BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of : **DOCKET NO. 960001-EI**

Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor.

FIRST DAY - MORNING SESSION

VOLUME 1

Pages 1 through 196

PROCEEDINGS: **HEARING**

BEFORE: COMMISSIONER J. TERRY DEASON
COMMISSION JULIA L. JOHNSON
COMMISSIONER JOE GARCIA

DATE: **Thursday, August 29, 1996**

TIME: Commenced at 10:00 a.m.
Concluded at 11:30 a.m.

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

REPORTED BY: H. RUTHE POTAMI, CSR, RPR
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Official Commission Reporter

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VICKI JOHNSON, Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0870, Telephone No. (904) 413-6199, appearing on behalf of the **Commission Staff.**

WITNESSES VOLUME 1

NAME	PAGE NO.
DAVID P. DEVELLE	
Prefiled Direct Testimony Inserted into the Record by Stipulation	13
LARRY G. TURNER	
Prefiled Direct Testimony Inserted into the Record by Stipulation	22
GEORGE M. BACHMAN	
Prefiled Direct Testimony Inserted into the Record by Stipulation	37
MICHAEL F. OAKS	
Prefiled Direct Testimony Inserted into the Record by Stipulation	42
M.W. HOWELL	
Prefiled Direct Testimony Inserted into the Record by Stipulation	49
SUSAN D. CRANMER	
Prefiled Direct Testimony Inserted into the Record by Stipulation	56
G.D. FONTAINE	
Prefiled Direct Testimony Inserted Into the Record by Stipulation	71
MARY JO PENNINO	
Prefiled Direct Testimony Inserted into the record by Stipulation	84
GEORGE A. KESELOWSKY	
Prefiled Direct Testimony Inserted into the Record by Stipulation	103
WILLIAM N. CANTRELL	
Prefiled Direct Testimony Inserted into the Record by Stipulation	131
KARL H. WIELAND	
Direct Examination By Mr. McGee	137
Prefiled Direct Testimony Inserted Into the Record by Stipulation	139
Cross Examination By Mr. Howe	156
Cross Examination By Mr. Hart	159
Cross Examination By Mr. Stone	185
Cross Examination By Ms. Johnson	193
Redirect Examination By Mr. McGee	196

EXHIBITS VOLUME 1

NUMBER		ID.	ADMTD.
1	RS-1	10	
2	RS-2	10	
3	RS-3	10	
4	RS-4	10	
5	CV-1	10	
6	RM-1	10	
7	RM-2	10	
8	RM-3	10	
9	RM-4	10	
10	RM-5	10	
11	RM-6	10	
12	RLW-1	10	
13	RLW-2	10	
14	DPD-1	10	
15	DPD-2	10	
16	KHW-1	10	
17	KHW-2	10	
18	LGT-1	10	
19	LGT-2	10	
20	GMB-1	10	
21	MFO-1	10	
22	MFO-2	10	
23	MWH-1	10	
24	SDC-1	10	
25	SDC-2	10	
26	GDF-1	10	
27	GDF-2	10	
28	MJP-1	10	
29	MJP-2	10	
30	MJP-3	10	
31	MJP-4	10	
32	GAK-1	10	
33	GAK-2	10	
34	GAK-3	10	
35	WNC-1	10	
36	HL-1	10	
1-3,			12
6-11			12
14-35			12

P R O C E E D I N G S

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

COMMISSIONER DEASON: We can proceed to the 01 docket. Are there any preliminary matters in the 01 docket?

MS. JOHNSON: Commissioner, several of the issues in the 01 docket have been stipulated as well. There is not a clean division of stipulated testimony and exhibits for several of the Florida Power & Light witnesses; and Mr. Childs, I believe, is prepared at this time to offer some additional information on that.

COMMISSIONER DEASON: Mr. Childs.

MR. CHILDS: Commissioners, when we reach the point of offering FPL witnesses, I had intended to call to your attention that there have been multiple sets of testimony filed for certain witnesses where although some of those sets of testimony and exhibits are not really related to issues that are actively disputed, they nevertheless need to be admitted into the record. And I also thought that it would be a waste of time to go through the identification process for each of those sets of testimony individually.

And so what I had proposed to do is that when our witnesses are called, I would identify for you the testimony that the witness was sponsoring as to an issue that we were litigating, and I have prepared a document, for whatever assistance it is, to indicate the additional testimony and exhibits that we want in the record so that we -- so that the reporter will know what is supposed to go in the record.

And I'm trying to divide that between the testimony, for instance, that relates to outages at St. Lucie from testimony that relates to general calculation of the fuel adjustment factor and other matters that I don't believe are in dispute. And I can distribute that to the Commissioners and the reporter now or when we get to FPL witnesses. I have already given a copy to Public Counsel, FIPUG and Staff.

COMMISSIONER DEASON: Well, I would like to have that announced, though, if you don't mind going ahead and doing that. (Pause)

Mr. Childs, let me ask you this: I appreciate this breakout, but how is this going to assist us in this proceeding? It was my intent is to simply for those witnesses whose testimony has not been stipulated in its entirety, we would take that testimony and go through normal procedure, and the parties could cross-examine on whatever portions of the testimony they deemed relevant.

MR. CHILDS: Certainly they can. What I was doing, if you will look at Page 1 for Mr. Silva, you will see that he is identified in the middle of the page as it relates to Issue 11. It is my understanding that that's the only issue that Mr. Silva is really addressing now that anybody really disputes or wants to inquire about.

However, if you go down to the next section under Mr. Silva, you will see that there are five other sets of testimony for Mr. Silva, and what I was proposing is that rather than me asking Mr. Silva the series of questions about is this your testimony and do you have any changes and corrections and do you adopt it and identify it by date, and do that five times, that I would simply call to your attention that it's his prefiled testimony dated 7/26/96, and his Document No. 1 one which has been preidentified as RS-4 that I think is an active issue; and that I would ask, subject to objection by parties, that the other testimony simply be inserted into the record, and that the other three documents be marked for identification in accordance with our procedure as we go through the hearing. And if anyone wants to inquire about any of this testimony, that's fine with us. I was just trying to cut the procedural questions down.

COMMISSIONER DEASON: Very well. Staff, do you have suggestions as to how we proceed at this point?

MS. JOHNSON: I'm prepared at this time, having looked at the list that Mr. Childs prepared, to identify which exhibits can be admitted into the record for issues that have been stipulated.

I will note that on the list that Mr. Childs provided there are listed two exhibits that are omitted from the prehearing order, RM-5 and RM-6, so those would have to be inserted as well.

I would also add that it's customary, when there are certain issues that are remaining, to have the witness identify only those portions of the testimony that relate to those issues, and that it's understood that the other testimony is admitted into the record as though read.

COMMISSIONER DEASON: Very well. What I propose to do at this point before we start taking witnesses, the exhibits which are shown on Pages 29, 30, 31, 32, just go ahead and preidentify, and give those preidentified exhibits -- and give them exhibit numbers, realizing that we need to add RM-5 and RM-6 to that list; is that correct?

MS. JOHNSON: That's correct.

COMMISSIONER DEASON: So what I propose to do is to identify for purposes of the record -- and these exhibits can be moved into the record or stipulated into the record at the appropriate time -- but they would be numbered beginning with the first exhibit, RS-1 appearing on Page 29 and would be numbered consecutively beginning there, and would be Exhibits 1 through 36, the last exhibit being HL1, which would be Exhibit 36.

The two exhibits which are added, RM-5 and RM-6 would be Exhibits 10 and 11, and I believe that that numbering is consistent. If there's some problem with that numbering, someone point it out, but those numbers will be applied to those prefiled exhibits.

(Exhibits 1-36 marked for identification.)

COMMISSIONER DEASON: There are a number of witnesses whose testimony can be inserted into the record in its entirety and all cross-examination waived, and those witnesses have been identified in the prehearing order with an asterisk by their names, and those appear on Page 5. So what I would propose to do is to go ahead and if there is a motion to have that testimony inserted into the record, take that up at this time. Does Staff so move?

MS. JOHNSON: Staff so moves.

COMMISSIONER DEASON: Okay. Without objection, the prefiled testimony of the witnesses appearing on Page 5 whose name is accompanied by an asterisk, those witnesses' prefiled testimony will be inserted into the record.

Likewise, the exhibits which have been prenumbered, which we just discussed, which accompany that prefiled testimony, I assume likewise they are being moved into the record at this point?

MS. JOHNSON: Yes. According to my count, Staff moves all exhibits except Exhibits 4, 5, 12, 13 and 36.

COMMISSIONER DEASON: Could you repeat those numbers again, please?

MS. JOHNSON: Staff moves all exhibits except exhibits 4, 5, 12, 13 and 36.

COMMISSIONER DEASON: Any objection to the admittance of all exhibits except for 4, 5, 12, 13 and 36? (No response)

Hearing no objection -- I want to make sure everyone has ample opportunity to review those exhibit numbers, because I just assigned those just a few minutes ago. (Pause) Any objection?

MR. HOWE: No objection.

MS. KAUFMAN: No objection.

COMMISSIONER DEASON: Very well. Those exhibits then will be admitted into the record and the cross examination will be waived for those witnesses whose name is accompanied by the asterisk on Page 5.

(Exhibits 1-3, 6-11, 14-35 received in evidence.)

FLORIDA POWER CORPORATION

DOCKET NO. 960001-EI

Re: Fuel Cost Recovery and Capacity Cost Recovery Final True-up Amounts for October 1995 through March 1996

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. Have your duties and responsibilities remained the same since you last testified in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Company's Fuel Cost Recovery Clause final true-up amount for the period of October 1995 through March 1996, 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 1995 through March 1996 period. Also, I will sponsor the applicable Schedules A1 through A9 for the month of March 1996 (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, 1996 for fuel cost recovery?

A. The actual ending balance as of March 31, 1996 for true-up purposes is an underrecovery of $29,993,960.

Q. How does this amount compare to the Company's estimated ending balance to be included in the April through September 1996 period?

A. When the estimated underrecovery of $5,915,935 to be collected during the period of April through September 1996 is taken into acccunt, the final true-up ending balance attributable to the six month period ended March 31, 1996 is an underrecovery of $24,078,025.

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 underrecovery of $30 million as shown on your exhibit DPD-1?

A. The factors contributing to the underrecovery are summarized on Sheet 1 of 3. The actual jurisdictional kwh sales were higher than the original estimate by 627,520,393 KWH. This increase in KWH sales, attributable to abnormally cold weather, resulted in higher jurisdictional revenues of $10.4 million and also accounted for much of the $40.2 million unfavorable variance in jurisdictional fuel and purchased power expense.

When these differences in jurisdictional revenues and jurisdictional fuel expenses are combined, the net result is an underrecovery of $30.3 million related to the October 1995 through March 1996 time period.

Other variances not directly related to the period, result in the actual ending balance underrecovery of $30 million, as of March 31, 1996.

Q. Please explain the components shown on exhibit (DPD-1), Sheet 2 of 3 which produced the $43.1 million unfavorable 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 increase of $36.9 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 $1.0 million. Lower 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 increase of $5.2 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 unfavorable variance were the annual payment to the Department of Energy for the Decontamination and decommissioning fund and an increase in the price of QF payments.

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, a decrease in the MWH requirements of nuclear generation shows up on Schedule A3 and on Sheet 2 of my exhibit as a cost decrease of $2.7 million. While this may be correct in isolation, the true effect of decreased nuclear generation is obviously a corresponding increase in the MWH requirements of a number of other more costly energy sources, primarily heavy and light oil. The result is a higher net system cost of $11.6 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 higher than the original forecast by 945,000 MWH. This would have led to higher net costs of \$23.1 million even if the mix of generation had not changed, since the higher system load increases oil generation at a cost above the system average.

Q. Please explain how this analysis was performed.

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

Q. What were the major contributors to the $36.9 million cost increase associated with the variance in MWH requirements?

A. Higher than expected system requirements during the period accounted for $23.1 million of the unfavorable variance. The remaining $13.8 million unfavorable increase is caused by the use of higher cost oil generation.

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 1995?

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 1995, the short cut method resulted in revenues of $237.6 million which were $.4 million or .15% 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, 1996 for capacity cost recovery?

A. The actual ending balance as of March 31, 1996 for true-up purposes is an overrecovery of $12,864,473.

Q. How does this amount compare to the Company's estimated ending balance to be included in the April through September 1996 period?

A. When the estimated overrecovery of $4,119,057 to be refunded during the period of April through September 1996 is taken into account, the final true-up ending balance attributable to the six month period ended March 1996 period is an overrecovery of $8,745,416.

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, the actual jurisdictional capacity cost revenues were $10.1 million higher than forecast due to higher KWH sales during the period, thus contributing to over 83% of the unfavorable variance.

Q. Does this conclude your testimony?

A. Yes, it does.

FLORIDA POWER CORPORATION

DOCKET NO. 960001-EI

Re: GPIF Reward/Penalty Amount 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 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 1995 through March 1996. 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 $1,498,216. 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.

FLORIDA POWER CORPORATION

DOCKET NO. 960001-EI

GPIF Targets and Ranges for October 1996 through March 1997

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 a Senior 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 1996 through March, 1997. This development includes the targets and improvement/degradation ranges for unit equivalent availability and unit average net operating heat rate in accordance with the Commission's Generating Performance Incentive Implementation Manual.

Q. Do you have an exhibit to your testimony?

A. Yes, I will sponsor an exhibit containing 78 pages, which consists of the GPIF standard form schedules prescribed in the Implementation Manual and supporting data, including unplanned outage rates, net operating heat rates, and computer analyses and graphs for each of the individual GPIF units, all of which are attached to my prepared testimony.

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

A. We have included the same units as were included for the current period, Crystal River Units 1 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 rates can then be converted into an overall equivalent unplanned outage factor (EUOF). Because factors are additive (unlike rates), the unplanned and planned outage factors (EUOF and POF) when added to the equivalent availability factor (EAF) will always equal 100%. For example, an EUOF of 15% and a POF of 10% results in an EAF of 75%.

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

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

A. The EAF target for Crystal River Unit 3 is 96.17%. Since no planned outages are scheduled for the upcoming winter period, the unit's EUOR and EUOF targets are both 3.83%.

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. 960001-EI

Re: GPIF Reward/Penalty Amount for October 1995 through March 1996

REVISED

DIRECT TESTIMONY OF LARRY G. TURNER

Q. Please state your name and business address.

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

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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 1995 through March 1996. 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 $1,527,566. 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
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 960001-EI
CONTINUING SURVEILLANCE AND REVIEW OF
FUEL COST RECOVERY CLAUSES OF ELECTRIC UTILITIES

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

Q. Please state your name and business address.

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

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Have you previously testified in this Docket?

A. Yes.

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

A. I will briefly describe the basis for the computations that were made in the preparation of the various Schedules that we have submitted in support of the October 1996 - March 1997 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 1996 - September 1996 and to establish a "true-up" amount to be collected or refunded during October 1996 - March 1997

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

A. Yes.

Q. Which of the Staff's set of schedules has your company completed and filed?

A. We have filed Schedules E1, E1A, E1-B, E1B-1, E2, E7, E8 and E10 for Marianna and Fernandina Beach. They are included in Composite Prehearing Identification Number GMB-3. These schedules support the calculation of the levelized fuel adjustment factor for October 1996 - March 1997. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period April 1996 - September 1996 based on 2 Months Actual and 4 Months Estimated data.

Q. In derivation of the projected cost factor for the October 1996 - March 1997 period, did you follow the same procedures that were used in the prior period filings?

A. Yes.

Q Why has the GSLD rate class for Fernandina Beach been excluded from these computations?

A. Demand and other purchased power costs are assigned to the GSLD rate class directly based on their actual CP KW and their actual KWH consumption. That procedure for the GSLD class has been in use for several years and has not been changed herein. Costs to be recovered from all other classes is determined after deducting from total purchased power costs those costs directly assigned to GSLD.

Q. How will the demand cost recovery factors for the other rate classes be used?

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

Q. Please address the calculation of the total true-up amount to be collected or refunded during the October 1996 - March 1997 period.

A. We have determined that at the end of September 1996 based on two months actual and four months estimated, we will have under-recovered $450,909 in purchased power costs in our Marianna division. Based on estimated sales for the period October 1996 - March 1997, it will be necessary to add .35148¢ per KWH to collect this under-recovery.

In Fernandina Beach we will have under-recovered $251,508 in purchased power costs. This amount will be collected at .22790¢ per KWH during the October 1996 - March 1997 period. Page 3 and 12 of Composite Prehearing Identification Number GMB-3 provides a detail of the calculation of the true-up amounts.

Q. Looking back upon the October 1995 - March 1996 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 $174,082 and Fernandina Beach Division under-recovered $102,872. 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 1995 through March 1996 for both divisions?

A. In Marianna the final remaining true-up amount was an under-recovery of $305,558. The final remaining true-up amount for Fernandina Beach was an under-recovery of $155,552.

Q. What are the estimated true-up amounts for the period of April 1996 through September 1996?

A. In Marianna, there is an estimated under-recovery of $145,351. Fernandina Beach has an estimated under-recovery of $95,956.

Q. What will the total fuel adjustment factor, excluding demand cost recovery, be for both divisions for the period October 1996 - March 1997?

A. In Marianna the total fuel adjustment factor as shown on Line 33, Schedule E1, is 2.995¢ per KWH. In Fernandina Beach the total fuel adjustment factor for "other classes", as shown on Line 43, Schedule E1, amounts to 3.252¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period October 1996 - March 1997 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 $72.08, a decrease of $1.60 from the previous period. In Fernandina Beach a customer will pay $71.63, an increase of $4.29 from the previous period.

Q. Does this conclude your testimony?

A. Yes.

Disk 19

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GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Michael F. Oaks
Docket No. 960001-EI
Date of Filing: May 20, 1996

Q. Please state your name and business address.

A. My name is Michael F. Oaks and my business address is 500 Bayfront Parkway, Post Office Box 1151, Pensacola, Florida 32520-0328.

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

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

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

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

Q. What are your duties as Supervisor of Fuel Supply?

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

Q. Mr. Oaks, have you previously testified before this Commission?
A. No.

Q. Mr. Oaks, what is the purpose of your testimony in this docket?
A. The purpose of my testimony is to summarize Gulf Power Company's fuel expenses and to certify that these expenses were properly incurred during the period October 1995 through March 1996. Also, it is my intent to be available to answer any questions that may arise among the parties to this docket concerning Gulf Power Company's fuel expenses.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes. I have prepared an exhibit consisting of one schedule.

Counsel: We ask that Mr. Oak's exhibit consisting of one schedule be marked as Exhibit No. 21 (MFO-1).

Q. During the period October 1, 1995, through March 31, 1996, how did Gulf's actual fuel expenses compare with the budget or projected expenses?
A. Gulf's actual fuel expense was $80,685,429 as compared with the projected amount of $88,082,064, or under our estimate by 8.40%. Gulf's total net system generation was 3,899,733 MWH compared to the

projected generation of 4,449,710 MWH or 12.58% less than predicted. The resulting total fuel cost per KWH generated was 2.0743¢/KWH or 4.79% over the projected amount of 1.9795¢/KWH.

Q. In his projection testimony filed on behalf of Gulf Power in this docket in January 1996, Mr. Lane Gilchrist discussed Gulf's agreement with Peabody CoalSales to cancel scheduled purchases under an existing long-term contract for a period of two years. Mr. Oaks, did Gulf Power make any other significant changes in its fuel purchasing program during the six months ending March 1996?

A. No. With regard to the Peabody suspension agreement mentioned in the course of your question, the Commission approved Gulf's recovery of the costs associated with this partial buyout in Order No. PSC-96-0353-FOF-EI, issued March 13, 1996.

Q. How much spot coal did Gulf Power Company purchase during the period ending March 31, 1996?

A. Gulf purchased 352,852 tons or 23% of its supply from the spot coal market. My Schedule 1 of Exhibit No. 21 (MFO-1) consists of a list of contract and spot coal suppliers for the period ending March 31, 1996.

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 1.55% higher than projected, a relatively small amount.

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 ensure the most economical price of oil.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Michael F. Oaks
Docket No. 960001-EI
Date of Filing: June 24, 1996

Q. Please state your name and business address.

A. My name is Michael F. Oaks and my business address is 500 Bayfront Parkway, Post Office Box 1151, Pensacola, Florida 32520-0328.

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

A. I am the Supervisor of Fuel Supply at Gulf Power Company and I also serve as the Company's Compliance Administrator.

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

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

Q. What are your duties as Supervisor of Fuel Supply?

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

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

A. Yes.

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

A. The purpose of my testimony is to support Gulf Power Company's projection of fuel expenses for the period October 1, 1996 to March 31, 1997 and to be available to answer any questions that may occur concerning the Company's fuel procurement procedures.

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

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

COUNSEL: We ask that Mr. Oaks' exhibit, consisting of one schedule, be marked as Exhibit No. 22 (MFO-2).

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

A. No.

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

A. No.

Q. How much spot market coal does Gulf Power project it will purchase during the October 1996 through March 1997 period?

A. We are projecting the purchase of approximately 846,000 tons. This includes 500,000 tons of Peabody contract replacement coal to be purchased on the spot market and represents approximately 35% of our projected purchase requirements.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 960001-EI
Date of Filing: May 20, 1996

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 Transmission and System Control Manager for Gulf Power Company.

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

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

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

I 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 recoverable costs for energy purchases and sales that were incurred during the October 1, 1995 through March 31, 1996 recovery period. I will then compare these actual costs to their projected levels for the period and discuss the primary reasons for the differences.

I will also summarize the actual capacity expenses and revenues that were incurred during the April 1, 1995 through September 30, 1995 recovery period, compare these figures to their projected levels, and discuss the reasons for the differences.

Q. During the period October 1, 1995 through March 31, 1996, 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 $23,950,773 as compared to the projected amount of $9,801,000. This resulted in a variance above budget of

$14,149,773, or 144%. The actual cost per KWH purchased was 2.1822 ¢/KWH as compared to the projected 1.8481 ¢/KWH, or 18% above the projection.

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

A. During October and November of the recovery period, the availability of lower cost pool energy allowed Gulf to purchase more economy power from the Southern electric system. Then, the extremely cold temperatures of February 1996 produced higher than projected territorial loads across the Southern system and caused Gulf to purchase more power at a significantly higher unit price than was forecasted in order to meet its load obligation.

Therefore, lower cost energy in October and November, coupled with February's higher territorial load and pool energy cost, resulted in Gulf's increased purchase of pool energy at a higher than projected price during the recovery period. Gulf purchased 1,097,550,097 KWH, shown on line 12 of Schedule A-1, as compared to the estimate of 530,330,000 KWH, or 107% more than forecasted.

Q. During the period October 1, 1995 through March 31, 1996, 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 \$10,585,257 as compared to the projected amount of \$15,231,600. This resulted in a variance below budget of \$4,646,343, or 31%. The actual fuel cost per KWH sold was 1.6073 ¢/KWH as compared to 1.8910 ¢/KWH, or 15% below the projection.

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

A. Gulf's pool and off-system sales, shown on line 18, were 658,575,213 KWH, or 18% under the projection for the period. These sales were under the projection due to Gulf's decreased sale of energy to Unit Power customers and the Southern electric system power pool to meet the system's off-system energy requirements. The higher cost of energy available from Gulf's resources compared with the cost of energy generated by the other pool members caused Gulf to sell less energy than budgeted.

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

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

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

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

A. In the Purchased Power Capacity Cost Recovery portion of Docket No. 950001-EI, I testified that the projected net purchased power capacity cost for the April 1, 1995 through September 30, 1995 recovery period, consisting entirely of IIC capacity cost, was $1,995,968. The actual net capacity cost was $1,842,381. This represents a decrease in cost of $153,587, or 8% less than projected.

Q. Please explain the reasons for this minor difference.
A. During the recovery period, Gulf's actual net IIC capacity cost was lower than budget because there was less actual system capacity to be equalized due to the delayed installation of planned system capacity.

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

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. 960001-EI
Fuel and Purchased Power Capacity Cost Recovery
Date of Filing: May 20, 1996

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

A. My name is Susan Cranmer. My business address is 500 Bayfront Parkway, Pensacola, Florida 32501. I hold the position of Assistant Secretary and Assistant Treasurer of Gulf Power Company. In this position, I am responsible for supervising the Rates and Regulatory Matters Department.

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

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

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

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

A. Yes, I have.

Counsel: We ask that Ms. Cranmer's Exhibit consisting of four schedules be marked as Exhibit No. 24 (SDC-1).

Q. Are you familiar with the Fuel and Purchased Power (Energy) True-up Calculation for the period of October 1995 through March 1996 and the Purchased Power Capacity Cost True-up Calculation for the period of April 1995 through September 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 1996 through March 1997?

A. An amount to be collected of $7,291,590 was calculated as shown in Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $7,291,590 was calculated by taking the difference in the estimated October 1995 through March 1996 under-recovery of $496,180 as approved in Order No. PSC-96-0353-FOF-EI, dated March 13, 1996 and the actual under-recovery of $7,787,770 which is the sum of lines 7 and 8 shown on Schedule A-2, page 2 of 3, Period-to-date of the monthly filing for March 1996.

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

A. Schedules CCA-1, CCA-2, and CCA-3 of my exhibit relate to the Purchased Power Capacity Cost True-up Calculation for the period April 1995 through September 1995.

Q. What is the amount to be refunded or collected in the period October 1996 through September 1997?

A. An amount to be refunded of $410,705 was calculated as shown in Schedule CCA-1 of my exhibit.

Q. How was this amount calculated?

A. The $410,705 was calculated by taking the difference in the estimated April 1995 through September 1995 over-recovery of $190,165 as approved in Order No. PSC-95-1089-FOF-EI, dated September 5, 1995 and the actual over-recovery of $600,870 which is the sum of lines 11 and 12 under the total column of Schedule CCA-2.

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

A. Schedule CCA-2 shows the calculation of the actual over-recovery of purchased power capacity costs for the period April 1995 through September 1995. Schedule CCA-3 of my exhibit is the calculation of the interest provision on the over-recovery. This is the same method of calculating interest that is used in the Fuel and

Purchased Power (Energy) Cost Recovery Clause and the Environmental Cost Recovery Clause.

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

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Susan D. Cranmer
Docket No. 960001-EI
Fuel and Purchased Power Cost Recovery
Date of Filing: June 24, 1996

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

A. My name is Susan Cranmer. My business address is 500 Bayfront Parkway, Pensacola, Florida 32501. I hold the position of Assistant Secretary and Assistant Treasurer for Gulf Power Company.

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

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

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

Q. Have you previously filed testimony before this Commission in Docket No. 960001-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 1996 through March 1997. I will also discuss the calculation of the purchased power capacity cost recovery factors for the period October 1996 through September 1997.

Q. Are you familiar with the Fuel and Purchased Power Cost Recovery Clause Calculation for the period of October 1996 through March 1997?
A. Yes, these documents were prepared under my supervision.

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

Counsel: We ask that Ms. Cranmer's Exhibit consisting of fifteen schedules, along with Schedules A1 through A9 previously filed with the Commission for the months of December 1995, January, February, March, April, and May 1996, be marked as Exhibit No. 25 (SDC-2).

Q. Ms. Cranmer, what has Gulf calculated as the true-up to be applied in the period October 1996 through March 1997?
A. The true-up for this period is an increase of .256¢/kwh. This includes a final true-up under-recovery of $7,291,590. As shown on Schedule E-1A, it also includes an estimated true-up under-recovery of $2,727,188 for the current period. The resulting under-recovery is $10,018,778.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of October 1995 through March 1996?

A. This is shown on Line 32b of Schedule E-1 as a decrease of .0011¢/kwh, thereby penalizing Gulf by $44,234.

Q. Ms. Cranmer, what is the levelized projected fuel factor for the period October 1996 through March 1997?

A. Gulf has proposed a levelized fuel factor of 2.317¢/kwh. It includes projected fuel and purchased power energy expenses for October 1996 through March 1997 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 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 2.345¢/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 1996 through March 1997. These factors included the GPIF, true-up, and special contract recovery cost amounts and were adjusted for line losses. These time-of-use fuel factors are also shown on Schedule E-1E.

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

A. The current fuel factor for Rate Schedule RS applicable to September 1996 is 2.193¢/kwh compared with the proposed factor of 2.345¢/kwh. For a residential customer who uses 1000 kwh in October 1996, the fuel portion of the bill will increase from $21.93 to $23.45.

Q. Ms. Cranmer, has Gulf updated its estimates of the as-available avoided energy costs to be shown on COG1 as required by Order No. 13247 issued May 1, 1984, in Docket No. 830377-EI and Order No. 19548 issued June 21, 1988, in Docket No. 880001-EI?

A. Yes. A tabulation of these costs is set forth in Schedule E-11 of my Exhibit SDC-2. These costs represent the estimated averages for the period from October 1996 through September 1998.

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

A. Schedule CCE-1, including CCE-1a and CCE-1b, and Schedule CCE-2 of my exhibit relate to the calculation of the PPCC recovery factors for the period October 1996 through September 1997.

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

A. Schedule CCE-1 shows the calculation of the amount of capacity payments to be recovered through the PPCC Recovery Clause. Mr. Howell has provided me with Gulf's projected purchased power capacity transactions under the Southern Company Intercompany Interchange Contract (IIC) and Gulf's contract with Monsanto Chemical

Company. Gulf's projected capacity payments for the period October 1996 through September 1997 are purchases of $11,481,953. The jurisdictional amount is $11,059,291. For the period, Gulf's requested recovery before true-up is the difference between the jurisdictional projected purchased power capacity costs and the approved adjustment for former capacity transactions embedded in current base rates. This adjustment amount was fixed in Order No. PSC-93-0047-FOF-EI, dated January 12, 1993, as an embedded credit of $1,678,580, or $1,652,000 net of revenue taxes. Thus, the projected recovery amount to be collected through the PPCC recovery factors in the period October 1996 through September 1997 is $12,711,291. This amount is added to the total true-up amount to determine the total purchased power capacity transactions to be recovered through the factors to be applied in the period.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period October 1996 through September 1997?

A. The true-up for this period is a decrease of $784,861 as shown on Schedule CCE-1a. This includes a final capacity cost true-up over-recovery amount for April 1995 through September 1995 of $410,705. It also includes an estimated over-recovery of $374,156 for the period October 1995 through September 1996, 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 PPCC Recovery Clause, Gulf has allocated the net purchased power capacity costs to rate class with 12/13th on demand and 1/13th on energy. This allocation is consistent with the treatment accorded to production plant in the cost of service study used in Gulf's last rate case.

Q. How were the allocation factors calculated for use in the PPCC Recovery Clause?

A. The allocation factors used in the Purchased Power Capacity Cost Recovery Clause have been calculated using the 1995 load data filed with the Commission in accordance with FPSC Rule 25-6.0437. The calculations of the allocation factors are shown in columns A through I on page 1 of Schedule CCE-2.

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

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

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

A. The purchased power capacity costs recovered through the clause for a residential customer who uses 1000 kwh would be $1.67.

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

A. The fuel factors will apply to October 1996 through March 1997 billings beginning with Cycle 1 meter readings scheduled on September 27, 1996 and ending with meter readings scheduled on March 28, 1997. The capacity factors will apply to October 1996 through September 1997 billings beginning with Cycle 1 meter readings scheduled on September 27, 1996 and ending with meter readings scheduled on September 27, 1997.

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. 960001-EI
Date of Filing May 20, 1996

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, 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 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 26 (GDF-1).

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-95-1089-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, +10.00 points, and Daniel 2, -0.83 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 1995, 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, +0.00 for Crist 7, -2.58 for Smith 1, -2.00 for Smith 2, -5.47 for Daniel 1, and -10.00 for Daniel 2. The heat rates for Daniel 1 and Daniel 2 have been excluded from the GPIF results calculation by setting the weighting factors to zero as approved in the previously mentioned Commission Order approving the targets for the present reporting period.

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

A. Using the unit equivalent availability and heat rate points previously mentioned, along with the adjusted weighting factors, the Company points would be -0.51 as indicated on page 2 of Schedule 4. This calculates to a penalty in the amount of $44,234.

Q. Mr. Fontaine, do you have any other comments relative to the GPIF?

A. Yes. Targets for the current April 1996 through September 1996 period were established in January 1996 based on projections at that time. We have recently been made aware that Plant Daniel has continued its seasonal burn of Powder River Basin coal longer than originally anticipated at the time the targets were set.

Q. What was the purpose of this change?

A. This change was made in order to save fuel costs for the general body of customers.

Q. Does this affect the validity of the targets for the period of April 1996 through September 1996?

A. The targets that were submitted in January 1996 included burning Powder River Basin coal at Plant Daniel through April 1996 and then switching to high BTU western coal for the remainder of the period. Although the targets equations are not valid for burning Powder River Basin coal, Gulf filed our targets with the assumption that one month of burning Powder River Basin coal would not significantly impact the results. However, burning Powder River Basin coal more than one month may have a serious impact on the final results of Plant Daniel for the April 1996 through September 1996 reporting period.

Q. What is the reason for your comments at this time?
A. We wanted to advise the Commission of the change as early as possible. No action is needed at this time. We would expect to make appropriate adjustments at the time results for the period are filed in November 1996.

Q. Mr. Fontaine, would you please summarize your testimony?
A. Yes, Sir. In view of the adjusted actual equivalent availabilities, as shown on page 9 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 16 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a penalty in the amount of $44,234 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. 960001-EI
Date of Filing June 24, 1996

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. Have you previously testified in this Docket?

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

Q. What is the purpose of your testimony in this proceeding?
A. The purpose of my testimony today is to present GPIF targets for Gulf Power Company for the period of October 1, 1996 through March 31, 1997.

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

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

Counsel: We ask that Mr. Fontaine's exhibit be marked for identification as exhibit 27 (GDF-2).

Q. Which units does Gulf propose to include under the GPIF for the subject period?
A. We propose that Crist Units 6 and 7, Smith Units 1 and 2, and Daniel Units 1 and 2 continue to be the Company's GPIF units.

Q. What are the target heat rates Gulf proposes to use in the GPIF for these units for the performance period October 1, 1996 through March 31, 1997?

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. With the exception of data used for the statistical development of the Plant Daniel Units 1 and 2 target equations, the target heat rates 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. Why was the statistical development of the Plant Daniel Unit's target equations treated different than the other GPIF units?

A. Plant Daniel has been burning Powder River Basin fuel for the last three winter periods. Burning Powder River Basin fuel reduces the maximum output of the Daniel Units. However, during peak periods, burning high BTU western coal allows the Daniel Units to run at full capacity. The Powder River Basin fuel is a high moisture content, low BTU coal and the high BTU western fuel is a low moisture, higher BTU coal. The amount of moisture in these two fuels is the major factor that causes a significant difference in the Plant Daniel heat rate when one fuel is burned when compared to the other fuel.

We previously believed the regression process would factor the seasonal difference between the two different fuels into the target equations. When the regression was initially performed for this filing period, the regression analysis did not reasonably separate the off-peak and peak periods when the different fuels are burned. Therefore, only data from the October through March winter periods was utilized for the regression of the Plant Daniel Units 1 and 2 target equations.

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

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

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

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

Q. Mr. Fontaine, has Gulf completed the GPIF minimum filing requirements data package?

A. Yes, we have completed the required data. Schedule 3 of my exhibit contains this information.

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

A. Yes. Gulf asks that the Commission accept:

1. Crist Units 6 and 7, Smith Units 1 and 2 and Daniel Units 1 and 2, for inclusion under the GPIF for the period of October 1, 1996 through March 31, 1997.

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.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

MARY JO PENNINO

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

A. My name is Mary Jo Pennino. My business address is 702 North Franklin Street, Tampa, Florida 33602. My position is Manager - Energy Issues and Administration in the Regulatory and Business Strategy Department of Tampa Electric Company.

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

A. I received a Bachelor of Science Degree in Chemical Engineering from the University of South Florida, Tampa, Florida in 1985. Upon graduation, I began my career at Tampa Electric Company in the Production Department. My responsibilities included heat rate testing, support services for the Plant Chemical Engineers, and start-up assistance for Hookers Point Station. In 1991, I transferred to the Generation Planning Department where I was responsible for annual expansion planning analyses, alternative technology evaluation and several other business planning activities. In 1993, I was promoted to Administrator - Wholesale and Fuel in the Regulatory and Business Strategy Department and in 1995 to Manager - Energy Issues and Administration, also in Regulatory and Business Strategy. My present responsibilities include the areas of fuel adjustment filings, capacity cost recovery filings, and rate design.

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

A. The purpose of my testimony is to present the net true-up amounts for the October 1995 through March 1996 period for both the Fuel Cost Recovery and the Capacity Cost Recovery Clauses.

FUEL COST RECOVERY CLAUSE

Q. What is the net true-up amount for the fuel cost recovery clause for the period October 1995 through March 1996?

A. An over/(under) - recovery of ($5,676,277). The actual fuel cost over/(under) - recovery, including interest, is ($4,639,090) for the period October 1995 through March 1996 (Schedule A2, page 2 of 3, of March 1996 monthly filing, in

Document No. 4, reflects an end of period total net true-up of ($5,076,375). Subtracting the beginning of period deferred true-up of ($437,285) yields the ($4,639,090). This ($4,639,090) amount, less the actual/estimated over/(under) - recovery approved in the February 1996 fuel hearings of $1,037,187 results in a final over/(under) - recovery for the period of ($5,676,277). This over/(under) - recovery amount of ($5,676,277) will be carried over and applied in the calculation of the fuel recovery factor for the period October 1996 through March 1997.

Q. How much effect will this ($5,676,277) over/(under) - recovery in the October 1995 through March 1996 period, have on the October 1996 through March 1997 period?

A. The ($5,676,277) over/(under) - recovery will cause a 1,000 KWH residential bill to be approximately $0.83 higher.

Q. Have you prepared an Exhibit in this proceeding?

A. Yes. Exhibit No. (MJP-1, Fuel Cost Recovery and Capacity Cost Recovery) which contains four documents. Document No. 3 is used to explain the capacity cost recovery clause which is discussed later in my testimony. Document No. 4 contains Commission Schedules A-1 through A-9 for the months of October 1995 through March 1996. Included with the March 1996 monthly filing is a six months summary for each of Commission Schedules A6, A7, A8, and A9 for the period October 1995 through March 1996.

Q. Please explain Document No. 1.

A. Document No. 1, entitled "Tampa Electric Company Final Fuel Over/(Under) - Recovery for the period October 1995 through March 1996" shows the calculation of the final fuel over/(under) - recovery for the period of ($5,676,277) which will be applied to jurisdictional sales during the period October 1996 through March 1997.

Line 1 shows the total company fuel costs of $161,831,344 for the period October 1995 through March 1996. The jurisdictional amount of total fuel costs is $164,240,454 as shown on line 2. This amount is compared to the jurisdictional fuel revenues applicable to the period on line 3 to obtain the actual over/(under) - recovered fuel costs for the period, shown on line 4. The resulting ($4,477,634) over/(under) - recovered fuel costs for the period, combined with ($161,456) of interest shown on line 5, constitute the actual over/(under) - recovery of ($4,639,090) shown on line 6. The ($4,639,090) less the actual/estimated over/(under) - recovery of $1,037,187 shown on line 7, which was approved in the February 1996 fuel hearings, results in the final over/(under) - recovery of ($5,676,277) shown on line 8.

Q. What does Document No. 2 show?

A. Document No. 2, entitled "Tampa Electric Company Calculation of True-Up Amount Actual vs. Original Estimates for the period October 1995 through March 1996," shows the calculation of the actual over/(under) - recovery as compared to the original estimate for the same period.

Q. What was the variance in jurisdictional fuel revenues for the period October 1995 through March 1996?

A. As shown on line C1 of my Document No. 2, the company collected $9,193,149 or 5.8% more jurisdictional fuel revenues than originally estimated.

Q. What was the total fuel and net power transaction cost variance for the period October 1995 through March 1996?

A. As shown on line A7 of Document No. 2, the fuel and net power transactions cost variance is $13,364,563 or 9.0%.

Q. What are the reasons for the total fuel and net power transactions cost being higher by $13,364,563 or 9.0%?

A. The primary reason for the 9.0% increase is due to Net Energy for Load being up 398,735 MWH or 5.7%. This 5.7% combined with the ¢/KWH for Total Fuel and Net Power Transaction being greater than estimated by 3.1%, accounts for the 9.0% increase.

CAPACITY COST RECOVERY CLAUSE

Q. What is the net true-up amount for the capacity cost recovery clause for the period October 1995 through March 1996?

A. An over/(under) - recovery of $785,067. The actual capacity cost over/(under) - recovery, including interest, is $946,679 for the period October 1995 through March 1996 (Document No. 3, pages 2 and 3 of 5). This amount, less the actual/estimated over/(under) - recovery approved in the February 1996 fuel hearings of $161,612 results in a final over/(under) - recovery for the period of $785,067 (Document No. 3, page 5 of 5). This over/(under) - recovery amount of $785,067 will be carried over and applied in the calculation of the capacity cost recovery factor for the period October 1996 through March 1997.

Q. How much effect will this $785,067 over/(under) - recovery in the October 1995 through March 1996 period, have on the October 1996 through March 1997 period?

A. The $785,067 over/(under) - recovery will approximately cause a $0.11 decrease in a 1,000 KWH residential bill.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

MARY JO PENNINO

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

A. My name is Mary Jo Pennino. My business address is 702 North Franklin Street, Tampa, Florida 33602. My title is Manager - Energy Issues and Administration. I work in the Regulatory and Business Strategy Department of Tampa Electric Company.

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

A. I graduated from the University of South Florida with a Bachelor of Science Degree in Chemical Engineering in 1985. Upon graduation, I began my career with Tampa Electric Company as an Engineer in the Production Department. In 1991, I transferred to the Generation Planning Department where I was responsible for annual expansion planning analyses, alternative technology evaluation and several other business planning activities. In 1993, I was promoted to Administrator - Wholesale and Fuel in the

Regulatory and Business Strategy and in 1995 to Manager - Energy Issues and Administration, also in Regulatory and Business Strategy. My present responsibilities include the areas of fuel adjustment filings, capacity cost recovery filings, and rate design.

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

A. The purpose of my testimony is to present to the Commission the proposed Total Fuel and Purchased Power Cost Recovery factors for the period of October 1996 - March 1997, and the proposed Capacity Cost Recovery factors for the same period. I am also presenting billing refund credit factors beginning October 1996 per the $25 million refund in the stipulation approved in Order No. PSC-96-0670-S-EI.

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

Q. Did you review the projected data necessary to calculate the Total Fuel and Purchased Power Cost Recovery factors for the period October 1996 - March 1997?

A. Yes I have.

Q. Do you wish to sponsor an exhibit consisting of Schedules H-1 (October - March, 1994 through 1997) and Schedules E-1 through E-10 (October 1996 - March 1997)?

A. Yes. Also contained in this exhibit are Schedules E-2, E-3, E-5, E-6, E-7, E-8 and E-9 for the prior period April 1996 - September 1996. These schedules are furnished as back-up for the projected true-up for this period and consist of two actual months and four projected months.

(Have identified as Exhibit No. 29 (MJP-2), Fuel Projection.)

Q. Does Schedule E-1 of Exhibit No. 29 (MJP-2), Fuel Projection, show the proper value for the Total Fuel and Purchased Power Cost Recovery Clause as projected for the period October 1996 - March 1997?

A. Yes.

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

A. The proper value for the new period is 2.401 cents per kwh before the application of the factors that adjust for variations in line losses.

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

A. The GPIF and True-up factors are provided on Schedule E-1C. We propose that a GPIF penalty of ($104,014) be included in the projection period. The True-up amount for the April 1996 - September 1996 period is an underrecovery of ($4,519,107). This underrecovery is comprised of a final True-up underrecovery amount of ($5,676,277) for the October 1995 - March 1996 period and an estimated overrecovery in the amount of $1,157,170 for the April 1996 - September 1996 period.

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

A. Schedule E-1D presents the company's on-peak and off-peak fuel charge factors for the October 1996 - March 1997 period.

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

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

Q. Have the fuel Recovery Loss Multipliers that reflect the variation in line losses been modified?

A. Yes. Document No. 2 of exhibit (MJP-2) shows revised Fuel Recovery Loss Multipliers and a revised Jurisdictional Loss Multiplier which have been modified to reflect actual 1995 sales data and losses. The Company requests approval of these factors for the calculation of fuel factors applicable to each fuel group.

Q. Please recap the proposed Fuel and Purchased Power Cost Recovery factors for the October 1996 - March 1997 period.

A.

Rate Schedule	Fuel Charge Factor (cents per kwh)
Average Factor	2.401
RS, GS and TS	2.418
RST and GST	2.841 (on-peak)
	2.258 (off-peak)
SL-2, OL-1 and OL-3	2.345
GSD, GSLD, EV-X, and SBF	2.404
GSDT, GSLDT, EVT-X and SBFT	2.825 (on-peak)
	2.245 (off-peak)
IS-1, IS-3, SBI-1, SBI-3	2.326
IST-1, IST-3, SBIT-1, SBIT-3	2.733 (on-peak)
	2.172 (off-peak)

Q. How does Tampa Electric Company's proposed average fuel charge factor of 2.401 cents per kwh compare to the average fuel charge factor for the April 1996 - September 1996 period?

A. The proposed fuel charge factor is 0.009 cents per kwh (or 9 cents per 1000 kwh) higher than the average fuel charge factor of 2.392 cents per kwh for the April 1996 - September 1996 period.

Stipulation Refund

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

A. Yes.

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

A. Yes. It consists of five pages identified as Exhibit No. 30 MJP-3, Capacity Cost Recovery.

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

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

Q. Please re-cap the proposed Capacity Cost Recovery Clause factors for the October 1996 - March 1997 period.

A.

Rate Schedule	Capacity Cost Recovery Factor (cents per kwh)
RS	0.198
GS and TS	0.191
GSD, EV-X	0.146
GSLD and SBF	0.130
IS-1, IS-3, SBI-1, SBI-3	0.011
SL-2, OL-1 and OL-3	0.024

These factors can be seen in Exhibit No. 30 (MJP-3), page 3 of 5.

Q. Will retail bills beginning October 1, 1996 contain a refund factor as agreed to in the stipulation approved in Docket No. 950379-EI, Order No. PSC-96-0670-S-EI?

A. Yes, as contained in the aforementioned stipulation, all customer bills beginning with the new fuel adjustment charge in October 1996 will reflect a refund credit. The refund is for $25 million plus interest over a one year period. The retail average refund credit factor beginning in October 1996 is 0.173 ¢/kWH.

Q. Do you have an exhibit supporting the calculation of the refund credit factor?

A. Yes, Exhibit No. 31 (MJP-4) is a worksheet showing the level of the refund credit factor, the expected monthly refund balance and expected monthly interest. As can be seen in Document No. 3, the balance approaches zero in September 1997, the end of the twelve month refund period.

Q. How will the refund credit be reflected on the customer's bill?

A. The refund credit will be reflected as a line item credit on customer's bills calculated by multiplying a levelized factor adjusted for line losses times the actual kwh usage during the period of the credit.

Q. What are the refund credit factors adjusted for line losses beginning in October 1996?

A. As shown in Document No. 3 of my exhibit, the credit factors beginning in October 1996 are:

Rate Class	Credit Factor
RS, RST, GS, GST, TS	0.174 ¢/kWh
GSD, GSDT, GSLD, GSLDT, EV-X, EVT-X, SBF, SBFT	0.173 ¢/kWh
IS1, IS1T, IS3, IST3, SBI1 SBI1T, SBI3, SBIT3	0.168 ¢/kWh
SL, OL	0.174 ¢/kWh

Q. What interest rate is applied to the average monthly refund balance?

A. The projected 30-day commercial paper rate is applied to the average monthly balance. This is consistent with Rule 25-6.109, Florida Administrative Code. The same projected 30-day commercial paper rate has been used to calculate the refund credit factor as was used to calculate the true-up in the Fuel and Purchased Power Cost Recovery Clause factors.

Q. How do you propose that the refund credit factor be administered?

A. The current factor is based on a projected twelve month energy sales forecast. In January 1997, when Tampa Electric files for new fuel adjustment factors using a new energy sales forecast, the refund credit factor should be updated. This update will incorporate the actual refund balance as it is known at the time, any changes in interest rates and the new energy sales forecast. This update will set a new refund credit factor for the months of April 1997 through September 1997.

Q. How do you propose any refund balance remaining at the end of the twelve month period be treated?

A. As contained in the stipulation, any over or under collection associated with the credit will be handled as a true-up component in the normal course of Tampa Electric's fuel cost recovery proceeding.

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

A. A residential bill for 1,000 kwh will decrease $1.20 beginning October 1996. See table below. The table also includes the impact of a proposed Environmental Cost Recovery Clause factor currently being reviewed in Docket No. 960688-EI.

Type of Charge	Apr. 96 Thru Sept. 96	Oct. 96 thru Mar. 97
Customer	$ 8.50	$ 8.50
Energy	43.42	43.42
Conservation	1.62	1.62
Environmental	0.00	0.41
Fuel	24.07	24.18
Capacity	1.93	1.98
Deferred Revenue Plan Refund	0.00	(1.74)
FGR Tax	2.04	2.01
Total	$ 81.58	$ 80.38

Q. When should the new charges and refund go into effect?

A. They should go into effect commensurate with the first billing cycle in October 1996.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GEORGE A. KESELOWSKY

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

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

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

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

Q. What are your current responsibilities?

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

Q. What is the purpose of your testimony?

A. My testimony presents the actual performance results from unit equivalent availability and station heat rate used to determine the Generating Performance Incentive Factor (GPIF) for the period October 1995 through March 1996. I will also compare these results to the targets established prior to the beginning of the period.

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

A. Yes. Under my direction and supervision an exhibit has been prepared entitled, "Tampa Electric Company, October 1995 - March 1996, Generating Performance Incentive Factor Results" consisting of 28 pages that was filed with this testimony (Have identified as Exhibit GAK-1).

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

A. Yes I have. This is shown on page 4 of my exhibit. Based upon -0.494 GPIF points, the result is a penalty amount of $104,014 for the period.

Q. Please proceed with your review of the actual results for the October 1995 - March 1996 period.

A. On page 3 of my exhibit, the actual average common equity for the period is shown on line 8 as $1,037,899,631. This produces the maximum penalty or reward figure of $2,105,538 as shown on line 15, page 3, and also page 2 of my exhibit.

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

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

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

A. Not exactly. Adjustments to equivalent availability may be required as noted in section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown on page 6 of my exhibit. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J.H. Hoffsis of the Commission's Staff. The adjustments for each unit are as follows:

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

On this unit, 1248 planned outage hours were originally scheduled to fall within the Winter 1995 period. The actual planned outage activities required 1362.3 hours. Consequently, the actual equivalent availability of 60.4% is adjusted to 62.6%, as shown on page 7 of my exhibit.

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

On this unit, 168 planned outage hours were originally scheduled to fall within the Winter 1995 period. The actual planned outage activities required 170.2 hours. Consequently, the actual equivalent availability of 84.9% is adjusted to 85.0%, as shown on page 8 of my exhibit.

Big Bend Unit No. 1

This unit was not scheduled to have a planned outage during the Winter 1995 period and did not in fact have one. Consequently, the actual equivalent availability of 87.4% requires no adjustment as shown on page 9 of my exhibit.

Big Bend Unit No. 2

On this unit 936 planned outage hours were originally scheduled to fall within the Winter 1995 period. Due to a revision of the outage schedule, planned outage activities were rescheduled such that no planned outage took place during the period. Consequently, the actual equivalent availability of 85.5% is adjusted to 67.3% as shown on page 10 of my exhibit.

Big Bend Unit No. 3

On this unit no planned outage hours were originally scheduled to fall within the Winter 1995 period. Due to a revision of the outage schedule, an outage was moved forward and associated planned outage activities required 457.1 hours. Consequently, the actual equivalent availability of 75.7 is adjusted to 84.5 as shown on page 11 of my exhibit.

Big Bend Unit No. 4

On this unit 384 planned outage hours were originally scheduled to fall within the Winter 1995 period. Actual planned outage activities required 484.6 hours. Consequently, the actual equivalent availability of 84.4% is adjusted to 86.5% as shown on page 12 of my exhibit.

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

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

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

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

Q. Were any additional adjustments to heat rate required?

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

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

A. Yes.

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

A. This is shown on page 28 of my exhibit. Essentially, the weighting factors shown on page 4, column 3, plus the equivalent availability points and the heat rate points shown on page 4, column 4, are substituted within the equation. This resultant value, -0.494, is then entered into the GPIF table on page 2. Using linear interpolation, a penalty amount of $104,014 is calculated.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GEORGE A. KESELOWSKY

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

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

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

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

Q. What are your current responsibilities?

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

Q. What is the purpose of your testimony?

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

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

A. Yes, I have prepared, under my direction and supervision, an exhibit entitled "Tampa Electric Company, Generating Performance Incentive Factor" October 1996 - March 1997, consisting of 35 pages filed with the Commission on June 24, 1996. (Have identified as Exhibit GAK-2). The data prepared within this exhibit is consistent with the GPIF Implementation Manual previously approved by this Commission.

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

A. Six of our coal-fired units are included. These are: Gannon Station Units 5 and 6; and Big Bend Station Units 1, 2, 3, and 4.

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

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

Q. Please continue.

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

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

A. Yes I will. The Planned Outage Factor (POF) and the Equivalent Unplanned Outage Factor (EUOF) were subtracted from 100% to determine the target equivalent availability. The factors for each of the 6 units included within the GPIF are shown on page 5 of my exhibit. For example, the projected EUOF for Big Bend Unit Four is 8.7%. The Planned Outage Factor for this same unit during this period is 0%. Therefore, the target equivalent availability for this unit equals:

$$100\% - [(8.7\% + 0\%)] = 91.3\%$$

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

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

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

Equivalent Availability Maximum

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

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

$EAF_{MAX} = 100\% - [0.8\ (8.7\%) + 0.95\ (0\%)] = 93.0\%$

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

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

A. The potential for unit availability degradation is significantly greater than is the potential for unit availability improvement. This concept was discussed extensively and approved in earlier hearings before this Commission. Tampa Electric Company's approach to incorporating this skewed effect into the unit availability tables is to use a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is arrived at via the following formula:

<u>Equivalent Availability Minimum</u>

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

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

$EAF_{MIN} = 100\% - [1.4\ (8.7\%) + 1.1\ (0\%)] = 87.8\%$

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

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

A. Our planned outages for this period are shown on page 19 of my exhibit. A Critical Path Method (C.P.M.) for each major planned outage which affects GPIF is included in my exhibit. For example, Big Bend Unit 2 is scheduled for an annual maintenance outage November 4 to November 19, 1996. There are 384 planned outage hours scheduled for the winter 1996 period, and a total of 4369 hours during this 6 month period. Consequently, the Planned Outage Factor for Unit 2 at Big Bend is 384/4369 x 100% or 8.8%. This factor is shown on pages 5 and 16 of my exhibit. Big Bend Unit 1 has a planned outage factor of 13.7%, Big Bend Unit 3 has a planned outage factor of 17.0% and Big Bend Unit 4 has a planned outage factor of zero. Gannon Units 5 and 6 each have planned outage factors of 7.7%.

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

A. Graphs of both of these factors (adjusted for planned outages) vs. time are prepared. Both monthly data and 12 month moving average data are recorded. For each unit the most current, March 1996, 12 month ending value was used as a basis for the projection. This value was adjusted up or down by analyzing trends and causes for recent forced and maintenance outages. All projected factors are based upon historical unit performance, engineering judgment, time since last planned outage, and equipment performance resulting in a forced or maintenance outage. These target factors are additive and result in a EUOF of 8.9% for Gannon Unit Five. The Equivalent Unplanned Outage Factor (EUOF) for Gannon Unit Five is verified by the data shown on page 13, lines 3, 5, 10 and 11 of my exhibit and calculated using the formula:

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

or

$$EUOF = \frac{(342 + 49)}{4391} \times 100 = 8.9\%$$

Relative to Gannon Unit Five, the EUOF of 8.9% forms the basis of our Equivalent Availability target development as shown on sheets 4 and 5 of my exhibit.

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

<u>Big Bend Unit One</u>

A. The projected EUOF for this unit is 11.1% during this period. This unit will have a planned outage this period and the Planned Outage Factor is 13.7%. This results in a target equivalent availability of 75.2% for the period.

<u>Big Bend Unit Two</u>

The projected EUOF for this unit is 14.2%. This unit will have a planned outage during this period and the Planned Outage Factor is 8.8%. Therefore, the target equivalent availability for this unit is 77.0%.

Big Bend Unit Three

The projected EUOF for this unit is 12.3% during this period. This unit will have a planned outage this period and the Planned Outage Factor is 17.0%. Therefore, the target equivalent availability for this unit is 70.7%.

Big Bend Unit Four

The projected EUOF for this unit is 8.7%. This unit will not have a planned outage during this period and the Planned Outage Factor is 0%. This results in a target equivalent availability of 91.3% for the period.

Gannon Unit Five

The projected EUOF for this unit is 8.9%. This unit will have a planned outage during this period and the Planned Outage Factor is 7.7%. Therefore, the target equivalent availability for this unit is 83.4%.

Gannon Unit Six

The projected EUOF for this unit is 9.7%. This unit will have a planned outage during this period and the Planned Outage Factor is 7.7%. Therefore, the target equivalent availability for this unit is 82.6%.

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

A. Yes I will. Please note on page 5 that the GPIF system weighted Equivalent Availability Factor (EAF) equals 79.2%. This target compares very favorably to previous GPIF periods when compared on a common planned outage factor basis. These targets represent an outstanding level of performance for our system.

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

A. This adjustment makes these factors more accurate and comparable. Obviously, a unit in a planned outage stage or reserve shutdown stage will not incur a forced or maintenance outage. Since our units are usually base loaded, reserve shutdown is generally not a factor. To demonstrate the effects of a planned outage, note the EUOR and EUOF for Big Bend Unit Three on page 17. During the months of October through January, EUOF and EUOR are equal. This is due to the fact that no planned outages are scheduled during these months. During the months of February and March, EUOR exceeds EUOF. The reason for this difference is the scheduling of a planned outage. The adjusted factors apply to the period hours after planned outage hours have been extracted.

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

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

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

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

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

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

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

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

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

Q. How were these targets determined?

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

Q. The accomplishment of scrubbing the flue gas from Big Bend Unit 3 requires an additional amount of station service power. How do you plan to address the associated effect to net heat rate for GPIF purposes?

A. The change in heat rate for this unit resulting from increased utilization of the Unit 4 scrubber can be quantified, but the operational history is short of GPIF guidelines. The target for Big Bend 3 has, therefore, been developed in the standard fashion using data without scrubber power. In order to assure compatability with this target, scrubber power will be removed prior to calculating Unit 3 heat rate for the subsequent True-Up process. This method has been reviewed and approved by the PSC

Staff to be employed until there is sufficient history to meet target preparation guidelines. Successful implementation of this innovation to maximize the potential of existing plant equipment, represents a major cost savings and a significant benefit for our customers.

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

A. Yes.

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

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

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

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

Q. Can you summarize your heat rate projection for the winter 1996 period?

A. Yes. The heat rate target for Big Bend Unit 1 is 10,004 Btu/Net kwh. The range about this value, to allow for potential improvement or degradation, is ±210 Btu/Net kwh. The heat rate target for Big Bend Unit 2 is 9,979 Btu/Net kwh with a range of ±273 Btu/Net kwh. The heat rate target for Big Bend Unit 3 is 9,600 Btu/Net kwh, with a range of ±332 Btu/Net kwh. The heat rate target for Big Bend Unit 4 is 10,047 Btu/Net kwh with a range of ±245 Btu/Net kwh. The heat rate target for Gannon Unit 5 is 10,258 Btu/Net kwh with a range of ±271 Btu/Net kwh. The heat rate target for Gannon Unit 6 is 10,443 Btu/Net kwh with a range of ±304 Btu/Net kwh. A zone of tolerance of ± 75 Btu/Net kwh is included within the range for each target. This is shown on page 4, and pages 7 through 12 of my exhibit.

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

A. Yes I do.

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

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown on pages 7 through 12. Our PROMOD III cost simulation model was used to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $117,272,400 is shown on page 6 column 2.

The PROMOD III output was then used to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6 column 4. After all the individual savings are calculated, column 4 is totaled: $3,775,800 reflects the savings if all units operated at maximum improvement. A weighting factor for each parameter is then calculated by dividing individual savings by the total. For Big Bend Unit Two, the weighting factor for equivalent availability is 5.46% as shown in the right hand column on page 6. Pages 7 thru 12 .show the point table, the Fuel Savings/(Loss), and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, on Big Bend Unit Two, page 10, if the unit operates at 80.3% equivalent availability, fuel savings would equal $206,200 and 10 equivalent availability points would be awarded.

The Generating Performance Incentive Factor Reward/Penalty Table on page 2 is a summary of the tables on pages 7 through 12. The left hand column of this document shows the Tampa Electric Company's incentive points. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, $3,775,800. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How were the maximum allowed incentive dollars determined?

A. Referring to my exhibit on page 3, line 8, the estimated average common equity for the period October 1996 - March 1997 is shown to be $1,102,485,857. This produces the maximum allowed jurisdictional incentive dollars of $2,241,397 shown on line 15.

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

A. Yes. Incentive dollars are not to exceed fifty percent of fuel savings. Page 2 of my exhibit demonstrates that the incentive amount calculated on page 3 has been reduced in order to meet this constraint.

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

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

$$GPIP = (0.0310\ EAP_{GN5} + 0.0775\ EAP_{GN6}$$
$$+ 0.0198\ EAP_{BB1} + 0.0546\ EAP_{BB2}$$
$$+ 0.0745\ EAP_{BB3} + 0.0606\ EAP_{BB4}$$
$$+ 0.067\ HRP_{GN5} + 0.1144\ HRP_{GN6}$$
$$+ 0.0985\ HRP_{BB1} + 0.1292\ HRP_{BB2}$$
$$+ 0.1351\ HRP_{BB3} + 0.1378\ HRP_{BB4})$$

Where:

GPIP = Generating performance incentive points.

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

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

Q. Have you prepared a document summarizing the GPIF targets for the October 1996 - March 1997 period?

A. Yes. The availability and heat rate targets for each unit are listed on attachment "A" to this testimony entitled "Tampa Electric Company GPIF Targets, October 1, 1996 - March 31, 1997".

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

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

Q. Briefly describe this exhibit.

A. This exhibit consists of 23 pages. This data is Tampa Electric Company's estimate of the Unit Performance Data and Unit Outage Data for the October 1996 - March 1997 period.

Q. Does this conclude your testimony?

A. Yes.

DOCKET NO. 960001-EI
TAMPA ELECTRIC COMPANY
SUBMITTED FOR FILING 06/24/96

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM N. CANTRELL

Q. Please state your name, address and occupation.

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

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

A. I was educated in the public schools of Tampa, Florida and received a Bachelor of Science degree in Electrical Engineering from the Georgia Institute of Technology in 1974. I am a registered Professional Engineer licensed in the State of Florida. I also received a Master of Business Administration degree in 1979 from the University of Tampa. I have been employed at Tampa Electric Company since June 1975. Since that time, I have served as Manager of Generation Planning, Assistant Director, Budgets and Director of Fuels. In 1987, I was elected Vice President of the company. In 1994, I was elected to my current position as Vice President-Energy Supply.

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

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

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to report to the Commission the actual 1995 costs of Tampa Electric's affiliated coal and coal transportation transactions compared to the benchmark prices calculated in accordance with Order No. 20298 (coal transportation) and Order No. PSC-93-0443-FOF-EI ("Order No. 93-0443") (coal). I conclude that the 1995 prices paid by Tampa Electric to its affiliates TECO Transport and Trade Company and Gatliff Coal are reasonable and prudent.

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

A. Yes. Exhibit No. (WNC-1) titled "Exhibit of William N. Cantrell", consisting of 2 documents, was prepared under my direction and supervision.

AFFILIATED COAL AND COAL TRANSPORTATION PRICES

Q. Were Tampa Electric's actual affiliated coal transportation prices for 1995 at or below the transportation benchmark?

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

Q. Were Tampa Electric's actual 1995 affiliated coal prices at or below the benchmark as established in Order No. 93-0443?

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

Q. Please summarize your testimony.

A. My testimony justifies the prices paid for coal and coal transportation by Tampa Electric Company in 1995 to its affiliated suppliers, Gatliff Coal and TECO Transport and Trade. I demonstrate that the average prices for the year 1995 for all coal and coal waterborne transportation services were at or below the appropriate benchmark calculations as directed by Order No. 20298 and Order No. 93-0443 of this Commission. Therefore, Tampa Electric should recover its payments for coal and coal transportation made during 1995.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMISSIONER DEASON: Now, that leaves witnesses that will be appearing for Florida Power & Light, Florida Power Corporation, TECO and Public Counsel's Office; is that correct?

MS. JOHNSON: That's correct.

COMMISSIONER DEASON: I assume, then, that we will just proceed with the first scheduled witness, which would be Witness Silva, appearing for Florida Power & Light.

MS. JOHNSON: Commissioner Deason, before we do that, I just wanted to point out the remaining issues. The remaining issues are Issues 3, 4, 5 and 7, which are generic issues for Florida Power & Light only. Issue 9 is a generic issue, 11a, 11b, 23a, and 24a for Florida Power & Light, and also to note that Issues 3, 4, 5, 7 and 23a are fallout issues.

COMMISSIONER DEASON: Could you go through that listing of issues again, please?

MS. JOHNSON: Yes. Issue 3 for Florida Power & Light, 4 for Florida Power & Light, 5 for Florida Power & Light, 7 for Florida Power & Light, and those are all fallout issues.

Issue 9; Issue 11a is a Florida Power & Light Company specific issue, as well as Issue 11b; Issue 23a for Florida Power & Light, and it's a fallout issue; and Issue 24a, which is a company-specific issue for Florida Power & Light.

Given that, Issues 3 through 7 are all fallout issues, Staff would recommend beginning with Issue 9 and the testimony relating to this issue.

COMMISSIONER DEASON: Mr. Childs, which witness is appearing today to address Issue 9?

MR. CHILDS: Florida Power & Light does not have a witness on that issue.

COMMISSIONER DEASON: So, Staff, it's your intent, then, to go instead of by witness order, go by issue order?

MS. JOHNSON: I think that would make it a little bit clearer for the Commissioners, the panel, if we did it by issue number.

COMMISSIONER DEASON: Any objection by the parties?

MR. HOWE: No.

COMMISSIONER DEASON: Who is the first scheduled witness, then, to address Issue 9?

MR. McGEE: I think that would be Mr. Wieland, Florida Power's witness.

MS. JOHNSON: That's correct.

COMMISSIONER DEASON: Now, this issue is the issue that's being raised by Public Counsel's Office?

MR. HOWE: That's correct.

COMMISSIONER DEASON: Very well. Mr. Wieland.

MR. McGEE: I don't think he has been sworn yet, Commissioner.

COMMISSIONER DEASON: I'm going to ask all witnesses who are in the hearing room at this time who will be taking the stand and testifying to please stand and raise your right hand.

(Witnesses collectively sworn.)

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KARL H. WIELAND

was called as a witness on behalf of Florida Power Corporation and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. McGEE:

Q Would you give us your name and business address for the record, please?

A I'm Karl H. Wieland. I'm with Florida Power Corporation. My business address is 14042, Post Office Box 14042, St. Petersburg, Florida, 33733.

Q Mr. Wieland, do you have before you a document entitled "Revised Direct Testimony and Exhibits of Karl H. Wieland," dated July 1st, 1996?

A Yes, I do.

Q And was that testimony prepared by you or under your direct supervision and control as your testimony for this proceeding today?

A Yes, it was.

Q Do you have any additions or corrections that you need to make to that testimony?

A No, I don't.

Q And if you were asked the questions that are contained in there, would your answers be the same today?

A Yes, they would.

MR. McGEE: Mr. Chairman, we ask that Mr. Wieland's prepared testimony be inserted into the record as though read.

COMMISSIONER DEASON: Without objection, it will be so inserted.

FLORIDA POWER CORPORATION
DOCKET NO. 960001-EI

Levelized Fuel and Capacity Cost Factors
October 1996 through March 1997

REVISED
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 1996 through March 1997.

Q. Do you have an exhibit to your testimony?

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

FUEL COST RECOVERY

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

A. Schedule E1, page 1 of the "E" Schedules in my exhibit, shows the calculation of the Company's basic fuel cost factor of 2.054 ¢/kWh (before line loss adjustment). The basic factor consists of a fuel cost for the projection period of 1.7155 ¢/kWh (adjusted for jurisdictional losses), a GPIF reward of 0.0105 ¢/kWh, a coal market price true-up credit of 0.0016 ¢/kWh and an estimated prior period true-up charge of 0.3281 ¢/kWh.

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

Schedule E1-E develops the TOU factors 1.181 ¢/kWh On-peak and 0.926 ¢/kWh Off-peak. The levelized fuel cost factors (by metering voltage) are then multiplied by the TOU factors, which results in the final fuel factors to be applied to customer bills during the projection period. The final fuel cost factor for residential service is 2.058 ¢/kWh.

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

A. Line 4 shows costs for the conversion of four Intercession City combustion turbine units to burn natural gas instead of distillate fuel oil, and an annual payment to the Department of Energy for the decommissioning and decontamination of their enrichment facilities.

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 409 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 Stratified 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 689 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

Georgia Power Company and 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 Stratified 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 these customers on a higher, stratified cost basis. The development of this adjustment is shown on Schedule E6.

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

A. The total true-up amount was determined in two parts. First, a period-to-date actual under-recovery of $60,552,885 through May 1996 was obtained from the Company's Operating Report. This balance was projected to the end of September 1996, including interest estimated at the May ending rate of 0.45% per month. The projection assumes that the Commission approves the Company's petition for mid-course correction, with revised rates in effect for July through September. The development of the estimated true-up amount for the current April through September 1996 period is shown on Schedule E1B, Sheet 1. Second, the total estimated under-recovery of $22,768,661 for the current period was combined with the prior period (October 1995 through March 1996) under-recovery of $29,993,960 and $5,915,935 being collected during the current period for a total under-recovery of $46,846,686 at the end of September 1996. This results in an estimated true-up charge on line 28 of Schedule E1 (Basic) of 0.3281 ¢/kWh for application in the October 1996 through March 1997 projection period.

Q. What are the primary reasons for the projected September 1996 under-recovery of $46.8 million?

A. The $30.0 million actual under-recovery for the period ending March 1996 being rolled forward into the current period, the longer than anticipated nuclear outage, and higher than projected oil prices were the primary factors contributing to the $46.8 million under-recovery in September.

Q. How was the market price true-up for Powell Mountain coal purchases 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 1995, and a calculated cost using the market price index for compliance coal in BOM District 8 for 1995, as adopted in Order No. 22401. The true-up amount of $235,010 also includes interest through May 1996.

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 11) 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 10). Cycle 11 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 11 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 11 is \$0.33 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 1995.

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

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

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

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

CAPACITY COST RECOVERY

Q. How was the Capacity Cost Recovery factor developed?

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

Sheet 1: Projected Capacity Payments. This schedule contains system capacity payments for 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 jurisdictional recoverable capacity payments for the October 1996 through March 1997 period are $131,182,318.

Sheet 2: Estimated/Actual True-Up. This schedule presents the actual ending true-up balance after two months of the current period and re-forecasts the over/(under) recovery balances for the next four months to obtain an ending balance for the current period. This estimated/actual balance of $10,754,129 is then carried forward to Sheet 1, to be refunded during the October 1996 through March 1997 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 jurisdictional capacity payments compared to the prior six- month period.**

A. The increase in capacity payments from $126.1 million in the April through September 1996 period to $131.2 million for the October 1996 through March 1997 period is primarily due to the escalation provisions in the contracts which take effect in January of each year.

GENERIC ISSUE

Q. **At the last fuel adjustment proceeding an issue regarding the appropriate use of average fuel costs for cost recovery purposes was raised and deferred to this proceeding. What is Florida Power's position on the use of average cost fuel pricing?**

A. As a general rule, Florida Power believes that any sale, either retail or wholesale, should be priced at the average cost of the generation resources used to make the sale. In other words, sales from a utility's system should be based on system average fuel costs, and sales from a single generating unit (*e.g.,* a Unit Power Sales arrangement) or from a combination of units (*e.g.,* a "stratified" sales arrangement) should be based on the average cost of the particular unit or units involved with the sale. Following this approach will ensure that retail customers do not subsidize wholesale sales. Should a utility choose to price its product in the wholesale markets in a manner that recovers less than the average cost of the sale, the Commission should still allocate costs to that sale on an average cost basis.

Q. Are there exceptions to this general rule of average cost pricing?

A. Yes. Average cost pricing should not be applied to sales made for economy purposes, *i.e.,* sales made to more efficiently utilize existing capacity. Sales of economy energy, such as sales on the broker system, have always been and should continue to be made at incremental rather than average cost in order to gain economic efficiency and maximize use of existing resources. In order to eliminate discriminatory pricing and reduce the risk of increasing cost for retail ratepayers, Florida Power restricts the use of incremental cost pricing, when below average cost, to sales that meet the following criteria:

1. Short term (less than one year) non-firm sales.

2. Firm sales from existing reserves which do not commit the Company to construct or purchase additional capacity.
3. Sales that are made from the system and for which resources are not subject to jurisdictional separation.
4. Sales for which all revenues (fuel as well as non-fuel) are credited back to the retail customers. Consideration of incentive compensation (such as the 80/20 sharing of profits from broker sales) is a separate issue and should be used when appropriate.

There may be other valid applications of incremental pricing, such as economic development rates which may be desirable from a retail ratepayer perspective, but such applications should be made on a case-by-case basis with specific approval by the Commission.

Q. Would you please summarize Florida Power's position on this issue?

A. Except in the case of economy sales, Florida Power believes that there should be consistency in cost allocation between retail and wholesale sales. Allocation for both fuel and non-fuel costs should continue to be on an average, embedded cost basis, applied to the generation resources from which sales are made. Incremental pricing should be allowed for the specific types of wholesale sales listed above, as long as all revenues from these sales (less incentives if appropriate) are credited back to retail ratepayers. Such practice will ensure that retail customers are not charged fuel costs which exceed the average cost of generation out of any of its units.

Q. Does this conclude your testimony?

A. Yes.

MR. McGEE: Commissioners, Mr. Wieland's testimony has been stipulated on all issues except for Issue 9, so what I would propose to do is to ask him to give a summary of his testimony on that issue; and that portion of his testimony begins towards the bottom of Page 11 on Line 20, and goes through the end of his testimony.

Q **(By Mr. McGee)** So if that's acceptable, Mr. Wieland, I would ask you to give a summary of Florida Power's position as it relates to Issue 9.

A Sure. Commissioners, let me start by saying that this is an issue that arose largely because of the competition that's going on in the wholesale markets.

In the markets today there's a lot of power being sold at cost or quite often below a utility's average embedded cost. Because of that, if a utility is going to compete in those markets either by trying to gain additional customers or by -- keep from losing ones that they're currently serving, they feel a lot of pressure to sell power at prices below average cost. And what that situation does is it puts the economic principles of incremental pricing squarely at odds with the regulatory principle of average embedded cost pricing.

Now, this Commission in the past has recognized that pricing certain off-system wholesale sales at incremental cost has a lot of benefits. The best example I can give you is the Florida broker system. It's based purely on short-term incremental fuel cost, and it's worked extremely well for all of our customers. I don't think anyone here would suggest that this practice should end.

Rather, I think the issue here is to what extent a utility should extend those kinds of pricing principles to other kinds of sales, including sales that are long-term in nature, that are firm, which are substantially different than the broker system.

And, furthermore, the issues should -- as I understand it, the issues should -- utilities, if they do discount the fuel, should they be able to automatically collect that difference to the fuel clause.

The position that Florida Power has taken on that issue really reflects a practice that we're currently following, and I've outlined that in my testimony. We think it's a practice that, first of all, we follow it both with this Commission as well as with the FERC. We think it's a good practice. It protects the retail ratepayer. But we do not claim that that is absolutely the only method that works or makes economic sense.

I don't know that there is ultimately a right answer. I think much of it boils down to philosophy. What we are asking this Commission to do is to give us some policy guidance on how those kind of sales can and should be structured and what the recovery of those discounts is.

Ultimately, if this Commission allows sales to be made at incremental costs -- or at below average costs, I should say -- for a wider variety of sales, then I think all utilities should be allowed to engage in that practice. Because what we find ourselves in is in a peculiar situation to where Florida Power may go to the very same customer that another utility is approaching. We feel obliged to go with average embedded cost pricing. Another utility says, no, incremental pricing is the way to go. And I think ultimately that doesn't lead to a proper outcome for the utilities as a whole.

So what we're looking for is for the Commission to consider this issue and really to make policy statements as to how those kinds of sales and what type of sales should be priced at something other than the average cost. That summarizes my testimony.

MR. McGEE: We tender Mr. Wieland for cross.

COMMISSIONER DEASON: Questions for Mr. Wieland? Any of the utilities? Mr. Hart?

MR. HART: We have some questions, but we would suggest, if it's appropriate, that Public Counsel go first since they agree with this witness, that they may conduct the, perhaps, friendly cross examination first.

COMMISSIONER DEASON: Mr. Howe.

MR. HOWE: Yes, sir.

CROSS EXAMINATION

BY MR. HOWE:

Q Mr. Wieland, what would the effect be on Florida Power Corporation's retail customers if Florida Power Corporation were to charge its long-term firm wholesale customers less than average fuel costs?

A Well, I think if you are to charge purely short-term incremental costs, which we do on the broker, for example, and you charge that for a long-term firm customer, you may wind up harming the retail ratepayers solely by the fact that you may have -- you may incur some long-term obligations for that customer that have a cost higher than your short-term incremental.

Q Considering the manner in which the

Commission calculates the retail fuel cost recovery, would a -- if Florida Power Corporation were to charge less than average fuel costs to a long-term wholesale customer, would that increase the fuel cost or the fuel adjustment charge to the retail customer?

A Yes, I think it would.

Q Can you state what would Florida Power Corporation do in the future if this Commission permits the charging of less than average fuel costs to wholesale customers to increase the cost responsibility of the retail jurisdiction?

A Well, since we compete in the wholesale markets as well -- in fact, we have a fairly substantial wholesale business -- I think we would in essence play by the same rules. I mean, that's really what we're asking for is to have a level playing field, and we would engage in exactly the same pricing practices.

Q Does Florida Power Corporation have any current customers or potential future customers, wholesale customers, that could be considered incremental customers?

A At this stage, Mr. Howe, I would argue that perhaps all of our wholesale customers could be considered incremental. Most of them have very short exit times; in other words, times that they can leave our business.

I mean, the best example I can give you is as everybody, I think, here is aware, Seminole, which is a large customer of ours, just went out for a request for proposal for 1,000 megawatts. And while we don't know whether that's all Florida Power business, because FPL has some witnesses -- has some business there as well, we certainly think that we are at risk for a large portion of that.

We have historically lost a number of wholesale municipalities, and most of the others as their contracts expire, so -- opt to go out for requests for proposals, to shop around. So, I mean, in a sense, maybe not this very moment, but over the period of the next few years I would argue that virtually all of our wholesale business is at risk.

MR. HOWE: I have no further questions.

COMMISSIONER DEASON: Ms. Kaufman?

MS. KAUFMAN: I have no questions.

COMMISSIONER DEASON: Mr. Hart?

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CROSS EXAMINATION

BY MR. HART:

Q Mr. Wieland, your testimony and the issue here is stated with regard to the cost recovery in the fuel clause, whether there should -- I interpreted it to be whether there should be some additional credit to the fuel cost for the difference between incremental and average cost. Is that your position?

A Our position is essentially this: I think the retail Commission assigns costs to the wholesale business. It does not necessarily determine how a particular utility prices that product, but if -- what we're -- what our position is, and, in fact, what we do for anything that we have a contract for that's in excess of one year, through separation studies we separate out the average cost for the nonfuel elements, and for the fuel purpose we also separate out or assign average fuel costs.

Now, once that assignment is made, what a utility actually sells the product for, whether they want to discount fuel or discount capacity, I don't think really matters, because at that point the retail customer has been protected.

Q Well, in your testimony, though, in response to Public Counsel and in your summary, I understood you to say that such sales should not be made or allowed.

A No. I don't -- no. If I said that, I certainly didn't mean to. What I'm really saying is that a utility can make sales at whatever price they want to. I think it's -- what the issue is, what costs does this Commission assign to those sales and do they automatically get to recover any discounts for the fuel clause.

Q So then the issue that you're addressing is the cost recovery of the fuel clause, not the prudence of whether or not it's in the best interest of the company to make such sales?

A That's right.

Q Now, you would agree, would you not, that if -- I know we can discuss what net benefits means -- but if a sale produces net benefits to a company and incremental fuel pricing is required to get those benefits, it would be, in fact, imprudent on the company's behalf not to make such a sale, would it not?

A Yes, although I would make very certain that your benefits do indeed accrue to the ratepayers.

Q Yes. But it's the existence of benefits and the regulatory treatment that's the issue, not whether or not the sale should be made?

A Yes.

Q And you would agree, would you not, that in determining whether or not a sale is appropriate, that you would have to look at the total transaction, not just the fuel piece?

A Well, there are two issues, I think. I mean, first of all there is the basic principle of average embedded cost pricing.

If a utility chooses not to follow that, then I think the first question the Commission has to ask itself, should we still assign an average embedded cost, both of fuel and nonfuel; and then the -- whatever difference there is in that cost versus what the utility charges becomes the utility's problem.

Now, if you go beyond that and say, well, we'd like to really adopt economic pricing, or incremental pricing, then I think there is a demonstration that perhaps needs to be made to the Commission that says, yes, in this particular instance, that may provide some benefits to the retail ratepayers as a whole, and, therefore, that practice may be adopted.

That I see more of a case-by-case analysis and demonstration, rather than just a general statement by the Commission, and I think that's really been my position and testimony is that as a general rule, we ought to follow average cost allocation.

If there's an exception to that, and it makes economic sense and it's demonstrated that it makes economic sense, then certainly I think it would be in the best interests of everybody to do, quote, the right thing.

Q My question is a little bit simpler than that, and it was just simply that in order to determine whether or not a transaction is beneficial, you would have to look at more than just the fuel element. You would have to look at the total economics of the transaction in order to make the determination as to whether or not they're net benefits to anyone?

A Yes, you would.

Q And so the criteria that you've listed on Page 12 is not really the criteria for whether or not a sale should be made, but whether it should achieve certain regulatory treatment in the fuel clause; is that correct?

A Yes, I think so.

COMMISSIONER JOHNSON: Could you say that again? Could you repeat your question?

MR. HART: The question was whether or not his criteria on Page 12 and 13 of his testimony, whether that criteria was for whether or not a sale should be made or whether it was the criteria for the regulatory treatment of such sales.

COMMISSIONER JOHNSON: And yours was, it was for the regulatory treatment of such sales?

WITNESS WIELAND: Yes. I mean, I'm still making a difference between costs that the Commission assigns to a sale, which I guess I would call the regulatory treatment, versus the price that a utility charges. Those don't necessarily need to be the same thing.

Q **(By Mr. Hart)** Now, you have wholesale sales, don't you?

A Yes, we do.

Q Do you have any that don't fall under your criteria for being exempted from review?

A Not to my knowledge.

Q So your position is that incremental pricing as a matter of principle works, and you've set up a standard for regulatory review which exempts all of your wholesale transactions from such review; is that correct?

A I'm not sure I followed that. Would it help if I just told you what the practices that we follow -- I mean, it's really quite simple. In one sense what we're doing is any sale that is less than one year in duration, return all of the revenues, capacity revenues, and there's nonfuel revenues and fuel revenues, back to our customer through the fuel cost, the fuel or the capacity cost recovery clause.

So to that extent there's an incremental sale, which we do at times, for those short-term sales. Then the customer immediately gets all of the benefits. We have drawn the line that anything that's more than a year in duration is separated, and all of the separated sales right now we price out on an average cost basis.

Q Well, in your criteria on the top of Page 13, firm sales from existing reserves which do not commit the company to construct or purchase additional capacity don't have a time requirement in them. Did you mean to include one?

A No. The way that we view these four criteria is that really they all need to be met, not just one at a time.

Q So the short-term, less than one year, nonfirm sales didn't mean one year just for nonfirm sales? That one year was supposed to apply to criteria No. 2, firm sales?

A Yes. I think perhaps if you look at the position we adopted, it may clear up, because I, quite frankly, when we reviewed that wording it seemed like it was a little bit overlapping. I think if you read the position that we've taken on that issue, that might clarify exactly how 1 and 2 relate to one another.

Q But you do intend to have a time limit on your criteria under both sales?

A Yes. The criteria that we follow is essentially that anything less than a year, we flow everything back through the pass-through clauses. Anything over a year at this stage we segregate out, or we separate out and price everything at average.

What we're saying and where No. 2 would apply, that if we were to have a sale that perhaps went several years, and it were at below average cost, then our criteria would say, you give all of the capacity and -- in other words, all of the fuel and nonfuel revenues back through the cost recovery clause as well, rather than splitting them out. I think that's the intent of the criteria.

Q But in that analysis the criteria that really makes the difference is whether or not the sale is separated, is it not?

A Yes, I think it does.

Q So, for example, you wouldn't think a transaction that had the same economic benefits for 11 months and one that had the same benefits for 14 months should be treated differently, except for the fact that they're separated differently?

A Well, what we would do today, if I understand your question right, is that if it's 11 months -- well, first of all, if it's at something other than average cost to begin with; okay. If it's at 11 months, we would flow all of the revenues back. If it's for 13 months, for longer than a year, then we would separate it and then we would essentially keep the capacity revenues, because they've been separated, and we would price -- at least as far as cost recovery from this Commission goes, we would price it at average, and the one year is an arbitrary line. I mean, you'd have -- you know, we felt we needed to draw it somewhere, and there's nothing magic about 12 months versus 11 or 13. That's just decided where we would make a break.

Q But the line is being drawn for the question of determining separation?

A Yes.

Q And it's separation that determines how you think the fuel should be treated?

A No; it's separation and how the fuel is priced.

Q Well, if for some reason the Commission were to determine that separation was not the issue or that separation was not an appropriate criteria, would you still think that it should be treated differently if it's nine months or 14 months?

A Are you asking if the sale were not separated?

Q Well, I'm saying if the Commission were to decide that separation was not part of the criteria, and so that the issue then was you had a sale, one is 14 months and one is nine months, would you treat them differently in the fuel clause simply because one was more than a year and one was less than a year?

A Well, I think that would depend on how it's priced.

Q Well, then both cases in my example they're priced at incremental fuel.

A Okay. Well, if separation is an issue, then I think my argument would be that all of the revenues should flow back through the pass-through clauses. I mean, that's the practice that we're following.

COMMISSIONER DEASON: Let me ask a clarifying question. If you have a contract which exceeds one year, it is your practice to price that at average embedded fuel costs?

WITNESS WIELAND: Yes, sir.

COMMISSIONER DEASON: You have no contracts that are at some type of an incremental fuel cost basis which exceed one year?

WITNESS WIELAND: When we filed with Florida Commission, I think there is a statement that says if our cost, if our incremental cost were above average -- not below but above -- then we would charge at the incremental system cost if it's higher than average, but never below.

So all of our wholesale fuel clauses are based on average cost, and the only incremental sales, the only things that we price at the increment are broker sales and very short term day-to-day, week-to-week type of sales; and all of the revenues from those sales are passed back to our customers through the fuel clause.

COMMISSIONER DEASON: Now, for the contracts which exceed a year, is there a separation made, a jurisdictional separation made for the investment aspect of that transaction?

WITNESS WIELAND: Yes.

Q **(By Mr. Hart)** Do you have any wholesale sales in which the incremental fuel cost is, in fact, below average?

A Are you talking about the price we charge, or the price we incur?

Q The price you incur.

A It's possible, but, frankly, we don't -- you know we don't determine for each sale what our incremental cost actually is, because it's not something that you can really look up. You'd have to do a lot of studies and things like that. So it's possible, yes, but I don't know.

Q Then it's possible that you don't have any?

A Yes.

Q Now, in your testimony you also indicated that you needed a position on this policy because if you were allowed to, you would price at incremental?

A Yes. We have -- much like Tampa, we have units, coal units, we have a gas-fired unit coming up whose incremental fuel cost is significantly below average. We buy spot coal in the markets.

We have in some instances fixed transportation costs, and so it makes as much economic sense in some instances as it does for TECO, but we're just not following that practice. So, I mean, what we're looking for is to basically play under the same rules.

Q Your testimony, though, didn't address the competition issue, did it?

A No.

Q But that was really the point of it?

A Well, as I said, it's the competition that's developing is what has given rise to this issue and the practice of discounting prices.

Q But ultimately that competition is not just between utility companies, is it, it's between other power sellers who are not constrained by these issues?

A That's right.

Q So that the Commission may not be able to affect the competition by requiring average fuel prices?

A That's right.

Q Adopting that policy just simply may mean that all the wholesale sales go to an out-of-state seller?

A Well, I think what the Commission can and should do is to look out for its constituents, the native load, and make sure that they're not adversely affected by what's going on in the wholesale markets.

Q But the native load in Florida will be adversely affected if all the wholesale goes to out-of-state sellers; isn't that correct?

A I don't know that. That would depend largely on what their cost of services, or the cost of providing service, compared to the revenues that they bring in. And I think you could have cases where losing them may be good and in other cases where losing them may be bad, but that would have to be looked at on a case-by-case basis.

Q Now, it's true that there is competition for all types of sales, including the broker sales, short-term sales, sales of all other links; isn't that correct?

A Yes.

Q So whether or not there's competition for the sale is not really a distinguishing factor in identifying one sale from another, is it?

A No.

Q Well, if the Commission is going to -- if the Commission were to consider adopting a policy on looking at wholesale sales, why shouldn't the Commission simply look at all of them?

A Look at all what? All wholesale sales?

Q Well, look at whether or not there's

negative fuel impacts from all wholesale sales.

A Well, I think what the Commission can look at is to see if there were negative impacts from the total sales revenues, but the way I look at it is that as long as you follow the principles of embedded or average cost pricing and you apply that uniformly to all customers, it would be difficult to say that one group of customers is being priced unfairly.

I think the issue becomes a little bit more serious or of concern to the Commission if the product is being sold at below the average cost, because, I mean, in many ways you can take every one of our retail ratepayers, whether it be commercial, industrial, residential, and claim that perhaps one group is costing more than average or less than average, but I don't know that that's the issue.

I think as long as you follow average cost, average embedded cost pricing for all customers, retail and wholesale, then I don't think there's cause for concern. I think the concern becomes when a group of customers is being priced at below that.

Q Well, let's talk about that for a second. A wholesale customer who buys power using average fuel cost doesn't mean, does it, that it's average fuel cost that's incurred by that customer or the company in serving that customer; isn't that correct?

A Well, no more or no less than any other customer, and I could -- you could make that same argument for an industrial customer, for a residential customer. I mean, the whole idea of average pricing is to not try to make those distinctions and try to figure out who is on the increment.

Q Well, at least one could say that that's the principle that's used for customers that you're required to serve and customers who are required to buy from you. But for those customers where the sale is discretionary and you enter into a sale with a wholesale customer at average fuel price when that customer always takes on-peak power, that wholesale transaction adversely affects the average fuel cost, does it not?

A I'm sorry; say that again. I'm not sure I followed that.

Q If you have a wholesale transaction with average fuel costs in which the wholesale customer always takes on-peak power, then that wholesale customer, although he's taking at average fuel cost, may adversely affect the average fuel cost by actually incurring higher than average fuel cost?

A It could.

Q Okay. Now, if the purpose of the proceeding is to determine the adverse impact on the fuel clause, fuel revenues as a result of wholesale transactions, why shouldn't the Commission look at all wholesale transactions for purposes of determining whether or not they have what you perceive as a negative impact on fuel cost of retail customers?

A Well, first of all, I don't believe that that's the issue that we're debating. I don't think we're debating the issue as to whether wholesale sales in general are beneficial or not.

I think the issue here is the pricing particularly of fuel, incremental versus average, and the assignment or the cost allocation that this Commission needs to make to that. I think your issue is a different issue and much broader than that.

Q Well, the Commission is beginning to look -- the generic issue was raised with regard to fuel pricing and impacts on fuel pricing as a result of wholesale sales; and you set up a standard which causes some incremental fuel price sales to be examined by the Commission and some not to be.

Yours happens to fall into the category that's not examined. And then we have another whole host of wholesale sales that may have negative impacts on the fuel of retail customers. And wouldn't it be appropriate, if we're going to move in that direction, to simply look at the adverse fuel impacts of all wholesale sales?

A Well, the Commission could choose to do that. What our position is, as long as everybody pays average embedded costs, everybody pays the same price, then I don't think you need to be so concerned about figuring out whether one particular group of customers is above or below that embedded cost.

I think the concern we're talking about here is that if you pick out a group of customers and you sell it at below embedded cost. I'm not sure that the Commission should be concerned if there's a group of customers that pays a lot more than average cost.

Q Well, when you say embedded costs, are you talking about fuel or are you talking about another part of the transaction?

A I'm talking about both.

Q So when you use that term, you're not just talking about fuel, you're talking about both sides of the transaction?

A Yes; although in the case of wholesale sales, my understanding is that if you're separating costs, you're separating that on an average cost --

average embedded cost basis. So the Commission is assigning cost to the wholesale business on an average embedded cost basis for nonfuel, and all we're suggesting is that they follow the same practice for the fuel portion.

Q Well, with regard to discretionary sales, though, incremental fuel price may be the cost that's actually incurred to make the sale, might it not?

A It may.

Q So do you object to those types of sales as well?

A To what type of sales?

Q The type of sale in which you charge the actual cost of fuel to the customer that incurred it, if it's a wholesale transaction.

A I think you have to ask yourself who should -- you know, who should get the benefit of those sales. I mean, we have sales, as I mentioned, where the fuel is priced at increment, and there may be a nonfuel component. And the practice we follow today is we say, well, that bundle as a whole is beneficial for the ratepayers, but in order to make sure it's beneficial, we give all of the revenues back to our customers.

Q Do you know of any investor-owned utilities in Florida that have the type of sales that you think should be examined by the Commission, other than Tampa Electric?

A There may be some. Not that I know of. My understanding is that FPL practices the average cost -- much like we do.

Q So, really, what you want is for the Commission to examine Tampa Electric's wholesale sales or to prohibit Tampa Electric from making certain types of --

A No, that's not what I'm after at all. What I'm looking for is a set of rules that we can all follow. I'm not debating that what Tampa Electric is doing is necessarily harmful for anyone. I mean, I don't know that. That's something for the Commission to find out.

All I'm saying is right now we're debating -- and we're approaching our customers in a different manner than what Tampa Electric does, and we just want to play by the same set of rules. And we have drawn this magic line, which I said in my summary, you know, there is no right answer necessarily, but we just simply have adopted one set of practices and TECO has adopted a separate one; and it doesn't make sense for us to deal with the same customers on a different basis.

Q But part of your issue is that you don't think the benefits of the sales are flowing back to the retail ratepayers; is that correct?

A In the case of Tampa Electric?

Q Yes.

A Well, I'm not sure how that works, and I think that's a question for the Commission and the Staff to answer.

My understanding is that the nonfuel, with the capacity sales of nonfuel portion is not being flowed at least directly, but I'm not familiar enough with exactly how TECO's whole rate situation works to really comment on that.

Q And you're not really aware of the extent to which the Commission and Staff have looked at Tampa Electric's wholesale transactions; is that --

A No.

Q So it may be that the policy you want is already in place?

A I don't know. Certainly not to my knowledge. I mean. My understanding right now is that we have chosen to follow a practice which is very different from TECO's. If this Commissions says that, no, TECO's practice is one that's proper, then we'd like to follow it as well.

Q Well, are you aware of the amount of wholesale sales that were separated in Tampa Electric's 1992 rate case?

A No.

Q Well, assuming for purposes of this discussion that the amount that was separated were revenue requirements in excess of 30 million and that a significant portion of those sales that were separated were incrementally priced in fuel at the time of the separation. Isn't it correct that the ratepayers are, in fact, receiving all of the benefits of those incrementally priced sales because they were embedded permanently in their rates since 1992?

A Well, they are receiving, I would think, whatever benefits they are for the nonfuel portion, but I don't know how the level of sales that TECO is making today compares to what they did in the rate case.

I don't follow that that closely. But that doesn't necessarily follow that with average embedded separation of fixed costs that the discounting of fuel and putting those two together necessarily works in the best interest of the ratepayers. I mean, I don't know whether it does or not.

Q Well, at the time of Tampa Electric's rate case, though, there were incrementally priced, fuel priced wholesale sales that were examined, looked at and separated. And to the extent that's true, isn't it correct that the retail customers are receiving the benefits of the incrementally priced sales that the Commission thought was appropriate?

A I don't really know that I can answer that. I'm not that familiar with TECO's rate case issues.

Q So it may be that the policy you want in place is already in place for Tampa Electric; isn't that correct?

A It may be. I mean, that's a judgment for the Commission to make. But all I'm saying is that if that's a policy that's in place for Tampa Electric, then I think it ought to be in place for Florida Power and Florida Power & Light and Gulf Power as well.

I mean, ultimately our goal is not, you know, to say that what TECO is doing is wrong. What TECO is doing may be correct. I don't know that, and I don't know whether it's beneficial or harmful to ratepayers. I mean, our bottom line is that we need to play under the same set of rules.

Q Well, in order to undertake the same type of review that Tampa Electric had on its separated sales and its incremental priced sales, you would have to have a full-blown rate case.

A I don't think so.

Q Well, to get the same type of review that Tampa Electric had of its wholesale sales, you would.

A No. I think you could do it in this forum right here.

Q You mean in the fuel adjustment clause?

A Sure. I mean, if there needs to be a demonstration that certain type of sales are beneficial, I don't think it takes a rate case to do that.

Q But what you get is an adjustment to the fuel clause in that proceeding; isn't that correct?

A I suppose yes.

Q But that doesn't deal with the other issues that you raised with regard to whether or not the incremental pricing of fuel was appropriate, does it?

A I don't understand.

Q Well, in this proceeding what we're dealing with is how to treat incrementally priced fuel in the fuel adjustment clause; isn't that correct?

A Yes.

Q And you've raised questions about that treatment based on issues that are outside the fuel adjustment clause?

A I don't believe so.

Q Well, the first issue that you raised with regard to distinguishing which type of sales should receive which treatment was whether or not the sales were separated; isn't that correct?

A Yes.

Q And that happens outside this proceeding?

A Yes, but it's not exclusively tied to rate cases. I mean, separation is a continuing process. As the wholesale business changes, separation factors change monthly or annually.

Q You mean separations in the sense of the surveillance reports?

A Yes.

Q But you don't mean for purposes of actually flowing the benefits or embedding the benefits in the base rates of retail customers?

A Well, if I understand your question right, what I'm saying is if we separate a sale, a new one that's made tomorrow, if it's separated, we price it at average. If it's not separated, we flow all the revenues back.

Q For purposes of the surveillance reports, but not for purposes of changing the rates paid by your retail customers?

A No. Absolutely for purposes of changing the rates, because if you flow back nonfuel revenues, it affects the fuel factor. It lowers it.

Q Okay.

COMMISSIONER DEASON: Let me ask a question. If you have a contract which exceeds one year, it is your practice currently to separate that investment between jurisdictions?

WITNESS WIELAND: Yes, sir.

COMMISSIONER DEASON: How do you account for the revenue from that sale that has been separated?

WITNESS WIELAND: The revenue, the nonfuel revenue would stay with the company, as will the expenses that were allocated there.

COMMISSIONER DEASON: Because it has been separated to another jurisdiction.

WITNESS WIELAND: Yes.

COMMISSIONER DEASON: And you price -- I guess you could price it whatever you want to, but you allocate fuel revenue for fuel adjustment purposes on an average basis.

WITNESS WIELAND: Yes, sir. And, in fact, to follow up, not only have we allocated it that way for retail recovery purposes, we also price it that way in our wholesale markets.

We've had to have some discounting of the fixed costs, which we've had to do in order to keep the customers in, but that's been -- that's become a shareholder issue, in essence.

MR. HART: We have no further questions.

COMMISSIONER DEASON: Staff. I'm sorry. Mr. Stone.

CROSS EXAMINATION

BY MR. STONE:

Q Good morning, Mr. Wieland. Am I correct that Florida Power Corporation is a winter peaking utility?

A Yes.

Q I'd like for you to assume some -- to make some assumptions I'm going to give you for purposes of the hypothetical question I'm going to ask you.

First I'd like you to assume that Power Corp has surplus summer capacity.

A Okay.

Q I'd also like you to assume that the City of Tallahassee needs 200 megawatts of summer capacity.

A Okay.

Q And that Tallahassee issues a request for proposal and that they're seeking 200 megawatts of capacity from May to December for 10 years, and that their energy needs related to that RFP are at a 70% capacity factor.

I'd like you also to further assume that Florida Power Corp has sufficient surplus summer capacity, that it would like to make a proposal in response to that request for proposal.

I'd also would like you to assume that Enron is making a proposal to the City of Tallahassee, and Tallahassee gets two bids under these assumptions, one is from Enron with capacity at $4.00 per kilowatt month and incremental energy at 18 mills per kilowatt hour.

Let's assume that your capacity, you were also able to price it at $4.00 per kilowatt month, but that you are limiting your energy proposal to average cost energy at 22 mills per kilowatt hour, but that you have an incremental energy cost of 17 mills per kilowatt hour. Okay? Do you have the assumptions?

A I think so. I probably should have written them down. I may ask you to clarify a little bit if I get bogged down, but I think I understand it.

Q Given those assumptions in the RFP about the capacity and the energy and the capacity factor, can we agree that we're talking about 5.11 million kilowatt hours over that period?

A Okay.

Q Can you tell me which offer the City of Tallahassee would take under those two bids?

A Well, if I understood it all right, they would take the cheaper one, which I think would be Enron's, if I got all your numbers right.

Q Okay. Given that under the assumptions that

I've asked you to -- under the facts I've asked you to assume for purposes of this hypothetical, given that Florida Power Corp's incremental cost of 17 mills for energy is such that you could provide it cheaper than Enron, but because you have constrained yourself only to offer average energy at 22 mills, that is consistent with the proposal that your company and Office of Public Counsel has made in this proceeding; is that correct?

A Yes.

Q And it's that pricing that has kept you from making a successful bid to the City of Tallahassee into this scenario?

A Yes.

Q Given that Power Corp would not be successful in making that sale, will Florida Power Corporation's customers benefit from Enron providing the power to the City of Tallahassee?

A Well, I think that would depend. I mean, I hate to give a wishy-washy answer, buy I guess my reaction is, first of all, we're talking about a 10-year contract if I recall. I mean, if I put myself in position of how would Florida Power do a bid like that to begin with, I think we'd have to ask ourselves can we really provide -- do we really have excess power for 10 years. That's a big hurdle to overcome.

Q I understand, but that's an assumption I --

A Assuming that you do, then I think you'd have to look at it in terms of what -- you know, what truly is your total cost of providing that service. And the other issue that you get into is who takes the risk of pricing it at something less than that.

If you price it below, you might make the economic argument, but then the question is if you're wrong and it winds up costing you more, do you put that risk on the shareholder or do you put that risk on the customer.

I mean, it might well be that the Commission could assign average costs, both capacity and energy to that deal, and then the company can price it in a manner that maybe makes it reasonably whole and makes it a good deal for both sides.

So I'm not sure I can really give you a clear answer, but certainly I think our position is that in the long-term, you know, we're looking at following a general principle of a general rule of cost allocation. But that's not to say that under certain specific circumstances, if you construct a scenario with a whole bunch of assumptions, that you might not be able to put a good case together that says in this particular set of circumstances it makes sense to do something different than average pricing, but I think that's a burden of proof that the company would have.

You and I could sit here with a whole long list of assumptions and I'll agree that, yes, that's a reasonable thing to do, but I think that's a case-by-case analysis. And what we're talking about is, you know, as a general principle of pricing should we just give blanket authority for all pricing in that manner.

Q But the fact of the matter is under the assumptions that I've asked you to make, you would be constrained from making a competitive offer and you would lose the sale even if you had satisfied yourself with the risk factors involved that it was the appropriate thing --

A You could, and that's certainly -- I mean, that's why this issue has arisen, as I said before. I mean, that is an issue that I think is going to get more serious as time goes on and not better.

Q But you're making a determination on this policy not based on the assessment of risk, but rather on the fact that you're determining that you should only allocate on average cost, the energy?

A No. Well, what I would fall back to is if you look at my testimony on my Page 13, I said there are -- as in any rule, there are going to be exceptions, and there should be; and there may be certain types of pricing provisions that may be desirable. In fact, to quote, "may be desirable from a retail ratepayer perspective."

Such applications should be made on a case-by-case basis with specific approval by the Commission.

Q Okay. Well, let's go to the specific case that I've outlined for you in the hypothetical. Again, assuming that you did not make the sale, that Enron made the sale, your ratepayers received nothing from the sale, enron is certainly not tied to Florida Power Corporation.

A Right.

Q Okay. It is also true that the City of Tallahassee's retail customers are losing out because they're paying more for Enron power than they would have had to have paid had you priced your power and energy at incremental?

A Possibly, yes.

Q Could we calculate that difference as being the difference between 18 mills of Enron's proposal and 17 mills as your incremental, because our assumption was the capacity cost was the same?

A Okay. Yes, under that circumstance, I think that's right.

Q And we said earlier there was 511 million kilowatt hours times that one mill difference. That basically works out to $5,110,000 difference over the 10 years.

A I'll trust your arithmetic on that one, yes.

Q If Florida Power Corporation had made the sale and it has the lower cost, as we've indicated in our assumptions, isn't it true that the Florida Power Corporation retail customers would benefit through the purchased power capacity cost recovery clause to the tune of $40 million?

A You're assuming that the revenues are being passed back to the capacity cost recovery clause?

Q Isn't that the policy of this Commission?

A Not if the sales are separated. I mean, I would agree with you -- and in fact that's one of the criteria that if all of the capacity, all of the fuel and nonfuel revenues are passed back through the pass-through clauses, be it fuel or capacity costs or a combination of both, and those sales are clearly less than the cost of providing them, then I think those kind of sales should be made.

I think it becomes a little tougher when you're looking at sales where the fuel is a pass-through, the other costs go to the stockholder. I just think there's a little bit more possibility of gaming and not really being -- for the Commission to really being -- satisfy itself that the customer is really getting all of these benefits that you mentioned.

Q Mr. Wieland, do you recall when the purchase power capacity cost recovery clause was created with this Commission?

A I think so, yes.

Q Do you recall that at that time Gulf Power Company was making wholesale power sales to Florida Power Corporation?

A Indirectly through to Southern Company, you mean?

Q It was a Schedule E sale, as I recall.

A Right; uh-huh.

Q And do you recall that at that time Gulf Power Company, which previously there was no purchase power capacity cost recovery clause, but with the creation of that clause, that the revenues from those sales were flowed back through the clause?

A I don't know that, but I certainly believe --

Q Would you accept that, subject to check?

A Certainly.

Q And would you agree with my calculation of the benefit that is forgone to Florida Power Corporation's customers if you failed to make the sale because Enron is able to price it at 18 mills, and by the constraint you have imposed, you could not price your energy any lower than 22 mills --

A Uh-huh, yes.

MR. STONE: I have no further questions.

COMMISSIONER DEASON: Staff.

CROSS EXAMINATION

BY MS. JOHNSON:

Q Good morning, Mr. Wieland. There's been a lot of discussion regarding separable versus nonseparable sales and the pricing of those sales.

Would you agree that one of the reasons the Commission separates sales is because the facilities that typically -- are built to serve these long-term customers?

A Yes.

Q Do you feel it's appropriate to bill additional facilities when you know that the sales price would have to be discounted to make them marketable?

A No, I don't believe so. I mean, that, if I understand your question right, would tend to raise rates for the retail customers.

Q Are you aware of the term "capital fuel symmetry"?

A No, not really.

Q Would you agree that under a situation where a customer pays for average embedded plant costs and receives the benefits associated with capital fuel costs, that there is capital fuel symmetry?

A Could you explain that a little bit more? I think my answer is yes, but I'm not sure I understand it well enough.

Q Do you agree that when there's average capital and average fuel, that there's symmetry?

A Yes.

Q And would you agree that the policy that Florida Power Corp is putting forth is basically one of capital fuel symmetry as I've described?

A Yes.

Q Based on this position, do you think it's fair to charge one class of customers incremental fuel costs and another class of customers average fuel prices when both classes pay the same capital costs for generation?

A I think what we're saying is as a general rule, no, I think they should all be treated the same, but with the caveat that under certain circumstances, and perhaps broker sales is one, and, you know, that there's an exception that can be made, given the fact that it can be demonstrated that retail customers actually benefit from such sales.

Q So do you think that it's reasonable for the Commission to have a policy which would require utilities making long-term separable sales to demonstrate to the Commission that incremental pricing is beneficial to the ratepayers prior to crediting anything less than average fuel costs through the fuel clause?

A Yes, I do.

MS. JOHNSON: That's all that we have.

COMMISSIONER DEASON: Commissioners? Redirect?

MR. McGEE: Just one.

REDIRECT EXAMINATION

MR. McGEE: Mr. Wieland, you responded to the hypothetical that Mr. Stone was discussing with you and identified, and agreed with him that there might be certain detrimental effects on Florida Power and its ratepayers in not engaging in the sale that he described.

Were those situations examples of your statement on Line 10, Page 13 of an instance where Florida Power might view that an appropriate situation for an exception from the average cost pricing principle?

A Yes, that's exactly the type of thing I have in mind.

MR. McGEE: That's all I have.

COMMISSIONER DEASON: Thank you. I believe the exhibits have been already admitted.

MS. JOHNSON: That's correct.

COMMISSIONER DEASON: Thank you, Mr. Wieland.

(Witness Wieland excused.)

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(Transcript continues in sequence in Volume 2.)