BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 020001-EI

In the Matter of

FUEL AND PURCHASED POWER COST
RECOVERY CLAUSE WITH GENERATING
PERFORMANCE INCENTIVE FACTOR.
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VOLUME 1

PAGES 1 THROUGH 182

PROCEEDINGS: HEARING

BEFORE: CHAIRMAN LILA A. JABER
COMMISSIONER J. TERRY DEASON
COMMISSIONER BRAULIO L. BAEZ
COMMISSIONER MICHAEL A. PALECKI
COMMISSIONER RUDOLPH "RUDY" BRADLEY

DATE: Wednesday, November 20, 2002

TIME: Commenced at 9:30 a.m.
Adjourned at 4:20 p.m.

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

REPORTED BY: JANE FAUROT, RPR
Chief, Office of Hearing Reporter Services
FPSC Division of Commission Clerk and
Administrative Services
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APPEARANCES:

JAMES A. McGEE, Post Office Box 14042, 3201 34th Street South, St. Petersburg, Florida 33733, appearing on behalf of Florida Power Corporation.

RUSSELL BADDERS, Beggs & Lane, 700 Blount Building, 3 West Garden Street, Post Office Box 12950, Pensacola, Florida 32576-2950, appearing on behalf of Gulf Power Company.

JAMES D. BEASLEY, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company (TECO).

VICKI GORDON KAUFMAN, McWhirter, Reeves, McGlothlin, Davidson, Decker, Kaufman & Arnold, P.A, 400 North Tampa Street, Suite 2450, Tampa, Florida 33601-3350, appearing on behalf of Florida Industrial Power Users Group (FIPUG).

JOHN T. BUTLER, Steel, Hector & Davis, LLP, 200 South Biscayne Boulevard, Suite 4000, Miami, Florida 33131-2939; appearing on behalf of Florida Power & Light Company (FPL).

ROBERT D. VANDIVER, Associate Public Counsel, Office of Public Counsel, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

APPEARANCES CONTINUED:

WILLIAM COCHRAN KEATING, IV, Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0870, appearing on behalf of the Commission Staff.

I N D E X

WITNESSES

WITNESS CONTINUED:

EXHIBITS

PROCEEDINGS

CHAIRMAN JABER: All right. We are on to our last proceedings, 02001.

Mr. Keating, are you ready?

MR. KEATING: Yes.

CHAIRMAN JABER: All right. Preliminary matters.

MR. KEATING: Commissioners, there are no pending motions to resolve as preliminary matters. I would point out there are, as you will note in the prehearing order, several pending confidentiality requests. An order has been issued on Tampa Electric's request for confidential classification of its Exhibit JTW-1 by order issued this morning. The remaining confidentiality requests relate to information or documents that will not be used today at the hearing. And to the extent that any of these documents are no longer needed by the Commission, they will be returned, and for any remaining documents Staff will prepare an order expeditiously to take care of those.

CHAIRMAN JABER: Thank you, Mr. Keating. And we have stipulated issues and witnesses whose testimony has been stipulated, is that correct?

MR. KEATING: That is correct.

CHAIRMAN JABER: Okay. How about we take up the -- I think it would be appropriate to resolve the witnesses first, correct?

MR. KEATING: I believe so. The witnesses in this proceeding are listed on Pages 6 and 7 of the prehearing order, and of those witnesses the following have been excused, and I believe we can go ahead and move their prefiled testimony into the record.

COMMISSIONER BRADLEY: State that again, please.

MR. KEATING: The witnesses are listed on Page 6 and 7 of the prehearing order, and I believe we can go ahead and for those witnesses that are noted as excused --

CHAIRMAN JABER: Are those the ones with the asterisk, Mr. Keating?

MR. KEATING: Yes. The ones that are noted with an asterisk, and there are three additional witnesses that have been excused since the prehearing order was issued.

CHAIRMAN JABER: Okay. Let me go through the prehearing order ones first. You keep track, though, so I don't forget anyone and then let me know who the other ones are.

The prefiled testimony of Michael F. Jacob shall be inserted into the record as though read. The prefiled testimony of F. Irizarry shall be inserted into the record as though read. The prefiled testimony of George M. Bachman shall be inserted into the record as though read. The prefiled testimony of M.F. Oaks inserted into the record as though read. The prefiled testimony of L.S. Noack shall be inserted into the record as though read. The prefiled testimony of H. Homer Bell, III shall be inserted into the record as though read. The prefiled testimony of William A. Smotherman inserted into the record as though read.

MR. KEATING: Those are all the witnesses that are listed as excused in the prehearing order. The additional witnesses that have been excused are T.A. Davis for Gulf Power Company, W. Lynn Brown for Tampa Electric Company, and Joann T. Wehle for Tampa Electric Company.

CHAIRMAN JABER: The prefiled testimony of T.A. Davis shall be inserted into the record as though read. The prefiled testimony of W. Lynn Brown shall be inserted into the record as though read. The prefiled testimony of Joann T. Wehle shall be inserted into the record as though read.

MR. KEATING: And I have had some discussions with some of the parties regarding stipulating into the record the testimony of Staff's Witness Matthew Brinkley and the three -- I'm sorry, there is one more witness that should have been included in the last category that has been excused already and that is S.D. Ritenour who filed rebuttal testimony on behalf of Gulf Power Company.

CHAIRMAN JABER: The prefiled rebuttal testimony of S.D. Ritenour shall be inserted into the record as though read.

MR. KEATING: And to pick up where I had left off, I have had some discussions with some of the parties about the possibility of stipulating Staff Witness Matthew Brinkley's testimony into the record, as well as the testimony of rebuttal Witnesses Javier Portuondo, K.M. Dubin, and J. Denise Jordan. And since I haven't talked to all the parties about that, I would ask if any party has an objection to stipulating those testimonies into the record.

CHAIRMAN JABER: Okay. The question is do we have a stipulation to insert the testimony of Brinkley, Portuondo, Dubin rebuttal, Jordan rebuttal, is that what you said? Well, the question is outstanding for everybody's testimony.

MR. BUTLER: FPL would have no objection to doing that.

CHAIRMAN JABER: To everybody's testimony?

MR. BUTLER: Well, gosh, that is very tempting.

CHAIRMAN JABER: We are going to take a five-minute break and get together very quickly and tell me which testimony can be stipulated.

(Off the record.)

CHAIRMAN JABER: Let's get back on the record. Okay. Mr. Keating.

MR. KEATING: I believe we have agreement now that the testimony of Staff Witness Matt Brinkley and the rebuttal testimony of Witness Javier Portuondo, K.M. Dubin, and J. Denise Jordan can be stipulated into the record.

CHAIRMAN JABER: I am assuming there is no objection to inserting Brinkley, Portuondo, Dubin, and Jordan's testimony into the record.

MR. KEATING: And that would just be the rebuttal testimony for Portuondo, Dubin, and Jordan.

CHAIRMAN JABER: Thank you. Okay. With that, the prefiled testimony of Matthew Brinkley shall be inserted into the record. The prefiled rebuttal testimony of Mr. Portuondo shall be inserted into the record. The prefiled rebuttal testimony of K.M. Dubin shall be inserted into the record. The prefiled rebuttal testimony of J. Denise Jordan shall be inserted into the record. Thank you.

Exhibits?

MR. KEATING: Witness Jacob -- and these exhibits are listed starting at Page 34 of the prehearing order. Witness Jacob for Florida Power Corporation has Exhibits MFJ-1 and MFJ-2.

CHAIRMAN JABER: MFJ-1 and MFJ-2 are identified as Composite Exhibit 1.

MR. KEATING: Witness Irizarry for Florida Power and Light on Page 36 of the prehearing order has listed Exhibits FI-1 and FI-2.

CHAIRMAN JABER: FI-1 and FI-2 are identified as Composite Exhibit 2.

MR. BUTLER: Madam Chairman.

CHAIRMAN JABER: Yes.

MR. BUTLER: A clarification there. Mr. Irizarry is adopting testimony that was originally filed by Rene Silva and what is there as FI-1 really should be RS-1, and then what is FI-2 ought to be FI-1.

CHAIRMAN JABER: Okay. Let's do that again. FI-1 is really RS --

MR. BUTLER: RS-1. And then FI-2 is really FI-1.

CHAIRMAN JABER: Okay, thank you. So just for purposes of clarifying the record, RS-1 and FI-1 are identified as Composite Exhibit 2.

MR. KEATING: Witness George Bachman for Florida Public Utilities Company has Exhibits GMB-1 and GMB-2.

CHAIRMAN JABER: GMB-1 and GMB-2 are identified as Composite Exhibit 3.

MR. KEATING: Witness M.F. Oaks for Gulf Power Company has Exhibits MFO-1 and MFO-2.

CHAIRMAN JABER: MFO-1 and MFO-2 are identified as Composite Exhibit 4.

MR. KEATING: Witness T.A. Davis for Gulf Power Company has Exhibits TAD-1, TAD-2, and TAD-3.

CHAIRMAN JABER: TAD-1 through TAD-3 identified as Composite Exhibit 5.

MR. KEATING: And Witness Noack for Gulf Power Company has Exhibits LSN-1 and LSN-2.

CHAIRMAN JABER: LSN-1 and LSN-2 are identified as

Composite Exhibit 6.

MR. KEATING: Witness H. Homer Bell, III for Gulf Power Company has Exhibit HHB-1.

CHAIRMAN JABER: HHB-1 is identified as Hearing Exhibit 7.

MR. KEATING: Witness William Smotherman of Tampa Electric Company has Exhibits WAS-1 and WAS-2.

CHAIRMAN JABER: WAS-1 and WAS-2 are identified as Composite Exhibit 8.

MR. KEATING: And Witness Joann Wehle for Tampa Electric Company has Exhibits JTW-1 and JTW-2.

COMMISSIONER JACOBS: JTW-1 and JTW-2 are identified as Composite Exhibit 9. And Exhibits 1 through 9 are admitted into the record.

(Exhibits 1 through 9 marked for identification and admitted into the record.)

CHAIRMAN JABER: Are there other exhibits?

MR. KEATING: I believe that is all the exhibits that were filed with the prefiled testimony of those witnesses whose testimony was moved into the record.

FLORIDA POWER

Docket No. 020001-EI

GPIF Reward/Penalty Amount for January through December 2001

DIRECT TESTIMONY OF MICHAEL F. JACOB

Q. Please state your name and business address.

A. My name is Michael F. Jacob. My business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601.

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

A. I am employed by Carolina Power & Light Company as Manager of Generation Modeling and Analysis.

Q. What are your responsibilities as Manager of Generation Modeling and Analysis?

A. As Manager of Generation Modeling and Analysis, I am responsible for the development and application of the models, analysis and data used for generation planning purposes. In particular, my duties include responsibility for the preparation of the information and material required by the Commission's Generation Performance Incentive Factor (GPIF) mechanism.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of the Company's GPIF reward/penalty amount for the period of January through December 2001. This was developed by comparing the actual performance of the Company's nine 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, my exhibit (MFJ-1) consists of the 27 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 $608,057. 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 each unit's Generating Performance Incentive Points Table found on Sheets 8 through 16 of my exhibit.

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 26 of my exhibit summarizes the planned outages experienced by the Company's GPIF units during the period. Sheet 27 presents an as-worked schedule for each individual planned outage.

Q. Does this conclude your testimony?

A. Yes.

FLORIDA POWER CORPORATION

Docket No. 020001-EI

Re: GPIF Targets and Ranges for January through December 2003

DIRECT TESTIMONY OF MICHAEL F. JACOB

Q. Please state your name and business address.

A. My name is Michael F. Jacob. My business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601.

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

A. I am employed by Carolina Power & Light Company as Manager of Generation Modeling and Analysis.

Q. What are your responsibilities as Manager of Generation Modeling and Analysis?

A. As Manager of Generation Modeling and Analysis, I am responsible for the development and application of the models, analysis and data used for generation planning purposes. In particular, my duties include responsibility for the preparation of the information and material required by the Commission's Generation Performance Incentive Factor (GPIF) mechanism.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the development of the Company's GPIF targets and ranges for the period of January through December 2003. These GPIF targets and ranges have been developed from individual unit equivalent availability and average net operating heat rate targets and improvement/degradation ranges for each of Florida Power's GPIF generating units, in accordance with the Commission's GPIF Implementation Manual.

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

A. Yes, I am sponsoring Exhibit No. ____ (MFJ-1) containing 77 pages, which consists of the GPIF standard form schedules prescribed in the GPIF 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. This exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

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

A. For the 2003 projection period, GPIF units are Anclote Unit 2, Crystal River Units 1 through 5, and Hines Unit 1. These units account for 80.3% of the estimated total system net generation for the period. Hines Unit 1 was added to the GPIF program for the 2003 projection period since the unit now has sufficient performance history to provide representative data for setting targets and ranges. With the addition of Hines Unit 1, three units (Anclote 1, Bartow 3 and Tiger Bay) included in previous filings have been removed.

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

A. Yes. This information is included in the GPIF Target and Range Summary on page 4 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 GPIF Implementation Manual. This includes 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 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 pages 41-77 of my exhibit in the section entitled "Unplanned Outage Rate Tables and Graphs."

Q. Please describe the methodology utilized to develop the improvement/degradation ranges for each GPIF unit's availability targets?

A. The methodology described in the GPIF 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 term 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. This information is included in the Target and Range Summary on page 4 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 years, as described in the GPIF Implementation Manual. A "least squares" procedure was used to curve-fit the heat rate data within ranges having a 90% confidence level of including all data. The analyses and data plots used to develop the heat rate targets and ranges for each of the GPIF units are contained in pages 26-40 of my exhibit in the section 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 incentive points. The maximum savings (loss) dollars are the same as those used in the calculation of the weighting factors.

Q. How were the GPIF weighting factors determined?

A. To determine the weighting factors for availability, a series of PROSYM simulations were made in which each unit's maximum equivalent availability was substituted for the target value to obtain a new system fuel cost. The differences in fuel costs between these cases and the target case determines the contribution of each unit's availability to fuel savings. The heat rate contribution of each unit to fuel savings was determined by multiplying the BTU savings between the minimum and target heat rates (at constant generation) by the average cost per BTU for that unit. Weighting factors were then calculated by dividing each individual unit's fuel savings by total system fuel savings.

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

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

Q. What is Florida Power's estimated maximum incentive amount for 2003?

A. The estimated maximum incentive for Florida Power is $8,307,671. The calculation of the estimated maximum incentive is shown on page 3 of my exhibit.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF F. IRIZARRY

DOCKET NO. 020001-EI

SEPTEMBER 20, 2002

Q. Please state your name and business address.

A. My name is Frank Irizarry and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am the Manager of Business Services in the Power Generation Division of FPL.

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

A. No, I have not.

Q. Mr. Irizarry, are you adopting the testimony of FPL witness Rene Silva entitled "Generating Incentive Performance Factor, Performance Factor Results for January through December 2001" as your own?

Yes, I am.

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

A. The purpose of my testimony is to present the target unit average net operating heat rates and target unit equivalent availability for the period of January through December, 2003, for use in determining the Generating Performance Incentive Factor (GPIF).

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

A. For the period of January through December, 2003, FPL projects a weighted system equivalent planned outage factor of 5.0 % and a weighted system equivalent unplanned outage factor of 6.3 %, which yield a weighted system equivalent availability target of 88.7 %. The targets for this period reflect planned refueling outages for three nuclear units. FPL also projects weighted system average net operating heat rate target of 9,556 btu/kwh for the period January through December, 2003. As discussed later in this testimony, these targets represent fair and reasonable values when compared to historical data. Therefore, FPL requests that the targets for these performance indicators be approved by the Commission.

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

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

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

A. Yes, I have. In my Document No.1, pages 6 and 7, contain the information summarizing the targets and ranges for unit equivalent availability and average net operating heat rates for the fifteen (15) generating units which FPL proposes to be considered as GPIF units for the period of January through December, 2003. The Sheets presented in these pages were prepared in accordance with the latest revisions of the GPIF Manual. All of these targets have been derived utilizing methodologies as adopted in Section 4 of the GPIF Manual.

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

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

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

A. Yes, they were.

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

A. The fifteen (15) units which FPL proposes to use for the period of January through December, 2003, represent the top 81.8% of the total forecasted system net generation for this period. These units were selected in accordance with the GPIF Manual, Section 3.1, using the estimated net generation for each unit taken from the production costing simulation program, POWRSYM, which forms the basis for the projected levelized fuel cost recovery factor for the period. As shown on page 3 of Document 1, three units were excluded from the GPIF. They are the Ft. Myers Repowered unit and the Sanford Repowered Units 4 and 5. The repowering of these units from conventional steam units to combined cycle units constitute a major design change affecting both their generation capacity and their performance. As a result, the future performance of these units will not be comparable to their historical performance. Therefore, consistent with established practices, FPL anticipates excluding these units from the GPIF calculations for 3 years from their new commercial start-up date to establish a minimal history to use in projecting future performance.

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

A. Yes, they do.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 020001-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 January 2003 - December 2003 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 January 2002 - December 2002 and to establish a "true-up" amount to be collected or refunded during January 2003 - December 2003.

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, and E10 for

Marianna and E1, E1A, E1-B, E1-B1, E2, E7, E8, and E10 for Fernandina Beach. They are included in Composite Prehearing Identification Number GMB-2. Schedule E1-B and E1-B1 for both Marianna and Fernandina Beach were filed last week in Composite Prehearing Identification Number GMB-1.

These schedules support the calculation of the levelized fuel adjustment factor for January 2003 - December 2003. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period January 2002 - December 2002 based on 6 Months Actual and 6 Months Estimated data.

Q. In derivation of the projected cost factor for the January 2003 - December 2003, 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 January 2003 - December 2003.

A. We have determined that at the end of December 2002 based on six months actual and six months estimated, we will have under-recovered $147,999 in purchased power costs in our Marianna division. Based on estimated sales for the period January 2003 - December 2003, it will be necessary to add .04802¢ per KWH to collect this under-recovery.

In Fernandina Beach we will have over-recovered $328,323 in purchased power costs. This amount will be refunded at .09844¢ per KWH during the January 2003 - December 2003 period (excludes GSLD customers). Page 3 and 10 of Composite Prehearing Identification Number GMB-2 provides a detail of the calculation of the true-up amounts.

Q. Looking back upon the January 2001 - December 2001 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 $151,039 and Fernandina Beach Division over-recovered $116,653. 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 January 2001 - December 2001 for both divisions?

A. In Marianna the final remaining true-up amount was an under-recovery of $88,866. The final remaining true-up amount for Fernandina Beach was over-recovery of $133,516.

Q. What are the estimated true-up amounts for the period of January 2002 - December 2002.

A. In Marianna, there is an estimated under-recovery of $59,133. Fernandina Beach has an estimated over-recovery of $194,807.

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

A. In Marianna the total fuel adjustment factor as shown on Line 33, Schedule E1, is 2.248¢ per KWH. In Fernandina Beach the total fuel adjustment factor for "other classes", as shown on Line 43, Schedule E1, amounts to 2.272¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January 2002 - December 2002 including base rates, 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 $61.25, a decrease of 1.79 from the previous period. In Fernandina Beach a customer will pay $57.82, a decrease of $2.09 from the previous period.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Michael F. Oaks
Docket No. 020001-EI
Date of Filing: April 1, 2002

Q. Please state your name and business address.
A. My name is Michael F. Oaks and my business address is One Energy Place, Pensacola, Florida 32520-0328.

Q. What is your occupation?
A. I am the Fuel Manager at Gulf Power Company.

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

Q. What are your duties as Fuel Manager?
A. I supervise and administer the Company's fuel procurement, transportation, budgeting, contract administration, and quality control to ensure the generating plants are provided a high quality fuel supply at the lowest practical cost.

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

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 January 2001 through December 2001. Also, it is my intent to be available to answer 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. Oaks' exhibit consisting of one schedule be marked as Exhibit No. ______________ (MFO-1).

Q. During the period January 2001 through December 2001 how did Gulf's recoverable fuel expenses compare with the projected expenses?
A. Gulf's recoverable fuel expense was $196,688,083 or 1.63% less than the projected amount of $199,947,293. Total net system generation for the period was also lower than projected. Actual generation was 11,423,135 MWH compared to the projected generation of 12,669,590 MWH or 9.84% less than predicted. The resulting total fuel cost per KWH

generated was 1.7218¢/KWH or 9.10% over the projected amount of 1.5782¢/KWH. The increase on a per unit basis was primarily a result of higher spot coal market prices in 2001. The year 2001 was an unusual year, in that, Gulf's generation was down as a result of mild weather conditions and the economic slowdown, but spot coal prices remained higher throughout the year. This was a carryover from the dramatic increase in natural gas and coal prices that began in the fourth quarter of 2000. Gas prices rose to $6/MMBtu in November 2000, $10/MMBtu in December 2000 and sustained a level near or above $5/MMBtu through April of 2001. Market conditions for electricity and fuel caused spot coal prices to rise substantially in early 2001. Although the coal markets have fallen since, they remained at an elevated level for the rest of the year. During late spring and early summer, natural gas prices dropped to a level at which gas-fired combined cycle generating units on the Southern Electric System displaced some coal-fired units in dispatch. This market-driven situation, coupled with mild weather, reduced Gulf's coal-fired generation during the peak summer season and for the remainder of 2001.

Q. How much spot coal did Gulf Power Company purchase during the period?

A. Excluding Plant Scherer 3, Gulf purchased 2,777,977 tons or 54% of its supply from the spot coal market. My Schedule 1 in Exhibit No. (MFO-1) consists of a list of contract and spot coal suppliers for the period January 1, 2001 - December 31, 2001.

Q. How did the total projected cost of coal purchased compare with the actual cost?
A. The total actual cost of coal purchased was $214,139,829 compared to our projection of $185,230,726, or 15.61% more than projected.

Q. How did the total projected cost of coal burned compare with the actual cost?
A. The total actual cost of coal burned was $190,760,333, which is the sum of lines 3 and 3a on schedule A-3. This is 0.89% lower than our projection of $192,473,087. On a fuel cost per MMBtu basis, the actual cost (including startup fuel) was $1.64/MMBtu, 8.61% higher than the projected $1.51/MMBtu.

Q. Were there any other significant developments in Gulf's fuel procurement program during the period?
A. No.

Q. Should Gulf's fuel purchases for the period be accepted as reasonable and prudent?
A. Yes. Gulf's current coal supply plan is based on a combination of long term contracts and spot purchases at market prices. Coal vendors are selected by procedures designed to assure a reliable quantity of high quality coal at competitive delivered prices. Gulf has administered the provisions of its contracts and purchase orders appropriately. Natural gas was purchased using indexed contracts and from the spot market on an as-needed basis. Gas was also purchased and placed into storage to

ensure a reliable supply. 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. 020001-EI
Date of Filing: August 20, 2002

Q. Please state your name and business address.

A. My name is Michael F. Oaks and my business address is One Energy Place, Pensacola, Florida 32520-0335.

Q. What is your occupation?

A. I am the Fuel Manager at Gulf Power Company.

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

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

Q. What are your duties as Fuel Manager?

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

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

Q. Mr. Oaks, what is the purpose of your testimony in this docket?
A. The purpose of my testimony is to compare projected fuel expenses with estimated/actual costs for the January through December 2002 recovery periods and to summarize any noteworthy developments in Gulf Power Company's fuel program. Also, it is my intent to be available to answer questions that may arise in this docket concerning Gulf Power Company's fuel expenses.

Q. During the period January 2002 through December 2002, how will Gulf's estimated/actual recoverable fuel expenses compare with the original projection of expenses?
A. Gulf's expected recoverable fuel expense for the period is now $274,104,721 or 9.76% less than the original projected amount of $303,747,744. Total net system generation for the period is expected to be 13,452,072 MWH compared to a projection of 15,005,870 MWH or 10.35% less than originally forecast. The resulting total fuel cost per KWH generated will be 2.0376¢/KWH or 0.66% higher than the projected cost of 2.0242¢/KWH.

Q. How did the total projected cost of coal compare with the actual cost during the first seven months of 2002?

A. The total actual cost of coal burned was $94,663,084 compared to a projected cost of $125,225,979, or 24.41% lower than projected. Also, considerably less coal was purchased during the period than projected resulting in the total cost of coal purchased being significantly lower. Actual purchases were $94,815,728 as compared to projected purchases of $124,777,951. The lower cost of coal purchased and burned during the first seven months of the year can be attributed to a couple of factors. First, because the price of natural gas dropped much more dramatically and rapidly than expected, gas-fired combined cycle units on the Southern electric system (SES) ran ahead of coal-fired generation for the first two months of the year, into early March. This reduced the coal burn across the SES and made low priced coal-fired power available for purchase on the system at prices lower than Gulf Power's coal-fired generating plants could produce it. Secondly, except for Gulf, loads were down across the SES through July, further reducing Gulf's coal usage. Finally, with the exception of Powder River Basin coal into Plant Scherer, the average price of coal was slightly lower than projected.

Q. How did the total projected cost of natural gas compare with the actual cost during the first seven months of 2002?

A. The total actual cost of natural gas burned was $38,926,955 compared to a projected cost of $30,214,972, or 28.83% more than projected. The increase can be attributed to Gulf's new combined cycle unit, Smith 3, being placed in commercial operation over a month prior to the projected date (April 22 vs. June 1), plus the additional cost of natural gas used for testing during January through April. The total actual cost of natural gas purchased was $40,554,688, 34.22% higher than projected. These purchases were necessary to accommodate the additional burn from Smith 3, and to commence natural gas storage for the unit. The average cost of natural gas burned was about 14% lower than projected.

Q. Are there other significant developments in Gulf's fuel procurement program for the 2002 recovery period?
A. No.

Q. Should Gulf's fuel purchases for the period be accepted as reasonable and prudent?
A. Yes. Gulf's coal purchases were either from long term contracts or the competitive spot market. Coal vendors are selected by procedures designed to assure a deliverable quantity of high quality coal for a specific term at the lowest available delivered cost. Gulf has administered the provisions of its contracts and purchase orders appropriately. Natural gas was purchased using indexed contracts and from the spot market on an as needed basis. 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 and Exhibit of
Michael F. Oaks
Docket No. 020001-EI
Date of Filing: September 20, 2002

Q. Please state your name and business address.
A. My name is Michael F. Oaks and my business address is One Energy Place, Pensacola, Florida 32520.

Q. What is your occupation?
A. I am the Fuel Manager at Gulf Power Company.

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

Q. What are your duties as Fuel Manager?
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 January 1, 2003 through December 31, 2003, and to be available to answer any questions that may arise 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 costs 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. ______________ (MFO-2).

Q. Has Gulf Power Company made any changes to its methods in this period for projecting fuel cost?
A. No.

Q. Does the 2003 projection of fuel expenses reflect any major changes in Gulf's fuel purchasing program during this period?

A. Yes. Gulf's long-term coal contract with Peabody COALSALES for 1.9 million tons per year is subject to a market price reopener effective February 1, 2003. At that time, the contract will either be renewed at a new market adjusted delivered price, or terminated. If the contract is terminated, Gulf will be seeking a similar quantity from the spot market. The projection reflects this change in price. Also, 2003 will be the first full year of operation of Gulf's new natural gas-fired combined cycle unit, Smith 3. Gulf will utilize financial instruments to hedge a portion of its natural gas needs if market conditions warrant.

Q. How much spot market coal does Gulf Power project it will purchase during the January 2003 through December 2003 period?

A. We are projecting the purchase of approximately 2,302,487 tons on the spot market. This represents approximately 39.9% of our projected purchase requirements.

Q. What financial hedging guidelines will Gulf Power implement to prohibit speculative hedging activity?

A. Gulf Power's financial hedging activity will be limited to the following guidelines: Fixed Priced hedges will not exceed 100% of Gulf's projected gas purchase requirements, Option Priced hedges will not exceed 110% of Gulf's projected gas purchase requirements and Forward hedges will be limited to 42 months.

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

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GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony and Exhibit of
L. S. Noack
Docket No. 020001-EI
Date of Filing April 1, 2002

Q. Please state your name, address and occupation.

A. My name is Lonzelle S. Noack. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Power Generation Specialist, Senior for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Environmental Engineering from the University of Florida in 1995 and received my Master of Business Administration degree from the University of West Florida in 2000. I joined Gulf Power in 1995 as an Environmental Engineer and served in that role with increasing levels of responsibility for over six years. Major responsibilities included coordination of federal and state air-related compliance testing for all Gulf Power generating units, management of the Continuous Emission Monitoring (CEM) System program at each of the Company's generating facilities, and coordination of the Company's air compliance reporting to state and federal regulatory agencies. I was also responsible for serving as Gulf's Environmental Subject Matter Expert on Company and system-wide compliance teams. As previously mentioned in my testimony, my current job position is Power Generation Specialist, Senior at Gulf Power Company. In this position, I am responsible for preparing all GPIF filings as well as other generating plant reliability and heat rate performance reporting.

I am also a member of several professional organizations including the Air and Waste Management Association and the Florida Association of Environmental Professionals. I am currently serving as a subcommittee Vice Chair for the Southeastern Electric Exchange. I also hold Fundamentals of Engineering and Environmental Professional Intern certifications.

Q. Ms. Noack, 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 January 1, 2001, through December 31, 2001.

Q. Ms. Noack, 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 five schedules.

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

Counsel: We ask that Ms. Noack's exhibit consisting of five schedules be marked for identification as exhibit _____(LSN-1).

Q. Ms. Noack, were average net operating heat rate (ANOHR) targets that included the new BTU/LB independent variable used for plant Daniel Units 1 & 2 in this period?
A. Yes. The target heat rate equations for Plant Daniel Units 1 and 2 included the BTU/LB independent variable as described in the year 2001 GPIF target filing dated September 21, 2000 and subsequently approved in Commission order PSC-00-2385-FOF-EI. The actual monthly BTU/LB parameters used are shown on pages 6 and 7 of Schedule 3.

Q. Ms. Noack, is there any other information which has been supplied to the Commission pertaining to this GPIF period which requires amendment?
A. Yes, some corrections need to be made to the actual unit performance data that was submitted monthly to the Commission during this period. These corrections are based on discoveries made during our final review. The Actual Unit Performance Data tables on pages 14 to 25 of Schedule 5 incorporate these changes. The data contained in these tables is the data upon which the GPIF calculation was made.

Q. Ms. Noack, 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-00-2385-FOF-EI is on page 9 of Schedule 2. The results are: Crist 6, -8.33 points; Crist 7, -10.00 points; Smith 1, +10.00 points;

Smith 2, +10.00 points; Daniel 1, +10.00 points, and Daniel 2, +10.00 points.

Q. Ms. Noack, 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.

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 September 2000, 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: -9.75 for Crist 6, -1.13 for Crist 7; 0.00 for Smith 1, 0.00 for Smith 2; +3.57 for Daniel 1; and -7.19 for Daniel 2.

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

A. Using the unit equivalent availability and heat rate points previously mentioned, along with the appropriate weighting factors, the Company points would be -1.88 as indicated on page 2 of Schedule 4. This calculated to a penalty in the amount of $369,498.

Q. Ms. Noack, would you please summarize your testimony?
A. Yes. 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 $369,498 as provided for by the GPIF plan.

Q. Ms. Noack, does this conclude your testimony?
A. Yes.

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony of
L. S. Noack
Docket No. 020001-EI
Date of Filing September 20, 2002

Q. Please state your name, address and occupation.

A. My name is Lonzelle S. Noack. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Power Generation Specialist, Senior for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Environmental Engineering from the University of Florida in 1995 and received my Master of Business Administration degree from the University of West Florida in 2000. I joined Gulf Power in 1995 as an Environmental Engineer and served in that role with increasing levels of responsibility for over six years. Major responsibilities included coordination of federal and state air-related compliance testing for all Gulf Power generating units, management of the Continuous Emission Monitoring (CEM) System program at each of the Company's generating facilities, and coordination of the Company's air compliance reporting to state and federal regulatory agencies. I was also responsible for serving as Gulf's Environmental Subject Matter Expert on Company and system-wide compliance teams. As previously mentioned in my testimony, my current job position is Power Generation Specialist, Senior at Gulf Power Company. In this position, I am responsible for preparing all GPIF filings as well as other generating plant reliability and heat rate performance reporting.

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

A. The purpose of my testimony is to present GPIF targets for Gulf Power Company for the period of January 1, 2003 through December 31, 2003.

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

A. Yes. I have prepared one 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 Ms. Noack's exhibit be marked for identification as exhibit_____(LSN-2).

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

A. We propose that Crist Units 4, 5, 6, and 7, Smith Units 1 and 2, and Daniel Units 1 and 2 be the Company's GPIF units. Crist Unit 5 has been added to the other seven GPIF units. The projected net generation from these units, which represent all of Gulf's qualifying base and intermediate load units for GPIF, is 79% of the projected total Gulf net generation for 2003. Combined-cycle unit Smith 3 came on-line in April of 2002 and will be considered for inclusion in the GPIF after it has been in commercial operation for at least one year as described in the GPIF implementation manual for Gulf.

Q. What are the target heat rates Gulf proposes to use in the GPIF for these units for the performance period January 1, 2003 through December 31, 2003?

A. I would like to refer you to Page 43 of Schedule 1 of my exhibit_____(LSN-2) where these targets are listed.

Q. How were these proposed target heat rates determined?

A. They were determined according to the GPIF implementation manual procedures for Gulf.

Q. Describe how the targets were determined for Gulf's proposed GPIF units.

A. Page 2 of Schedule 1 of exhibit_____(LSN-2) shows the target average net operating heat rate equations for the proposed GPIF units, and pages 4 through 39 of Schedule 1 contain the weekly historical data used for the statistical development of these equations. Pages 40 through 42 of Schedule 1 present the calculations that provide the unit target heat rates from the target equations.

Q. Were the maximum and minimum attainable heat rates for each proposed GPIF unit, indicated on page 43 of Schedule 1 of exhibit_____(LSN-2), 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, maximum, and minimum equivalent availabilities are listed on page 4 of Schedule 2 of exhibit_____(LSN-2).

Q. How are the 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 of exhibit_____(LSN-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 of exhibit_____(LSN-2), were determined per GPIF manual procedures for Gulf.

Q. Ms. Noack, has Gulf completed the GPIF minimum filing requirements data package?

A. Yes, we have completed the minimum filing requirements data package. Schedule 3 of my exhibit_____(LSN-2) contains this information.

Q. Ms. Noack, would you please summarize your testimony?

A. Yes. Gulf asks that the Commission accept:

1. Crist Units 4, 5, 6 and 7, Smith Units 1 and 2, and Daniel Units 1 and 2 for inclusion under the GPIF for the period of January 1, 2003 through December 31, 2003.

2. The target, maximum attainable, and minimum attainable average net operating heat rates, as proposed by the Company and as shown on page 43 of Schedule 1 and also page 5 of Schedule 3 of my exhibit_____(LSN-2).

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_____(LSN-2).

4. The weekly average net operating heat rate least squares regression equations, shown on page 2 of Schedule 1 and also pages 20 through 35 of Schedule 3 of my exhibit_____(LSN-2), for use in adjusting the annual actual unit heat rates to target conditions.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
H. Homer Bell
Docket No. 020001-EI
Date of Filing: August 20, 2002

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

A. My name is H. Homer Bell, and my business address is One Energy Place, Pensacola, Florida 32520. I am a Senior Engineer in the Generation Services Department of Gulf Power Company.

Q. Have you previously testified before this Commission?

A. No.

Q. Please summarize your educational and professional background.

A. I received my Bachelor of Science Degree in Electrical Engineering from Mississippi State University in 1980 and I received my Master of Business Administration Degree from the University of Southern Mississippi in 1982. I joined Gulf Power Company (Gulf) as an associate engineer in Gulf's Pensacola District Engineering Department, and have since held engineering positions in the Rates and Regulatory Matters Department and the Transmission and System Control Department. I was promoted to my current position as Senior Engineer in the Generation Services Department in 2002. I am primarily responsible for the administration of Gulf's Intercompany Interchange Contract (IIC) and coordination of Gulf's generation planning activities.

During my years of service with the company, I have gained experience in the areas of distribution operation, maintenance, and construction; retail and wholesale electric service tariff administration; wholesale transmission service tariff administration; IIC and bulk power sales contract administration; and transmission and control center operations.

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

A. The purpose of my testimony is to summarize Gulf 's actual / estimated true-up projections of purchased power recoverable energy purchases and sales for the January 2002 through December 2002 recovery period. I will compare these January 2002 through December 2002 estimated true-up amounts to the amounts originally projected in Gulf's September 2001 fuel filing for the period and discuss the reason for the difference.

I will also summarize the actual / estimated true-up projection of net capacity expenses for the January 2002 through December 2002 recovery period. I will compare these figures to the amounts originally projected in Gulf's September 2001 capacity filing for the period and discuss the reason for the difference.

Q. During the period January 2002 through December 2002, what is Gulf's actual / estimated purchased power recoverable cost for energy purchases and how does it compare with the September 2001 projected amount?

A. Using actual data for January through July 2002 and a revised projection for August through December 2002, Gulf's total estimated purchased power recoverable cost for energy purchases, shown on line 12 of the January 2002 - December 2002 Schedule E-1B1 is $39,371,209. The estimated amount of purchased energy is 2,024,745,313 KWH. The September 2001 projected cost of energy purchases was $21,710,832, for 755,649,000 KWH. The estimated true-up cost per KWH purchased is 1.9445 ¢/KWH as compared to the originally projected cost of 2.8731 ¢/KWH, or 32% under the projection made last fall.

Q. What is the primary reason for the difference between Gulf's original filing and the current projection of Gulf's energy purchases?

A. Through July 2002 of the recovery period, Gulf purchased more energy from the Southern electric system (SES) pool because of an increased availability of lower cost SES generation resources. Gulf was able to purchase this additional pool energy at a significantly lower cost per KWH than originally projected due to the availability of lower cost SES resources resulting from lower than projected loads experienced by the other SES companies through July.

Gulf has revised its purchased power projection for August through December 2002 to incorporate recent updates to the forecast for SES generating unit marginal fuel prices, maintenance outage schedules, and SES loads. This revised projection indicates slightly lower than originally budgeted energy purchase cost for August through December 2002. However, this is more than offset by the higher actual energy purchase cost for January through July 2002 caused by Gulf's higher purchases of economical pool energy.

Q. During the period January 2002 through December 2002, what is Gulf's actual / estimated purchased power fuel cost for energy sales and how does it compare with the September 2001 projected amount?

A. Using actual data for January through July 2002 and a revised projection for August through December 2002, Gulf's total estimated purchased power fuel cost for energy sales for January through December 2002, shown on line 18 of the January 2002 - December 2002 Schedule E-1B1, is $70,328,328. The estimated amount of energy sales is 3,887,325,384 KWH. The September 2001 projected amount was $105,918,000 for 4,456,170,000 KWH. The estimated true-up cost per KWH sold is 1.8092 ¢/KWH as compared to 2.3769 ¢/KWH, or 24% lower than originally projected.

Q. What is the primary reason for the difference between Gulf's original filing and the current projection of Gulf's energy sales?

A. During January through July of the 2002 recovery period, Gulf's energy sales were under the September 2001 projected amount due to lower SES loads at the other companies through July 2002, which reduced Gulf's opportunities to sell energy from its generating units. The unit prices for these sales during the January through July 2002 recovery period were also lower than projected due to the availability of lower cost generation alternatives on the SES produced by lower overall loads at the other companies.

Gulf's pool sales for August through December 2002 are projected to continue at slightly lower levels than originally projected, but the lower level of actual sales that Gulf experienced in January through July 2002 due to lower SES loads is the primary reason Gulf's projected fuel cost for energy sales is lower than the September 2001 projection.

Q. During the period January 2002 through December 2002, what is Gulf's projection of actual / estimated net purchased power capacity transactions and how does it compare with the September 2001 projection of net capacity transactions?

A. As shown on Line 5 of Schedule CCE-1b, the total estimated net capacity cost for the January 2002 through December 2002 recovery period, consisting of actual amounts for January through July and the originally projected amounts for August through December, is $3,147,925 as compared to Gulf's September 2001 projected purchased power capacity cost of $3,584,605. The difference between these projections is a $436,680 cost decrease, or 12% lower than the cost that was filed in September 2001.

Q. Please explain the reason for the decrease in capacity cost.

A. The projected $436,680 capacity cost decrease for the January 2002 through December 2002 period is primarily attributable to changes in Gulf's owned capacity amounts that are used in the Intercompany Interchange Contract (IIC) capacity equalization calculation to determine Gulf's monthly IIC costs. Gulf's IIC costs during January through July were lower than projected because Smith Unit 3 became commercially available on April 22, 2002, which was over one month earlier than projected. The addition of Smith Unit 3 to the IIC calculation of owned capacity earlier than expected resulted in Gulf being a lower net purchaser of capacity through the IIC during the January through July period.

Gulf's IIC costs during August through December 2002 are not expected to differ significantly from those included in the original projection for these months. Therefore, the above mentioned change that lowered Gulf's actual IIC costs for January through July is the primary reason for Gulf's $436,680 capacity cost decrease during the January 2002 through December 2002 cost recovery period.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
H. Homer Bell
Docket No. 020001-EI
Date of Filing: September 20, 2002

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

A. My name is H. Homer Bell, and my business address is One Energy Place, Pensacola, Florida 32520. I am a Senior Engineer in the Generation Services Department of Gulf Power Company.

Q. Have you previously filed testimony with this Commission?

A. Yes. I have filed testimony in support of Gulf's estimated/actual true-up projections of capacity and energy costs for the January 2002 through December 2002 recovery period.

Q. Please summarize your educational and professional background.

A. I received my Bachelor of Science Degree in Electrical Engineering from Mississippi State University in 1980 and I received my Master of Business Administration Degree from the University of Southern Mississippi in 1982. That year I joined Gulf Power Company (Gulf) as an associate engineer in Gulf's Pensacola District Engineering Department, and have since held engineering positions in the Rates and Regulatory Matters Department and the Transmission and System Control Department. I was promoted to my current position as Senior Engineer in the Generation Services Department in 2002. I am primarily responsible for the administration of Gulf's Intercompany Interchange Contract (IIC) and coordination of Gulf's generation planning activities.

During my years of service with the company, I have gained experience in the areas of distribution operation, maintenance, and construction; retail and wholesale electric service tariff administration; wholesale transmission service tariff administration; IIC and bulk power sales contract administration; and transmission and control center operations.

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

A. The purpose of my testimony is to support Gulf Power Company's (Gulf) projection of purchased power recoverable costs for energy purchases and sales for the period January 2003 - December 2003. I will also support Gulf's projection of purchased power capacity costs for the January 2003 - December 2003 recovery period.

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

A. Yes. I have one exhibit to which I will refer.

Counsel: We ask that Mr. Bell's Exhibit HHB-1 be marked for identification as Exhibit_____(HHB-1).

Q. What is Gulf's projected purchased power recoverable cost for energy purchases for the January 2003 - December 2003 recovery period?

A. Gulf's projected recoverable cost for energy purchases, shown on line 12 of Schedule E-1 of the fuel filing, is $6,912,775. These purchases result from Gulf's participation in the coordinated operation of the Southern electric system (SES) power pool, as well as the cogeneration purchased power contract with Solutia, Inc. (Solutia). This amount is used by Gulf's witness Ms. Davis as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. What is Gulf's projected purchased power fuel cost for energy sales for the January 2003 - December 2003 recovery period?

A. The projected fuel cost for energy sales, shown on line 18 of Schedule E-1, is $98,584,000. These sales also result from Gulf's participation in the coordinated operation of the SES power pool. This amount is used by Gulf's witness Ms. Davis as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. Please compare Gulf's projected purchased power recoverable costs for energy purchases and sales for the January 2003 - December 2003 recovery period to those projected costs for January 2002 - December 2002 recovery period and explain the reasons the differences.

A. Gulf's purchased power recoverable cost for energy purchases for the 2003 recovery period is $6,912,775, or $14,798,057 less than projected for the 2002 recovery period. This reduction in energy purchases can be attributed to the May 2002 expiration of a 150 megawatt purchased power agreement and the addition of 574 megawatts of generating capacity at Plant Smith that will provide an increased supply of economical energy to meet Gulf's customers' needs. The resulting net increase in capacity resources will reduce Gulf's need to purchase from the SES pool and other sources.

Gulf's projected purchased power fuel cost for energy sales was projected to be $98,584,000, or $7,334,000 less than projected for the 2002 recovery period. This reduction is primarily driven by the addition of other capacity resources on the SES operating companies' systems that will be available to serve the SES territorial and off system load needs.

Q. What information is contained in your exhibit?

A. My exhibit lists the long-term power contracts that are included for capacity cost recovery, their associated megawatt amounts, and the resulting capacity dollar amounts. Also listed on my exhibit are the revenues produced by two non-firm market capacity sales agreements between the SES operating companies and utilities outside the system.

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

A. Two power contracts that produce recoverable capacity transactions through Gulf's purchased power capacity adjustment factor are the SES Intercompany Interchange Contract (IIC) and Gulf's cogeneration purchased power contract with Solutia. The Commission has authorized the Company to include capacity transactions under the IIC for recovery through the purchased power capacity cost adjustment factor. Gulf will continue to have IIC capacity transactions during the January 2003 - December 2003 recovery period. The energy transactions under this contract are handled for cost recovery purposes through the fuel cost adjustment factor.

The Gulf/Solutia cogeneration purchased power contract enables Gulf to purchase 19 megawatts of firm capacity until June 1, 2005. Gulf has included the contract's annual costs for the January 2003 through December 2003 recovery period in this projection. The energy transactions under this contract have also been approved by the Commission for recovery, and these costs are included for cost recovery purposes through the fuel cost adjustment factor.

Q. Are there any other arrangements that produce capacity transactions that are recovered through Gulf's purchased power capacity cost adjustment factor?

A. Yes. Gulf, as a member of the SES, will participate in two agreements to sell non-firm market capacity in 2003 that are included in Gulf's capacity cost projections for the January 2003 - December 2003 recovery period. One agreement provides for the sale of non-firm, fully recallable capacity from SES resources to a neighboring utility. The other agreement, which is also non-firm and fully recallable, provides a load following type of service to another neighboring utility. These agreements will produce fixed monthly revenues that will be allocated to all SES operating companies. The revenues from these non-firm sales will produce credits that will lower the overall 2003 projected capacity costs. Any scheduled energy transactions associated with these capacity sales are handled for cost recovery purposes through the fuel cost adjustment factor.

Q. What are Gulf's IIC capacity transactions that are projected for the January 2003 - December 2003 recovery period?

A. As shown on my Exhibit HHB-1, capacity transactions under the IIC vary during each month of the recovery period. IIC capacity purchases in the amount of $6,042,798 are projected for the year. IIC capacity sales during the same period are projected to be $69,531. As a result of these purchases and sales, Gulf's net capacity transactions under the IIC for the recovery period are net purchases amounting to $5,973,267.

Q. What is the cost of Gulf's capacity purchase from Solutia that is projected for the January 2003 - December 2003 recovery period?

A. As shown on my Exhibit HHB-1, Gulf is projected to pay $746,424, or $62,202 per month, to Solutia for the firm capacity purchase made pursuant to the Commission approved contract.

Q. What amount of revenues associated with Gulf's market capacity sales is projected for the January 2003 - December 2003 recovery period?

A. As shown on my Exhibit HHB-1, Gulf is projected to receive a total of $210,672 from the sale of non-firm capacity to non-associated utilities.

Q. What are Gulf's total projected net capacity transactions for the January 2003 - December 2003 recovery period?

A. As shown on my Exhibit HHB-1, the net purchases under the IIC, the Solutia contract purchases, and the non-firm market capacity sales will result in a projected net capacity cost of $6,509,019. This figure is used by Gulf's witness Ms. Davis as an input into the calculation of the total capacity transactions to be recovered through the purchased power capacity cost adjustment factor for this annual recovery period.

Q. Please compare Gulf's January 2003 - December 2003 projected net capacity cost to those projected costs for January 2002 - December 2002 recovery period and explain the reason for the difference.

A. Gulf's net capacity cost is projected to be $2,846,414 higher than the 2002 net capacity cost projection due to its higher 2003 IIC capacity cost. This cost increase results from the addition of system capacity that is needed across the SES to reliably serve customers' current and future needs. Gulf is projected to purchase its share of the system reserves produced by these capacity additions, and its IIC capacity costs will increase under the monthly IIC reserve sharing process.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
H. Homer Bell
Docket No. 020001-EI
Date of Filing: Amended October 24, 2002

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

A. My name is H. Homer Bell, and my business address is One Energy Place, Pensacola, Florida 32520. I am a Senior Engineer in the Generation Services Department of Gulf Power Company.

Q. Have you previously filed testimony with this Commission?

A. Yes. I have filed testimony in support of Gulf's estimated/actual true-up projections of capacity and energy costs for the January 2002 through December 2002 recovery period.

Q. Please summarize your educational and professional background.

A. I received my Bachelor of Science Degree in Electrical Engineering from Mississippi State University in 1980 and I received my Master of Business Administration Degree from the University of Southern Mississippi in 1982. That year I joined Gulf Power Company (Gulf) as an associate engineer in Gulf's Pensacola District Engineering Department, and have since held engineering positions in the Rates and Regulatory Matters Department and the Transmission and System Control Department. I was promoted to my current position as Senior Engineer in the Generation Services Department in 2002. I am primarily responsible for the administration of Gulf's Intercompany Interchange Contract (IIC) and coordination of Gulf's generation planning activities.

During my years of service with the company, I have gained experience in the areas of distribution operation, maintenance, and construction; retail and wholesale electric service tariff administration; wholesale transmission service tariff administration; IIC and bulk power sales contract administration; and transmission and control center operations.

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

A. The purpose of my testimony is to support Gulf Power Company's (Gulf) projection of purchased power recoverable costs for energy purchases and sales for the period January 2003 - December 2003. I will also support Gulf's projection of purchased power capacity costs for the January 2003 - December 2003 recovery period.

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

A. Yes. I have one exhibit to which I will refer.

Counsel: We ask that Mr. Bell's Exhibit HHB-1 be marked for identification as Exhibit_____(HHB-1).

Q. What is Gulf's projected purchased power recoverable cost for energy purchases for the January 2003 - December 2003 recovery period?

A. Gulf's projected recoverable cost for energy purchases, shown on line 12 of Schedule E-1 of the fuel filing, is $6,912,775. These purchases result from Gulf's participation in the coordinated operation of the Southern electric system (SES) power pool, as well as the cogeneration purchased power contract with Solutia, Inc. (Solutia). This amount is used by Gulf's witness Ms. Davis as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. What is Gulf's projected purchased power fuel cost for energy sales for the January 2003 - December 2003 recovery period?

A. The projected fuel cost for energy sales, shown on line 18 of Schedule E-1, is $98,584,000. These sales also result from Gulf's participation in the coordinated operation of the SES power pool. This amount is used by Gulf's witness Ms. Davis as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. Please compare Gulf's projected purchased power recoverable costs for energy purchases and sales for the January 2003 - December 2003 recovery period to those projected costs for January 2002 - December 2002 recovery period and explain the reasons the differences.

A. Gulf's purchased power recoverable cost for energy purchases for the 2003 recovery period is $6,912,775, or $14,798,057 less than projected for the 2002 recovery period. This reduction in energy purchases can be attributed to the May 2002 expiration of a 150 megawatt purchased power agreement and the addition of 574 megawatts of generating capacity at Plant Smith that will provide an increased supply of economical energy to meet Gulf's customers' needs. The resulting net increase in capacity resources will reduce Gulf's need to purchase from the SES pool and other sources.

Gulf's projected purchased power fuel cost for energy sales was projected to be $98,584,000, or $7,334,000 less than projected for the 2002 recovery period. This reduction is primarily driven by the addition of other capacity resources on the SES operating companies' systems that will be available to serve the SES territorial and off system load needs.

Q. What information is contained in your exhibit?

A. My exhibit lists the long-term power contracts that are included for capacity cost recovery, their associated megawatt amounts, and the resulting capacity dollar amounts. Also listed on my exhibit are the revenues produced by two non-firm market capacity sales agreements between the SES operating companies and utilities outside the system.

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

A. Two power contracts that produce recoverable capacity transactions through Gulf's purchased power capacity adjustment factor are the SES Intercompany Interchange Contract (IIC) and Gulf's cogeneration purchased power contract with Solutia. The Commission has authorized the Company to include capacity transactions under the IIC for recovery through the purchased power capacity cost adjustment factor. Gulf will continue to have IIC capacity transactions during the January 2003 - December 2003 recovery period. The energy transactions under this contract are handled for cost recovery purposes through the fuel cost adjustment factor.

The Gulf/Solutia cogeneration purchased power contract enables Gulf to purchase 19 megawatts of firm capacity until June 1, 2005. Gulf has included the contract's annual costs for the January 2003 through December 2003 recovery period in this projection. The energy transactions under this contract have also been approved by the Commission for recovery, and these costs are included for cost recovery purposes through the fuel cost adjustment factor.

Q. Are there any other arrangements that produce capacity transactions that are recovered through Gulf's purchased power capacity cost adjustment factor?

A. Yes. Gulf, as a member of the SES, will participate in two agreements to sell non-firm market capacity in 2003 that are included in Gulf's capacity cost projections for the January 2003 - December 2003 recovery period. One agreement provides for the sale of non-firm, fully recallable capacity from SES resources to a neighboring utility. The other agreement, which is also non-firm and fully recallable, provides a load following type of service to another neighboring utility. These agreements will produce fixed monthly revenues that will be allocated to all SES operating companies. The revenues from these non-firm sales will produce credits that will lower the overall 2003 projected capacity costs. Any scheduled energy transactions associated with these capacity sales are handled for cost recovery purposes through the fuel cost adjustment factor.

Q. What are Gulf's IIC capacity transactions that are projected for the January 2003 - December 2003 recovery period?

A. As shown on my Exhibit HHB-1, capacity transactions under the IIC vary during each month of the recovery period. IIC capacity purchases in the amount of $7,889,180 are projected for the year. IIC capacity sales during the same period are projected to be $82,050. As a result of these purchases and sales, Gulf's net capacity transactions under the IIC for the recovery period are net purchases amounting to $7,807,130.

Q. What is the cost of Gulf's capacity purchase from Solutia that is projected for the January 2003 - December 2003 recovery period?

A. As shown on my Exhibit HHB-1, Gulf is projected to pay $746,424, or $62,202 per month, to Solutia for the firm capacity purchase made pursuant to the Commission approved contract.

Q. What amount of revenues associated with Gulf's market capacity sales is projected for the January 2003 - December 2003 recovery period?

A. As shown on my Exhibit HHB-1, Gulf is projected to receive a total of $210,672 from the sale of non-firm capacity to non-associated utilities.

Q. What are Gulf's total projected net capacity transactions for the January 2003 - December 2003 recovery period?

A. As shown on my Exhibit HHB-1, the net purchases under the IIC, the Solutia contract purchases, and the non-firm market capacity sales will result in a projected net capacity cost of $8,342,882. This figure is used by Gulf's witness Ms. Davis as an input into the calculation of the total capacity transactions to be recovered through the purchased power capacity cost adjustment factor for this annual recovery period.

Q. Please compare Gulf's January 2003 - December 2003 projected net capacity cost to those projected costs for January 2002 - December 2002 recovery period and explain the reason for the difference.

A. Gulf's net capacity cost is projected to be $4,680,277 higher than the 2002 net capacity cost projection due to its higher 2003 IIC capacity cost. This cost increase results from the addition of system capacity that is needed across the SES to reliably serve customers' current and future needs. Gulf is projected to purchase its share of the system reserves produced by these capacity additions, and its IIC capacity costs will increase under the monthly IIC reserve sharing process.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM A. SMOTHERMAN

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

A. My name is William A. Smotherman. My mailing and business address is Post Office Box 111, Tampa, Florida 33601. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Director, Resource Planning in the Resource Planning Department.

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

A. I received a Bachelor of Electrical Engineering degree in 1986 from University of South Florida in Tampa, Florida. In May 1986, I joined Tampa Electric as an associate engineer. I have been employed by Tampa Electric for 15 years working in the areas of system planning, commercial/ industrial account management and wholesale power marketing. In February 2001, I was promoted to Director, Resource Planning. My present responsibilities include the areas of system reliability, generation expansion and system fuel and purchased power forecasting and related economic analyses.

Q. What is the purpose of your testimony?

A. My testimony presents Tampa Electric's actual performance results from unit equivalent availability and station heat rate used to determine the Generating Performance Incentive Factor (GPIF) for the period January 2001 through December 2001. I will also compare these results to the targets established prior to the beginning of the period.

Q. Have you prepared any exhibits to support your testimony?

A. Yes, Exhibit No. _____ (WAS-1), consisting of two documents, was prepared under my direction and supervision. Document No. 1, entitled "Tampa Electric Company, Generating Performance Incentive Factor, January 2001 - December 2001, True-up" is consistent with the GPIF Implementation Manual previously approved by the Commission. In addition, Document No. 2, provides the company's Actual Unit Performance Data for the 2001 period.

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

A. Seven of the company's units are included. These are Big Bend Station Units 1, 2, 3, and 4, Gannon Station Units 5 and 6, and Polk Station Unit 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 Document No. 1, page 4 of 32. Based upon -1.611 GPIF points, the result is a penalty amount of $831,029 for the period.

Q. Please proceed with your review of the actual results for the January 2001 - December 2001 period.

A. On Document No. 1, page 3 of 32, the actual average common equity for the period is shown on line 14 as $1,303,090,000. This produces the maximum penalty or reward figure of $5,158,126 as shown on line 21.

Q. Will you please explain how you arrived at the actual equivalent availability results for the seven included within the GPIF?

A. Yes, I will. Operating data on each of our 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 twelve months provides the basis for the GPIF.

Q. Are the equivalent availability results shown on Document No. 1, page 6 of 32, 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 Document No. 1, page 6 of 32. 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:

Big Bend Unit No. 1

On this unit, 1176 planned outage hours were originally scheduled for 2001. Actual outage activities required 1249 planned outage hours. Consequently, the actual equivalent availability of 63.3% is adjusted to 63.9% as shown on Document No. 1, page 7 of 32.

Big Bend Unit No. 2

On this unit, 504 planned outage hours were originally scheduled for 2001. Actual outage activities required 517.5 planned outage hours. Consequently, the actual equivalent availability of 73.3% is adjusted to 73.4% as shown on Document No. 1, page 8 of 32.

Big Bend Unit No. 3

On this unit, 504 planned outage hours were originally scheduled for 2001. Actual outage activities required no planned outage hours. Consequently, the actual equivalent availability of 75.7% is adjusted to 71.3% as shown on Document No. 1, page 9 of 32.

Big Bend Unit No. 4

On this unit, 336 planned outage hours were originally scheduled for 2001. Actual outage activities required 755.2 planned outage hours. Consequently, the actual equivalent availability of 78.1% is adjusted to 82.3% as shown on Document No. 1, page 10 of 32.

Gannon Unit No. 5

On this unit, 672 planned outage hours were originally scheduled for 2001. Actual outage activities required 1057.5 planned outage hours. Consequently, the actual equivalent availability of 58.3% is adjusted to 61.2% as shown on Document No. 1, page 11 of 32.

Gannon Unit No. 6

On this unit, 672 planned outage hours were originally scheduled for 2001. Actual outage activities required 716 planned outage hours. Consequently, the actual equivalent availability of 74.6% is adjusted to 75.0%, as shown on Document No. 1, page 12 of 32.

Polk Unit No. 1

On this unit, 672 planned outage hours were originally scheduled for 2001. Actual outage activities required 327.8 planned outage hours. Consequently, the actual equivalent availability of 86.4% is adjusted to 82.8%, as shown on Document No. 1, page 13 of 32.

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 Document No. 1, page 6 of 32, column 4. This number is entered into the respective Generating Performance Incentive Point (GPIP) Table for each particular unit on pages 24 of 32 through 30 of 32. Page 4 of 32 summarizes the equivalent availability points to be awarded or penalized.

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

A. The actual heat rate and adjusted actual heat rate for Big Bend Units 1, 2, 3, and 4, Gannon Units 5 and 6 and Polk Unit 1 are shown on page Document No. 1, page 6 of 32. The adjustment was developed based on the guidelines of section 4.3.16 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 32. This heat rate number is entered into the respective GPIP table for the particular unit, shown on pages 24 of 32 through 30 of 32. Page 4 of 32 summarizes the weighted heat rate and equivalent availability points to be awarded.

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

A. This is shown on Document No. 1, page 32 of 32. Essentially, the weighting factors shown on page 4 of 32, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 32, column 4, are substituted within the equation. This resultant value, -1.611, is then entered into the GPIF table on page 2 of 32. Using linear interpolation, a penalty amount of $831,029 is calculated.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM A. SMOTHERMAN

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

A. My name is William A. Smotherman. My mailing and business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as the Director of the Resource Planning Department.

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

A. I received a Bachelor of Electrical Engineering degree in 1986 from the University of South Florida. In May 1986, I joined Tampa Electric as an associate engineer, and I have worked in the areas of system planning, commercial/ industrial account management and wholesale power marketing. In February 2001, I was promoted to Director, Resource Planning. My present responsibilities include the areas of system reliability, generation expansion and system fuel and purchased power forecasting and related economic analyses.

Q. What is the purpose of your testimony?

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

Q. Have you prepared any exhibits to support your testimony?

A. Yes, Exhibit No. _____ (WAS-2), consisting of two documents, was prepared under my direction and supervision. Document No. 1 is titled "Generating Performance Incentive Factor January 2003 - December 2003." Document No. 2 is a summary of the GPIF targets for the 2003 period.

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

A. Six of the company's coal-fired units and one integrated gasification combined cycle unit are included. These are

Gannon Station Units 5 and 6, Big Bend Station Units 1, 2, 3, and 4, and Polk Power Station Unit 1. Due to environmental compliance requirements, Gannon Units 5 and 6 are expected to stop operating in February 2003 and September 2003 respectively, however the data for these units are included in the GPIF calculations until the units are shut down for repowering.

Q. Do the exhibits you have prepared comply with Commission-approved GPIF methodology?

A. The documents I prepared are consistent with the GPIF Implementation Manual previously approved by the Commission, with the exception of the criterion that the company shall include generating units that will represent not less than 80 percent of projected system net generation.

Q. Please explain.

A. Due to the implementation of the final phases of repowering Gannon units 5 and 6 from coal to natural gas fired generation, 2003 will be a transition year for Tampa Electric. Since the company is repowering Gannon Units 5 and 6 to Bayside Units 1 and 2, its remaining

GPIF units will not represent 80 percent of projected system net generation. Although the first Bayside unit will begin operation in 2003, the repowered unit cannot be immediately included in the GPIF calculations because Tampa Electric will not have the historical operational data required by the GPIF Implementation manual to set GPIF targets. In addition, Tampa Electric has no other base load generating units to substitute for Gannon Units 5 and 6. Therefore, Tampa Electric requests approval of its calculation of the 2003 GPIF excluding the repowered units, as provided for by Section 3.2 of the GPIF Implementation Manual, which states that the Commission will approve exclusion of units from the calculation of the GPIF on a case-by-case basis.

Q. Please describe how Tampa Electric developed the various factors associated with the GPIF.

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2003 period. A range of potential improvements and degradations was determined for each of these parameters.

Q. How were the target values for unit availability determined?

A. The Planned Outage Factor ("POF") and the Equivalent Unplanned Outage Factor ("EUOF") were subtracted from 100% to determine the target Equivalent Availability Factor ("EAF"). The factors for each of the seven units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2003 period, the projected Equivalent Unplanned Outage Factor for Big Bend Unit 1 is 24.35% and the Planned Outage Factor is 5.75%. Therefore, the target equivalent availability factor for Big Bend Unit 1 equals 69.9% or:

$$100\% - [(24.35\% + 5.75\%)] = 69.9\%$$

This is shown on page 4, column 3 of Document No. 1.

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

A. Maximum equivalent availability is derived by using the following formula:

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

The factors included in the above equations are the same factors that determine the target equivalent availability. To determine the maximum incentive points, a 20% reduction in Equivalent Forced Outage Factor ("EUOF") and Equivalent Maintenance Outage Factor ("EMOF"), plus a 5% reduction in the Planned Outage Factor are necessary. Continuing with the Big Bend Unit 1 example:

$$EAF_{MAX} = 100\% - [0.8\ (24.35\%) + 0.95\ (5.75\%)] = 75.1\%$$

This is shown on page 4, column 4 of Document No. 1.

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

A. The potential for unit availability degradation is significantly greater than the potential for unit availability improvement. This concept was discussed extensively and approved in earlier hearings before the Commission. To incorporate this biased effect into the unit availability tables, Tampa Electric uses a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is calculated using the following formula:

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

Again, continuing with the Big Bend Unit 1 example,

$$EAF_{MIN} = 100\% - [1.4 \ (24.35\%) + 1.1 \ (5.75\%)] = 59.6\%$$

The equivalent availability MAX and MIN for the other six units is computed in a similar manner.

Q. How did Tampa Electric determine the Planned Outage, Maintenance Outage, and Forced Outage Factors?

A. The company's planned outages for January 2003 through December 2003 are shown on page 21 of Document No. 1. Also, a Critical Path Method (C.P.M.) for each major planned outage, which affects GPIF, is shown on pages 22 and 23 of Document No. 1. Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 1 is scheduled for a planned outage February 15 through March 7, 2003. There are 504 planned outage hours scheduled for the 2003 period, and a total of 8,760 hours during this 12-month period. Consequently, the Planned Outage Factor for Unit 1 at Big Bend is 5.75% or:

$$\frac{504}{8{,}760} \times 100\% = 5.75\%$$

The factor for each unit is shown on pages 5 and 14 of Document No. 1. Big Bend Unit 2 has a Planned Outage Factor of 3.84%. Big Bend Unit 3 has a Planned Outage Factor of 3.84%. Big Bend 4 has a Planned Outage Factor of 9.59%. Gannon Unit 5 has a Planned Outage Factor of 0%. Gannon Unit 6 has a Planned Outage Factor of 0%. Polk Unit 1 has a Planned Outage Factor of 12.05%.

Q. How did you determine the Forced Outage and Maintenance Outage Factors for each unit?

A. Graphs for both factors (adjusted for planned outages) versus time were prepared. Monthly data and 12-month rolling average data were recorded. For each unit the most current 12-month ending value, June 2002, was used as a basis for the projection. This value was adjusted 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 an Equivalent

Unplanned Outage Factor of 24.35% for Big Bend Unit 1. The Equivalent Unplanned Outage Factor for Big Bend Unit 1 is verified by the data shown on page 14, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

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

Or

$$EUOF = \frac{(1416 + 717)}{8,760} \times 100 = 24.35\%$$

Relative to Big Bend Unit 1, the EUOF of 24.35% forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 24.35%. This unit will have a planned outage in 2003 and the Planned Outage Factor is 5.75%. Therefore, the target equivalent availability for this unit is 69.9%.

Big Bend Unit 2

The projected Equivalent Unplanned Outage Factor for this unit is 33.16%. This unit will have a planned outage in 2003 and the Planned Outage Factor is 3.84%. Therefore, the target equivalent availability for this unit is 63%.

Big Bend Unit 3

The projected Equivalent Unplanned Outage Factor for this unit is 28.9%. This unit will have a planned outage in 2003 and the Planned Outage Factor is 3.84%. Therefore, the target equivalent availability for this unit is 67.3%.

Big Bend Unit 4

The projected Equivalent Unplanned Outage Factor for this unit is 12.68%. This unit will have a planned outage in 2003 and the Planned Outage Factor is 9.59%. Therefore, the target equivalent availability for this unit is 77.7%.

Gannon Unit 5

The projected Equivalent Unplanned Outage Factor for this unit is 28.07%. This unit will have a planned outage in 2003 and the Planned Outage Factor is 0%. Therefore, the target equivalent availability for this unit is 71.9%.

Gannon Unit 6

The projected Equivalent Unplanned Outage Factor for this unit is 24.05%. This unit will have a planned outage in 2003 and the Planned Outage Factor is 0%. Therefore, the target equivalent availability for this unit is 75.9%.

Polk Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 13.39%. This unit will have a planned outage in 2003 and the Planned Outage Factor is 12.05%. Therefore, the target equivalent availability for this unit is 74.6%.

Q. Please summarize your testimony regarding Equivalent Availability Factor.

A. The GPIF system weighted Equivalent Availability Factor of 69.3% is shown on Page 5 of Document No. 1 This target compares favorably to the July 2001 - June 2002 GPIF period.

Q. When graphing and monitoring Forced and Maintenance Outage Factors, why are they adjusted for planned outage hours?

A. The adjustment makes the 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 the units in the GPIF are usually base loaded, reserve shutdown is generally not a factor.

To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Big Bend Unit 1 on page 14 of Document No. 1. During the months of January and April through December, the Equivalent Unplanned Outage Rate and the Equivalent Unplanned Outage Factor are equal. This is due to the fact that no planned outages are scheduled during these months. During the months of February and March, Equivalent Unplanned Outage Rate exceeds Equivalent Unplanned Outage Factor due to the scheduling of a planned outage. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

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

A. Yes. Rates provide a proper and accurate method of determining the unit parameters, which are subsequently converted to factors. Therefore,

FOF + MOF + POF + EAF = 100%

Since factors are additive, they are easier to work with and to understand.

Q. Has Tampa Electric prepared the necessary heat rate data required for the determination of the GPIF?

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

Q. How were these targets determined?

A. Net heat rate data for the three most recent July through June annual periods, along with the PROMOD IV program, formed the basis of the target development. Projections of unit performance were made with the aid of PROMOD IV. 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 Units 1 and 2 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 these units resulting from utilization of the new scrubber can be quantified, but the operational history is short of GPIF guidelines. Therefore, targets for Big Bend Units 1 and 2 have been developed in the standard fashion using data without scrubber power. In order to assure compatibility with the targets, scrubber power will be removed prior to calculating Units 1 and 2 heat rates for the subsequent true-up process. This method was approved by the Commission for Big Bend Unit 3 when it began scrubbing operation. The company will utilize the aforementioned method until there is sufficient history to meet target preparation guidelines.

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 versus net output factor curves have been developed for each unit. This information is shown on pages 31 through 37 of Document No. 1.

Q. Please elaborate on the analysis used in the determination of the ranges.

A. The net heat rate versus net output factor curves are the result 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. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2003 period.

A. The heat rate target for Big Bend Unit 1 is 10,533 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±622 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10111 Btu/Net kWh with a range of ±537 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,132 Btu/Net kWh, with a range of ±677 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,028 Btu/Net kWh with a range of ±463 Btu/Net kWh. The heat rate target for Gannon Unit 5 is 10,862 Btu/Net kWh with a range of ±728 Btu/Net kWh. The heat rate target for Gannon Unit 6 is 10,775 Btu/Net kWh with a range of ±767 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,382 Btu/Net kWh with a range of ±767 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 13 of Document No. 1.

Q. Do the heat rate targets and ranges in Tampa Electric's projection meet the criteria of the GPIF and the philosophy of the Commission?

A. Yes.

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 13. The PROMOD IV 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 $546,407,900 is shown on page 6, column 2.

The PROMOD IV 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 of Document No. 1.

After all of the individual savings are calculated column 4 totals $29,158,500, which reflects the savings if all of the 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 1, the weighting factor for equivalent availability is 10.36% as shown in the right-hand column on page 6. Pages 7 through 13 of Document No. 1 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 1, page 7, if the unit operates at 75.1% equivalent availability, fuel savings would equal $3,021,700 and ten equivalent availability points would be awarded.

The GPIF Reward/Penalty Table on page 2 is a summary of the tables on pages 7 through 13. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, $29,158,500. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How were the maximum allowed incentive dollars determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January 2003 through December 2003 is $1,751,599,709. This produces the maximum allowed jurisdictional incentive dollars of $6,960,923 shown on line 21.

Q. Are there any other constraints set forth by the Commission regarding the magnitude of incentive dollars?

A. Yes. Incentive dollars are not to exceed 50 percent of fuel savings. Page 2 of Document No. 1 demonstrates that this constraint is met.

Q. Please summarize your testimony on the GPIF.

A. Tampa Electric has complied with the Commission's directions, philosophy, and methodology in our determination of GPIF. The GPIF is determined by the following formula for calculating Generating Performance Incentive Points (GPIP):

$$\begin{aligned} GPIP: = (\ & 0.1036\ EAP_{BB1} + 0.1461\ EAP_{BB2} \\ & + 0.1041\ EAP_{BB3} + 0.0696\ EAP_{BB4} \\ & + 0.0034\ EAP_{GN5} + 0.0441\ EAP_{GN6} \\ & + 0.0306\ EAP_{PK1} + 0.0895\ HRP_{BB1} \\ & + 0.0740\ HRP_{BB2} + 0.1001\ HRP_{BB3} \\ & + 0.0850\ HRP_{BB4} + 0.0050\ HRP_{GN5} \\ & + 0.0660\ HRP_{GN6} + 0.0781\ HRP_{PK1}\ ) \end{aligned}$$

Where:

GPIP = Generating Performance Incentive Points.

EAP = Equivalent Availability Points awarded/deducted for Big Bend Units 1, 2, 3 and 4, Gannon Units 5 and 6, and Polk Unit 1.

HRP = Average Net Heat Rate Points awarded/deducted for

Big Bend Units 1, 2, 3 and 4, Gannon Units 5 and 6, and Polk Unit 1.

Q. Have you prepared a document summarizing the GPIF targets for the January 2003 - December 2003 period?

A. Yes. Document No. 2 entitled "Tampa Electric Company, Summary of GPIF Targets, January 2003 - December 2003" provides the availability and heat rate targets for each unit.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Terry A. Davis
Docket No. 020001-EI
Fuel and Purchased Power Capacity Cost Recovery
Date of Filing: April 1, 2002

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

A. My name is Terry Davis. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the senior Staff Accountant in the Rates and Regulatory Matters Department of Gulf Power Company.

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

A. I graduated from Mississippi College in Clinton, Mississippi in 1979 with a Bachelor of Science Degree in Business Administration and a major in Accounting. Prior to joining Gulf Power, I was an accountant for a seismic survey firm, Geophysical Field Surveys in Jackson, Mississippi. In that capacity, I was responsible for accounts receivable, accounts payable, sales, use, and fuel tax returns, and various other accounting activities. In 1986, I joined Gulf Power as an Associate Accountant in the Plant Accounting Department. Since then, I have held various positions of increasing responsibility with Gulf in Accounts Payable, Financial Reporting, and Cost Accounting. In 1993, I joined the Rates and Regulatory Matters area, where I have participated in activities related to the cost recovery clauses, budgeting, and other regulatory functions. In 1998, I was promoted to my current position, which includes preparation and coordination of the Company's Fuel, Capacity and Environmental Cost Recovery Clause filings, administration of Gulf's retail tariff, and review of other regulatory filings submitted by the Company.

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. Davis' Exhibit consisting of four schedules be marked as Exhibit No. _____ (TAD-1).

Q. Are you familiar with the Fuel and Purchased Power (Energy) true-up calculations for the period of January 2001 through December 2001 and the Purchased Power Capacity Cost true-up calculations for the period of January 2001 through December 2001 set forth in your exhibit?

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

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 January 2003 through December 2003?

A. A net amount to be collected of $12,590,104 was calculated as shown on Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $12,590,104 was calculated by taking the difference in the estimated January 2001 through December 2001 under-recovery of $17,609,612 and the actual under-recovery of $30,199,716, which is the sum of the Period-to-Date amounts on lines 7 and 8 shown on Schedule A-2, page 2, of the monthly filing for December 2001. The estimated true-up amount for this period was approved in Order No. PSC-01-2516-FOF-EI dated December 26, 2001. Additional details supporting the approved estimated true-up amount are included on Schedule E1-A filed September 20, 2001.

Q. Ms. Davis has the estimated benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for 2002?
A. Yes, it has.

Q. What is the actual threshold for 2002?
A. Based on actual data for 1999, 2000, and now 2001, the threshold is calculated to be $1,197,565.

Q. Ms. Davis, 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 January 2001 through December 2001.

Q. What is the amount to be refunded or collected in the period January 2003 through December 2003?
A. An amount to be collected of $819,509 was calculated as shown in Schedule CCA-1, of my exhibit.

Q. How was this amount calculated?
A. The $819,509 was calculated by taking the difference in the estimated January 2001 through December 2001 over-

recovery of $1,515,391 and the actual over-recovery of $695,882, which is the sum of lines 12 and 13 under the total column of Schedule CCA-2. The estimated true-up amount for this period was approved in Order No. PSC-01-2516-FOF-EI dated December 26, 2001. Additional details supporting the approved estimated true-up amount are included on Schedule CCE-1A filed September 20, 2001.

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 January 2001 through December 2001. Schedule CCA-3 of my exhibit is the calculation of the interest provision on the over-recovery for the period January 2001 through December 2001. 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. Davis, does this complete your testimony?

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Terry A. Davis
Docket No. 020001-EI
Fuel and Purchased Power Capacity Cost Recovery
Date of Revised Filing: August 20, 2002

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

A. My name is Terry Davis. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the senior Staff Accountant in the Rates and Regulatory Matters Department of Gulf Power Company.

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

A. I graduated from Mississippi College in Clinton, Mississippi in 1979 with a Bachelor of Science Degree in Business Administration and a major in Accounting. Prior to joining Gulf Power, I was an accountant for a seismic survey firm, Geophysical Field Surveys in Jackson, Mississippi. In that capacity, I was responsible for accounts receivable, accounts payable, sales, use, and fuel tax returns, and various other accounting activities. In 1986, I joined Gulf Power as an Associate Accountant in the Plant Accounting Department. Since then, I have held various positions of increasing responsibility with Gulf in Accounts Payable, Financial Reporting, and Cost Accounting. In 1993, I joined the Rates and Regulatory Matters area, where I have participated in activities related to the cost recovery clauses, budgeting, a retail rate case, and other regulatory functions. In 1998, I was promoted to my current position, which includes preparation and coordination of the Company's Fuel, Capacity and Environmental Cost Recovery Clause filings, administration of Gulf's retail tariff, and review of other regulatory filings submitted by the Company.

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. Davis' Exhibit consisting of four schedules be marked as Exhibit No. _____ (TAD-1).

Q. Are you familiar with the Fuel and Purchased Power (Energy) true-up calculations for the period of January 2001 through December 2001 and the Purchased Power Capacity Cost true-up calculations for the period of January 2001 through December 2001 set forth in your exhibit?

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

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 January 2003 through December 2003?

A. A net amount to be collected of $12,368,122 was calculated as shown on Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $12,368,122 was calculated by taking the difference in the estimated January 2001 through December 2001 under-recovery of $17,609,612 and the actual under-recovery of $29,977,734, which is the sum of the Period-to-Date amounts on lines 7, 8, and 12 shown on Schedule A-2, page 2, of the monthly filing for December 2001. The estimated true-up amount for this period was approved in Order No. PSC-01-2516-FOF-EI dated December 26, 2001. Additional details supporting the approved estimated true-up amount are included on Schedule E1-A filed September 20, 2001.

Q. Ms. Davis has the estimated benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for 2002?

A. Yes, it has.

Q. What is the actual threshold for 2002?

A. Based on actual data for 1999, 2000, and now 2001, the threshold is calculated to be $1,197,565.

Q. Ms. Davis, 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 January 2001 through December 2001.

Q. What is the amount to be refunded or collected in the period January 2003 through December 2003?

A. An amount to be collected of $819,509 was calculated as shown in Schedule CCA-1, of my exhibit.

Q. How was this amount calculated?

A. The $819,509 was calculated by taking the difference in the estimated January 2001 through December 2001 over-recovery of $1,515,391 and the actual over-recovery of $695,882, which is the sum of lines 12 and 13 under the total column of Schedule CCA-2. The estimated true-up amount for this period was approved in Order No. PSC-01-2516-FOF-EI dated December 26, 2001. Additional details supporting the approved estimated true-up amount are included on Schedule CCE-1A filed September 20, 2001.

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 January 2001 through December 2001. Schedule CCA-3 of my exhibit is the calculation of the interest provision on the over-recovery for the period January 2001 through December 2001. 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. Davis, does this complete your testimony?

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Terry A. Davis
Docket No. 020001-EI
Fuel and Purchased Power Cost Recovery
Date of Filing: September 20, 2002

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

A. My name is Terry Davis. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the senior Staff Accountant in the Rates and Regulatory Matters Department of Gulf Power Company.

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

A. I graduated from Mississippi College in Clinton, Mississippi in 1979 with a Bachelor of Science Degree in Business Administration and a major in Accounting. Prior to joining Gulf Power, I was an accountant for a seismic survey firm, Geophysical Field Surveys, in Jackson, Mississippi. In that capacity, I was responsible for accounts receivable, accounts payable, sales, use, and fuel tax returns, and various other accounting activities. In 1986, I joined Gulf Power as an Associate Accountant in the Plant Accounting Department. Since then, I have held various positions of increasing responsibility with Gulf in Accounts

Payable, Financial Reporting, and Cost Accounting. In 1993, I joined the Rates and Regulatory Matters area, where I participated in activities related to the cost recovery clauses, budgeting, and other regulatory functions. In 1998, I was promoted to my current position, which includes preparation and/or coordination of the Company's Fuel, Capacity and Environmental Cost Recovery Clause filings, administration of Gulf's retail tariff, and review of other regulatory filings submitted by the Company.

Q. Have you previously filed testimony before this Commission in Docket No. 020001-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 January 2003 through December 2003. I will also discuss the calculation of the purchased power capacity cost recovery factors for the period January 2003 through December 2003.

Q. Are you familiar with the Fuel and Purchased Power Cost Recovery Clause Calculation for the period of January 2003 through December 2003?
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. Davis's Exhibit consisting of fourteen schedules, be marked as Exhibit No. ______(TAD-3).

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of January 2001 through December 2001?
A. The GPIF result is shown on Line 33 of Schedule E-1 as an decrease of .0036¢/kwh, thereby penalizing Gulf $369,498.

Q. What is the appropriate revenue tax factor to be applied in calculating the levelized fuel factor?
A. A revenue tax factor of 1.00072 has been applied to all jurisdictional fuel costs as shown on Line 31 of Schedule E-1.

Q. Ms. Davis, what is the levelized projected fuel factor for the period January 2003 through December 2003?

A. Gulf has proposed a levelized fuel factor of 2.348¢/kwh. It includes projected fuel and purchased power energy expenses for January 2003 through December 2003 and projected kwh sales for the same period, as well as the true-up and GPIF amount. The levelized fuel factor has not been adjusted for line losses.

Q. How does the levelized fuel factor for the projection period compare with the levelized fuel factor for the current period?

A. The projected levelized fuel factor for 2003 is .169 cents/kwh more or 7.7 percent higher than the levelized fuel factor for 2002 upon which current fuel factors are based.

Q. Ms. Davis, 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. Davis, 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 2.359¢/kwh for Group A. Fuel factors for Groups A, B, C, and D are shown on Schedule E-1E. These factors have all been adjusted for line losses.

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

A. These were calculated based on projected loads and system lambdas for the period January 2003 through December 2003. These factors included the GPIF and true-up, 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 December 2002 and how would the change affect the cost of 1000 kwh on Gulf's residential rate RS?

A. The current fuel factor for Rate Schedule RS applicable through December 2002 is 2.206¢/kwh compared with the proposed factor of 2.359¢/kwh. For a residential customer who uses 1000 kwh in January 2003, the fuel portion of the bill would increase from $22.06 to $23.59.

Q. Ms. Davis, 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 TAD-3. These costs represent the estimated averages for the period from January 2003 through December 2004.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2003 gains on non-separated wholesale energy sales eligible for a shareholder incentive?

A. In accordance with Staff's implementation plan, a benchmark level of $1,174,292 has been calculated for 2003. The actual gains for 2000, 2001, and the estimated gains for 2002 on all non-separated sales have been averaged to determine the minimum projected threshold for 2003 that must be achieved before shareholders may receive any incentive. As demonstrated on Schedule E-6, page 2 of 2, Gulf's projection reflects a credit to customers of 100 percent of the gains on non-separated sales for 2003. The estimated gains on all non-separated sales are projected to be $527,000, whereas the threshold is estimated at $1,174,292.

Q. Ms. Davis, 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 January 2003 through December 2003.

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. Bell has provided me with Gulf's projected purchased power capacity transactions under the Southern Company Intercompany Interchange Contract (IIC) and Gulf's contract with Solutia. Gulf's total projected net capacity expense includes a credit for transmission revenue for the period January 2003 through December 2003 is $6,377,019. The jurisdictional amount is $6,153,942. This amount is added to the total true-up amount to determine the total purchased power capacity transactions that would be recovered in the period.

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. PSC-02-0787-FOF-EI issued June 10, 2002, in Docket No. 010949-EI. 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 PPCC Recovery Clause have been calculated using the 2001 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 would be applied to each customer's total kwh to calculate the amount to be billed each month.

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

A. The purchased power capacity costs recovered through the clause for a residential customer who uses 1000 kwh will be $.75.

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

A. The fuel and capacity factors will be effective beginning with the first Bill Group for January 2003 and continuing through the last Bill Group for December 2003.

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

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Amended Direct Testimony and Exhibit of
Terry A. Davis
Docket No. 020001-EI
Fuel and Purchased Power Cost Recovery
Date of Filing: October 24, 2002

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

A. My name is Terry Davis. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the senior Staff Accountant in the Rates and Regulatory Matters Department of Gulf Power Company.

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

A. I graduated from Mississippi College in Clinton, Mississippi in 1979 with a Bachelor of Science Degree in Business Administration and a major in Accounting. Prior to joining Gulf Power, I was an accountant for a seismic survey firm, Geophysical Field Surveys, in Jackson, Mississippi. In that capacity, I was responsible for accounts receivable, accounts payable, sales, use, and fuel tax returns, and various other accounting activities. In 1986, I joined Gulf Power as an Associate Accountant in the Plant Accounting Department. Since then, I have held various positions of increasing responsibility with Gulf in Accounts

Payable, Financial Reporting, and Cost Accounting. In 1993, I joined the Rates and Regulatory Matters area, where I participated in activities related to the cost recovery clauses, budgeting, and other regulatory functions. In 1998, I was promoted to my current position, which includes preparation and/or coordination of the Company's Fuel, Capacity and Environmental Cost Recovery Clause filings, administration of Gulf's retail tariff, and review of other regulatory filings submitted by the Company.

Q. Have you previously filed testimony before this Commission in Docket No. 020001-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 January 2003 through December 2003. I will also discuss the calculation of the purchased power capacity cost recovery factors for the period January 2003 through December 2003.

Q. Are you familiar with the Fuel and Purchased Power Cost Recovery Clause Calculation for the period of January 2003 through December 2003?

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. Davis's Exhibit consisting of fourteen schedules, be marked as Exhibit No. _____(TAD-3).

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of January 2001 through December 2001?

A. The GPIF result is shown on Line 33 of Schedule E-1 as an decrease of .0036¢/kwh, thereby penalizing Gulf $369,498.

Q. What is the appropriate revenue tax factor to be applied in calculating the levelized fuel factor?

A. A revenue tax factor of 1.00072 has been applied to all jurisdictional fuel costs as shown on Line 31 of Schedule E-1.

Q. Ms. Davis, what is the levelized projected fuel factor for the period January 2003 through December 2003?

A. Gulf has proposed a levelized fuel factor of 2.348¢/kwh. It includes projected fuel and purchased power energy expenses for January 2003 through December 2003 and projected kwh sales for the same period, as well as the true-up and GPIF amount. The levelized fuel factor has not been adjusted for line losses.

Q. How does the levelized fuel factor for the projection period compare with the levelized fuel factor for the current period?

A. The projected levelized fuel factor for 2003 is .169 cents/kwh more or 7.7 percent higher than the levelized fuel factor for 2002 upon which current fuel factors are based.

Q. Ms. Davis, 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. Davis, 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 2.359¢/kwh for Group A. Fuel factors for Groups A, B, C, and D are shown on Schedule E-1E. These factors have all been adjusted for line losses.

Q. Ms. Davis, how were the time-of-use fuel factors calculated?
A. These were calculated based on projected loads and system lambdas for the period January 2003 through December 2003. These factors included the GPIF and true-up, 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 December 2002 and how would the change affect the cost of 1000 kwh on Gulf's residential rate RS?
A. The current fuel factor for Rate Schedule RS applicable through December 2002 is 2.206¢/kwh compared with the proposed factor of 2.359¢/kwh. For a residential customer who uses 1000 kwh in January 2003, the fuel

portion of the bill would increase from $22.06 to $23.59.

Q. Ms. Davis, 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 TAD-3. These costs represent the estimated averages for the period from January 2003 through December 2004.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2003 gains on non-separated wholesale energy sales eligible for a shareholder incentive?

A. In accordance with Staff's implementation plan, a benchmark level of $1,174,292 has been calculated for 2003. The actual gains for 2000, 2001, and the estimated gains for 2002 on all non-separated sales have been averaged to determine the minimum projected threshold for 2003 that must be achieved before shareholders may receive any incentive. As demonstrated on Schedule E-6, page 2 of 2, Gulf's projection reflects a credit to customers of 100 percent of the gains on non-separated sales for 2003. The estimated gains on all non-separated sales are projected to be $527,000, whereas the threshold is estimated at $1,174,292.

Q. Ms. Davis, 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 January 2003 through December 2003.

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. Bell has provided me with Gulf's projected purchased power capacity transactions under the Southern Company Intercompany Interchange Contract (IIC) and Gulf's contract with Solutia. Gulf's total projected net capacity expense includes a credit for transmission revenue for the period January 2003 through December 2003 is $8,210,882. The jurisdictional amount is $7,923,655. This amount is added to the total true-up amount to determine the total purchased power capacity transactions that would be recovered in the period.

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. PSC-02-0787-FOF-EI issued June 10, 2002, in Docket No. 010949-EI. 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 PPCC Recovery Clause have been calculated using the 2001 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 would be applied to each customer's total kwh to calculate the amount to be billed each month.

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

A. The purchased power capacity costs recovered through the clause for a residential customer who uses 1000 kwh will be $.95.

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

A. The fuel and capacity factors will be effective beginning with the first Bill Group for January 2003 and continuing through the last Bill Group for December 2003.

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

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

W. LYNN BROWN

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

A. My name is Lynn Brown. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the Wholesale Marketing and Fuels Department.

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

A. I received a Bachelor degree in Electrical Engineering from Louisiana State University in 1972 and subsequently joined Tampa Electric. I held various engineering, operations and managerial positions in Energy Delivery from 1973 through 1997. I became Manager of Short Term Wholesale Trading in April 1997 and was promoted to Director, Wholesale Marketing and Sales in August of 1998 where I was responsible for short- and long-term wholesale power purchases and sales. My current responsibilities include power origination and state/federal regulatory issues.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I testified before this Commission in Docket Nos. 990001-EI, 000001-EI and 010001-EI regarding the appropriateness and prudence of the company's purchased power agreements. I testified in Docket No. 991779-EI regarding the appropriate application of incentives to wholesale power sales. I also testified in Docket No. 010283-EI addressing the appropriate regulatory treatment for non-separated wholesale energy sales. I recently filed testimony in Docket No. 011605-EI on Tampa Electric's risk management activities regarding wholesale energy transactions.

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

A. The purpose of my testimony is to provide an overview of the current wholesale energy market and a description of Tampa Electric's 2002 and 2003 purchased power agreements that it has entered into and for which it is seeking cost recovery through the Fuel and Purchased Power Cost

Recovery and Capacity Cost Recovery Clauses. My testimony also describes Tampa Electric's purchased power strategy, for mitigating supply-side risk while providing customers with economically priced purchased power.

Q. Please describe Tampa Electric's wholesale energy purchases for 2002.

A. Tampa Electric assessed the wholesale energy market and entered into long-term and short-term purchases based on price and availability of supply. The company expects to meet 18 percent of customers' 2002 energy needs through purchased power, including purchased power from Hardee Power Partners and qualifying facilities. The company also purchased 200 MW of firm capacity for the winter of 2001-2002 and 260 MW for the summer of 2002. In addition, Tampa Electric contracted to lease 30 completely self-contained portable generators to supplement the company's supply through the summer period. The generators supply 50 MW of peaking power to retail customers.

Tampa Electric expects that 62 percent of its purchased power will be from long-term contracts, and the remaining 38 percent will be purchased through the short-term market. This purchasing strategy provides a reasonable and diversified approach to serving retail customers.

Q. Please describe Tampa Electric's wholesale energy sales for the year 2002.

A. Tampa Electric has entered into non-firm, non-separated wholesale sales this year, which provided benefits to retail customers because revenues from these sales flow back to customers through the Fuel and Purchased Power Cost Recovery Clause. The company has not entered into any firm separated or non-separated wholesale sales since 1998.

Q. What capacity and energy purchases are included in Tampa Electric's projections for 2003?

A. In addition to the Hardee Power Partners purchased power agreement and qualifying facility purchases, Tampa Electric has purchased 150 MW of short-term firm capacity and energy in addition to extending the lease of 50 MW of distributed generation for the 2002-2003 winter period. A combination of forward and spot market energy purchases will also be made to cover Tampa Electric's spring and fall generation maintenance periods and peak period needs.

Q. Has Tampa Electric reasonably managed its wholesale power purchases and sales practices for the benefit of its retail customers?

A. Yes, it has.

Q. On what do you base this conclusion?

A. Tampa Electric has fully complied with, and continues to fully comply with, the regulatory policies, practices and requirements set forth in the Commission's definitive March 11, 1997 fuel adjustment order governing the treatment of separated and non-separated wholesale sales, Order No. PSC-97-0262-FOF-EI, Docket No. 970001-EI. In addition, the company actively manages its wholesale sales and purchases with the goal of taking advantage of all opportunities to reduce cost to the retail customers. The company's purchased power activities and transactions are continually reviewed and have been audited on a routine and recurring basis by the Commission. In addition, Tampa Electric continually monitors its rights under contracts with purchased power suppliers as well as those to whom wholesale power is sold with an eye toward detecting and preventing any breach of the company's contractual rights. Tampa Electric continually strives to improve its knowledge of the markets and the available opportunities to minimize the costs of purchased power and to maximize the savings the company provides retail customers by making non-firm, non-separated wholesale sales when excess power is available on Tampa Electric's system.

Q. Please describe the efforts Tampa Electric has made to ensure that its wholesale purchases and sales activities are conducted in a reasonable and prudent manner.

A. Tampa Electric aggressively shops for wholesale capacity and energy, searching for reliable supply at the best possible price from creditworthy counterparties. These purchases are evaluated based on forward and spot markets. The company engages in wholesale power purchases and sales with numerous counterparties. Each counterparty's creditworthiness is carefully checked before engaging in wholesale energy transactions. Purchases are made to achieve required installed reserve capacity, to meet our customers' needs during planned and unplanned generating unit outages and for economical purposes.

Q. Does Tampa Electric engage in physical or financial hedging of its wholesale energy transactions to mitigate wholesale energy price volatility?

A. Florida's wholesale energy market is at an early developmental stage. Physical and financial hedges provide measurable market price volatility protection. However, the availability of financial instruments is limited, and Tampa Electric does not believe that financial instruments appropriate for its needs currently exist. Thus, Tampa Electric has not purchased any wholesale energy derivatives. The company employs a diversified power supply strategy, which includes self-generation and long- and short-term capacity and energy purchases. As stated earlier, approximately two thirds of Tampa Electric's 2002 purchased power was arranged through long-term contracts. This strategy provides the company the opportunity to take advantage of favorable spot market pricing while maintaining reliable service to its customers.

Q. Please summarize your testimony.

A. Tampa Electric constantly monitors and assesses the wholesale energy market to locate and take advantage of opportunities in the wholesale electric power market, and those efforts have benefited the company's retail customers. Tampa Electric's energy supply strategy includes self-generation and long- and short-term power purchases. The company purchases in both physical forward and spot wholesale energy markets to provide customers with reliable supply at the lowest possible cost. The company has also made non-firm, non-separated wholesale energy sales, which have benefited its customers. Finally, Tampa Electric does not purchase wholesale energy derivatives due to a lack of availability in the developing Florida wholesale electric market of financial instruments that are appropriate to the company's operations.

Q. Does that conclude your testimony?

A. Yes, it does.

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOANN T. WEHLE

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

A. My name is Joann T. Wehle. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of the Wholesale Marketing and Fuels Department.

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

A. I received a Bachelor's of Business Administration Degree in Accounting in 1985 from St. Mary's College, South Bend, Indiana. I am a CPA in the State of Florida and worked in several accounting positions prior to joining Tampa Electric. I began my career with Tampa Electric in 1990 as an auditor in the Audit Services Department. I became Senior Contracts Administrator, Fuels in 1995. In 1999, I was promoted to Director, Audit Services and subsequently rejoined the Fuels Department as Director in April 2001. I became Director, Wholesale Marketing and

Fuels in August 2002. I am responsible for managing Tampa Electric's wholesale energy marketing and fuel-related activities.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to report to the Florida Public Service Commission ("Commission") the 2001 actual costs of Tampa Electric's affiliated coal transportation transactions compared to the benchmark prices calculated in accordance with Order No. 20298. As shown by that comparison, the 2001 prices paid by Tampa Electric to its affiliated company, TECO Transport, are reasonable and prudent. I will also address a change regarding Tampa Electric's fuel needs for 2003 and beyond. In addition, I will address steps Tampa Electric has taken to manage fuel price and supply volatility and describe projected hedging activities and incremental operations and maintenance (O&M) costs for hedging activities. Finally, I will describe the company's natural gas forecast methodology.

Benchmark Prices For Affiliated Coal Transportation

Q. Have you prepared any exhibits pertaining to the transportation benchmark?

A. Yes. Exhibit No. ___ (JTW-1) was prepared under my direction and supervision.

Q. Were Tampa Electric's actual affiliated coal transportation prices for 2001 at or below the transportation benchmark?

A. Yes, as shown in my exhibit, the affiliated coal transportation prices for 2001 were at or below the transportation benchmark. The average price for the year was at or below the appropriate benchmark calculations as directed by Order No. 20298 of this Commission. Accordingly, it is appropriate for Tampa Electric to recover its payments included in the Fuel and Purchased Power Cost Recovery Clause for 2001 coal transportation.

2003 Fuel Mix Change

Q. Do you anticipate any changes to Tampa Electric's fuel mix in 2003?

A. As a result of the Gannon Station repowering, the company will use greater amounts of natural gas and fewer tons of coal. In 2002, the actual/estimated natural gas use represents 3%, and in 2003, it is projected to be 13% of total fuel (mmBtu) used. The first repowered unit will begin commercial operation in May 2003. Tampa Electric is developing strategies regarding the timing and volume of its natural gas purchases to prudently test the unit prior to commercial operation and to manage the operation once it is in service.

Q. Has Tampa Electric entered into fuel supply transactions for 2002 and 2003 delivery?

A. Yes, Tampa Electric has entered into transactions for fuel deliveries in 2002 and 2003. The company has purchased all of its expected coal needs for both years through bilateral agreements with coal suppliers. Therefore, the prices of the coal commodity portion of the Company's fuel mix have been established.

Q. Has Tampa Electric entered into financial hedging transactions in 2002 for natural gas?

A. Yes. To protect ratepayers from price risk, Tampa Electric purchased over-the-counter natural gas swaps for the peak months of July, August and September 2002. A swap is a financial derivative that provides a "fixed for floating" position. The buyer (Tampa Electric) pays a fixed price for the natural gas, which has a floating value until cash settlement at the end of the month. This strategy also allowed Tampa Electric to begin building expertise in using financial hedges. Because the company's combustion turbine natural gas needs are more predictable during the peak demand months, the swaps allowed Tampa Electric to lock in known natural gas prices and avoid upward price volatility. The transaction costs of swaps are embedded in the price of the commodity.

Q. Does Tampa Electric plan to hedge natural gas purchases for 2003?

A. Yes. Swaps are one of the hedging instruments Tampa Electric plans to use during 2003. Other potential instruments that Tampa Electric may use in 2003 are futures, options and collars. Given the company's limited expertise and ability to forecast the cost of hedging instruments, neither projected hedging transaction costs nor projected commodity gains or losses are included in its forecasts for 2003. Tampa Electric will seek recovery of these prudently incurred hedging costs in the actual/estimated fuel filing for 2003.

Q. Has Tampa Electric made organizational changes to prepare for its increased use of natural gas and hedging activities?

A. Yes, Tampa Electric hired an Administrator of Natural Gas Supply in May 2002. This individual is responsible for all day-to-day natural gas purchasing activities for the company's generating facilities. In addition, the individual administers the company's pipeline transportation contracts and is responsible for developing a financial hedging plan for natural gas usage for Tampa Electric.

Q. Does Tampa Electric anticipate incurring incremental O&M expenses related to hedging activities?

A. Yes, Tampa Electric proposes to recover incremental hedging O&M costs for 2003 totaling $450,000. The incremental costs are itemized in Exhibit No. ___ (JTW-2). The company is also evaluating the purchase and implementation of a software system to more efficiently track, monitor and evaluate hedging activities.

Q. Has Tampa Electric updated its fuel forecast methodology due to its projected increased use of natural gas, including considering the impact of higher than expected or lower than expected natural gas prices?

A. Yes, Tampa Electric has enhanced the methodology it uses to project prices of natural gas since natural gas is a liquid commodity that has greater price volatility than other fuels the company has used in the past, such as coal. Tampa Electric used forecasts commonly used in the energy industry to develop a base price forecast for natural gas. These sources include Cambridge Energy Research Associates (CERA), Energy Information Administration (EIA), outside energy consultants, and the NYMEX forward strip price for natural gas for 2003. Upon reviewing the historical volatility in NYMEX pricing and the implied volatility in natural gas options, Tampa Electric has determined that the actual price could be higher or lower than the base forecast by as much as 35 percent for 2003. Major fundamental or technical changes, such as abnormal weather, political instability or production shortages, will dramatically affect price volatility. In the event of a significant natural gas price increase, Tampa Electric will also consider potential lower cost alternatives such as purchased power, increased oil usage, and other alternate fuels.

Q. Has Tampa Electric reasonably managed its fuel procurement practices for the benefit of its retail customers?

A. Yes it has.

Q. On what do you base this conclusion?

A. Tampa Electric diligently manages its mix of long-, intermediate- and short-term purchases of fuel in a manner designed to minimize overall fuel costs. The company monitors and adjusts fuel volumes it takes within contractually allowed maximum and minimum amounts in accordance with the price of fuel available on the spot market to take advantage of the lowest available fuel prices. The company's fuel activities and transactions are continually reviewed and are audited on a routine and recurring basis by the Commission. In addition, the company continually monitors its rights under contracts with fuel suppliers with an eye toward detecting and preventing any breach of those rights. Tampa Electric continually strives to improve its knowledge of fuel markets and to take advantage of opportunities to minimize the costs of fuel.

Q. Does this conclude your testimony?

A. Yes it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Rebuttal Testimony of
Susan D. Ritenour
Docket No. 020001-EI
Fuel and Purchased Power Cost Recovery
Date of Filing: October 23, 2002

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

A. My name is Susan Ritenour. My business address is One Energy Place, Pensacola, Florida 32520-0780. I hold the position of Assistant Secretary and Assistant Treasurer for Gulf Power Company.

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

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

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the direct testimony of Staff's witness Matthew Brinkley as it relates to the determination of the appropriate amount of "incremental" expenses to be recovered through the fuel clause.

Q. What is your understanding of the nature of the "incremental" expenses referred to in Mr. Brinkley's testimony?

A. As a matter of sound policy, the Commission has allowed certain fuel-related costs that are normally recovered in base rates to be recovered through the fuel clause. These costs have been incurred in order to provide a fuel-related benefit to customers, usually in the form of a savings in fuel costs. Because the customer realizes the fuel benefits derived from incurring the cost through the fuel clause, the Commission has allowed the recovery through the fuel clause of these "incremental" costs incurred to achieve the fuel benefits.

Q. In certain circumstances, "incremental" costs incurred to achieve fuel benefits may also result in base rate benefits as well. How should this be considered in determining the amount of "incremental" costs to be recovered through the fuel clause?

A. In addition to fuel benefits, the incurrence of an "incremental" cost as defined earlier in my testimony may sometimes directly result in the reduction of an expense that was considered in the test year upon which the Company's current base rates were set. Under this circumstance, the amount of "incremental" expense allowed for recovery through the fuel clause should be reduced, or offset, by the amount of the reduction in the related expense included in base rates. This offset should only be considered in calculating recoverable "incremental" expense if the base rate expense reduction directly resulted from the incurrence of the "incremental" expense.

In other situations, the "incremental" expense incurred to achieve fuel benefits may be the result of a higher level of spending on an expense item currently reflected in base rates. In that case, the "incremental" expense to be recovered through the fuel clause would be the difference between the higher expense level incurred to achieve fuel benefits and the amount already reflected in the test year upon which current base rates were set.

Q. Please give an example of how the concepts described above would be applied.

A. In Docket No. 011605-EI, the Commission voted to allow Gulf and the other electric utilities to engage in gas hedging activities in order to achieve fuel-related benefits for our customers. Gulf is requesting the recovery of the incremental costs of implementing a hedging program through the fuel clause. In calculating the amount of such expenses appropriate for fuel cost recovery, Gulf has evaluated whether there will be any offsetting base rate expense reductions and whether there are any such costs already reflected in its base rates. Gulf's projected test year upon which its new base rates were recently set included no hedging activities; therefore the amount included in the projected test year related to hedging activities is $0. In addition, Gulf does not anticipate any reductions in base rate expenses as a result of engaging in hedging activities. However, if there were any such expense reductions, they would be offset against the amount of "incremental" hedging expenses to be recovered through the fuel clause, consistent with the concepts described above.

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

DIRECT TESTIMONY OF MATTHEW BRINKLEY

Q. Please state your name and business address.

A. My name is Matthew Brinkley. My business address is 2540 Shumard Oak Blvd., Tallahassee, Florida, 32399.

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

A. I am employed by the Florida Public Service Commission as a Regulatory Analyst IV in the Bureau of Surveillance/Finance, Division of Economic Regulation.

Q. Please provide a brief description of your educational background and your professional experience.

A. I received a Bachelor of Science degree with a major in Accounting and a minor in Finance from Florida State University in 1991. I received a Master of Business Administration from Florida State University in 1992. I received my Certified Public Accountant license in 1992 and practiced public accounting from 1992 to 1994.

Since joining the Florida Public Service Commission in 1994, I have held responsibilities relating to accounting, finance, and economic research and other accounting and ratemaking matters.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to propose that the Commission, in determining whether and to what extent "incremental" expenses may be recovered through the fuel clause, consider offsetting expenses proposed for recovery through the fuel clause with any base rate benefits associated with those expenses.

Q. Do you believe that offsetting is appropriate?

A. Yes. The Florida Public Service Commission is responsible for setting rates that allow the recovery of costs prudently incurred by a rate regulated utility under its jurisdiction. Rates can be set to recover costs through base rates, set either directly through rate cases or through the approval of rate case settlements brought before the Commission, or through factors set in cost recovery clauses like the fuel cost recovery clause. The Commission is responsible for ensuring that costs are not recovered through both base rates and cost recovery clauses simultaneously. I believe offsetting is necessary to guard against double recovery.

Q. How does offsetting relate to the measurement of incremental expenses?

A. When an expense is incurred to support a particular utility function, the expense may reduce other current or future expenses or increase current or future revenues. Reduced base rate expenses must be offset against proposed fuel clause expenses or those expenses would be recovered twice; once in base rates and now in the fuel clause. Similarly, since additional revenues were not contemplated at the time base rates were set, total rates would be too high if these new revenues were not used to offset proposed fuel clause expenses.

Q. Could you give a few general examples of offsetting expenses?

A. Yes. New remote metering technology expenses may replace five meter readers, a new truck with infrared capabilities may cut maintenance expense and save capital costs by replacing transformers only when they need replacing, or more frequent cleaning of generation equipment may extend the useful life of the equipment. In these cases, base rate expenses reduce base rate expenses, so these are merely illustrative examples.

Q. What importance does the choice of a base year have in calculating incremental expenses?

A. At the time rates are set through a rate case, projected test year expenses are examined in order to determine revenue requirements which are then used to set rates. The projected test year is a snapshot of expenses. Only for the projected test year are rates set to recover the dollar amount of expense in a utility's Minimum Filing Requirements (MFRs). Each year subsequent to the projected test year, it is expected that the utility will sell more energy with the additional revenues covering increases in expenses since the projected test year, assuming the company's return on equity is stable. At a minimum, expenses from a base year used for comparison purposes need to be grossed up by the growth rate in energy sold since the base year.

Q. Order No. 14546 in Docket No. 850001-EI-B, issued July 8, 1985, states that "fossil fuel-related costs normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine current base rates and which, if expended, will result in fuel savings to customers" may be allowed recovery through the fuel clause. Could you comment?

A. Yes. It is my opinion that this provision was intended to encourage utilities to look for ways in which to lower costs recoverable through the fuel clause, and also to reduce a disincentive which would exist if costs were "recovered" through base rates while the benefit was "recovered" through the fuel clause. I do not believe that it is intended to make the fuel clause an avenue for recovery of costs incurred to maintain and operate a process already in place upon the threat of higher costs otherwise.

Q. What is the proper treatment of security costs?

A. Security costs are appropriate for base rate treatment. Security costs protect assets, people, and reliability. Security costs have been and are still being recovered by the utilities through base rates. Both Florida Power & Light Company and Florida Power Corporation reported security costs in their MFRs filed in Docket Nos. 001148-EI and 000824-EI, respectively. The utilities' heightened security costs are simply previously unanticipated expenses which are being expended to protect against future base rate expenses, not to reduce current or future expenses which are recoverable through the fuel clause. Base rates are the appropriate place for expenses which protect against increases in base rates.

By Order No. PSC-01-2516-FOF-EI in Docket No. 010001-EI, issued December 26, 2001, the Commission found merit in the protection of nuclear generation facilities which could mitigate the threat of higher fuel costs if there was a nuclear outage. However, the approval was a stop gap measure in a time of crisis. Further, the request for recovery of these costs was made only 15 days prior to hearing in that docket, leaving little opportunity for review.

The Order further added "recognizing that these costs are not now clearly defined, we do not foreclose our ability to consider an alternative recovery mechanism for these costs at a later time." I believe it appropriate to consider moving these security costs into base rates at least by December 31, 2005, the end of the rate settlements approved in Order No. PSC-02-0655-AS-EI, in Docket Nos. 000824-EI and 020001-EI, issued May 14, 2002, for Florida Power Corporation and Order No. PSC-02-0501-AS-EI, in Docket Nos. 001148-EI and 020001-EI, issued April 11, 2002, for Florida Power & Light Company. By that time, all parties will be able to better evaluate whether these costs are of a limited nature as originally thought or of a long-term nature, and whether these costs are incurred to principally result in fuel savings or to protect base rate assets, personnel, and reliability. Until that time, it is appropriate to examine security costs in light of any offsetting base rate savings as illustrated earlier in my testimony.

Q. Briefly, could you summarize your testimony?

A. Yes. It is prudent for the Commission to consider current and future base rate expense savings and incremental revenues as offsets in order to determine what is an appropriate level of "incremental" expense to be recovered through the fuel clause. When base year expenses are compared to current year expenses, base year expenses should be grossed up for the growth in energy sales in kilowatt-hours. Finally, security costs should be reexamined for inclusion in base rates once a better understanding of their nature and longevity is attained.

Q. Does this conclude your testimony?

A. Yes, it does.

FLORIDA POWER CORPORATION

DOCKET NO. 020001-EI

REBUTTAL TESTIMONY OF JAVIER PORTUONDO

Q. Please state your name and business address.

A. My name is Javier Portuondo. 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 Progress Energy Service Company, LLC, in the capacity of Manager, Regulatory Services - Florida.

Q. Have your duties and responsibilities remained the same since your testimony was last filed in this docket?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address the testimony of Staff witness Matthew Brinkley regarding his proposed changes to the determination of "incremental" expenses recovered through the fuel clause. In particular, I will address the three main points of Mr. Brinkley's proposal; (1) that incremental expenses reflect an offset for any reduction in related base rate expenses caused by the increase subject to fuel clause recovery;

(2) that the base rate amount of expenses subject to fuel clause recovery be "grossed up" for sales growth since base rates were set; and (3) that consideration be given to moving the recovery of incremental plant security costs to base rates by December 31, 2005.

Q. Do you disagree with Mr. Brinkley's proposal that incremental expenses reflect an offset for any reduction in related base rate expenses caused by the increase subject to fuel clause recovery?

A. No, Mr. Brinkley's "offsetting" proposal appears to be reasonable and fair, with one important caveat. As I understand his proposal, incremental costs for fuel clause recovery would be reduced by any decrease in base rate expenses if, and only if, the decrease is the direct result of the increased costs in question. Absent this understanding, we would quickly find ourselves on a slippery slope to the type of "mini-rate case" exercise that I believe everyone recognizes should be avoided.

Q. Do you have any concerns regarding Mr. Brinkley's proposal that, in determining incremental costs for fuel clause recovery, the base rate amount of these costs should be "grossed up" for sales growth since base rates were set?

A. Yes, I have two concerns with Mr. Brinkley's proposal. The first is that it is inconsistent with the revenue sharing mechanism under which Florida Power currently operates pursuant to the settlement approved by the Commission in Docket No. 000824-EI. Mr. Brinkley proposes that the revenues attributable to the base rate component of the costs to be recovered through the fuel clause should be adjusted for sales growth since base rates were set. Under Florida Power's revenue sharing mechanism, however, two-thirds of the revenues from sales growth above the forecasted level used to establish the sharing threshold would be refunded to customers. This would require Florida Power to reduce the incremental costs it could recover through the fuel clause because of revenues it did not receive. From a customer perspective, they would receive the benefit of these revenues twice; once through a direct refund and again through a reduction in the incremental costs they otherwise would have paid in their fuel charge.

My other concern is that Mr. Brinkley's proposal only includes a gross-up of base rate costs for sales increases. It does not provide for a symmetrical treatment of these base rate costs that would require a reduction of these costs in the event of a sales decrease. These kinds of problems and inconsistencies with his gross-up proposal lead me to conclude that incremental costs should continue to be determined in the traditional manner by simply netting out the test year costs used to set base rates.

Q. What is your reaction to Mr. Brinkley's proposal that consideration be given to moving the recovery of incremental plant security costs to base rates by December 31, 2005?

A. Mr. Brinkley states: "I believe it appropriate to consider moving these security costs into base rates at least by December 31, 2005 … ." If he means that this matter should be considered prior to the end of 2005, I have no disagreement with his proposal. However, if he is proposing that a decision on the matter should be made at this time (which would be consistent with Staff's Issue 12), I believe such a proposal is extremely premature.

In his comment immediately following the statement quoted above, Mr. Brinkley himself appears to recognize the need for addition time before addressing the issue of fuel clause recovery versus base rate recovery. He states: "By that time [the end of 2005], all parties will be able to better evaluate whether these costs are of a limited nature as originally thought or of a long-term nature, and whether these costs are incurred to principally result in fuel savings or to protect base rate assets, personnel, and reliability." Obviously, these and other important factors cannot be known at this time.

I am also concerned by Mr. Brinkley's failure to recognize the highly unique nature and circumstances of the utilities' recent security cost increases in his statement that these increases "are simply previously unanticipated expenses which are being expended to protect against future base rate expenses ... ." It would be more accurate to recognize that the utilities' increased security costs are not only unanticipated, but are also significant in magnitude, volatile in nature, mandated by national security interests beyond the utilities' control and, based on the mandates currently in effect, temporary in duration. In addition, the heightened security measures are intended to prevent the loss of low-cost sources of generation and therefore, contrary to Mr. Brinkley's assertion, diminish the potential for future fuel clause increases.

These unique considerations, several of which could limit or preclude altogether base rate recovery, provide ample and, in my view, strong support for the recovery of the related incremental costs through the fuel clause. The extent to which these considerations continue in their current state after the

2005 cost recovery period simply cannot be known at this juncture, which is all the more reason why Staff's Issue 12 is premature and should be deferred until additional knowledge and experience regarding security measures can be gained.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 020001-EI

OCTOBER 24, 2002

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

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

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

A. I am employed by Florida Power & Light Company (FPL) as the Manager of Regulatory Issues in the Regulatory Affairs Department.

Q. **Have you previously filed testimony in this docket?**

A. Yes, I have.

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

A. The purpose of my testimony is to comment on the testimony of Staff's witness Matthew Brinkley. Specifically, I will address recovery of incremental power plant security costs through the fuel clause.

Q. Mr. Brinkley states that "Security costs are appropriate for base rate treatment. Security costs protect assets, people, and reliability. Security costs have been and are still being recovered by the utilities through base rates. Both Florida Power & Light Company and Florida Power Corporation reported security costs in their MFRs filed in Docket Nos. 001148-EI and 000824-EI, respectively. The utilities' heightened security costs are simply previously unanticipated expenses which are being expended to protect against future base rate expenses, not to reduce current or future expenses which are recoverable through the fuel clause". Do you agree with Mr. Brinkley's assessment of FPL's incremental power plant security costs?

A. No. I disagree with Mr. Brinkley's characterization of these costs as "simply previously unanticipated expenses." Mr. Brinkley implies that FPL's security upgrades represent merely a budget variance. That is not the case. The upgrades and associated expenses are extraordinary and unanticipated, as they are intended to address the events of 9/11/01 and potential future terrorist attacks. The principle underlying recovery of incremental costs through the fuel clause is to provide a mechanism to recognize extraordinary changes in a utility's operational requirements that have occurred since its base rates were set and/or to accommodate recovery of incremental expenses that are likely to be volatile and hence would not appropriately be included in base rates. The Commission recognized this when approving recovery of these incremental power plant security costs through the Fuel Cost Recovery Clause. In Order No. PSC-01-2516-FOF-EI, dated December 26, 2001, the Commission stated:

> "We find that recovery of this incremental cost through the fuel clause is appropriate in this instance because there is a nexus between protection of FPL' s nuclear generation facilities and the fuel cost savings that result

> from the continued operation of those facilities. Further, we believe that this type of cost is a potentially volatile cost, making it appropriate for recovery through a cost recovery clause. We are comforted that the true-up mechanism inherent in the fuel clause will ensure that ratepayers pay no more than the actual costs incurred. In addition, we find that recovery of this cost through the fuel clause provides a good match between the timing of the incurrence and recovery of the cost.
>
> We believe that approving recovery of this incremental power plant security cost through the fuel clause sends an appropriate message to Florida's investor-owned electric utilities that we encourage them to protect their generation assets in extraordinary, emergency conditions as currently exist".

When determining to seek recovery of incremental power plant security costs through the Fuel Cost Recovery Clause, FPL considered several factors: 1) the guidance provided by NARUC and FERC, 2) the costs are fuel-related, and 3) the costs are uncertain.

First, the NARUC and FERC both issued policy statements addressing cost recovery to "safeguard the reliability and security of our energy supply infrastructure". NARUC's resolution on "Supporting Recovery in State Regulated Rates of Extraordinary Expenditures Necessary to Safeguard National Energy Suppliers" issued in November 2001 states:

"Resolved, that States should approve applications by gas and electric companies subject to their jurisdiction to recover prudently incurred costs necessary to further safeguard the reliability and security of our energy supply infrastructure and should allow companies to propose separate rate recovery mechanisms, such as a surcharge to existing rates or deferred accounting treatment."

FERC's Statement of Policy issued on September 14, 2001 states:

"In light of tragic events that have taken place in our country this week and the high state of alert the country is now experiencing, the Commission believes it is appropriate to provide regulatory guidance on certain energy infrastructure reliability and security matters that may be affected by this Commission's rate jurisdiction. The Commission understands that electric, gas, and oil companies may need to adopt new procedures, update existing procedures, and install facilities to further safeguard their electric power transmission grid and gas and oil pipeline systems. The Commission is aware that there may be uncertainty about companies' ability to recover the expenses necessary to further safeguard our energy infrastructure, especially if they are operating under frozen or indexed rates. In order to alleviate this uncertainty, the Commission wants to assure the companies we regulate that we will approve applications to recover prudently incurred costs necessary to further safeguard the reliability and security of our energy supply infrastructure in response to the heightened state of alert. Companies may propose a separate rate recovery mechanism, such as a surcharge to currently existing rates or some other cost recovery method.

The Commission will give its highest priority to processing any filing made for the recovery of extraordinary expenditures to safeguard the reliability of our energy transportation systems and energy supply infrastructure. The Commission views the reliability of our Nation's energy transportation systems and energy supply infrastructure as critical to meeting the energy requirements essential to the American people. The Commission calls for the cooperation of the energy industry, customers, and state and local governments to provide any additional safeguards necessary to protect the country's vital energy transportation systems and energy supply infrastructure."

Second, FPL considered the fact that these increased security costs are fuel-related, because the increased security protects FPL's ability to provide economical nuclear and fossil generation to its customers. Clearly, the inability to operate one or more of our generating units, particularly our nuclear generating units, would have a significant impact on our fuel costs.

And, last, FPL considered that there are significant uncertainties in these costs. FPL cannot predict what additional security requirements may be imposed or found necessary in the future, or what those requirements may cost. As a result, the level of incremental security costs is potentially volatile, making these costs appropriate for recovery through a cost recovery clause.

Mr. Brinkley is correct that there are security costs included in FPL's MFRs filed in Docket No. 001148-EI. However, the costs in the MFRs do not include any incremental power plant security costs as a result of 9/11/01 that FPL has sought to recover through the fuel clause. On November 9, 2001, FPL filed adjustments to its 2002 Total Company O&M and Capital forecast in Docket No. 001148-EI due to certain revisions including the impact of the September 11, 2001 tragedies on the forecasted costs and expenses. The footnote on Attachment 1 of the November 9, 2001 filing states that the adjusted forecast "Reflects recovery of additional security costs through the fuel clause as filed 11/05/2001 in Docket 010001-EI." Thus, these incremental power plant security costs as a result of 9/11/01 were never included in base rates.

Q. Mr. Brinkley proposes "that the Commission, in determining whether and to what extent 'incremental' expenses may be recovered through the fuel clause, [should] consider offsetting expenses proposed for recovery through the fuel clause with any base rate benefits associated with those expenses ... I believe offsetting is necessary to guard against double recovery". Would you please comment on Mr. Brinkley's proposal?

A. While an offsetting adjustment might be appropriate in evaluating whether certain types of increased costs are eligible for recovery through the fuel clause, Mr. Brinkley's proposal is irrelevant to the recovery of FPL's incremental power plant security costs since these costs are discrete, truly incremental costs. FPL determines that an expense should be classified as a cost related to security against terrorism if the power plant security requirements have been imposed since and in response to the events of 9/11/01. For the nuclear plants, FPL responds to NRC-mandated security requirements and complies with requirements imposed. For the fossil plants, after 9/11/01, security guards were required at selected fossil units, especially at Turkey Point due to its close proximity to the nuclear units. These incremental power plant security costs are tracked and segregated by work order and charged only to the fuel clause, thus ensuring there is no double recovery.

Q. Mr. Brinkley states that "I believe it appropriate to consider moving these security costs into base rates at least by December 31, 2005, the end of the rate settlements approved in ... Order No. PSC-02-0501-AS-EI, in Docket Nos. 001148-EI and 020001-EI, issued April 11, 2002, for Florida Power & Light Company. Please comment on this recommendation.

A. It is unnecessary and premature to make such a decision at this time. Whether to recover incremental security costs in base rates should be considered the next time base rates change.

Q. Mr. Brinkley states that "Only for the projected test year are rates set to recover the dollar amount of expense in a utility's Minimum Filing Requirements (MFRs). Each year subsequent to the projected test year, it is expected that the utility will sell more energy with the additional revenues covering increases in expenses since the projected test year, assuming the

company's return on equity is stable. At a minimum, expenses from a base year used for comparison purposes need to be grossed up by the growth rate in energy sold since the base year." Do you agree that this sort of "gross up" adjustment would be appropriate for FPL?

A. No. Mr. Brinkley proposes to make an adjustment to reflect revenues in the calculation of incremental costs by grossing up the expense in the base year by the growth rate in energy sold. This proposal is inconsistent with the Revenue Sharing Plan that was included in the Stipulation and Settlement approved by the Commission, in Order No. PSC-02-0501-AS-EI, Docket No. 001148-EI dated April 11, 2002. The Revenue Sharing Plan provides a mechanism for FPL to share with customers the benefits of additional revenues above prescribed thresholds. That mechanism represented a compromise on revenue sharing that was acceptable to all of the signatories to the stipulation in Docket No. 001148-EI and that would apply for the remainder of 2002 and for calendar year 2003, 2004 and 2005. That compromise did not contemplate making additional adjustments such as the one that Mr. Brinkley's proposal suggests, which would have the effect of shifting the balance of revenue sharing away from what the parties had agreed to accept.

Q. Does that conclude your rebuttal testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED REBUTTAL TESTIMONY

OF

J. DENISE JORDAN

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

A. My name is J. Denise Jordan. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Rates and Planning in the Regulatory Affairs Department.

Q. Are you the same Denise Jordan who submitted Prepared Direct Testimony in this proceeding.

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address certain deficiencies in the direct testimony of Mr. Matthew Brinkley, testifying on behalf of the Florida Public Service Commission Staff.

Q. Please address Mr. Brinkley's concern about offsetting expenses proposed for recovery through the fuel and purchased power cost recovery clause ("fuel clause") with base rate benefits associated with those expenses.

A. Mr. Brinkley states that offsetting is necessary to guard against double recovery. Mr. Brinkley's offsetting analysis could mire the Commission and the parties in continuous disputes when the focus ought to be on whether the expense for which cost recovery is sought is truly incremental. Certainly the additional security alert expenses Tampa Electric has incurred and will continue to incur as a result of the September 11 attacks are incremental. In my direct testimony I addressed the variable and previously unanticipated nature of the security alert costs that make them appropriate for recovery through the fuel clause. While Mr. Brinkley states that base rate benefits associated with expenses proposed for recovery through the fuel clause should be "offset," he has not identified any base rate benefits associated with the incremental security costs Tampa Electric is proposing for cost recovery. The incremental and extraordinary expenses Tampa Electric is incurring as a result of the September 11 attacks do not effect double recovery since no one could have anticipated the attacks of September 11 and the incremental costs resulting from those attacks when its base rates were last set. Therefore no "offsetting" is necessary to ensure against double recovery.

Q. Do you agree with Mr. Brinkley's suggestion on pages 4 and 5 of his testimony that expenses from a base year used for comparison purposes need to be grossed up by the growth rate in energy sold since the base year?

A. No, I do not. There is no necessary correlation between the growth rate in energy sales and the level of expenses incorporated into base rates. If anything, a utility will attempt to reduce expenses over time following a base year in order to avoid having to initiate a base rate proceeding to adjust for inflation and attrition.

Q. Do you believe Mr. Brinkley's approach is consistent with Order No. 14546 in Docket No. 850001-EI-B, referred to on page 5 of Mr. Brinkley's testimony?

A. No, I do not. I believe his approach is inconsistent with that order. I also believe that the incremental post-September 11 increased security costs Tampa Electric has incurred are exactly the type of expense Order No.

14546 indicates should be recovered. They are clearly costs that were not recognized or anticipated in the cost levels used to determine current base rates and they are costs which, if expended, are likely to result in fuel savings to customers. This squarely meets the cost recovery qualifications in the referenced order.

Q. Do you believe that post-September 11 incremental security costs are ". . . simply previously unanticipated expenses which are being expended to protect against future base rate expenses, not to reduce current or future expenses which are recoverable through the fuel clause. . . ," as Mr. Brinkley states at page 6 of this testimony?

A No, I do not. If a power plant were disabled or destroyed by a terrorist act, the utility would have to replace the generating capacity. However, it is doubtful that the Commission would allow the destroyed plant and the new plant to be simultaneously included in rate base. In the interim, while the new plant is being constructed, the utility would have to serve its customers with higher-cost replacement power. The resulting higher-cost replacement power is the very expense that the incremental security activity is designed to protect against.

Q. Please address Mr. Brinkley's suggestion that incremental security costs incurred subsequent to the September 11 attacks be moved into base rates by the end of 2005.

A. I do not believe it would be appropriate for the Commission to arbitrarily choose a future date for any such conversion from recovery through the fuel clause to base rate recovery. The key goal, instead, should be to ensure that any incremental security costs are, indeed, incremental , i.e., are not being recovered through base rates and a cost recovery mechanism. This can be accomplished without mandating a future conversion to base rate recovery. This Commission has recently found that capitalized items currently approved for recovery through the environmental cost recovery clause (ECRC) need not be included in base rates. In that base rate proceeding, the Commission concluded that no benefits to customers had been shown by including such costs in base rates and that the impact on customers is essentially the same whether the costs are recovered through base rates or through the ECRC. The same can be said about incremental post-September 11 security costs. The Commission should not attempt to tie the hands of future

Commissioners by adopting an arbitrary conversion date.

Q. Do you believe the Commission should authorize Tampa Electric to recover through the fuel and purchased power cost recovery clause expenditures of $1,204,598 for incremental 2001, 2002 and 2003 operation and maintenance expenses associated with post-September 11, 2001 security costs?

A. Yes. These costs were unanticipated prior to September 11, 2001 and are incremental in the true sense of the word. In Order No PSC-01-2516-FOF-EI the Commission approved for recovery through the fuel adjustment clause post-September 11 increased security costs on the grounds that they (a) were incremental; (b) have a nexus to fuel cost savings from continued operation of generation facilities; and (c) are potentially volatile. In addition, the Commission found that the fuel adjustment true-up mechanism ensures that ratepayers pay no more than the actual costs incurred and that allowing recovery through the fuel clause of these charges provides a good match between the timing of the occurrence and the recovery of the cost. The Commission concluded that allowing recovery of these expenses through the fuel clause gives utilities appropriate encouragement to protect their generation assets. These grounds fully support Tampa Electric's proposed cost recovery of its incremental post-September 11 security costs.

Q. Does this conclude your rebuttal testimony?

A. Yes it does.

(Transcript continues in sequence in Volume 2.)

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

I, JANE FAUROT, RPR, Chief, Office of Hearing Reporter Services, FPSC Division of Commission Clerk and Administrative Services, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 26TH DAY OF NOVEMBER, 2002.

Jane Faurot

JANE FAUROT, RPR
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