony?

A. Yes.

FLORIDA POWER CORPORATION

DOCKET NO. 950001-EI

Re: GPIF Reward/Penalty Amount for October 1994 through March 1995

DIRECT TESTIMONY OF LARRY G. TURNER

Q. Please state your name and business address.

A. My name is Larry G. Turner. My business address is 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 Senior Performance Engineer in Energy Supply Services, Plant Performance.

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 describe the calculation of the Company's Generation Performance Incentive Factor (GPIF) amount for the period of October 1994 through March 1995. 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 (LGT-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 reward of $183,528. 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 through 28 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.

BEFORE THE PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF R. SILVA

DOCKET NO. 950001-EI

MAY 15, 1995

Q. Pleas 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 actual performance results for the Equivalent Availability Factor (EAF) and Average Net Operating Heat Rate (ANOHR) for the nineteen (19) units used to determine the Generating Performance Incentive Factor (GPIF) and to compare these actual results to the targets that were approved in Commission Order No. PSC-94-1092-FOF-EI issued September 6, 1994 for the period October, 1994 through March, 1995. On the basis of this comparison, I have calculated an incentive amount 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 t. e contents of the document.

Q. What is the incentive amount you havecalculated for the period October, 1994 through March, 1995?

A. I have calculated a GPIF reward of $3,109,109.

Q. Will you please explain how the reward amount is calculated?

A. The steps involved in making this calculation are contained in Document No. 1. Page 2 of Document No. 1 is the GPIF Reward/Penalty Table (Actual) and shows an overall GPIF performance point value of +3.6765 which corresponds to a GPIF reward of $ 3,109,109. Page 3 is the calculation of the maximum allowed incentive dollars. The calculation of the system actual GPIF performance is shown on page 4. This page lists each unit, the performance indicators (ANOHR and EAF), the weighing factors and the associated GPIF points.

Pages 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 outafe variation, which is shown on page 6. Column 7 is the adjusted actual EAF 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 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. These same tables are shown on pages 8 through 26.

Q. Mr. Silva, will you explain the primary reason or reasons why FPL will be rewarded under the GPIF for the period October, 1994 through March, 1995 ?

A. Yes. The primary reason that FPL will receive a reward for the period was that Turkey Point nuclear unit 3 and St. Lucie nuclear unit 2 had better availability than was projected. Additionally, the availability performance at the St. John's 1 and 2 fossil units contributed to the GPIF reward.

Q. Mr Silva, would you please summarize the performance of FPL's nuclear unit availability ?

A. Turkey Point Unit 3 operated at an adjusted actual EAF of 97.3% as compared to its target of 93.6%. This will result in a +10.00 point reward which corresponds to a GPIF reward of $1,018,188.

Turkey Point Unit 4 operated at an adjusted actual EAF of 60.3% as compared to its target of 60.6%. This will result in a -1.00 point penalty which corresponds to a GPIF penalty of ($66,470).

St. Lucie Unit 1 operated at an adjusted actual EAF of 59.7% as compared to its target of 60.6%. This will result in a -3.00 point penalty which corresponds to a GPIF penalty of ($247,105).

St. Lucie Unit 2 operated at an adjusted actual EAF of 97.2% as compared to its target of 91.6%. This will result in a +10.00 point reward which corresponds to a GPIF reward of $1,081,613.

The total GPIF reward for the nuclear units' availability performance is $1,786,226.

Q. Mr. Silva, please summarize the nuclear units performance as it relates to the ANOHR of the units.

A. Turkey Point nuclear unit 3 operated with an adjusted actual ANOHR of 10882 BTU/KWH which was poorer than projected by 17 BTU/KWH. This ANOHR is within ± 75 BTU/KWH of the projected target , therefore there is no GPIF reward or penalty.

Turkey Point nuclear unit 4 operated with an adjusted actual ANOHR of 10862 BTU/KWH which was better than projected by 140 BTU/KWH. This will result in a +10.00 point reward which corresponds to a GPIF reward of $550,532.

St. Lucie nuclear unit 1 operated with an adjusted actual ANOHR of 10810 BTU/KWH which was better than projected by 44 BTU/KWH. This ANOHR is within ± 75 BTU/KWH of the projected target , therefore there is no GPIF reward or penalty.

St. Lucie nuclear unit 2 operated with an adjusted actual ANOHR of 10869 BTU/KWH which was poorer than projected by 106 BTU/KWH. This will result in a -1.61 point penalty which corresponds to a GPIF penalty of ($88,373).

The total reward for the nuclear units' heat rate performance is $462,159.

Q. Mr. Silva, what will the total GPIF incentive reward be for the FPL nuclear units for EAF and ANOHR?

A. $2,248,385.

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

A. The performance of the fifteen (15) fossil units included in the GPIF for the period of October, 1994 through March, 1995 will receive a total combined GPIF reward of $860,724 for EAF and ANOHR.

Eleven (11) of the units performed better than their availability targets, while the remaining four (4) performed poorer than their targets. The combined fossil unit availability performance will result in a GPIF reward of $817,679.

Four (4) of the units operated with ANOHR's that were better than projected and five (5) units operated with ANOHR's that were poorer than projected. The remaining seven (7) units were within the + 75 BTU/KWH dead band and they will receive no incentive reward or penalty. The combined fossil unit heat rate performance will result in a GPIF reward of $43,045.

Q. Mr. Silva, 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. 950001-EI

June 20, 1995

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 October, 1995 through March, 1996. In addition, my testimony addresses FPL's purchase of railcars to be used to deliver Western coal to FPL's Scherer Unit No.4, for the purpose of reducing fuel costs.

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, 1995 through March, 1996 period?**

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

In general, world demand for crude oil and petroleum products for the second half of 1995 and 1996 is projected to be moderately higher than in 1994, as a result of the continued economic recovery in Western Europe and Japan, plus the rapid economic growth in other countries in the Pacific Rim.

On the supply side, total non-OPEC crude oil supply for the second half of 1995 and 1996 is projected to be slightly higher than in 1994 due to increases in production in the North Sea and Colombia.

Regarding OPEC crude oil production, it is projected that in the second half of 1995 and in 1996 OPEC production will effectively match demand for OPEC crude oil.

It is projected that these factors will cause crude oil prices, and consequently heavy fuel oil prices, to continue to increase moderately during the second half of 1995 and 1996, relative to 1994 prices.

Q. What is the projected relationship between heavy fuel oil and crude oil prices during the October, 1995 through March, 1996 period?

A. Heavy fuel oil prices on the U. S. Gulf Coast are projected to be approximately 75% 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, 1995 through March, 1996 period based on FPL's evaluation of the key factors discussed above.

A. FPL's projection for the dispatch cost of heavy fuel oil is provided on page 3 of Appendix I in dollars per barrel at each of the oil-fired plants. We project that during this period the dispatch cost of heavy fuel oil will range from \$14.66 to \$16.96 per barrel for 2.5% sulfur grade fuel oil, \$14.71 to \$17.44 per barrel for 2.0% sulfur grade fuel oil, \$15.12 to \$17.28 per barrel for 1.0% sulfur grade fuel oil, and from

$15.94 to $17.65 per barrel for 0.7% sulfur grade fuel oil, approximately, (depending on the month and the delivery location).

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. Therefore, in general the market price of light fuel oil is projected to increase moderately during 1995 and 1996.

Q. Please provide FPL's projection for the dispatch cost of light fuel oil for the period from October, 1995 through March, 1996 based on FPL's evaluation of the key factors discussed above.

A. FPL's projection for the dispatch cost of light oil for each of the combustion turbine and combined cycle plants is shown on page 4 of Appendix I. We project that during this period the dispatch cost of light fuel oil will range from $21.43 to $25.37 per barrel, approximately, depending on the month and delivery location.

Q. What is the basis for FPL's projections of the

dispatch cost of coal at the St. Johns River Power Park (SJRPP)?

A. The projected dispatch cost of coal at SJRPP is based on FPL's price projection of spot coal delivered to SJRPP.

About 73% of the coal purchased for SJRPP during the period will be under the terms of the three long-term coal supply contracts. Annual coal volumes delivered under these contracts are fixed on October 1st of the previous year. Therefore, they do not affect the daily dispatch decision. The dispatch price of coal for SJRPP is based on the variable component of the coal cost, the projected spot coal price. About 27% of coal purchased for SJRPP for the period is projected to be spot coal.

Q. **Please provide FPL's projection for the dispatch cost of coal for SJRPP for the October, 1995 through March, 1996 period.**

A. FPL's projected dispatch cost of coal at SJRPP, shown on page 5 of Appendix I, is approximately $1.54 per million BTU, delivered to SJRPP.

Q. What is the basis for FPL's projections of the dispatch cost of coal at Scherer Unit 4 for the October, 1995 through March, 1996 period?

A. FPL's projected dispatch cost of coal at Scherer Unit 4 is the projected monthly delivered spot price of coal. Approximately 80% of the coal purchased during the period is projected to be spot coal from the Powder River Basin. The balance will be Eastern coal delivered under existing long-term contracts.

Q. Please provide FPL's projection for the dispatch cost of coal for Scherer Unit 4 during the October, 1995 through March, 1996 period.

A. FPL's projected dispatch cost of coal at Scherer Unit 4, shown on page 5 of Appendix I, is approximately $1.56 per million BTU delivered to Plant Scherer.

Q. Does FPL's proposed fuel factor reflect a return on, and depreciation of, railcars owned by FPL that are used to deliver coal to Scherer Plant?

A. Yes. FPL owns 462 railcars, with an initial value of $24 million, that are used to deliver coal to Scherer Plant. Like the railcars used to deliver coal to SJRPP, which have been previously approved for cost recovery purposes, a return on, and depreciation of, these Scherer railcars is reflected in FPL's fuel factor.

Q. When did FPL purchase the railcars it uses to deliver coal to Scherer Plant?

A. FPL ꜀tered into a contract with Trinity Industries, Inc., on April 26, 1994, to purchase the 462 Scherer railcars. The railcars were delivered and placed in service in four installments between January 10 and March 23, 1995.

Q. Why did FPL purchase railcars to deliver coal to Scherer Plant?

A. FPL purchased these railcars in order to reduce fuel costs. In order for FPL to purchase and transport the less expensive Western coal from the Powder River Basin in Wyoming to Scherer Plant, FPL had to supply the railcars. FPL compared the projected cost of Western coal delivered to Scherer Plant to that of Eastern coal, and determined that purchasing and transporting Western coal in FPL's railcars would result in net savings of at least $24 million and more likely about $67 million over a 16-year period, present valued in 1992 dollars. These projected savings are net of all costs, including the cost of the railcars.

Q. Why is the projected $67 million savings more likely t‥n the $24 million savings?

A. The $24 million savings was projected using a "worst case" scenario. The magnitude of the savings to be realized due to the change to Western coal depends primarily on two factors: the total Scherer Plant capital investment required by the change to Western coal, and the quantity of Western coal utilized in the entire Scherer Plant (which produces the fuel savings). FPL's "worst case" analysis scenario assumed that the required capital investment would include $23 million for a stacker-reclaimer to handle the coal, and that the Plant would operate at a 30% capacity factor. Based on these "worst case" assumptions, the net savings to FPL's customers was projected to be about $24 mil] on. The savings calculation for this scenario is summarized on page 8 of Appendix I to my testimony.

The more probable scenario, which assumed that the stacker-reclaimer would not be required, and that the Plant (overall) would operate at a 65% capacity factor, resulted in projected savings of $67 million. The savings calculation for this scenario is summarized on page 9 of Appendix I to my testimony.

Delivery of Western coal to Scherer Plant began in October, 1993. Based on the experience acquired during 20 months of handling both Eastern and Western coal effectively without a stacker-reclaimer, it is now the Plant co-owners' opinion that the stacker-reclaimer will not be required. In addition, the Plant (overall) has been operating at a 67% capacity factor. Therefore, since current and projected operating conditions are consistent with the second analysis scenario, it is much more likely that the net savings will be about $67 million.

Q. **What is the basis for the projected savings associated with Western coal?**

A. Western coal is significantly less expensive than Eastern coal. At present, Eastern coal is priced at approximately $1.12 per MMBTU, while Western coal is priced at $0.26 per MMBTU. This $0.86 price differential makes the conversion to Western coal the economic choice. In addition, this price difference is projected to increase due to rising demand for Eastern "compliance" (very low sulfur) coal among coal plants located East of the Mississippi that have to reduce SO2 emissions to meet the requirements of Phase II of the Clean Air Act. It is projected that the average price difference over the next 15 years will be well over $1 per MMBTU.

Q. **Does the use of Western coal at Scherer Plant provide any strategic benefits?**

A. Yes. The decision to use Western coal at Scherer Plant has very significantly broadened the coal resource base from which Scherer Plant can obtan coal. The Plant can only use "compliance" coal which emits less than 1.2 lbs. of SO2 per MMBTU of energy input. Before having access to Western coal sources, all the coal supplied to Scherer Plant was produced in only those Central Appalachia mines served by the Norfolk Southern Railroad (NS), the only railroad with a line to

Scherer Plant. Since NS serves only one third of the "compliance" coal production in Central Appalachia, our ability to create price competition among coal suppliers was very limited. For example, if all the units at Scherer Plant were to operate at 65% capacity factor, the coal requirement would be 7.3 million tons of Eastern coal per year, or 35% of current compliance coal production served by NS. On the other hand, the Plant's Western coal requirement, operating at the same capacity factor, represents less than 6% of current Powder River Basin (Western) coal production capacity. This diversification of coal supply made possible by having access to Western coal will enable us to effectively create price competition among coal producers and will result in reduced coal costs from all sources in the future.

Q. **Why does the purchase of Western coal make it necessary for FPL to provide its own railcars?**

A. For two reasons. First, because the number of available high-capacity aluminum railcars was not sufficient to meet the Scherer Plant requirement. Second, because, based on offers received, the total cost of transporting coal in existing railcars (including the cost of leasing the railcars) would have been at least 6% higher than the cost of transporting the coal in the new railcars manufactured for FPL (including the cost of the railcars themselves).

The total number of railcars offered to the Scherer Plant co-owners was barely sufficient to transport half the quantity required by the Plant. In order to meet the Plant's requirement, the Scherer Plant co-owners have had to purchase a total of 13 newly manufactured unit trains, while the number of railcars, a combination of different designs and materials, offered for lease was barely sufficient to complete 7 unit trains. More importantly, the cost of the new railcars (in dollars per ton) was lower than the lowest offer for existing railcars. In addition, the rates specified in FPL's coal transportation contracts for Western coal resulted in significantly lower costs for coal hauled in the new high capacity, aluminum railcars purchased by FPL.

Q. How did FPL determine the number of railcars that would be necessary to deliver Western coal for its Scherer Unit No.4?

A. Using FPL's system simulation model (POWRSYM) we projected that Scherer Unit No.4 would operate at an annual capacity factor of 85%, or higher, every year beginning in 1996, and that it would require at least 2.3 million tons of Western coal per year.

One unit-train, composed of 110 railcars, can deliver about 500,000 tons of Western coal per year. Therefore 4.6 unit-trains would be required to deliver the total projected Western coal requirement for Scherer Unit No.4. FPL decided to purchase four unit-trains, plus 22 spare railcars, for a total of 462 railcars. These four unit trains are projected to be fully utilized.

Since it is projected that a fifth unit-train would not be fully utilized, and since there are sufficient railcars available to meet FPL's remaining need, we have decided that at present the remaining required coal tonnage, if any, will be delivered using railcars owned by other Plant Scherer co-owners, or the railroad, or other parties. As stated above, for fully utilized unit-trains, it is more economic to purchase the new railcars. However, for railcars that are not to be fully utilized, and where the rate of utilization is uncertain, it is appropriate to lease railcars to meet fluctuating coal requirement levels. The need to pur hase additional railcars will be re-evaluated periodically, using more current information about the operation of Scherer Unit No.4.

Q. How was Trinity Industries selected to provide FPL's railcars?

A. Trinity was selected as a result of a competitive bid evaluation process conducted by Southern Company Services acting as agent for the Scherer Plant co-owners, which include FPL. Trinity's total cost was the lowest of the three bidders. FPL reviewed the bids and the evaluation process, verified that Trinity's was the lowest cost bid, and concurred with the selection of Trinity Industries.

Q. What are the factors that affect FPL's natural

gas prices during the October, 1995 through March, 1996 period?

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

In general, domestic demand for natural gas during the second half of 1995 and 1996 is projected to be moderately higher than in 1994 due primarily to increased usage for electric generation. On the supply side, U.S. production of natural gas, storage availability and Canadian imports are also projected to increase moderately. As indicated previously, heavy fuel oil prices are projected to be somewhat higher.

It is projected that these factors will cause FPL's natural gas prices to increase moderately during 1995 and 1996.

Q. **What are the factors that affect the availability of natural gas to FPL during the October, 1995 through March, 1996 period?**

A. The key factors are (1) the existing capacity of natural gas transportation facilities into Florida and (2) the projected 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. FPL's total firm transportation capacity during the October, 1995 through March, 1996 period will range from 455,000 million BTU per day to 480,000 million BTU per day.

Total demand for natural gas in the State during the period (including FPL's firm capacity) is projected to be between 1,410,000 million BTU per day and 1,305,000 million BTU per day, or from 45,000 to 150,000 million BTU per day below the pipeline's total capacity. This projected available pipeline capacity could enable FPL to acquire additional natural gas.

Q. Please provide FPL's projections for natural gas unit costs and availability to FPL for the October, 1995 through March, 1996 period based

on FPL's evaluation of these factors.

A. FPL's projections of delivered natural gas unit costs and availability are provided on page 6 of Appendix I. We project that during this period the system-weighted-average total cost of natural gas delivered to the FPL system will range from $2.22 to $2.66 per million BTU and the average total availability of natural gas to FPL will range from 500,000 to 630,000 million BTU per day.

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 developed using the actual monthly Average Net Operating Heat Rates and the corresponding Net Output Factors from previous October through March periods. This historical data was used to calculate an efficiency factor, or heat rate multiplier, for each generating unit. The most recent unit dispatch heat rate curves, modified by the unit's efficiency factors, were provided as input to the POWRSYM model.

Q. **Are you providing the outage factors projected for the period October, 1995 through March, 1996?**

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 actual unplanned outage factor of each generating unit for the previous twelve-month period 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, 1995 through March, 1996 period.

Q. **Please describe significant planned outages for the October, 1995 through March, 1996 period.**

A. Planned outages at our nuclear units are the most significant in relation to Fuel Cost Recovery. Turkey Point Unit No.3 is scheduled to be out of service for refueling from September 4 until October 27, 1995 or twenty six days during the period. St. Lucie Unit No.2 is scheduled to be out of service for refueling from October 2 until November 24, 1995 or fifty three days during the period. Turkey Point Unit No.4 is scheduled to be out of service for refueling from March 1 until April 24, 1996 or thirty one days during the period. There are no other significant planned outages during the projected period.

Q. **Are any changes to FPL's generation capacity planned during the October, 1995 through March, 1996 period?**

A. No.

Q. **Please discuss the arrangements between FPL and JEA regarding the St. Johns River Power Park (SJRPP).**

A. Under the terms of the contract, FPL owns 20% of the units and has the right to schedule an additional 30% of the capacity of the units from JEA's portion. The portion of energy scheduled by FPL related to FPL's 20% ownership of the units is included in Fuel Cost Recovery Schedules as FPL generation, and the balance of energy scheduled and related energy costs are included in Fuel Cost Recovery Schedules as purchased power.

Q. Are you providing the projected interchange and purchased power transactions forecasted for October, 1995 through March, 1996?

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, 1995 through March, 1996 period.

A. Under the UPS agreement FPL's capacity entitlement during the projected period is 916 MW from October, 1995 through March, 1996. 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 1,596,506 MWH of UPS Energy at a cost of $29,588,655. In addition, we project the purchase of 1,367,382 MWH of UPS Replacement energy (Schedule R) at a cost of $23,372,045. 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 1,393,462 MWH for the period at an energy cost of $20,986,800. 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 179,233 MWH at a cost of $788,275. 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 2,620,366 MWH at a cost to FPL of $45,648,559.

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, corrected to remove non-recurring factors.

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

A. We have projected 208,550 MWH of Economy energy sales for the period. The projected fuel cost related to these sales is $4,628,776. The projected transaction revenue from the sales is $6,372,101. Eighty percent of the gain for Schedule C is $1,394,650 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?**

A. The costs of these purchases are shown on Schedule E9 of Appendix II. For the October, 1995 through March, 1996 period FPL projects it will purchase a total of 2,155,149 MWH at a cost of $38,821,030. If generated, we estimate that this energy would cost $43,646,079. Therefore, these purchases are projected to result in savings of $4,825,049.

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 258,199 MWH of energy at a cost of $1,166,444. These projections are shown on Schedule E6 of Appendix II.

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, 1995 through March, 1996. 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, 1995 through March, 1996 period.

My testimony also explains FPL's decision to use Western coal at its Scherer Unit No.4 and purchase 462 railcars to deliver the Western coal, and thereby achieve significant savings.

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. 950001-EI

JUNE 20, 1995

Q. Ple. .e 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, 1995 through March, 1996, 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 13.9% and a weighted system equivalent unplanned outage factor of 7.5% which yield a weighted system equivalent availability of 78.6%. This target includes the refueling of all four nuclear units during the October, 1995 through March, 1996 period. FPL also projects a weighted system average net operating heat rate of 9729 BTU/KWH. As discussed in later in this testimony, these targets represent fair and reasonable values when compared to historical data . I therefore ask that the targets for these performance indicators and the respective improvement/degradation ranges in my testimony be approved by the Commission for FPL.

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 seventeen (17) 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 seventeen (17) units which FPL proposes to use represent the top 80.64% of the forecast system net generation for the October, 1995 through March, 1996 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 seventeen 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 C. VILLARD

DOCKET NO. 950001-EI

June 20, 1995

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

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

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

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

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

A. 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 1995 through March 1996.

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 1995 through March 1996.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period October 1995 through March 1996.

A. We estimate the nuclear units will produce 110,965,066 MBTU of energy at a cost of $0.408 per MMBTU, excluding spent fuel disposal costs for the period October 1995 through March 1996. 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 1995 through March 1996 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 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 1995 through March 1996 and what is the basis for FPL's projection.**

A. As indicated in prior testimony, The National Energy Policy Act of 1992 (The Act) requires FPL to make certain payments to a fund established at the U.S. Treasury, to cover the cost of decontamination and decommissioning DOE's enrichment facilities. D&D payments are in direct proportion to the amount of enrichment services purchased by FPL, divided by the amount produced by the DOE, through October 1992, multiplied by the total annual assessment of $480M, as specified in the Energy Policy Act of 1992, and escalated for inflation using the CPI-U (consumer price index - for urban customers). FPL's projection of $5.1M for D&D costs to be paid during the period October 1995 through March 1996 is included on Schedule E-2 of Appendix II.

Q. **Are there any other fuel-related costs which FPL is including in the calculation of the proposed Fuel Cost Recovery Factor?**

A. No. However, FPL is requesting pre-approval to recover through the Fuel Cost Recovery Clause, the implementation costs associated with changing from an 18 month to a 24 month fuel cycle operation for FPL's St. Lucie Nuclear Units 1 and 2. These implementation costs, which consist of costs for outside services and contractors hired for this specific project, costs for materials and construction needed for implementation, and Nuclear Regulatory Commission (NRC) fees, are projected to total $2.7M over the next four years. If approved, FPL will request recovery of these costs when the 24 month fuel cycle is implemented. Details of the accounting treatment and the basis for requesting the recovery of these costs through the Fuel Cost Recovery Clause are contained in the testimony of FPL witness B. T. Birkett.

Q. **What benefits will FPL's customers receive by the St. Lucie nuclear units operating on a 24 month**

fuel cycle?

A. Operating the St. Lucie nuclear units on a 24 month fuel cycle will eliminate one refueling outage every six years per unit or one refueling outage every three years for the St. Lucie Plant. The elimination of outages will increase the expected generation of the units. According to a recent feasibility study of 24 month fuel cycle operation for the St. Lucie Plant, the additional nuclear generation gained by the 24 month fuel cycle produces a fuel savings of approximately $171M through the year 2016, net of the implementation costs and the expected increase in nuclear fuel costs. These savings result from the fuel cost differential between lower cost nuclear fuel and higher cost fossil fuel. The estimated fuel savings were calculated by using the production costing model, POWRSYM. We are assuming as input into the POWRSYM model, that the first 24 month cycle of operation would begin in late Spring of 1997, for St. Lucie Unit 2, and in late Spring 1998, for St. Lucie Unit 1.

We are currently completing a similar feasibility and economic study for the Turkey Point Plant. We expect that, if the results are cost effective, FPL will implement the same 24 month fuel cycle operation at the Turkey Point Plant.

Q. **What activities and costs are involved in implementing 24 month fuel cycle operation for the nuclear units at St. Lucie?**

A. The 24 month fuel cycle operation will require FPL to formally amend the operating license for St. Lucie with the Nuclear Regulatory Commission. To receive a license amendment, FPL will evaluate and perform analyses on all affected plant systems, structures, and components to demonstrate and ensure that there are no adverse impacts on plant safety, equipment reliability, and operations resulting from an extended cycle length.

These activities include a) analyses to justify changing the Plant Technical Specifications intervals for surveillance and inspection from 18 month to 24 month, b) analyses to revise allowances for instrument drift between calibration every 24 months and to update impacted safety analyses, c) an evaluation of equipment history to verify that no degradation of equipment reliability will occur when plant maintenance intervals are extended to accommodate 24 month fuel cycle operation, and d) revision of all of our design bases documents to incorporate our evaluation of the impact of 24 month fuel cycle operation.

Additionally, our material and construction cost estimates assume that some plant design modifications will be required, such as the replacement of instrumentation due to expected increased drift between calibration. Finally, FPL will pay certain fees to the NRC to cover application costs and their review.

As mentioned earlier, the implementation costs related to the 24 month fuel cycle operation of FPL's St. Lucie Units 1 and 2 are estimated at \$2.7M. We estimate these costs will occur over a four year period, beginning in 1995, with approximately 60% of the costs for outside services and contractors hired for this specific project, 30% for materials and construction costs, and 10% for fees payable to the NRC.

Q. Are there currently any unresolved disputes under

FPL's nuclear fuel contracts?

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

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

In late April 1995, the Department of Energy (DOE) issued an opinion that concludes it has no legal obligation to begin accepting spent fuel for disposal in 1998 or to provide interim storage under the Nuclear Waste Policy Act. The DOE was required by the U.S. Court of Appeals for the District of Columbia to submit, by April 28, 1995, its final conclusion on a Notice of Inquiry it had issued since May 1994.

The DOE has indicated its willingness to discuss financial or other assistance that may be appropriate in light of its inability to provide disposal services beginning in 1998, but has provided no specifics on its intent.

Secondly, FPL is currently seeking to resolve a price dispute for uranium enrichment services purchased from the United States (U.S.) Government, after October 1, 1992. For deliveries from October 1, 1992 to July 1, 1993, enrichment services were provided by the DOE. Subsequent to July 1, 1993, DOE's responsibilities were transferred to a new entity, the United States Enrichment Corporation (USEC) as discussed below. Because of this transfer of responsibilities, our dispute with the U.S. Government has to be resolved with two separate entities.

Our 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 the 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 1993, as FPL has been doing. Therefore, D&D should not have been included in the price charged by DOE since then, and the price should have been reduced accordingly. FPL has written to DOE to request such refund. DOE's first response has been to acknowledge our letter and to request clarifying information on the amount of our claim. However, on May 9, 1995, The Justice Department responded on behalf of DOE, deemed this issue to be in dispute and requested that all correspondence be addressed to them. FPL's next step will be to file a claim with the Contracting Officer, which we intend to pursue in the coming months.

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

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

In prior testimony, FPL had stated that it filed three claims challenging the price charged by the USEC for delivery of enrichment services since July 1, 1993. Since filing our claims, FPL has negotiated a new contract with the USEC in which the USEC has agreed to reduce its price for current contractual commitments. This contract settled our claims against the USEC for deliveries from July 1, 1993. We are still requesting a refund from the DOE for enrichment services they provided prior to the transfer of responsibilities to the USEC.

Q. **Does this conclude your testimony?**
A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF B.T. BIRKETT

DOCKET NO. 950001-EI

May 19, 1995

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

A. My name is Barry T. Birkett, and my business address is 9250 West Flagler Street, Miami, Florida, 33174. I am employed by Florida Power & Light Company (FPL) as Manager of Rates and Tariff Administration.

Q. Have you previously testified in this docket?

A. Yes, I have.

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), Capacity Cost Recovery Clause (CCR), and Oil Backout Cost Recovery Clause (OB) Net True-Up amounts for the period October 1994 through March 1995. The Net True-Up for FCR is an overrecovery, including interest, of $12,465,206. The Net True-Up for CCR is an overrecovery, including interest, of $4,856,873. The Net True-Up for OB is an underrecovery, including interest, of $6,647. I am requesting Commission approval to include these true-up amounts in the calculation of the FCR, CCR, and OB factors respectively, for the period October 1995 through March 1996.

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 four appendices. Appendix I contains the FCR related schedules, Appendix II contains the CCR related schedules, and Appendix III contains the OB related schedules. Also attached to this filing is Appendix IV, which contains Commission Schedules A-1 through A-13 for October 1994 through March 1995 period.

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 (FCR)

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 period, an overrecovery of $12,465,206, which I am requesting be included in the calculation of the Fuel Cost Recovery Factor for the period October 1995 through March 1996. 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 overrecovery of $27,079,758 shown on line 1 less the estimated/actual End-of-Period overrecovery of $14,614,552 shown on line 2 that was included in the calculation of the Fuel Cost Recovery Factor for the period April 1995 through September 1995, results in the Net True-Up for the period shown on line 3, an overrecovery of $12,465,206.

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 Amount", shows the actual fuel costs and revenues compared to the estimated/actuals for the period October 1994 through March 1995.

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 $8.2 million lower than the estimated/actual projection. This variance is detailed by major cost components on Appendix I, page 5, entitled "Final True-up Variance Analysis". The $8.2 million total system variance was primarily caused by a $21.3 million decrease in the Fuel Cost of System Net Generation, a $4.0 million decrease in the Fuel Cost of Purchased Power, offset by a $15.7 million increase in Energy Cost of Economy Purchases.

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 $3.6 million higher than the estimated/actual projection. This increase was due to higher jurisdictional kWh sales. Jurisdictional sales were 238,029,837 kWh (.69%) higher than the estimated/actual projection.

Q. **Have you provided a schedule explaining the reasons for these variances?**

A. Yes Pages 5 and 6, of Appendix I, contain a more detailed analysis of the cost variances with a corresponding explanation for each significant variance.

CAPACITY COST RECOVERY CLAUSE (CCR)

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

A. Appendix II, page 3, entitled "Summary of Net True-Up Amount" shows the calculation of the Net True-Up for the period, an overrecovery of $4,856,873, which I am requesting be included in the calculation of the Capacity Cost Recovery Factor for the period October 1995 through March 1996.

The actual End-of-Period overrecovery of $19,979,456, shown on line 1 less the estimated/actual End-of-Period overrecovery of $15,122,583, shown on line 2 that was included in the Capacity Cost Recovery Factor for the period April 1995 through September 1995, results in the Net True-Up shown on line 3, an overrecovery of $4,856,873.

Q. Have you provided a schedule showing the calculation of the End-of-Period true-up?

A. Yes. Appendix II, page 4, entitled "Calculation of Final True-up Amount", shows the calculation of the CCR End-of period tue-up for the period October 1994 through March 1995. The End of-Period true-up shown on line 19 is an overrecovery of $19,979,456.

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 A-2 "Calculation of True-Up and Interest Provision" for the Fuel Cost Recovery Clause.

Q. Please explain the calculation of the interest provision.

A. Appendix II, page 5, entitled "Calculation of Interest Provision", shows the calculation of the interest provision for the period October 1994 through March 1995 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 (line 4) by the monthly average interest rate (line 9). The average interest rate 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 interest calculated during the period amounts to $649,218 as shown on line 10.

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

A. Yes. Appendix II, page 6, entitled "Calculation of Final True-up Variances", shows the actual capacity charges and applicable revenues compared to the estimated/actuals for the period October 1994 through March 1995.

Q. What was the variance in net capacity charges?

A. As shown on line 6, actual net capacity charges on a Total Company basis were $0.9 million lower than the estimated/actual projection. This variance was primarily due to lower than expected capacity payments to the Southern Company for Unit Power Sales (UPS). The actual UPS capacity charges were $1.1 million lower than the estimated/actual projection primarily due to common investment for the Miller units being lower than projected.

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

A. As shown on line 13, actual Capacity Cost Recovery revenues, net of revenue taxes, were $3.9 million higher than the estimated/actual projection. This increase was primarily due to higher jurisdictional kWh sales than projected. Jurisdictional sales were 238,029,837 kWh (.69%) higher than estimated/actual projection.

OIL BACKOUT COST RECOVERY CLAUSE (OB)

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

A. Appendix III, page 3, entitled "Summary of Net True-Up Amount", shows the calculation of the Net True-Up for the period, an underrecovery of $6,647, which I am requesting be included in the calculation of the Oil Backout Cost Recovery Factor for the period October 1995 through March 1996.

The actual End-of-Period underrecovery of $522,576, shown on line 1 less the estimated/actual End-of-Period underrecovery of $515,929, shown on line 2 that was included in the Oil Backout Cost Recovery Factor for the period April 1995 through September 1995, result in the Net True-Up shown on line 3, an underrecovery of $6,647.

Q. What is the purpose of the schedule showing kWh sales?

A. The purpose of the schedule showing kWh sales on page 5, is to calculate the monthly percentage of retail (jurisdictional) kWh sales to total kWh sales. This monthly percentage (jurisdictional factor) is used to allocate costs between retail and wholesale customers. These kWh sales are consistent with the kWh sales shown in the FCR and CCR schedules.

Q. Have you provided a schedule showing the calculation of the End-of-Period true-up?

A. Yes. Appendix III, page 6, entitled "True-up Calculation" shows the calculation of the OB End-of-Period true-up for the period October 1994 through March 1995. The End-of-Period true-up shown on line 12, is an underrecovery of $522,576.

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 A-2 "Calculation of True-Up and Interest Provision" for the Fuel Cost Recovery Clause.

Q. Please explain the calculation of the interest provision.

A. Appendix III, page 7, shows the calculation of the interest provision for the period October 1994 through March 1995 and is consistent with the procedures used in calculating the interest for the FCR and CCR clauses. The interest calculated for the period is $1,912, as shown on line 10.

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

A. Yes. Appendix III, page 8, entitled "Calculation of Final True-up

Variances", shows the actual Oil Backout costs and revenues compared to the estimated/actuals for the period October 1994 through March 1995.

Q **Have you provided a schedule explaining the reasons for these variances?**

A Yes. Pages 9 and 10, of Appendix III, provide a more detailed analysis of the variances with corresponding explanations.

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

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF BARRY T. BIRKETT

DOCKET NO. 950001-EI

JUNE 20, 1995

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

A. My ame is Barry T. Birkett 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 the Manager of Rates and Tariff Administration.

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, the capacity payment factors and the oil backout factor for the Company's rate schedules, including the Time of Use rates, for the period October 1995 through March 1996. 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 providing updated projections of avoided energy costs for purchases from small power producers and cogenerators and 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), Capacity Cost Recovery Clause(CCR), and Oil Backout Cost Recovery Clause (OB), for the period April 1995 through September 1995.

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, III, IV, and V. Appendices II and III contain the FCR related schedules, Appendix IV contains the capacity related schedules, and Appendix V contains the Oil-backout related schedules.

Appendix III contains the Commission Schedules A1 through A9 for April and May 1995. These schedules were prepared by various departments including Power Supply, Rates, Power Generation and Accounting, and present a monthly comparison between the original projections and the actual generation, sales and fuel costs for the two months.

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. 1.769¢ per kWh. Schedule EI, 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 1995 through March 1996 and also the six-month levelized fuel factor for the period.

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

A. Yes. Schedule E1-D, Page 8 of Appendix II provides a six-month levelized fuel factor of 1.812¢ per kWh on-peak and 1.754¢ 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 28 of Schedule E1, Page 3, of Appendix II the estimated/actual fuel cost underrecovery for the April 1995 through September 1995 period amounts to $50,864,415. This estimated/actual underrecovery for the April 1995 through September 1995 period plus the final overrecovery $12,465,206 for the October 1994 through March 1995 period results in a total underrecovery of $38,399,209. This amount, divided by the projected retail sales of 35,446,721 MWh for October 1995 through March 1996 results in an increase of .1083¢ per kWh before applicable revenue taxes. In his testimony for the Generating Performance Incentive Factor, FPL Witness R. Silva calculated a reward of $3,109,109 for the period ending March 1995, to be applied to the October 1995 through March 1996 period. This $3,109,109 divided by the projected retail sales of 35,446,721 MWh during the projected period, results in an increase of .0088¢ per kWh, as shown on line 32 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 April 1995 through September 1995 is an underrecovery, including interest, of $50,864,415 (Column g, lines D7 plus D8). This amount, when combined with the Final True-up overrecovery of $12,465,206 (Column g, line D9a) deferred from the period October 1994 through March 1995, presented in my Final True-up testimony filed on May 19, 1995, results in the End of Period underrecovery of $38,399,209 (Column g, line D11).

This schedule also provides a summary of the Fuel and Net Power Transactions (lines A1 through A7), kWh Sales (lines C1 through C4), Jurisdictional Fuel Revenues (line D1 through D3), the True-up and interest calculation (lines D4 through D10) for this period, and the End of Period True-up amount (line D11).

The data for April and May 1995, columns (a) and (b), reflects the actual results of operations and the data for June 1995 through September 1995, columns (c) through (f), are based on updated estimates.

The variance calculation of the Estimated/Actual data compared to the original projections for the April 1995 through September 1995 period is provided in Schedule E1-B-1, Page 6 of Appendix II.

As shown on line A1 the variance in fuel cost of system net generation is $49.9 million. This is mainly due to an increase in heavy oil costs and generation. The heavy oil cost increase is primarily due to higher demand for heavy fuel oil in Mexico and Asia and less supply of residual fuel oil as refiners are trying to meet higher gasoline demand in the U.S. The increase in heavy oil generation is primarily due to an 85.2% increase in heavy oil generation (see Appendix III, Schedule A3, page 7) in the month of May 1995 due to a 7.4% increase in sales (see Appendix III, Schedule A2, page 5).

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 in this proceeding in Appendix III.

Q. **Has FPL included any other cost in the calculation of the fuel charge?**

A. Yes. FPL has included the depreciation and return on investment in rail cars that it purchased to deliver coal to the Scherer Plant consistent with Order No. 14546 in Docket No. 850001-EI-B which allows for the recovery of "transportation costs to the utility system". Specifically, Appendix A of the Order, Nos. 06 - 08 address rail car expenses and state that the fuel clause is the appropriate method for recovery. FPL has included these costs to be recovered through the fuel clause in the same manner as the rail cars used to deliver coal to the St. John River Power Park (SJRPP). Mr. Silva's testimony discusses FPL's decision to purchase 462 rail cars to deliver Western coal to its Scherer Unit No. 4 , and thereby achieve significant savings.

Q. Is FPL requesting that any other costs be recovered through the Fuel Cost Recovery Clause?

A. Yes. FPL is requesting to defer $2.7 million in implementation costs associated with changing from an 18 month fuel cycle operation to a 24 month fuel cycle operation of St. Lucie Units 1 and 2. FPL proposes to recover these costs through the Fuel Cost Recovery Clause in 1998, the same time that the fuel savings are realized by the customers. The change from an 18 month fuel cycle operation to a 24 month fuel cycle is discussed in more detail in the testimony of Claude Villard.

Q. What is the basis for requesting recovery of these implementation costs through the Fuel Cost Recovery Clause?

A. The Commission in Docket No. 850001-EI-B, Order No. 14546 issued on July 8, 1985 stated, regarding the charges appropriately included in the calculation of fuel "Fossil fuel-related costs normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine current base rates and which, if expended, will result in fuel savings to customers. Recovery of such costs should be made on a case by case basis after Commission approval."

The fuel savings associated with changing from an 18 month fuel cycle operation to a 24 month fuel cycle is projected to be $171 million through the year 2016. These expenditures will result in significant fuel savings for FPL's customers and appear to be the type of a cost which the Commission contemplated being recovered through the clause. For these reasons, FPL believes that it is appropriate to bring this issue forward for Commission consideration and approval.

Q. **What is shown on Pages 36-39 of Appendix II?**

A. Pages 36-39 of Appendix II contain revised Tariff Schedules COG-1 and COG-2. These tariff sheets contain, for informational purposes, updated projections of avoided energy costs for purchases from small power producers and cogenerators.

Q. **What is shown on Page 40 of Appendix II?**

A. Page 40 of Appendix II shows the revised loss factors for each rate group and for the retail sales in accordance with the annual energy loss report for 1994. The Company requests approval of these loss factors for the calculation of any fuel factors applicable to each rate group.

CAPACITY PAYMENT RECOVERY CLAUSE

Q. Please describe Page 3 of Appendix IV.

A. Page 3 of Appendix IV provides a summary of the requested capacity payments for the projected period of October 1995 through March 1996. Total recoverable capacity payments amount to $218,222,960 and include payments of $110,474,638 to non-cogenerators and payments of $138,261,934 to cogenerators. This amount is offset by revenues from capacity sales of $1,321,508 and $28,472,796 of jurisdictional capacity related payments included in Base Rates plus the net underrecovery of $2,615,886 reflected on line 8. The net underrecovery of $2,615,886 includes the final overrecovery of $4,856,873 for the October 1994 through March 1995 period less the estimated/actual underrecovery of $7,472,759 for the April 1995 through September 1995 period.

Q. Please describe Page 4 of Appendix IV.

A. Page 4 of Appendix IV 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 IV.**

A. Page 5 of Appendix IV 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. Appendix IV, page 6, shows the calculation of the CCR Estimated/Actual True-up amount. The Estimated/Actual True-up for the period April 1995 through September 1995 is an underrecovery, including interest, of $7,472,759 (Column 7, lines 14 plus 15). This amount, plus the Final True-up overrecovery of $4,856,873 (Column 7, line 17) deferred from the period October 1994 through March 1995, presented in my Final True-up testimony filed on May 19, 1995, results in the End of Period underrecovery of $2,615,886 (Column 7, line 19).

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 underrecovery of $2,615,886 has been included in the calculation of the Capacity Cost Recovery factor for the period October 1995 through March 1996.

Q. Please explain the calculation of the Interest Provision.

A. Appendix IV, page 7, shows 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 1994.

OIL BACKOUT COST RECOVERY CLAUSE (OB)

Q. Please explain the calculation of the OB Factor you are requesting this Commission to approve.

A. Appendix V, page 3, shows the derivation of the OB Factor of .013 cents per kWh requested for the projected period October 1995 through March 1996. This Factor represents the $4,333,094 in projected costs divided by the total kWh sales projected for the period, less the End of Period underrecovery of $138,014, divided by the retail kWh sales projected for the period October 1995 through March 1996. The resulting factor was then multiplied by the Revenue Tax Factor to arrive at the OB Factor for the period. Both the Revenue Tax Factor and the kWh sales are the same as those used in our Fuel Cost Recovery Clause included in this filing.

Q. What are the projected costs requested for recovery through the OB Factor for the period October 1995 through March 1996?

A. Appendix V, page 4, reflects the total projected costs requested for recovery for the period. These costs consist solely of the 500 kV Transmission Line Project (Project) revenue requirements, which total $4,333,094 for the projected period.

As detailed on page 4, the Project revenue requirements include a return on investment, taxes other than income taxes, income taxes, and O&M expenses. No depreciation is included since the capital investment in the 500 kV line was fully depreciated in October 1989. A detailed description of the methodology used to calculate the revenue requirements of the Project was included in E.L. Hoffman's testimony, Document No. 1 for the February 1983 hearing.

Q. Have you also presented the Estimated/Actual costs for the period April 1995 through September 1995?

A. Yes, Appendix V, page 6, shows the components of the $4,331,718 Estimated/Actual Project revenue requirements requested for the period. It contains similar information as that described in the previous paragraph, except it reflects two months actual data and four months updated estimates.

Q. What is the purpose of the schedules showing kWh sales?

A. The purpose of the schedules showing kWh sales on pages 5 and 7, is to show the calculation of the monthly percentage of retail (jurisdictional) kWh sales to total kWh sales, for the projected and Estimated/Actual periods respectively. These monthly percentages (jurisdictional factor) are used to allocate costs between retail and wholesale customers. The kWh sales reflected on these schedules are consistent with the kWh sales shown in the FCR and CCR schedules.

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

A. Appendix V, page 8, shows the calculation of the OB Estimated/Actual True-up amount. The Estimated/Actual True-up for OB is an underrecovery, including interest, of $131,367 (Column 9, lines 7 plus 8). This amount, when combined with the Final True-up underrecovery of $6,647 (Column 9, line 10) deferred from the period October 1994 through March 1995, presented in my Final True-up testimony filed on May 19, 1995, results in the End of Period underrecovery of $138,014 (Column 9, line 12).

Q. Please explain the calculation of the interest provision.

A. Appendix V, page 9, shows the calculation of the interest provision for the period April 1995 through September 1995 and is consistent with the procedures used in calculating the interest for the FCR and CCR clauses. The interest as result of net underrecoveries during the period is $13,231 as shown on line 10.

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

A. Yes. Appendix V, page 10, entitled "Calculation of Estimated/Actual True-up Variances", shows the estimated/actual Oil Backout costs and revenues compared to the original projections for the period April 1995 through September 1995.

Q Have you provided a schedule explaining the reasons for these variances?

A Yes. Pages 11 and 12, of Appendix V, provide a more detailed analysis of the variances with corresponding explanations for Revenue Requirements, and Jurisdictional kWh Sales, respectively.

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

A. The Company is requesting that the new factors become effective with customer billings on cycle day 3 of October 1995 and continue through Customer billings on cycle day 2 of April 1996. This will provide for 6 months of billing on these factors for all our customers.

Q. What will be the charge for a Residential customer using 1,000 kWh effective October 1995?

A. The total residential bill, excluding taxes and franchise, for 1,000 kWh will be $75.69. The base bill for 1,000 residential kWh is $47.38, the fuel cost recovery charge from Schedule E1-E, Page 9 of Appendix II for a residential customer is $17.73, the Conservation charge is $2.51, the Oil Backout charge is $.13, the Capacity Recovery charge is $6.94, the Environmental Cost Recovery charge is $.23 and the Gross Receipt Tax is $.77. A Residential Bill Comparison (1000kWh) is presented in Schedule E10, Page 34 of Appendix II.

Q. Does this conclude your testimony.

A. Yes, it does.

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

Direct Testimony of
Cheryl Martin
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. Cheryl Martin, 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. No.

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 1995 - March 1996 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 1995 - September 1995 and to establish a "true-up" amount to be collected or refunded during October 1995 - March 1996.

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 CMM-1.
These schedules support the calculation of the levelized fuel adjustment factor for October 1995 - March 1996. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period April 1995 - September 1995 based on 2 Months Actual and 4 Months Estimated data.

Q. In derivation of the projected cost factor for the October 1995 - March 1996 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 cost

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

A. The factors are as follows:

RS	.05228 $/KWH
GS	.05292 $/KWH
GSD	.04500 $/KWH
OL & SL	.04123 $/KWH

Q. Please address the calculation of the total true-up amount to be collected or refunded during the October 1995 - March 1996 period.

A. We have determined that at the end of September 1995 based on two months actual and four months estimated, we will have over-recovered $31,424 in purchased power costs in our Marianna division. Based on estimated sales for the period October 1995 - March 1996, it will be necessary to subtract .02553¢ per KWH to refund this over-recovery.

In Fernandina Beach we will have over-recovered $13,938 in purchased power costs. This amount will be refunded at .01303¢ per KWH during the October 1995 - March 1996 period. Page 3 and 12 of Composite Prehearing Identification Number CMM-1 provides a detail of the calculation of the true-up amounts.

Q. Looking back upon the October 1994 - March 1995 period, what were the actual End of Period - True-Up amounts for Marianna and Fernandina Beach, and their significance, if any?

A. The Marianna Division experienced an under-recovery of $77,221 and F nandina Beach Division over-recovered $223,977. 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 1994 through March 1995 for both divisions?

A. In Marianna the final remaining true-up amount was an over-recovery of $66,717. The final remaining true-up amount for Fernandina Beach was an over-recovery of $86,437.

Q. What are the estimated true-up amounts for the period of April 1995 through September 1995?

A. In Marianna, there is an estimated under-recovery of $35,293. Fernandina Beach has an estimated under-recovery of $72,499.

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

1995 - March 1996?

A. In Marianna the total fuel adjustment factor as shown on Line 33, Schedule E1, is 2.819¢ per KWH. In Fernandina Beach the total fuel adjustment factor for "other classes", as shown on Line 43, Schedule E1, amounts to 3.612¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period October 1995 - March 1996 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 $71.14, a decrease of $2.83 from the previous period. In Fernandina Beach a customer will pay $72.33, an increase of $1.94 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
M. L. Gilchrist
Docket No. 950001-EI
Date of Filing: May 19, 1995

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

Q. By whom are you employed and in what capacity?
A. I am the Manager of Fuel and Environmental Affairs for Gulf Power Company.

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

Q. What are your duties as Manager of Fuel and Environmental Affairs?
A. I manage the fuel supply and environmental compliance activities of the Company My responsibilities include fuel procurement, contract administration, and budgeting.

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

A. Yes.

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

A. The purpose of my testimony is to summarize Gulf Power Company's fuel expenses and to certify that these expenses were properly incurred during the period October 1994 through March 1995. Also, it is my intent to be available to answer any questions that may arise among the parties to this docket concerning Gulf Power Company's fuel expenses.

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

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

Counsel: We ask that Mr. Gilchrist's exhibit consisting of 1 schedule be marked as Exhibit No. ___20___ (MLG-1).

Q. During the period October 1, 1994, through March 31, 1995, how did Gulf's actual fuel expenses compare with the budget or projected expenses?

A. Gulf's actual fuel expense was $87,631,975 as compared with the projected amount of $111,500,080, or under our estimate by 21.41%. Gulf's total net system generation was 4,298,211 MWH compared to the projected generation of 5,907,450 MWH or 27.24% less than predicted.

The resulting total fuel cost per KWH generated was 2.0388¢/KWH or 8.02% over the projected amount of 1.8874¢/KWH.

Q. Mr. Gilchrist, did Gulf Power make any significant changes in its fuel purchasing program during the six months ending March 1995?

A. No. Peabody CoalSales is supplying a blend of Venezuelan and Illinois coal sufficiently low in sulfur content to ensure compliance with Phase I of the Clean Air Act which became effective January 1, 1995.

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

A. For the period, Gulf's average unit cost of coal purchased was 6.22% greater than projected.

Q. What caused Gulf's average unit cost of coal purchased to be 6.22% greater than projected?

A. Gulf Power's unit cost of coal was up due to a drop in generation, resulting in the purchase of a lesser amount of spot market coal to reduce the overall unit cost.

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

A. The current fuel supply program, called the seasonal Powder River Basin (PRB) fuel program, was implemented in 1994 as a cost-saving strategy for Plant Daniel. During the off peak season, when full plant capacity is not normally needed, the plant will burn lower cost PRB coal. During the peak season, when full plant capacity is required, the plant will burn high Btu western coal. To date, the seasonal fuel program is working very well.

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

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

Q. How much spot coal did Gulf Power Company purchase during the period ending March 31, 1995?

A. Gulf purchased 333,219 tons or 18% of its supply from the spot coal market. My Schedule 1 of Exhibit No. 20 (MLG-1) consists of a list of contract and spot coal suppliers for the period ending March 31, 1995.

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

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

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

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

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
M. L. Gilchrist
Docket No. 950001-EI
Date of Filing June 16, 1995

Q. Please state your name and business address.

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

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

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

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

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

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

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

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

Q. Mr. Gilchrist, what is the purpose of your testimony in this docket?
A. The purpose of my testimony is to support Gulf Power Company's projection of fuel expenses for the period October 1, 1995 to March 31, 1996 and to be available to answer any questions that may occur concernin[illegible] the Company's fuel procurement

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes. I have prepared an exhibit consisting of one schedule. Schedule 1 of my exhibit is a tabulation of projected and actual fuel cost for the past ten years. The purpose of this schedule is to illustrate the accuracy of our short term projections of fuel expenses.

COUNSEL: We ask that Mr. Gilchrist's exhibit, consisting of one schedule, be marked as Exhibit No. 21 (MLG-2).

Q. Has Gulf Power Company made any changes to its projection methods for this period?
A. No.

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

A. No. Gulf will continue to receive contract coal from Peabody CoalSales. The Company will supplement these receipts with purchases from the spot market.

Q. How much spot market coal does Gulf Power project it will purchase during October 1995 through March 1996?

A. We are projecting the purchase of approximately 463,895 tons. This represents approximately 19% of our projected purchase requirements.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 950001-EI
Date of Filing: May 19, 1995

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

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

Q. Have you previously testified before this Commission?

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

Q. Please summarize your educational and professional background.

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

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

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

A. I will summarize Gulf Power Company's purchased power recove: ıble costs for energy purchases and sales that were incurred during the October 1, 1994 through March 31, 1995 recovery period. I will then compare the actual costs to their projected levels for the period and discuss the primary reasons for the differences.

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

Q. During the period October 1, 1994 through March 31, 1995, 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 $12,615,250 as compared to the projected amount of $2,335,000. This resulted in a variance above budget of

$10,280,250, or 440%. The actual cost per KWH purchased was 1.1635 ¢/KWH as compared to 1.8658 ¢/KWH, or 38% below the projection.

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

A. Gulf was able to purchase significantly more economy power through the Southern electric power pool to meet its load than was forecasted for the period due to the availability of lower cost pool energy. Gulf purchased 1,084,248,708 KWH, shown on line 12 of Schedule A-1, as compared to the estimate of 125,150,000 KWH, or 766% more. The actual average cost was 1.1635 ¢/KWH as compared to the estimate of 1.8658 ¢/KWH, a decrease of 0.7023 ¢/KWH from budget.

This average actual cost of purchases of 1.1635 ¢/KWH was actually 43% less per KWH than Gulf's actual average fuel cost of system generation, shown on line 5, which was 2.0388 ¢/KWH. Gulf's system net generation was 4,298,211,000 KWH, or 27% under our estimate, but was over budget in unit cost by 8%.

Q. During the period October 1, 1994 through March 31, 1995, 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 \$17,850,216 as compared to the projected amount of \$33,651,600. This resulted in a variance below budget of \$15,801,384, or 47%. The actual fuel cost per KWH sold was 1.2917 ¢/KWH as compared to 1.7530 ¢/KWH, or 26% below the projection.

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

A. Gulf's off-system sales, shown on line 18, were 554,687,293 KWH, or 29%, under the projection for the period. These off-system sales were under the projection due to Gulf's decreased sale of energy to the Southern electric system power pool to meet the pool's overall energy requirements. The higher cost of energy available from Gulf's units compared with the cost of energy generated by the other pool members caused Gulf to sell less energy than budgeted to the pool for off-system obligations.

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

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

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

Q. During the period October 1, 1994 through March 31, 1995, how did Gulf's actual net purchased power capacity cost compare with the net projected cost?

A. In the Purchased Power Capacity Cost Recovery portion of Docket No. 940001-EI, I testified that the projected net purchased power capacity cost for the October 1, 1994 through March 31, 1995 recovery period was $5,125,921. The actual net capacity cost was $4,891,009. This represents a decrease in cost of $234,912, or 5% less than projected.

The projected net IIC capacity cost for the October 1, 1994 through March 31, 1995 recovery period was $5,425,921. The actual net IIC capacity cost for the filing period was $5,187,189, which is $238,732 or 4% less than projected.

The projected Florida Power Corporation Schedule E capacity revenue for the period was $300,000. The actual Schedule E capacity revenue for the recovery period was $296,180, or 1% less than projected. This revenue was essentially on target for the recovery period.

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

A. Gulf's actual net IIC capacity cost was less than budget because the Southern electric system had less actual system capacity to be equalized. Therefore, Gulf was responsible for purchasing its historical load ratio share of the lower system reserve capacity, enabling the company have a lower IIC capacity cost.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 950001-EI
Date of Filing: June 16, 1995

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

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

Q. Have you previously testified before this Commission?

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

Q. Please summarize your educational and professional background.

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

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

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

A. The purpose of my testimony is to support Gulf Power Company's projection of purchased power recoverable costs for energy purchases and sales and its projection of purchased power capacity costs for the period October, 1995 - March, 1996. I will also support the company's projection of purchased power capacity costs for the proposed October, 1995 - September, 1996 annual recovery period.

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

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

Counsel: We ask that Mr. Howell's Exhibit, comprised of one Schedule, be marked for identification as Exhibit 22 (MWH-1).

Q. What are Gulf's projected purchased power recoverable costs for energy purchases and sales for the October, 1995 - March, 1996 recovery period?

A. Gulf's projected recoverable cost for energy purchases, shown on line 12 of Schedule E-1 of the fuel filing, is $9,801,000. The projected fuel cost for energy sales, shown on line 18 of Schedule E-1, is $15,231,600. These transactions result from Gulf's participation in the coordinated operation of the Southern electric system power pool. These amounts are used by Gulf's witness Susan Cranmer as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. What information is contained in your exhibit?

A. Schedule 1 of my exhibit lists the name of the power contract that is included for capacity cost recovery, its associated megawatt amounts, and the resulting capacity dollar amounts.

Q. What power contract produces capacity transactions that are recovered through Gulf's purchased power capacity cost recovery factors?

A. The Commission has authorized the Company to include capacity transactions under the Southern electric system's Intercompany Interchange Contract

(IIC) for recovery through the purchased power capacity cost recovery factors. Gulf will have IIC capacity transactions during the October, 1995 - March, 1996 recovery period, as well as the proposed October, 1995 - September, 1996 annual recovery period. The energy transactions under the contract for these periods are handled for cost recovery purposes through the fuel cost recovery factors. At this time, Gulf does not participate in any other power contracts that would produce capacity transactions during either the six month or the proposed annual recovery period.

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

A. No, there have not been any changes to the contract itself. However, on November 1, 1994, in accordance with both the contract and the requirements of the Federal Energy Regulatory Commission (FERC), the Southern electric system made its annual IIC informational filing with the FERC. The informational filing reflects updated historical load responsibility ratios, the expected system load, and the capacity amounts for 1995 that are used in the capacity equalization calculation performed pursuant to the IIC to determine the capacity transactions and costs for each operating company. These updates have decreased Gulf's projected capacity payments for October, 1995 - March, 1996 recovery period by $37,566 from what they otherwise would have been prior to the update. Similiarly, the projected capacity payments for the proposed October, 1995 - September, 1996 annual recovery period have decreased by $729,441.

Q. What are Gulf's IIC capacity transactions that are projected for the October, 1995 - March, 1996 recovery period?

A. As shown on Schedule 1 of my exhibit, capacity transactions under the IIC vary from month to month. IIC capacity purchases in the amount of $7,748,129 are projected for the period. There are no IIC capacity sales projected for the recovery period. Therefore, the Company's net capacity transactions under the IIC for the period are net purchases amounting to $7,748,129. This compares to net purchases of $1,995,968 that were projected for the period April, 1995 - September, 1995.

Q. What are Gulf's total projected net capacity transactions for the October, 1995 - March, 1996 recovery period?

A. As shown on Schedule 1 of my exhibit, the net purchases under the IIC will cause Gulf to have a projected net capacity cost of $7,748,129. This figure is used by Ms. Cranmer as the sole input into the calculation of the total capacity transactions to be recovered through the purchased power capacity cost recovery factors for this recovery period.

Q. Gulf is proposing to set capacity cost recovery factors on an annual basis. Do you have any comments on this proposal?

A. Yes. As discussed in the testimony of Ms. Cranmer, the nature of Gulf's purchased power capacity costs recovered through the purchased power capacity cost recovery clause, when taken in conjunction with the normal expected variation in the Company's kilowatt-hour sales from one traditional six month recovery period to the next, is such that there is routinely a significant change in the recovery factors up and down every six months. The purpose of the proposed change is to dampen the swing in the factors experienced by Gulf's customers.

Q. What are Gulf's IIC capacity transactions that are projected for the proposed October, 1995 -September, 1996 annual recovery period?

A. Schedule 1 of my exhibit shows the IIC capacity transactions that vary during each month of the proposed annual period. IIC capacity purchases in the amount of $11,024,949 are projected for the proposed twelve month period. IIC capacity sales during the same period are projected to be $525,875. The sum of these purchases and sales yields the Company's net capacity transactions under the IIC for the period, which are net purchases amounting to $10,499,074. This annual figure would be used by Ms. Cranmer in the same manner as is the six month capacity figure to calculate the total capacity transactions to be recovered through the purchased power capacity cost recovery factors for this proposed twelve month recovery period.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Susan D. Cranmer
Docket No. 950001-EI
Fuel and Purchased Power Capacity Cost Recovery
Date of Filing: May 19, 1995

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

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

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

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

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

Q. Have 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. 23 (SDC-1).

Q. Are you familiar with the Fuel and Purchased Power (Energy) True-up Calculation and the Purchased Power Capacity Cost True-Up Calculation for the period of October 1994 through March 1995 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 1995 through March 1996?

A. An amount to be collected of $1,737,576 was calculated as shown in Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $1,737,576 was calculated by taking the difference in the estimated October 1994 through March 1995 under-recovery of $577,273 as approved in Order No. PSC-95-0450-FOF-EI, dated April 6, 1995 and the actual under-recovery of $2,314,849 which is the sum of lines 7 and 8 shown on Schedule A-2, page 3 of 4, Period-to-date of the monthly filing for March 1995.

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 1994 through March 1995.

Q. What is the amount to be refunded or collected in the period October 1995 through March 1996?

A. An amount to be collected of $35,386 was calculated as shown in Schedule CCA-1 of my exhibit.

Q. How was this amount calculated?

A. The $35,386 was calculated by taking the difference in the estimated October 1994 through March 1995 under-recovery of $101,423 as approved in Order No. PSC-95-0450-FOF-EI, dated April 6, 1995 and the actual under-recovery of $136,809 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 under-recovery of purchased power capacity costs for the period October 1994 through March 1995. Schedule CCA-3 of my exhibit is the calculation of the interest provision on the under-recovery. This is the same method of calculating interest that is used in the Fuel and Purchased Power (Energy) Cost Recovery Clause and the Environmental Cost Recovery Clause.

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

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Susan D. Cranmer
Docket No. 950001-EI
Fuel and Purchased Power Capacity Cost Recovery
Date of Filing: June 16, 1995

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

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

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

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

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

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

Q. What is the purpose of your testimony?
A. The purpose of my testimony is to discuss the calculation of Gulf Power's fuel cost recovery factors for the period October 1995 through March 1996. I will also discuss the calculation of the purchased power capacity cost recovery factors for that period.

Q. Are you familiar with the Fuel and Purchased Power Cost Recovery Clause Calculation for the period of October 1995 through March 1996?
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 seventeen schedules, along with Schedules A1 through A12 previously filed with the Commission for the months of December 1994, January, February, March, April, and May 1995, be marked as Exhibit No. 24 (SDC-2).

Q. Ms. Cranmer, what has Gulf calculated as the true-up to be applied in the period October 1995 through March 1996?

A. The true-up for this period is an increase of .069¢/kwh. This includes a final true-up under-recovery of $1,737,576. As shown on Schedule E-1A, it also includes an estimated true-up under-recovery of $875,443 for the current period. The resulting under-recovery is $2,613,019.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of October 1994 through March 1995?

A. This is shown on Line 32b of Schedule E-1 as $0. As discussed in the testimony of Mr. Fontaine, Gulf is proposing neither a reward nor a penalty for the period of October 1994 through March 1995.

Q. Ms. Cranmer, what is the levelized projected fuel factor for the period October 1995 through March 1996?

A. Gulf has proposed a levelized fuel factor of 2.210¢/kwh. It includes projected fuel and purchased power energy expenses for October 1995 through March 1996 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 2.237¢/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 1995 through March 1996. 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 applicable to September 1995 is 2.343¢/kwh compared with the proposed factor of 2.237¢/kwh. For a residential customer who uses 1000 kwh in October 1995, the fuel portion of the bill will decrease from $23.43 to $22.37.

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

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

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

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 purchased power capacity cost recovery factors for the period October 1995 through March 1996. As I will discuss later in my testimony, Gulf is proposing to change its PPCC factors from semi-annual to annual factors. Schedule CCE-3, including CCE-3a and CCE-3b, and CCE-4 show the calculation of the cost recovery factors for the period October 1995 through September 1996.

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

A. Schedule CCE-1 shows the calculation of the amount of capacity payments to be recovered through the Purchased

Power Capacity Cost Recovery Clause. Mr. Howell has provided me with Gulf's projected purchased power capacity transactions under the Southern Company Intercompany Interchange Contract (IIC). Gulf's projected capacity payments for the period October 1995 through March 1996 are purchases of $7,748,129. The jurisdictional amount is $7,469,087. For the period, Gulf's requested recovery before true-up is the difference between the jurisdictional projected purchased power capacity costs and the approved adjustment for former capacity transactions embedded in current base rates. This adjustment amount was fixed in Order No. PSC-93-0047-FOF-EI, dated January 12, 1993, as an embedded credit of $839,290, or $826,000 net of revenue taxes. Thus, the projected recovery amount to be collected through the purchased power capacity cost recovery factors in the period October 1995 through March 1996 is $8,295,087. 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 1995 through March 1996?

A. The true-up for this period is a decrease of $154,779 as shown on Schedule CCE-1a. This includes a final capacity cost true-up under-recovery of $35,386. It also includes an estimated over-recovery of $190,165 for the period April 1995 through September 1995, as calculated on Schedule CCE-1b.

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

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

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

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

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

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

Q. What is the amount related to purchased power capacity costs recovered through this factor that would be included on a residential customer's bill for 1000 kwh if the Commission were to approve the Company's proposed traditional six-month recovery factors?

A. The purchased power capacity costs recovered through the clause for a residential customer who uses 1000 kwh would be $2.64.

Q. Gulf is proposing to change the cycle for setting its purchased power capacity cost (PPCC) recovery factors from a six-month to a one-year cycle. Please comment on the reasons for the proposed change.

A. For Gulf, this is a customer satisfaction issue. Since the commencement of the PPCC recovery clause in 1993, Gulf's PPCC factors have consistently moved up and down between the traditional summer (April through September) and winter (October through March) recovery periods. The trend we have experienced results in a much higher factor in the winter than in the summer. Gulf is proposing an annual factor for its PPCC recovery in order to levelize the factors and thereby eliminate the variations experienced by the customer that occur simply because the factors have been set every six months. The nature of Gulf's purchased power capacity costs recovered through the PPCC combined with the regular seasonal differences in kwh sales causes Gulf's PPCC factors to vary significantly from one traditional six-month recovery period to the next. Because Gulf's capacity costs and kwh sales do not vary as widely from year to year as they do from one of the current six-month recovery periods to the next, the resulting fluctuations in customers' bills could be significantly reduced through the implementation of annual cost recover, factors for Gulf's purchased power capacity cost recovery clause.

Q. Please describe Schedules CCE-3 and CCE-4 of your exhibit.

A. Schedules CCE-3 and CCE-4 show the calculation of the recoverable capacity costs and associated cost recovery factors for the period October 1995 through September 1996. The methodology used in the calculations on these schedules is identical to the methodology used on Schedules CCE-1 and CCE-2 to calculate the semi-annual factors.

Q. What are Gulf's projected capacity payments for the period October 1995 through September 1996?

A. Gulf's projected capacity payments for the period October 1995 through September 1996 are purchases of $10,499,074. The jurisdictional amount is $10,120,959. For the 12-month period, the adjustment for former capacity transactions embedded in current base rates is a credit of $1,652,000, or two times the semi-annual credit of $826,000. For the annual recovery period, Gulf's requested recovery before true-up is the difference between the jurisdictional projected capacity costs of $10,120,959 and this embedded credit, or $11,772,959. The total true-up to be collected in the annual period is the same as that for the semi-annual period, an over-recovery of $154,779 net of revenue taxes. The total amount to be recovered in the period October 1995 through September 1996, including revenue taxes, is $11,805,117.

Q. What is the amount related to purchased power capacity costs that will be included on a residential customer's bill for 1,000 kwh using the annual PPCC factor?

A. The purchased power capacity costs recovered through the clause for a residential customer who uses 1,000 kwh will be $1.68 using an annual cost-recovery factor. This compares to $2.64 projected for the period October 1995 through March 1996, and an estimated $.91 for the period April 1996 through September 1996, using semi-annual factors.

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

A. These factors will apply to October 1995 through March 1996 billings beginning with Cycle 1 meter readings scheduled on September 28, 1995 and ending with meter readings scheduled on March 28, 1996. If the Commission approves an annual recovery period for the capacity costs, the annual PPCC factors shown on Schedule CCE-4 will apply to October 1995 through September 1996 billings beginning with Cycle 1 meter readings scheduled on September 28, 1995 and ending with meter readings scheduled on September 26, 1996.

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

A. Yes, it does.

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony of
G. D. Fontaine
Docket No. 950001-EI
Date of Filing May 19, 1995

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, 1994, through March 31, 1995.

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 25 (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, are there any modifications to the results that need clarification?

A. Yes, we have made an adjustment to essentially remove Daniel 1 and Daniel 2 from the heat rate results portion of this GPIF filing. The heat rate targets for these two units were rendered inapplicable to the period due to a significant change in the fuel supply at the Plant for the period. When the targets for this period were established, the two generating units at Plant Daniel were identified as GPIF units.

As discussed in the testimony of M. L. Gilchrist, the Company has recently implemented a fuel supply plan for Plant Daniel that includes the seasonal firing of Powder River Basin ("PRB") coal during non-summer months. The seasonal burning of PRB coal at Plant Daniel produces significant fuel cost savings for Gulf's territorial customers. PRB coal was the fuel burned at Plant Daniel during the October 1994 through March 1995 GPIF period.

Q. Why does the switch to PRB coal during the GPIF results period render the heat rate targets for Daniel 1 and Daniel 2 inapplicable?

A. The PRB coal has a substantially lower heat and higher moisture content than what had previously been the year round fuel supply for Plant Daniel. The targets for the period had been based on burning the higher heat and lower moisture content coal that had previously been the normal fuel supply for Plant Daniel. At the time the targets for the period were determined, there was not adequate data to properly derive target equations for both Daniel Units 1 and 2 based on the PRB coal. Because the targets had been based on experience with coal having higher heat and lower moisture content than the coal actually used during the period, the targets themselves became an unattainable standard.

Q. Should the Company be penalized for failing to meet heat rate targets that had been based on coal with a higher heat and lower moisture content?

A. No. As I previously mentioned, a prime driver in the decision to burn PRB coal at Plant Daniel during non-summer months was to save fuel costs for our customers. Assuming that both Daniel Units would have operated on their target equations with the higher heat and lower moisture content fuel, I calculated that burning the PRB coal instead of the higher heat and lower moisture content fuel saved Gulf's territorial customers over $2 million. Because of the differences inherent to PRB coal, these fuel savings could not have been achieved without the side effect of causing the Daniel units to miss the heat rate targets established based on experience with coal having a higher heat and lower moisture content. Therefore, for the reasons explained above, I have adjusted the heat rate weighting factors for Plant Daniel Units 1 and 2 to zero and left the remaining weighting factor the same.

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

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

A calculation of GPIF availability points based on these availabilities and the targets established by Commission Order PSC-94-1092-FOF-EI is on page 9 of Schedule 2. The results are: Crist 6, +10.00 points; Crist 7, +10.00 points; Smith 1, +10.00 points; Smith 2, +10.00 points; Daniel 1, +1.36 points, and Daniel 2, -10.00 points.

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

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

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

As calculated on page 16 of Schedule 3, the adjusted actual average net operating heat rates correspond to GPIF unit heat rate points of: 0.00 for

Crist 6, +5.62 for Crist 7; -0.70 for Smith 1, 0.00 for Smith 2. As explained earlier in my testimony, the heat rates for Daniel 1 and Daniel 2 have been excluded from the GPIF results calculation by setting the weighting factors to zero.

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 +1.18 as indicated on page 2 of Schedule 4. This calculates to a reward in the amount of $98,968. Because of the adjustments to the heat rate results made necessary due to the change in fuel supply at Plant Daniel, in lieu of the calculated reward, the Company believes that it is appropriate to set the reward/penalty for the period at zero dollars. It is this amount that the Company requests be approved by the Commission in this proceeding.

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 requests a net zero reward/penalty as provided for by the GPIF plan.

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

A. Yes, Sir.

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony of
G. D. Fontaine
Docket No. 950001-EI
Date of Filing June 16, 1995

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 today is to present GPIF targets for Gulf Power Company for the period of October 1, 1995 through March 31, 1996.

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 three 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 26 (GDF-2).

Q. Mr. Fontaine, 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. Mr. Fontaine, what are the target heat rates Gulf proposes to use in the GPIF for these units for the performance period October 1, 1995 through March 31, 1996?

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, Sir.

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, 1995 through March 31, 1996.

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.

(Transcript continues in sequence in Volume 2.)