BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 040001-EI

In the Matter of

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE WITH
GENERATING PERFORMANCE INCENTIVE
FACTOR.
_____________________________________/

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VOLUME 4

Pages 380 through 587

PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN BRAULIO L. BAEZ COMMISSIONER J. TERRY DEASON COMMISSIONER RUDOLPH "RUDY" BRADLEY COMMISSIONER CHARLES M. DAVIDSON
DATE:	Monday, November 8, 2004
TIME:	Commenced at 9:30 a.m. Concluded at 5:57 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JANE FAUROT, RPR Official FPSC Reporter (850) 413-6732
APPEARANCES:	(As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID	ADMTD.
63	Commission's Order No. 9558	419	445
64	Knapp Late-filed Depo Exhibit	424	445
45			445
46			445
65			445

P R O C E E D I N G S

(Transcript follows in sequence from Volume 3.)

CHAIRMAN BAEZ: Go back on the record.

Mr. Beasley.

MR. BEASLEY: Tampa Electric calls Mr. Knapp.

CHAIRMAN BAEZ: Mr. Knapp, you have been sworn, correct?

THE WITNESS: Yes, sir, I have.

DAVID R. KNAPP

was called as a witness on behalf of Tampa Electric Company, and having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BEASLEY:

Q Mr. Knapp, for the record, would you please state your name, your business address, and your position with Tampa Electric Company?

A Yes. My name is David Knapp. My address is 702 North Franklin Street, Tampa, Florida 33602. My position with Tampa Electric is senior engineer.

Q Thank you. Mr. Knapp, did you review the prepared direct testimony filed in this proceeding by Mr. William A. Smotherman on behalf of Tampa Electric, that filing having been made on April 1 of this year?

A Yes, sir, I have.

Q Do you adopt Mr. Smotherman's testimony as your own?

A Yes, sir, I do.

MR. BEASLEY: I would ask that Mr. Smotherman's prepared direct testimony be inserted into the record as though read and adopted by Mr. Knapp.

CHAIRMAN BAEZ: Without objection, show the prefiled direct testimony of William A. Smotherman as adopted by Witness Knapp entered into the record as though read.

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 2003 through December 2003. 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 2003 - December 2003, 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 2003 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 -6.397 GPIF points, the result is a penalty amount of $3,678,414 for the period.

Q. Please proceed with your review of the actual results for the January 2003 - December 2003 period.

A. On Document No. 1, page 3 of 32, the actual average common equity for the period is shown on line 14 as $1,448,420,030. This produces the maximum penalty or reward figure of $5,750,070 as shown on line 21.

Q. Will you please explain how you arrived at the actual equivalent availability results for the seven units 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, 504 planned outage hours were originally scheduled for 2003. Actual outage activities required no planned outage hours. Consequently, the actual equivalent availability of 64.7% is adjusted to 61.2% as shown on Document No. 1, page 7 of 32.

Big Bend Unit No. 2

On this unit, 336 planned outage hours were originally scheduled for 2003. Actual outage activities required no planned outage hours. Consequently, the actual equivalent availability of 60.2% is adjusted to 58.1% as shown on Document No. 1, page 8 of 32.

Big Bend Unit No. 3

On this unit, 336 planned outage hours were originally scheduled for 2003. Actual outage activities required no planned outage hours. Consequently, the actual equivalent availability of 62.4% is adjusted to 60.1% as shown on Document No. 1, page 9 of 32.

Big Bend Unit No. 4

On this unit, 840 planned outage hours were originally scheduled for 2003. Actual outage activities required 921.4 planned outage hours. Consequently, the actual equivalent availability of 71.3% is adjusted to 72.0% as shown on Document No. 1, page 10 of 32.

Gannon Unit No. 5

On this unit, no planned outage hours were originally scheduled for 2003. Actual outage activities required no planned outage hours but the planned period hours were 912 while the actual period hours were 744. Consequently, the actual equivalent availability of 78.4% is adjusted to 78.3% as shown on Document No. 1, page 11 of 32.

Gannon Unit No. 6

On this unit, no planned outage hours were originally scheduled for 2003. Actual outage activities required no planned outage hours. Consequently, the actual equivalent availability of 63.2% is adjusted to 63.2%, as shown on Document No. 1, page 12 of 32.

Polk Unit No. 1

On this unit, 1,056 planned outage hours were originally scheduled for 2003. Actual outage activities required 968.3 planned outage hours. Consequently, the actual equivalent availability of 68.4% is adjusted to 67.5%, 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, -6.397, is then entered into the GPIF table on page 2 of 32. Using linear interpolation, a penalty amount of $3,678,414 is calculated.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MR. BEASLEY:

Q Mr. Knapp, did you also review and do you adopt Mr. Smotherman's Exhibit WAS-1, which is marked as Hearing Exhibit Number 45?

A Yes, sir, I do

Q And did you prepare the document entitled, "Prepared Direct Testimony of David R. Knapp," that was submitted in this proceeding regarding the projections for 2005?

A Yes, sir, I did.

Q If I were to ask you the questions contained in that testimony, would your answers be the same?

A That is correct.

MR. BEASLEY: I would ask that Mr. Knapp's prepared direct testimony be inserted.

CHAIRMAN BAEZ: Without objection, show the prepared direct testimony of David R Knapp entered into the record as though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

DAVID R. KNAPP

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

A. My name is David R. Knapp. 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 a Senior Engineer in the Resource Planning Department.

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

A. I received a Bachelor of Marine Engineering degree in 1986 from the Maine Maritime Academy and a Master of Business Administration from the University of Tampa in 2002. Prior to joining Tampa Electric, I worked in the areas of operations engineering and management. In January 1996, I joined Tampa Electric and worked in field operations and power plant engineering. In April 2000, I transferred to the Resource Planning department where I provide engineering and technical support in the development of Tampa Electric's integrated resource planning process and business planning activities.

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. _____ (DRK-1), consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2005 period.

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

A. Four of the company's coal-fired units and one integrated gasification combined cycle unit are included. These are Big Bend Station Units 1, 2, 3, and 4, and Polk Power

Station Unit 1

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

A. Yes, the documents 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. Why does Tampa Electric not include units that represent 80 percent of projected system net generation?

A. Due to the repowering of Gannon Units 5 and 6 to H. L. Culbreath Bayside ("Bayside") Units 1 and 2, the remaining GPIF units do not represent 80 percent of projected system net generation. Although Bayside Units 1 and 2 began commercial operation in 2003 and 2004, respectively, the repowered units are not included in the GPIF calculations because the company does not have the historical operational data required by the GPIF Implementation Manual to set GPIF targets. Tampa Electric has no other base load generating units to substitute for Gannon Units

5 and 6. Section 3.2 of the GPIF Implementation Manual states that the Commission will approve exclusion of units from the calculation of the GPIF on a case-by-case basis, and the Commission approved this exception for Tampa Electric's 2003 and 2004 projected GPIF. Therefore, Tampa Electric requests approval of its 2005 GPIF calculation excluding the repowered units.

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 2005 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 or POF and the Equivalent Unplanned Outage Factor or EUOF were subtracted from 100 percent to determine the target Equivalent Availability Factor or EAF. The factors for each of the five units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2005 period, the projected Equivalent Unplanned Outage Factor for Big Bend Unit 4 is 17.48 percent, and the Planned Outage Factor is 3.84 percent. Therefore, the target equivalent availability factor for Big Bend Unit 4 equals 78.68 percent or:

$$100\% - [(17.48\% + 3.84\%)] = 78.68\%$$

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 percent reduction in Equivalent Forced Outage Factor or EUOF and Equivalent Maintenance Outage Factor or EMOF, plus a five percent reduction in the Planned Outage Factor are necessary. Continuing with the Big Bend Unit 4 example:

$$EAF_{MAX} = 100\% - [0.8\ (17.48\%) + 0.95\ (3.48\%)] = 82.4\%$$

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 during the development of the incentive. 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 4 example,

$$EAF_{MIN} = 100\% - [1.4\ (17.48\%) + 1.10\ (3.84\%)] = 71.31\%$$

The equivalent availability maximum and minimum for the other four units are 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 2005 through December 2005 are shown on page 17 of Document No. 1. Since only one GPIF unit has a major outage (28 days or greater) in 2005, one Critical Path Method diagram is provided in this testimony. Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 4 is scheduled for a planned outage from February 27, 2005 to March 12, 2005. There are 336 planned outage hours scheduled for the 2005 period, and a total of 8,760 hours during this 12-month period. Consequently, the Planned Outage Factor for Unit 4 at Big Bend is 3.84 percent or:

$$\frac{336}{8,760} \times 100\% = 3.84\%$$

The factor for each unit is shown on pages 5 and 12 through 16 of Document No. 1. Big Bend Unit 1 has a Planned Outage Factor of 15.34 percent. Big Bend Unit 2 has a Planned Outage Factor of 3.84 percent. Big Bend 3 has a Planned Outage Factor of 3.84 percent. Polk Unit 1 has a Planned Outage Factor of 3.77 percent.

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 2004, 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 17.48 percent for Big Bend Unit 4. The Equivalent Unplanned Outage Factor for Big Bend Unit 4 is verified by the data shown on page 15, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

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

Or

$$EUOF = \frac{(994.1 + 537.1)}{8,760} \times 100 = 17.48\%$$

Relative to Big Bend Unit 4, the EUOF of 17.48 percent 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 32.03 percent. This unit will have a planned outage in 2005, and the Planned Outage Factor is 15.34 percent. Therefore, the target equivalent availability for this unit is 52.63 percent.

Big Bend Unit 2

The projected Equivalent Unplanned Outage Factor for this unit is 34.52 percent. This unit will have a planned outage in 2005, and the Planned Outage Factor is 3.84 percent. Therefore, the target equivalent availability for this unit is 61.64 percent.

Big Bend Unit 3

The projected Equivalent Unplanned Outage Factor for this unit is 35.61 percent. This unit will have a planned outage in 2005, and the Planned Outage Factor is 3.84 percent. Therefore, the target equivalent availability for this unit is 60.55 percent.

Big Bend Unit 4

The projected Equivalent Unplanned Outage Factor for this unit is 17.48 percent. This unit will have a planned outage in 2005, and the Planned Outage Factor is 3.84 percent. Therefore, the target equivalent availability for this unit is 78.68 percent.

Polk Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 16.41 percent. This unit will have a planned outage in 2005, and the Planned Outage Factor is 3.77 percent. Therefore, the target equivalent availability for this unit is 79.76 percent.

Q. Please summarize your testimony regarding Equivalent Availability Factor.

A. The GPIF system weighted Equivalent Availability Factor of 68.54 percent is shown on Page 5 of Document No. 1. This target is approximately ten percent higher than the July 2003 through June 2004 GPIF period.

Q. Why are Forced and Maintenance Outage Factors 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 4 on page 15 of Document No. 1. During January and the months April through December, the Equivalent Unplanned Outage Rate and the Equivalent Unplanned Outage Factor are equal. This is because 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 formed the basis of the target development. 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. 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 25 through 29 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 2005 period.

A. The heat rate target for Big Bend Unit 1 is 10,853 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±529 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,672 Btu/Net kWh with a range of ±421 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,663 Btu/Net kWh, with a range of ±657 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,350 Btu/Net kWh with a range of ±483 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,342 Btu/Net kWh with a range of ±718 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 11 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 11. The baseline production costing analysis was performed 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 $781,574,600 is shown on page 6, column 2.

Multiple production costing simulations were then performed 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 $35,060,860 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 15.68 percent as shown in the right-hand column on page 6. Pages 7 through 11 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 4, page 10, if the unit operates at 82.4 percent equivalent availability, fuel savings would equal $4,096,800, 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 11. 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, $35,060,860. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January through December 2005 is $1,464,070,542. This produces the maximum allowed jurisdictional incentive of $5,807,604 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 its determination of the GPIF. The GPIF is determined by the following formula for calculating Generating Performance Incentive Points (GPIP):

$$\begin{aligned} GPIP: = (\ & 0.1568\ EAP_{BB1} + 0.1744\ EAP_{BB2} \\ & + 0.1830\ EAP_{BB3} + 0.1168\ EAP_{BB4} \\ & + 0.0544\ EAP_{PK1} + 0.0527\ HRP_{BB1} \\ & + 0.0472\ HRP_{BB2} + 0.0740\ HRP_{BB3} \\ & + 0.0774\ HRP_{BB4} + 0.0634\ HRP_{PK1}\ ) \end{aligned}$$

Where:

GPIP = Generating Performance Incentive Points.

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

HRP = Average Net Heat Rate Points awarded/deducted for Big Bend Units 1, 2, 3 and 4 and Polk Unit 1.

Q. Have you prepared a document summarizing the GPIF targets for the January 2005 - December 2005 period?

A. Yes. Document No. 2 entitled "Summary of GPIF Targets" provides the availability and heat rate targets for each unit.

Q. Does this conclude your testimony?

A. Yes.

BY MR. BEASLEY:

Q Mr. Knapp, did you prepare the exhibit attached to your prepared direct testimony marked Exhibit DRK-1 and identified as Hearing Exhibit Number 46?

A Yes, sir.

Q Have you prepared a summary of your testimony?

A Yes, sir, I have.

Q Please present your summary.

A Good afternoon, Commissioners. My name is David Knapp, and I am a senior engineer for Tampa Electric Company's Resource Planning Department. I have adopted for purposes of this hearing the prepared direct statement of Tampa Electric's Witness William A. Smotherman concerning the calculations of the GPIF penalty for Tampa Electric's units operations during 2003. I also sponsor Mr. Smotherman's Exhibit WAS-1 showing that calculation. The penalty for 2003 result I have calculated is $3,678,414, which is reflected in the 2005 projected fuel factor.

My direct testimony presents for the Commission's review and approval Tampa Electric's proposed 2005 GPIF targets and ranges against which our actual performance and results for 2005 will be measured when those results are known. The 2005 targets and ranges were developed in accordance with the procedure set forth in Section 4.4 of the generation performance incentive implementation manual as previously approved by this Commission. The 2005 targets and ranges are set forth in Attachment A to the prehearing order.

I would point out that the staff and Tampa Electric are in agreement to the appropriateness of the GPIF targets and ranges calculated for Tampa Electric in 2005.

That concludes my summary of testimony and exhibits I have adopted together with my direct prepared testimony and exhibits pertaining to the GPIF targets and ranges for 2005.

MR. BEASLEY: Thank you, sir.

We submit Mr. Knapp for questions.

CHAIRMAN BAEZ: Thank you, Mr. Beasley.

Ms. Christensen.

MS. CHRISTENSEN: Thank you.

CROSS EXAMINATION

BY MS. CHRISTENSEN:

Q Mr. Knapp, is it correct that your testimony addresses the GPIF schedules filed in this docket for Tampa Electric?

A That's correct.

Q Can you please explain what GPIF is?

A GPIF is generation performance incentive factor, which is a process that is used by the three utilities within the state.

Q And can you tell us what the purpose of the GPIF schedules are which you filed in this docket?

A The purpose of the GPIF incentive factor is to incent utilities to increase their unit operations based off of historical data.

Q What Tampa Electric plans are subject to the GPIF schedules?

A Currently in the 2005 GPIF schedules, Big Bend 1, Big Bend 2, Big Bend 3, Big Bend 4, and Polk Unit 1.

Q Are the Big Bend plants and units coal-burning plants?

A The Big Bend units are coal-burning, Polk Unit 1 is a coal-gasification plant.

Q You have four units at Big Bend, is that correct?

A There are four coal-burning units at Big Bend and three combustion turbines.

Q And the ones that we are talking about here today are the coal-burning units only?

A That is correct.

Q Is it correct that your Polk plant is a much smaller plant than the Big Bend plant which also burns coal?

A That is not necessarily correct. The net rating on the Polk Plant is 255 megawatts summer rating.

Q And what is the megawatt rating for the Big Bend plants?

A The summer net ratings for the Big Bend plants are Big Bend 1, 421; Big Bend 2, 411; Big Bend 3, 428; and Big Bend

4, 452.

Q Is it correct that Bayside is a combined cycle gas plant?

A That is correct.

Q Is it also correct that of all the plants Big Bend has the largest capacity and the lowest cost because it is coal burning?

A Both Big Bend and Bayside are in similar capacity on a net basis. I would have to do the calculation to determine which one is larger. There is a second part to your question?

Q Is generally a coal burning plant a lower cost plant to operate?

A A coal burning plant is a lower cost plant on an energy basis. There may be more O&M associated with that, though.

Q Okay. So would you agree then that as a plant operator you would first look to Big Bend when you would want to dispatch electricity onto the power grid?

A There are many factors which go into plant dispatch in Tampa Electric's system. The dynamics of the system, the locations of the plants and the transmission areas, and the demand for electricity within the Tampa Electric system.

Q Let me ask you this. Is coal considered a native load?

A Coal is considered a native load.

Q And is native load the type of, I guess, energy or plant that you would dispatch first because you would want to continue to use that to supply your native load?

A If the system is -- depending on the system dynamics, the answer is yes. However, there could be some changes where either there is a transmission issue or a load demand in a certain area that would require, to stabilize the system, another plant being used.

Q So in general the answer would be yes?

A In general, yes.

Q Do you file the same GPIF schedules every year?

A Tampa Electric submits the GPIF files every year.

Q Okay. Is it correct that this year your filing includes the GPIF targets for your generating plants for 2005?

A That's correct.

Q And as part of this process you also provide the final numbers for the penalties or rewards that you earned for 2003 performance, is that correct?

A That's correct. I'm providing the true-up for 2003.

Q Let me start first with EAF. Can you explain what that is?

A Yes. EAF stands for equivalent availability factor. EAF is made up of two components, planned outage factor and equivalent unplanned outage factor. EAF is a calculation of 100 minus the POF, planned outage factor, and the EUOF, or equivalent unplanned outage factor.

Q And in your deposition you agreed that it was okay for us to refer to EAF as availability, is that correct?

A Yes, it is.

Q And it would be still correct today to generally refer to that as availability?

A That is correct.

Q Would you agree that if the availability goes up that that is generally good for TECO and its customers?

A We had this discussion earlier, depending on which unit. Some units combustion turbines have a high EAF and it does not directly interpolate to benefits to the customer.

Q Would generally, though, having the plant being able to supply power to the grid be a benefit to the customers?

A Yes.

Q In deposition you said that the increased availability would be good for the customers if the pricing was right and the demand was there. Do you recall that statement?

A Yes.

Q And you pointed out that a combined cycle unit's availability might be high, but if that power was not needed because of pricing, then there would be no benefit to the customers, is that correct?

A That is correct.

Q Now, in the case of Big Bend you agreed earlier that

Big Bend is a native load unit and it is the first to be dispatched, is that correct?

A I'm not sure if I agreed that that was the first to be dispatched, but it is for native load.

MR. BEASLEY: Could I inquire? Is it intended to be native load or base load?

MS. CHRISTENSEN: Native load.

BY MS. CHRISTENSEN:

Q So let me make sure that I understand this. You agreed with certain caveats that Big Bend is a native load unit and that it would be first to be dispatched, am I understanding that correct?

A Generally, yes, you are.

Q And so for Big Bend, would it be correct to say that improved availability is good for customers?

A Yes.

Q Okay. Is it also correct to say that the Commission's GPIF rule is based on an assumption that availability is a good measure of a plant's sufficiency and that the company has control, to some extent, over the availability of the performance factor?

A Yes.

Q I'm going to ask you to take a look at what we will call the Commission's Order Number 9558.

MS. CHRISTENSEN: And if we could have that marked for identification. I think we are at 63?

CHAIRMAN BAEZ: We are at 63.

MS. CHRISTENSEN: Okay.

(Exhibit Number 63 marked for identification.)

BY MS. CHRISTENSEN:

Q I'm going to ask you to read the yellow highlighted paragraph that is Paragraph 2 of the front page of this document.

A Now?

Q I'm sorry?

A You want me to read that now?

Q Yes. Could you please read that into the record?

A "Throughout the investigation, we have emphasized our determinator to incorporate within the clause an explicit formula designed to provide to all utilities a monetary incentive to operate their generating units as efficiently as possible and thus minimize fuel costs borne by their customers." Should I continue? That is the highlighted area.

Q No, the highlighted area is fine. Can I also have you read the fourth paragraph highlighted section?

A "The Generating Performance Incentive Factor initially proposed by the staff is designed to encourage the improvement of the productivity of base load generating units by focussing upon the areas of thermal efficiency (heat rate) And unit availability. These two factors are, to some extent, within the control of the utilities, and can be precisely measured and evaluated from plant records."

Q Okay. So would you agree that the Commission implemented this reward and penalty plan in the 1980s to encourage companies to operate their plants more efficiently and at lower cost to the customers?

A Yes.

Q Would you also agree that the Commission meant that, in general, availability and heat rates of a plant are under the control of the utility?

A Yes.

Q And I think we can agree that if a tornado or some other catastrophic weather event were to take place, efficiency would likely go down in a particular plant, and that would be beyond the control of Tampa Electric?

A Or hurricane, yes.

Q Or a hurricane. And that, however, barring some catastrophic event like a tornado or hurricane, if you spend more money on maintenance, all other things being equal, the plant efficiency would probably go up?

A I cannot agree to that. There are many factors that go into availability, meaning the design of the equipment, the age of the equipment, environmental constraints on the equipment, fuel blends, fuel types being consumed. So maintenance, or dollars for maintenance isn't a sole determinant for increasing plant availability.

Q So am I to understand that you do not agree that having adequate maintenance would, in turn, increase your availability?

A Maintenance helps either maintain or increase availability. But with that said, I am not an expert in the maintenance field, therefore, I can't speak with authority on that.

Q Let me ask you, if, in general, would you agree -- would you agree with the statement, generally speaking, that if you spend less money on maintenance for a plant, the plant efficiency will probably go down?

A I cannot agree with that.

Q Would you agree that there is a correlation between the amount of money that you spend on plant maintenance and the likelihood that you are going to have problems maintaining availability at a plant?

A I cannot answer that due to the fact that I'm not in the maintenance area or involved with maintenance on those facilities, so I do not know if there is a correlation. Maybe technology has improved, maybe pricing on materials decrease that would not make that a correlation that is true.

Q Would you agree that GPIF gives a reward for doing the right things in terms of plant maintenance?

A I would agree that the GPIF rewards the utilities that are under that guidance. If they increase their performance over historical performance, it provides a reward.

Q You stated in your deposition that the heat rate is the thermal efficiency of a plant, is that correct?

A In a simple form, yes.

Q And you also agreed in your deposition that if the heat rate goes down, that's good, and if the heat rate goes up, that is bad, is that correct, in general terms?

A If heat rate goes down, there tends to be a lower cost of unit per electricity. Conversely, if it goes up, the costs will go up.

Q Let me make sure that I am correct that generating performance is measured by the availability and the heat rate, is that correct?

A Generating performance is measured by availability and heat rate; it's also measured by lost time injuries, emissions or lack of emissions

Q Would you agree that the forecast for the maximum allowable GPIF reward for 2005 would be $5.8 million, is that correct?

A Let me check.

Q We have an exhibit to hand out, if that would help.

A Could you repeat your question, please.

Q Would you agree that the forecast for the maximum allowable GPIF reward for 2005 would be $5.8 million?

A That is not on the handout, but --

Q Well, let me refer you to Page 16, Lines 1 through 4 on your testimony.

A If you will give me just one minute, please. The maximum allowable jurisdictional incentive dollars is $5,807,644.

Q Okay. Well, for right now I think the handout we handed was for some questions further on down the road, so we will get to those a little bit later. And, I'm sorry, I didn't hear your answer whether or not you agree with that?

A The maximum amount of jurisdictional incentive dollars for 2005, January through December, is $5,807,644.

Q And what is the maximum amount of the penalty you could experience for 2005?

A The penalty would be the same amount, $5,807,644.

Q Okay. Let me refer you to Page 5 of your exhibit attached to your testimony, Exhibit DRK-1. And I do believe we have a copy of that to hand out for ease of reference. In looking at the chart, can you tell us what is the title of this chart?

A The title of this chart is Tampa Electric Company's comparison of GPIF targets versus prior period actual performance.

Q Okay. Referring to the column at the far right at the top of this page, does this show your actual 12-month performance for all of your generating units for the prior 12 months ending July 2001?

A It shows the performance of the targets, the GPIF units that are being used this year from July of '01 through June of '02.

Q Okay. So that would be the prior 12 months with the month ending June of '02, then?

A That is correct.

Q Okay. And does that include the Polk facility?

A Yes, it does.

Q Is the combined availability for all of your units for that time period 71.1 percent?

A The GPIF system weighted equivalent availability for those units during that time period, July 2001 through June 2002, is 71.1.

Q Okay. Let me show you your late-filed deposition exhibit. I would like to ask you a series of questions regarding your late-filed deposition exhibit.

MS. CHRISTENSEN: And, Commissioners, I don't believe this is already part of prefiled testimony. If we could ask to have this marked as Exhibit 63.

CHAIRMAN BAEZ: We marked an order. 64.

MS. CHRISTENSEN: Exhibit 64, okay.

(Exhibit Number 64 marked for identification.)

BY MS. CHRISTENSEN:

Q Mr. Knapp, referring to your late-filed exhibit, I would ask are you familiar with this document?
A Yes, I am.
Q And did you prepare this document?
A I co-prepared it with several other people at Tampa Electric.
Q And are you familiar with the contents of the document?
A Yes, I am.
Q And that you can speak to the contents of this document?
A Yes.
Q Let me refer you to Page 2 of this document. On that page -- I'm sorry, let me clarify that. Okay. Page 2, do you have Page 2?
A Yes.
Q Okay. Can you please tell me whether or not this page shows that Tampa Electric was penalized $2,496,021 for its 2002 generating performance, is that correct?
A Tampa Electric was penalized in 2002, $2,496,021. That was based on historical information of the prior period.
Q Does it also show that in 2001 you were also penalized?
A Yes.
Q And can you please tell us what that amount was?

A The 2001 penalty Tampa Electric experienced was $831,029.

Q Now, looking at Number 3, and it is the first of ten pages, it shows a series of charts regarding your EAF performance for Big Bend all the way back to 1997, is that correct?

A Page 3 of 10 starts that.

Q Well, it is Page 3 of Number 3, if you are looking at 1 through 10, are those charts?

A Page 1 of 10, Number 3 is 1998 through 2004 actual equivalent availability factors.

Q Okay. I'm not going to go through all the charts, but I would like to refer you to the year 2000, which is the year just before you were penalized the $831,029, and I believe that is on Page 6 of 10. Could you please read the adjusted EAF performances for the four Big Bend units for that year?

A The adjusted EAF calculations were 74.3 for Big Bend 1, 83.2 for Big Bend 2, 79.6 for Big Bend 3, and 86.1 for Big Bend 4. Also on that page they were not aware of how much planned maintenance was done during that period, or the EUOF for those units during that period.

Q Well, let me ask you this. Without doing any math, would you agree that in the year 2000 that the Big Bend EAF performance was at or above 80 percent on average?

A Let me average them up, and then we would have to do that by capacity or weighting average.

Q If you can give us a more accurate number, that is fine.

A Ms. Christensen, I do not have the capacities of the units during that time frame, 2000 January through December. So to do a weighted average, I cannot.

Q And would you feel comfortable just taking a look at those numbers and making a best guesstimate whether or not you believe they were over 80 percent available?

A I would not say over 80, but close to 80. But, again, that does not include, or we don't have been the two components whether there was no planned outage during that time.

Q Well, let me refer you -- let's take a look at Page 5 of the exhibit, Page 5 of that. All right. And I think we are actually going back from -- we are not in your late-filed deposition exhibit anymore, but Page 5 of the exhibit that you actually filed with your testimony. And we have provided that handout with the highlighted yellow numbers on the bottom.

A Yes.

Q And looking at that, would you agree that the number for the GPIF system weighted equivalent availability for the period of 2005 is 63.6 percent, is that correct?

A The GPIF weighted equivalent availability for 2005 January through December is 63.6.

Q Okay. Looking at the actual 12-month performance by generating unit for the previous 12 months ending July 2002, is the combined availability for that time period 68.4 percent?

A For the time period -- could you repeat that, please?

Q For the time period 2002 -- or, I'm sorry, the time period ending June 2003, and the prior 12 months is the combined availability for that time period 68.4 percent?

A That is the GPIF system weighted equivalent availability, and those weighting factors are on the second column. They may not and do not equal the capacity weightings for those periods.

Q Okay. Was Tampa Electric penalized approximately $2 million for its GPIF performance in 2002?

A In 2002, Tampa Electric was penalized $2,496,021. That penalty was derived off of historical information leading up to that, a 12-month period of year 2000 July through June of 2001.

Q Looking at the actual 12-month performance by generating unit for the previous 12 months ending June 2004, is the availability for that period 64.6 percent?

A Yes. The GPIF system weighted equivalent availability is 64.6.

Q Is it correct that the Commission staff's recommendation is that Tampa Electric should be penalized $3,678,414 for its actual GPIF performance in 2003?

A Yes. The penalty for 2003 is $3,678,414, calendar year 2003 GPIF.

Q Okay. And, finally, looking at the 2005 target period, is it correct that the new combined target rate for 2005 EAF is 63.6 percent availability?

A That is correct. And the basis for that 63.6, however, is the preceding 12 months, July through June of 2003 through 2004. That is how the GPIF system works. It is historical information used to forecast future performance. And either a reward or a penalty will be based off of either beating or not beating that benchmark that is set by the historical operating characteristics of those facilities.

Q Okay. And the 2005 target rate is the starting point for calculating your 2005 reward or penalty, is that correct?

A The target rate is the starting point, that is correct, for 2005.

Q Referring to Page 4 of DRK-1, is it correct that this page shows Tampa Electric's GPIF penalty for 2003?

A For 2003? In what document are you --

Q I'll withdraw that question. I'm going to refer to, I believe, a handout that we provided possibly earlier which was attached to the prehearing order, and it showed the target for 2005. Page 3 of 3. And I believe we handed out a previous copy.

MS. CHRISTENSEN: Did we hand out Attachment A, Page

1 of 3 and 2 of 3 already?

CHAIRMAN BAEZ: Yes.

MS. CHRISTENSEN: Okay.

BY MS. CHRISTENSEN:

Q And referring to Page 3 of 3, is it correct that the GPIF targets, this shows the GPIF targets for all the plants for 2005, correct?

A For all of the utilities and their covered GPIF facilities or units.

Q Is it correct that looking at this document Crystal River's coal plants 1, 2, 4, and 5 are projected to run at greater than 80 percent availability?

A That is correct.

Q But if you look at the actual EAF targets for 2005, they read 92 percent, 85 percent, 89 percent, and 90 percent. Would it be fair to say that they are even running closer to 90 percent?

A I'm not sure how close to 90 percent.

Q Okay. I believe that we agreed earlier in your testimony today that the Big Bend plants are targeted to run at 63.6 percent availability, is that correct?

A That 63.6 target is the GPIF weighted target. Their actual capacities or actual targets are higher.

Q Do you know what the difference or why your targets are so much lower than Crystal River's targets?

A No, I do not, because I'm not familiar with the Crystal River units. However, many factors make up the projected EAF targets, including the technologies that are incorporated into the units, environmental constraints, system dispatch constraints, fuels that are consumed or burned in each of those facilities.

Q Would you agree that having more planned outages in a coal -- or more planned outages is better for a plant than having frequent high unplanned outages?

A No, I would not agree to that.

Q Then you would not agree that there is a benefit to having planned outages because you can plan ahead and schedule them for periods of low demand and do the work more efficiently?

A In a planned outage you can schedule the work ahead of time. However, in an unplanned outage if it is appropriate, additional maintenance can be taking place during that time.

Q Let me refer you to Page 9 of your testimony. Line 7 shows that you project an unplanned outage factor for Big Bend 1 of 32.03 percent for 2005, is that correct?

A That is correct.

Q And 34.52 percent for Big Bend 2 in 2005?

A That is correct.

Q And 35.61 percent for Big Bend 3 in 2005?

A That is correct.

Q And 17.48 percent for Big Bend 4?

A That is correct. But you have to remember that these EUOFs are determined or calculated by the process that is in the GPIF implementation manual that looks back at historical information to forecast or project the 2005 targets.

Q Let me refer you back to the order of the Commission that approves the GPIF. Can you flip to the second page of that order, the second full paragraph down and read that?

A The second paragraph on the second page reads, "At the end of the six month fuel adjustment period, the actual unit equivalent availability and average heat rate are compared to the --

Q Sir, I'm sorry, but the next full paragraph beginning with since, can you read that, please.

A Okay. "Since the performance targets are set prospectively in the GPIF, the staff proposal also provides for adjustments to the equivalent availability and average heat rate performance indicators where such adjustments are determined to be warranted by the Commission."

Q And would you agree that this gives the Commission some flexibility in what they do as far as approving the GPIF?

A I believe the intention of that was if a utility had a reason to change the projected EAF calculation or unit availability calculation due to either an engineering decision or equipment modification, that they could present that to the

Commission for their approval.

Q Okay. So am I to take it, it is your position that if the Commission were -- that the Commission has no flexibility to deny awarding declining performance if the formula itself allows for awards to be gained later?

MR. BEASLEY: I will object to the question. It assumes that the Commission awards declining performance, and I don't think that has been established.

CHAIRMAN BAEZ: Can you lay the foundation for that.

MS. CHRISTENSEN: Let me see if I can re-ask the question.

BY MS. CHRISTENSEN:

Q Mr. Knapp, would you agree that -- let me see if I understand. It is not your position that the Commission has no flexibility in what it determines are appropriate GPIF targets, awards, and penalties, is that correct?

A I believe the Commission has the authority to do whatever they like.

Q Enough for me. (Laughter.)

CHAIRMAN BAEZ: Cut, print. We're done here.

A But pertaining to this paragraph, how I interpret that, it is the adjustments are determined to be warranted by the Commission as if the utility presents to the Commission a reason why they would not use the historical 12-month period for setting the targets for the GPIF period.

Q Okay. So it is your position that only the utility can demonstrate why maybe that use of the previous 12 months historic data isn't appropriate?

A That is my interpretation of this paragraph.

Q Okay. Let me refer you back to if you have an unplanned outage factor of 30 percent for any given year, would it be correct to say that you could never run at a 90 percent availability, would that be correct?

MR. BEASLEY: I would ask for some clarification on that. The question is vague.

MS. CHRISTENSEN: I didn't think it was vague, but I will repeat it again.

CHAIRMAN BAEZ: And I didn't get you, so --

MS. CHRISTENSEN: Yes, I can certainly repeat it again.

BY MS. CHRISTENSEN:

Q If you have unplanned outages, outage factors of 30 percent in a given year, would it be correct to say that you could never run at a 90 percent availability?

A At a 90 percent availability if you have an equivalent unplanned outage of 30?

Q Correct.

A That is true.

Q Okay. In fact, an unplanned outage factor of 30 percent would automatically reduce your availability to a maximum of 70 percent, less any time that the plant was off-line due to planned outages, is that correct?

A That is correct.

Q Would it be fair to say that you are likely to have more unplanned outages if routine and planned maintenance are not kept up?

A I cannot answer that question with any authority.

Q Would you likely have a higher percentage of unplanned outages if your maintenance budgets are reduced?

A Again, I cannot answer that question.

Q Okay. Again referring to the Attachment A that was attached to the prehearing order, and I believe we handed out two papers with that information on it. Looking at Page 2, would you agree that in 2003 your company's actual availability for Big Bend 1 was 61.2 percent?

A The actual adjusted availability for Big Bend 1 was 61.2 percent.

Q Okay. Now, referring to Page 8 of your exhibit attached to your testimony -- or, I'm sorry, Page 7, would it be correct to say that if Big Bend 1 performed at the same 61.2 percent under the proposed 2005 GPIF, you would receive a full reward?

A What I see or what I think you are doing is comparing two different periods. The targets that were set for the 2003 January through December were calculated in 2001 and 2002, July through June. The targets that are set for Big Bend 1 in calendar year 2005 are a function or a calculation of the historical performance from June of -- I'm sorry, July of 2003 through June of 2004.

Q And that is correct. And I guess the question is that if these are approved, essentially Big Bend 1 performance has gone down, or the availability has certainly declined since 2002 time period, and you would receive a reward under the current proposed targets, is that not correct, if you performed up to the 2002 past historical performance?

A On an absolute basis, if you are looking at two numbers, the answer is yes. But what goes into that target for 2005 is planned maintenance of 15 percent. I'm not sure what was in the target for 61.2. So the planned maintenance, that is why it is very difficult to compare period to period due to the fact that, first, they are based off of two different assumptions; and, secondly, the planned maintenance needs to be known for each of those periods.

Q Well, let's look at Big Bend 2's performance in 2003 on Page 2, and the actual adjusted for Big Bend 2 was 58.1 percent, is that correct?

A That is correct. That is the actual GPIF adjusted EAF.

Q And look at Page 8, if it were to continue at the same percentage level of availability you would only incur a slight penalty if you are using the targets for 2005, is that correct?

A Again, on an absolute basis, that is correct. However, we are using two different periods, and you were comparing two different sets of information to come up to that absolute answer. Again, the basis of the 2005 target was off of July of '03 through June of '04, and we are looking at actual performance in 2003 not knowing what the planned outage was, the planned outage factor was.

Q Okay. In looking at Big Bend 3, if you were to meet the 2003 target of 63.0 percent, which was the zero amount in 2003, under the proposed 2005 range performance of 63 percent availability would result in an award, is that correct?

A Ma'am, I might not have heard the whole question. You are referring to Big Bend 3 and you gave two figures, could you repeat the figures?

Q Certainly. I believe your target in 2003 was set at 63 percent availability, is that correct?

A That is Big Bend 2's target.

Q Okay. Well, then Big Bend 3's target was -- let me stand corrected -- 67.3 percent?

A That was Big Bend's target, their actual adjusted was 60.1 on GPIF basis.

Q Okay. 60.1 is what they actually did. Let's assume for the sake of argument that your Big Bend 3 was able to maintain a 60.1 percent availability in 2005. Would you agree that under the current target schedule that you would incur no penalty for that unit?

A It would be very close to zero. But, again, we are comparing two different periods. And the basis of the GPIF is to look at historical information to set the targets and incent the utility to beat those historical targets.

Q Would you agree that the Big Bend 3 performance of 60.1 contributed to Tampa Electric receiving a penalty in 2003?

A Let me look. Would you repeat the question, please.

Q The 60.1 percent adjusted actual availability for Big Bend 3, was that part of or did that contribute to Tampa Electric receiving a penalty under the GPIF in 2003?

A Yes, it did.

MS. CHRISTENSEN: Okay. No further questions.

CHAIRMAN BAEZ: Ms. Kaufman.

MS. KAUFMAN: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MS. KAUFMAN:

Q Mr. Knapp, I'm Vicki Kaufman from the Florida Industrial Power Users Group, sir. I just have a few questions. I'm not going to take you back through the numbers that Ms. Christensen just reviewed with you, but I just want to talk to you for a second about philosophy.

Would you agree with me, sir, that the purpose of any incentive program, whether it is GPIF or some other, is to change or incent behavior?

A Yes, I would.

Q And I think Ms. Christensen reviewed with you the Order 9558 that set up the GPIF program, correct? It's Exhibit 63.

A Yes, she did.

Q And you agreed with her that when the Commission developed the GPIF program, what they were attempting to do was to incent the utilities to improve the productivity of their base load units, right?

A The intention of the program was to improve their performance off of their previous historical performance.

Q Well, you have Exhibit 63, right? And I think you already read this paragraph out loud. It is the second yellow section, and it says, does it not, and I will just paraphrase, that the GPIF is designed to encourage the improvement of the productivity of base load generating units, correct?

A That is correct

Q Now, if after Ms. Christensen's review of the various schedules with you, the Commission were to conclude that in this case Tampa Electric, for whatever reason, has not been incented to improve its units productivity, Tampa Electric wouldn't expect to receive a reward for that behavior, would it?

A Would you repeat that for me, please?

Q I will do my best. I said after reviewing the numbers and your discussion with Ms. Christensen, if the Commission were to conclude that this program has not incented Tampa Electric to improve the productivity of its base load generating units, Tampa Electric would not expect to receive a reward, would it?

A That is correct. If the units do not increase over their historical performance of that 12-month prior period, a reward will not be paid. However, I believe the program is working. If you look over the past three years, a penalty has been paid by Tampa Electric, 2001, 2002, and 2003. In 2004 that trend is reversing to a slight forecasted reward, and the performance that set up the slight forecasted reward will then be factored into saying part of the targets for 2006 GPIF.

Q Okay. My point is maybe a little bit more -- a little simpler than your explanation. It simply is if the Commission reviews the performance of the Big Bend units, say, from 2000 up through the current projected period, if they determine that the performance of those units has not improved, that they have not become more available to the ratepayers, you would not expect a reward, would you?

A That is correct.

MS. KAUFMAN: Thank you. That's all I have, Mr. Chairman.

CHAIRMAN BAEZ: Thank you, Ms. Kaufman.

Staff.

MS. VINING: Staff doesn't have any questions.

CHAIRMAN BAEZ: Commissioners, questions?

I just have a couple of questions, Mr. Knapp, because I want to understand the performance outage factors. Is there any -- generally speaking do they increase or decrease year over year?

THE WITNESS: Many factors go into equivalent availability factors. As I said in many areas, whether it is the design of the unit, the environmental constraints that may be placed on that unit, new environmental constraints, it could be the fuels that are going into the units, it could be the system dispatch of those units. So there are many factors. So it is hard to say that they will continue to get better over time or worse over time.

CHAIRMAN BAEZ: Well, and really that was any given number compared to the year before, the planned outage factor, there is nothing that can be inferred in your opinion as to whether there is an improvement or lack of improvement year over year depending on the number. If you look at a set, you know, 15.3 as a planned outage factor for any given year, that is made up of any number of reasons, correct? You can't say it is better than one year or another.

THE WITNESS: The planned outage factor is the time that that unit will be off-line for maintenance, and it is just a subtraction off the unit's viability.

CHAIRMAN BAEZ: But I'm trying to understand the relationship. Does the planned outage factor itself have a value when compared to previous years in a historical sense?

THE WITNESS: The only value it has, it tells -- you can compare the amount of time that unit has been off-line or unavailable for maintenance.

CHAIRMAN BAEZ: And are there ever any inferences that can get drawn by the difference in numbers year over year of the planned outages for a given plant?

THE WITNESS: Planned outages normally will follow a pattern of several smaller planned outage factors, and then a large planned outage factor where a major overhaul might take place. And the examples of that are in the diagram. One of the units has over 28 days. As specified in the manual, you have to detail out what events are going to take place during that outage. And that is on Big Bend 1. This year that is why it is over 15 percent PLF.

CHAIRMAN BAEZ: Now, when you can identify a planned outage that includes a major overhaul, for instance, even the planned outage has the effect of depressing what a target performance number may be for the years following?

THE WITNESS: It will certainly depress the year that the planned outage is in. I'm not sure of the correlation of future performance when an overhaul or a major outage is performed.

CHAIRMAN BAEZ: Well, the reason I ask that is I thought I heard you explain, I believe it was to Ms. Christensen, how the goals are set based on 12 months prior, the 12-month prior history, and that the performance factor establishes sort of a base line upon which to improve. So if it was 60 percent the year prior, whatever the actual was, then the incentives begin at 60, is that accurate?

THE WITNESS: That is accurate. Although I would like to add the equivalent unplanned outage factor and the planned outage factor make up EAF. The equivalent unplanned outage factor is off that historical information July through June of the preceding year or years. The planned outage factor is a number that is provided of the anticipated planned maintenance for that upcoming year, 2005. It is not a historical number that we are looking back and saying during this period we had that same amount of planned outage factor.

CHAIRMAN BAEZ: All right. Thank you.

THE WITNESS: So that is why it is very difficult to compare numbers to numbers, because they don't have the same planned outage factor. And when we have a 15, or essentially an eight-week outage, it lowers the equivalent availability by the PLF increasing.

CHAIRMAN BAEZ: Thank you.

Mr. Beasley, do you have redirect?

MR. BEASLEY: Yes, very short.

REDIRECT EXAMINATION

BY MR. BEASLEY:

Q Mr. Knapp, did you adhere to the approved policies and procedures of the GPIF manual in putting together your targets and ranges for 2005?

A Yes, sir, I did adhere to the manual.

Q And if you are able to achieve a reward, how does that effect the ratepayers economically?

A If Tampa Electric receives a reward, the way the program is set up the ratepayers or customers of Tampa Electric will receive fuel savings that exceed the reward, and it is mandated in there that the reward or penalty cannot be more than 50 percent of the potential fuel savings or costs.

MR. BEASLEY: Thank you. That's all I have. I would like to move the admission of Mr. Knapp's exhibits.

CHAIRMAN BAEZ: And I'm showing those to be 45 and 46.

MR. BEASLEY: Yes, sir.

CHAIRMAN BAEZ: Without objection, show them entered. And I have other exhibits, Ms. Christensen.

MS. CHRISTENSEN: Yes. I would ask to move Exhibits 63 and 64 into the record. I don't believe we actually marked for identification the attachments to the prehearing order, and since those may technically not be part of the record, I would ask that we go ahead and mark those for identification.

CHAIRMAN BAEZ: Right. And we will mark those attachments as Exhibit 65.

MS. CHRISTENSEN: And I believe the other handout was already attached to the prefiled testimony. So I would ask to move Exhibits 63, 64, and Composite Exhibit 65 into the record.

CHAIRMAN BAEZ: Without objection, show Exhibits 63, 64, and Composite 65 admitted into the record.

(Hearing Exhibit Numbers 45, 46, 63, 64 and Composite Exhibit 65 admitted.)

CHAIRMAN BAEZ: Mr. Knapp, thank you.

THE WITNESS: Thank you.

MR. BEASLEY: We call Mr. Smith.

CHAIRMAN BAEZ: You were sworn, correct, sir?

THE WITNESS: That is correct.

CHAIRMAN BAEZ: Thank you.

Whereupon,

BENJAMIN J. SMITH

was called as a witness on behalf of Tampa Electric Company, and having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BEASLEY:

Q Mr. Smith, would you please state your name for the record as well as your business address and your position with

Tampa Electric Company.

A My name is Benjamin Smith. My address is 702 North Franklin Street, Tampa, Florida 33602. I'm the manager of wholesale power for Tampa Electric.

Q Mr. Smith, did you prepare and submit in this proceeding a document entitled, "Prepared Direct Testimony of Benjamin F. Smith," dated and filed on September 9th, 2004?

A Yes, sir, I did.

Q If I were to ask you the questions contained in your testimony, would your answers be the same?

A They would be the same.

MR. BEASLEY: I would ask that Mr. Smith's testimony be inserted into the record as though read.

CHAIRMAN BAEZ: Without objection, show the direct testimony of Benjamin Smith entered into the record as though read.

TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
FILED: 9/9/04

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH

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

A. My name is Benjamin F. Smith. 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 of Science degree in Electric Engineering in 1991 from the University of South Florida in Tampa, Florida. I joined Tampa Electric in 1990 as a cooperative education student. During my years with the company, I have worked in the areas of transmission engineering, distribution engineering, resource planning, retail marketing, and wholesale marketing. I am currently the Manager, Wholesale Power in the

Wholesale Marketing and Fuels Department. My responsibilities are to evaluate, pursue, and negotiate hourly and other short-term purchase and sale opportunities within the wholesale power market. In this capacity, I interact with wholesale power market participants such as utilities, municipalities, electric cooperatives, power marketers, and other wholesale generators.

Q. Have you previously testified before this Commission?

A. Yes. I testified before this Commission in Docket No. 030001-EI. My testimony described the appropriateness and prudence of Tampa Electric's wholesale purchases and sales.

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

A. The purpose of my testimony is to provide a description of Tampa Electric's 2004 and 2005 purchased power agreements that the company has entered into and for which it is seeking cost recovery through the Fuel and Purchased Power Cost Recovery Clause ("fuel clause") and the Capacity Cost Recovery Clause. I also describe

Tampa Electric's purchased power strategy for mitigating supply-side risk while providing customers with a reliable supply of economically priced purchased power.

Q. Please describe Tampa Electric's wholesale energy purchases for 2004.

A. Tampa Electric assessed the wholesale energy market and entered into long- and short-term purchases based on price and availability of supply. The company expects to meet approximately 12 percent of its customers' 2004 energy needs through purchased power, including the existing long-term, firm purchased power agreements with Hardee Power Partners and qualifying facilities and a 150 MW non-firm purchase that began in June 2004.

Although Tampa Electric did not have a need to purchase firm capacity for its summer 2004 reserve margin requirements, the company had the opportunity to purchase economical power on the forward market. Tampa Electric made power purchases to assist with price stability and reliability of supply. For 2004, Tampa Electric expects that [redacted] percent of its purchased power will be from long-term contracts, and the remaining [redacted] percent will be purchased through the short-term market.

This purchasing strategy provides a reasonable and diversified approach to serving customers.

Q. Please describe Tampa Electric's purchase referred to above.

A. Tampa Electric entered into a contract to purchase 150 MW of non-firm power that is priced at system average fuel cost from sources within the state of Florida. The purchase took effect in June 2004 and expires at the end of 2005. The purchase allows Tampa Electric to provide customers with reliable energy at an economic price. While the purchase is categorized as non-firm capacity for the purposes of calculating firm reserves, the expected availability of the energy is high because it is backed by a utility's entire system. The contract has both capacity and energy charges. The purchase is projected to benefit customers by $7.1 million over the life of the contract, based on the company's expected usage of this economically priced product.

Q. Did Tampa Electric contract for capacity or energy purchases as a result of its 2005 Peaking Request for Proposals ("RFP"), issued on July 25, 2003?

A. No. Tampa Electric was unable to identify an economically viable, firm-delivered peaking resource beginning May 2005. Therefore, the company did not contract for purchased power through this RFP process. Additionally, since the issuance of its RFP in July 2003, the company updated its 2005 load forecast. The revised forecast, combined with the accelerated refurbishment of Big Bend CT 2, result in a need for only 25 MW in the summer of 2005 rather than up to 225 MW, as originally anticipated.

Q. What capacity and energy purchases are included in Tampa Electric's projections for 2005?

A. As I stated above, in addition to the existing long-term purchased power agreement with Hardee Power Partners, the 150 MW non-firm purchase, and qualifying facility purchases, Tampa Electric projects a need for 25 MW of firm capacity to meet summer 2005 reserve margin requirements. Because of this small amount, the company will continue to evaluate this need in early 2005 using the most current assumptions for load and other system parameters. If a need for summer reserves still exists, the company will pursue options to obtain the necessary capacity at that time.

In 2005, Tampa Electric expects that [redacted] percent of its purchased power will be from long-term contracts, and the remaining [redacted] percent will be purchased through the short-term market. Tampa Electric will continue to evaluate economic combinations of forward and spot market energy purchases during its spring and fall generation maintenance periods and peak periods to reduce the overall cost to customers.

Q. Please describe Tampa Electric's wholesale energy sales for 2004.

A. Tampa Electric has entered into various non-firm, non-separated wholesale sales in 2004. These transactions have provided benefits to customers because 100 percent of the revenues from the sales were flowed back to customers through the fuel clause.

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

A. Physical and financial hedges can provide measurable market price volatility protection. Thus far, Tampa Electric has engaged only in physical hedging for wholesale transactions because the availability of financial instruments within Florida is limited. The Florida market currently operates through bi-lateral contracts between various counterparties, and there is not a Florida trading hub where standard financial transactions could occur with enough volume for a liquid market. Due to this lack of liquidity, the appropriate financial instruments to meet the company's needs do not currently exist. Thus, Tampa Electric has not purchased any wholesale energy derivatives. Instead, Tampa Electric employs a diversified power supply strategy, which includes self-generation and long- and short-term capacity and energy purchases. This strategy provides the company the opportunity to take advantage of favorable spot market pricing while maintaining reliable service to its customers.

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 evaluates its potential purchased power needs by analyzing the expected available amounts of generation and the power needed to provide for the projected energy and demand to be used by its customers.

When there is a need, the company aggressively shops for wholesale capacity or energy, searching for reliable supplies 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. The creditworthiness of each counterparty is carefully checked before engaging in energy transactions. Purchases are made to achieve reserve margin requirements, to meet customers' needs, to supplement generation during both planned and unplanned generating unit outages, and for economical purposes. This process is strictly followed to minimize the cost of purchased power and maximize the savings to customers.

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

A. Yes, it has. Tampa Electric has fully complied with, and continues to fully comply with, the Commission's March 11, 1997 order, PSC-97-0262-FOF-EI, in Docket No. 970001-EI, which governs the treatment of separated and non-separated wholesale sales. In addition, the company actively manages its wholesale sales and purchases with the goal of capitalizing on all opportunities to reduce costs to its customers.

The company's wholesale purchases and sales activities and transactions are reviewed and have been audited on a recurring basis by the Commission. In addition, Tampa Electric monitors its contractual rights with purchased power suppliers as well as with entities to which wholesale power is sold to detect and prevent 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-separated wholesale sales when excess power is available on Tampa Electric's system.

Q. Please summarize your testimony.

A. Tampa Electric monitors and assesses the wholesale energy market to identify and take advantage of opportunities in the wholesale electric power market, and those efforts have benefited the company's customers. Tampa Electric's energy supply strategy includes self-generation and long- and short-term power purchases. The company purchases in both the physical forward and spot wholesale power markets to provide customers with a reliable supply at the lowest possible cost, and Tampa Electric enters into non-firm, non-separated wholesale sales that benefit customers. Tampa Electric does not purchase wholesale energy derivatives in the developing Florida wholesale electric market due to a lack of financial instruments that are appropriate for the company's operations. It does, however, employ a diversified power supply strategy to help mitigate price and supply risks.

Q. Does this conclude your testimony?

A. Yes.

BY MR. BEASLEY:

Q Mr. Smith, have you prepared a summary of your testimony?

A Yes, sir, I have.

Q Would you please present it?

A Yes, I would. Good afternoon, Commissioners.

My name is Benjamin Smith, and I am the manager of wholesale power for Tampa Electric. My testimony provides a description of Tampa Electric's 2004 and 2005 purchased power agreements that it has entered into and for which it is seeking cost-recovery. Included in the company's short-term and long-term purchased power agreements is Tampa Electric's only long-term firm purchased power agreement from the Hardee Power Station. This firm contract continues to satisfy firm reserve needs as well as provide economic benefit to Tampa Electric customers. As noted before this Commission last year, the sale of the Hardee Power Station --

MS. KAUFMAN: Excuse me, Chairman Baez, I'm sorry to interrupt. I think I need to interpose an objection because I don't believe that this is part of Mr. Smith's prefiled testimony.

CHAIRMAN BAEZ: Mr. Smith, can you point to me in your testimony where you discussed the Hardee Power sale? And I'm assuming that is what you are --

MS. KAUFMAN: Well, Mr. Chairman, he does mention the

Hardee Power sale. But he is now -- I thought he was getting ready to go off and discuss things that are not part of his prefiled testimony. He does mention it on Page 5.

CHAIRMAN BAEZ: Then can you describe for me exactly what flight of fancy you were anticipating so that we can nip this in the bud?

MS. KAUFMAN: I was anticipating him describing to you some findings that you had may last year in regard to the transaction, which I don't think he addresses in his testimony.

CHAIRMAN BAEZ: Mr. Smith, no need to summarize the Commission's decisions on the sale of plants, which we have already covered, but you can go ahead and continue your statement.

MR. SMITH: Okay.

A (Continuing) That long-term contract from the Hardee Power Station is a cost-based contract. The company always evaluates potential purchases and other resource options to take advantage of the most cost-effective products for its customers. Tampa Electric's purchased power agreements are prudent, and those costs should be approved for cost-recovery.

That concludes my summary.

MR. BEASLEY: And we submit Mr. Smith for questions.

CHAIRMAN BAEZ: Ms. Kaufman.

MS. KAUFMAN: I guess it's just me.

CHAIRMAN BAEZ: It's just you. Go ahead.

CROSS EXAMINATION

BY MS. KAUFMAN:

Q Good afternoon, Mr. Smith.

A Good afternoon.

Q Mr. Smith, you mentioned the Hardee Power contract, and you understand, don't you, that one of the issues in this case, 17E, is whether those charges related to that contract are reasonable?

A Yes, ma'am.

Q And you are the right witness to ask about that contract, correct?

A Yes, I am.

Q Do you have a copy of Ms. Jordan's E Schedules?

A I have a copy of --

Q Particularly E7?

A -- E6 and E7.

Q Okay, great. And if you look at E7 from Ms. Jordan's filing, that summaries the various wholesale contracts, or the wholesale purchases that you are projecting to make in 2005, correct?

A On a projected basis based on economic dispatch, yes.

Q If you would turn to Page 2 of 2 at the very bottom, that summarizes your purchases for the -- projected purchases for the entire year, right?

A It is a summary of those E7 purchases, yes.

Q And there are four categories there. The first is your Schedule J purchases, correct?

A Schedule J is the first one, yes.

Q And what kind of purchases make up Schedule J?

A If you notice under that Schedule J line there, there are also a portion of those that are going to interruptible customer megawatt hours, so those would be considered sort of an emergency JA type purchase.

Q Is that what you would call buy-though in Schedule J?

A Yes. Offshore provisional buy-though type stuff.

Q Are there other types of purchases in Schedule J, or is it all the buy-though power?

A Right now the Schedule J identified on that line is what we would consider simply optional provision and emergency type power. The way that works is when Tampa Electric gets into a situation where it needs to buy from the marketplace, maybe it runs out of its own generation, it goes out into the marketplace and it shops for the best product for that peaking period or its need. A portion of those megawatt hours would be prorated to interruptible customers to serve them and keep them under service. The balance of that would go to Tampa Electric Company customers to serve their need.

Q And the portion that goes to the interruptible customers so they can stay on line, the cost of that purchase are passed directly through to them, correct?

A Yes.

Q The next line is HPP, which is Hardee Power Partners, correct?

A That is the Hardee Power Station.

Q We are going to come back to that in a minute. Then the third line says various other. What kind of purchases are included in there?

A In that purchase line should be -- we have a 150-megawatt purchase with Progress Energy Florida and that should comprise the majority of that.

Q That is the new short-term purchase that you have discussed in this testimony, as well?

A Yes. It is it actually long term.

Q The 150-megawatts?

A It is about 19 months long.

Q And then the last line that comprises these kind of purchases is called market-based. What kind of purchases are those?

A Those are projections of spot purchases that we would make from the marketplace.

Q Now, when it is denominated market-based, does that mean that the selling price and the purchase price is based on conditions in the market, it is a competitive price for that power?

A That is probably a good way to describe it. It is not cost-based, meaning that whatever the market would bear for that particular product, that is what the seller would charge.

Q So that line represents what you are expecting to pay based on competitive conditions in the market for those megawatts that you are purchasing?

A That is correct.

Q Now, turning back to the Hardee Power Partners sale. First of all, I am correct, am I not, that at one time TECO Energy owned a part of Hardee Power Partners?

A An affiliate of Tampa Electric Company that was also a TECO Energy Company, TECO Power Services owned the project at one time, yes.

Q And that interest has been sold to a third party. When did that sale occur, do you know?

A September of '03, I believe. It was finalized September of '03.

Q Okay. Now, if I am reading correctly, you are projecting to buy almost 12 million megawatts from Hardee Power next year?

A Approximately, 11.9.

Q For regulatory work I was rounding. And what is the price that you project to pay for that energy?

A Of the Hardee?

Q Yes.

A Looking at the E7 schedule, the number that you see there includes O&M, both fixed and variable O&M.

Q And how much are you projecting to pay there?

A The number listed on the E schedule is roughly $72 per megawatt hour. However, once again, when we are dispatching the Hardee Power Station we are dispatching on fuel costs and we are dispatching on variable O&M. When you add fixed costs into an energy calculation, if you use less energy, it arbitrarily inflates the rate. If you use more energy, then the rate would be depressed.

Q The rate that you have shown us here on your E7, or Ms. Jordan's E7 schedule, is the rate that you are projecting to pay Hardee, the $72 per megawatt hour next year, right?

A Both fuel and O&M, yes, ma'am.

Q Right. And what you are projecting to pay under the market-based rate that we discussed is about $55, correct?

A Roughly $55, yes.

Q And that reflects, as we have said, the competitive price in the marketplace, the $55?

A Yes.

MS. KAUFMAN: That's all I have. Thank you.

CHAIRMAN BAEZ: Staff.

MS. VINING: Staff has no questions.

CHAIRMAN BAEZ: Mr. Beasley, do you have any redirect?

MR. BEASLEY: Briefly, sir.

REDIRECT EXAMINATION

BY MR. BEASLEY:

Q Mr. Smith, to your knowledge has the Commission looked at the Hardee Power purchases by Tampa Electric in the recent past?

A Yes, they have.

Q Was it looked at in the 2001 fuel adjustment hearing?

A Yes, it was.

Q What did the Commission conclude regarding those purchases?

A The Commission basically concluded that Tampa Electric's treatment of the Hardee Power Station, the Hardee agreement was reasonable, and that the costs were appropriate for cost-recovery.

Q Was that decision further reviewed?

A Yes, it was.

Q And what was the outcome of that review?

A The Florida Supreme Court basically agreed with this Commission that Tampa Electric Company's costs associated with the Hardee Power Station were appropriate for cost-recovery. And they further concluded that no evidence was really given tc look into the issue any further.

Q Did the Commission last year look at the very contract under which you are making the purchases from Hardee Power Station?

A Yes, they did.

Q And for which you are projecting to make purchases in 2005?

A Yes.

Q Do you have the decision that the Commission rendered following last year's hearing?

A Yes, I do.

Q Could you read for us, please, the portion of that order addressing that particular issue?

A Yes. The order number, by the way, is PSC-03-1461-FOF-EI. On Page 22 there is a heading that reads, "Review of amounts paid to HPP."

It reads as follows: "We decline to review the amounts paid by TECO under its contract with Hardee Power Partners simply because HPP was sold. This Commission has previously approved the contract for cost-recovery purposes and reviewed it as recently as 2001. The evidence in the record indicates that the rates, terms, and conditions of the contract have not changed as a result of the sale of HPP, and that the contract will not be amended, changed, or assigned as a result of the sale. No evidence to the contrary has been offered by any party to indicate that any specific problem concerning this contractual agreement should be addressed."

MR. BEASLEY: Thank you. I have no further questions.

CHAIRMAN BAEZ: Exhibits.

MR. BEASLEY: Mr. Smith did not sponsor any exhibits.

CHAIRMAN BAEZ: That is correct. I was just checking.

Thank you, Mr. Smith.

THE WITNESS: Thank you.

CHAIRMAN BAEZ: Now, the next witness is Ms. Jordan, but we don't expect her to have to testify, is that correct?

MR. BEASLEY: That's correct, sir.

CHAIRMAN BAEZ: Then next up is Witness Hartman.

Mr. Butler, we will take ten minutes, and you can get your witness ready.

MR. BUTLER: All right.

(Recess.)

CHAIRMAN BAEZ: Mr. Butler, call your witness.

MR. LITCHFIELD: Chairman Baez, this is Wade Litchfield, I will be presenting Mr. Hartman.

CHAIRMAN BAEZ: I'm sorry, Mr. Litchfield.

Whereupon,

THOMAS L. HARTMAN

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

DIRECT EXAMINATION

BY MR. LITCHFIELD:

Q Mr. Hartman, would you please state your name and business address for the record?

A My name is Thomas L. Hartman. The business address is 700 Universe Boulevard, Juno Beach, Florida.

Q Have you prepared and caused to be filed 22 pages of prefiled direct testimony dated September 9th in this proceeding?

A Yes, I have.

Q And did you cause to be filed a replacement Page 15 to your direct testimony, which finally was made on 10/20?

A Yes, I did.

Q Do you have any changes or revisions to your prefiled direct testimony as revised by the October 20th filing?

A No, I do not.

Q If I were to ask you the same questions contained in that prefiled direct testimony as revised, would your answers today be the same?

A Yes, they would.

MR. LITCHFIELD: Chairman Baez, I would ask that Mr. Hartman's prefiled direct testimony with replacement Page 15 be inserted into the record as though read.

CHAIRMAN BAEZ: Without objection, show the direct testimony of Thomas L. Hartman as revised by subsequent filing entered into the record as though read.

MR. MOYLE: Mr. Chairman, we have an objection to portions of Mr. Hartman's testimony.

CHAIRMAN BAEZ: And which portions are those?

MR. MOYLE: I have two portions that I would move to have stricken. Do you want me to take them up sequentially?

CHAIRMAN BAEZ: Yes, by all means.

MR. MOYLE: Okay. Mr. Chairman, I would move to strike certain portions of the testimony of Mr. Hartman, specifically Page 5, Line 23, through Page 6, Line 2. And this includes the following statement, "Alabama Power has indicated to FPL that, upon expiration of the UPS agreement, it is not willing to continue the wholesale sale of the Miller portion of the UPS Agreement."

Mr. Chairman, this is excludable as hearsay, but should surely not come in since this statement is based on double hearsay. During Mr. Hartman's deposition he was asked about the coal component of the Miller contract, and the basis for his understanding that Alabama Power would not continue the wholesale sale of the Miller portion of the UPS Agreement. You remember in our opening statement we said that the Miller unit represents 720-megawatts of coal-fired generation, and he is saying that that is not available.

Mr. Hartman provided the following sworn testimony in his deposition starting at Page 72, Line 22. And if I could read this. He was asked:

"Question: Why would they, they being Alabama Power, want to put in their portfolio and not sell it to you?

"Answer: I don't know, you would have to ask Alabama Power.

"Question: But you were in the negotiations, right?

"Answer: All I know is Alabama Power said they were unwilling to commit to sell the output to us at wholesale at this time.

"Question: Was Alabama Power at the table during these negotiations?

"Answer: No. Representatives of Southern Company Services were, and others were, and they were going back to Alabama Power and gave us the word that Alabama had said that they were not willing to commit to sell at wholesale.

"Question: Did you ever confirm this with Alabama Power independently?

"Answer: No, I did not.

"Question: Do you think that that could have been a negotiating ploy from your friends at Southern?

"Answer: I don't believe so in this instance.

"Question: But you don't know for sure because you never talked to Alabama Power, is that correct?

"Answer: I never talked to Alabama Power."

This deposition testimony establishes that the testimony Mr. Churbuck seeks to strike is double hearsay based upon comments made to him by folks at the negotiating table based upon comments that they reportedly had with folks from

Alabama Power. Section 120.57(1)(c) states, and I quote, "Hearsay evidence may be used for the purpose of supplementing or explaining other evidence, but it shall not be sufficient in itself to support a finding unless it would be admissible over objection in civil actions."

This type of double hearsay is clearly not admissible to establish that Alabama Power is not willing to sell coal generated power to FPL from its Miller units. And I would refer you to the case of Host v. Unemployment Appeals Commission, 848 So.2d 1235, where the court found that testimony described in a report about time sheet records, neither of which was introduced at hearing, was inadmissible double hearsay.

Here Mr. Hartman relies on hearsay statements made to him by SCI representatives who may or may not have based their comments on hearsay from Alabama Power. This statement should not be allowed under established Florida case law and statutory law, and we respectfully ask that this statement be stricken.

CHAIRMAN BAEZ: Mr. Litchfield.

MR. LITCHFIELD: Thank you, Mr. Chairman. I think it is a little disingenuous on Mr. Moyle's part to argue that this is double hearsay. I assume that he is familiar with the way in which Southern Company is organized and that the service company, in fact, provides, among other things, back up and support functions, marketing support functions, and negotiations on purchased power arrangements with outside entities. And that Alabama Power would not have been at the negotiating table, given Southern Company's structure. So I think it is absolutely appropriate for Mr. Hartman to have relied upon the statements of Southern Company Services in negotiating as agents for the operating companies within the Southern Company System to rely upon those statements and to make the representation that he has made as noted by Mr. Moyle in Mr. Hartman's direct testimony.

MR. MOYLE: A brief response.

CHAIRMAN BAEZ: Mr. Moyle.

MR. MOYLE: You know, I don't know that there is any evidence in the record with respect to how the Southern Company is set up, or who is at the table representing whom. I mean, we had evidence in this case, it is a contract between a particular entity. So I know that Mr. Litchfield is making an argument, but I don't think that what he was arguing is that those facts are in the record and before you today.

CHAIRMAN BAEZ: See, here is where I'm unclear. If Mr. Keating or staff counsel wants to educate me on this, I mean, how much notice are we able to take about the point that Mr. Litchfield has made in terms of the corporate structure and the fact, if any, that Southern Energy actually does the negotiating for the power sales from our knowledge?

MR. KEATING: And I apologize, I missed the very beginning of that question.

CHAIRMAN BAEZ: The question is this, how much ability to notice, to take notice of Southern Company's structure and the fact that Mr. Litchfield has offered up as to one part of the hearsay, I might add, but nevertheless he has made a point that everybody knows that Southern Company is structured a certain way and that Southern Energy Services generally handles the negotiation of power sales for all of its subsidiaries. Is that fact something that is subject to our taking notice of?

MR. KEATING: It may be. We can take notice of facts that are generally known within the jurisdiction. I don't know without having researched that question in particular whether this is something that is contemplated as a matter that could be judicially noticed, or in our case administratively noticed. I'm not sure we need to get to that point. We have typically allowed hearsay evidence as is allowed in administrative proceedings. The limitation being that you can't base your decision solely upon that hearsay evidence. There must be some corroborating evidence in support of it as a basis for your decision.

CHAIRMAN BAEZ: Well, but I think -- while I will agree with you and I think that the rules of evidence here are pretty liberally interpreted, in the interest of getting a complete record for the Commission to decide upon, technical as it may be, there is hearsay upon hearsay, but for the fact that we might be able to -- and, again, this is a question that I don't know the answer to. I will make a judgment call, but I needed to hear from counsel who probably knows, perhaps are a little bit more familiar with it than I do, what kind of opportunity or what kind of discretion we have to take notice of at least the fact that would cure one of the hearsay as you see it.

MR. LITCHFIELD: Mr. Chairman, if I might interject for a moment. I think the witness is fully able to clarify this on the record. I'm not sure Mr. Moyle wants to allow him that opportunity, he would prefer to strike it in advance, but the witness is certainly capable of clarifying what he meant.

CHAIRMAN BAEZ: And recognizing fully that certainly that statement is subject to cross-examination and impeachment. But, Mr. Moyle, do you have anything else to add before I rule?

MR. MOYLE: Other than just -- and I don't know if you need to make a ruling right now on this point, maybe you can consider it, but with respect to your question about matters to be judicially noticed, 90.202 of the Florida Statutes Evidence Code sets forth all the things that you can, and I'm not sure that there is one in there that would allow you to take official notice of a company's corporate structure. There's things like decisions and Federal Register, that kind of stuff, so it doesn't seem to me to be of that ilk.

CHAIRMAN BAEZ: I'm going to make a judgment call, and I am going to allow the statement only because it is subject to your cross-examination going forward, and you will be able to delve into the depths of what the contact was or what the witness' knowledge is. And you had a second?

MR. MOYLE: I did. And I wouldn't imagine Mr. Litchfield's argument would be the same if we were in a personal injury case trying to pierce corporate veil today, but that is neither here nor there.

CHAIRMAN BAEZ: I think it is well established that we are not a civil court.

MR. MOYLE: Understood. Mr. Churbuck would also move to strike reference to any benefits related to approval of these PPA agreements due to FPL receiving rights of first refusal for additional firm coal-fired capacity and energy from Southern's Miller and Scherer units. One of the items that FPL wants you to consider as a benefit, one of these intangible benefits to consider is a right of first refusal that they say that they have. And I can identify the various lines, if you will, or I can just go ahead and get into the argument and if we need to --

CHAIRMAN BAEZ: You have made the universal objection, but I would like to hear what the grounds are exactly.

MR. MOYLE: Let me defer identifying all the difference places where this appears. There are two reasons to grant this motion to strike reference to FPL's right of first refusal. First, again, this is impermissible hearsay. Mr. Hartman's testimony is based on what others not here today testifying may have told him, or he may have understood from a document which is not being offered into evidence. There is no way to test the validity of this statement, a key reason that hearsay is not admissible in cases such as this involving disputed issues of fact.

Secondly, the best evidence rule precludes the admission of Mr. Hartman's testimony about FPL receiving rights of first refusal. The best evidence rule generally stands for the notion that a witness should not be allowed to testify about a document, as the document speaks for itself and is the best evidence to what has been bargained for.

Mr. Hartman talks about the benefits of the rights of first refusal, but FPL has failed to offer the document containing the right of first refusal into evidence. Again, the deposition of Mr. Hartman is telling. On Page 21, Line 17, he was asked the following series of questions and answers:

"Question: Could you please identify the section in the purchased power agreement that provides these rights?" And these rights were referring to the rights of first refusal.

"Answer: There is no section in the PPA that provides those rights. The rights of first refusal are separate agreements.

"Question: Did you file those separate agreements with the Commission?

"Answer: No, we did not."

Again, as mentioned, and I won't go through the argument again, but it is hearsay prohibited under Section 120.57(1)(c). And it is also not allowed under the best evidence rule. The best evidence rule is found in Section 90.952, and it states, requirements for originals. "Except as otherwise provided by statute, an original writing, recording, or photograph is required in order to prove the contents of the writing, recording, or photograph."

And, again, I can refer you to a case, McKeen v. State. In that case the court stated plainly, and I quote, "The best evidence rule is predicated on the principle that if original evidence is available that evidence should be presented to ensure accurate transmittal of the critical facts contained within it."

Here the best evidence of the right of first refusal that FPL asked you all to rely on in approving these contracts are these rights of first refusal that are set forth in separate agreements. But they have not given you copies of these agreements, these rights of first refusal, nor have they given the parties these agreements.

For that reason, and for the reason that it is based on hearsay, we would ask that all reference to the right of first refusal as a benefit of these UPS agreements be stricken from Mr. Hartman's testimony.

CHAIRMAN BAEZ: I'm going to deny the objection. I am going to overrule the objection. But, Mr. Moyle, having said that, I do want you -- I do want to recognize that the questions that you have raised as to the presence or the absence of supporting documentation to these claims is perhaps a question that I would hope gets run down over the course of this testimony.

For the same basis that I denied the prior objection, because you are going to get a chance, as is staff, to ask questions. And perhaps the Commissioners may have some questions along those very lines, and I think that issue will get fleshed out and we will be able to give it the weight that it deserves. So motion overruled. Go ahead.

MR. MOYLE: If I could just have follow-up, and I appreciate your ruling and respect it. With respect to what I heard, the discourse about Mr. Hartman and his testimony, and that I would be able to ask questions on cross-examination, I would ask that if the agreements that contain the right of first refusal are available that they be made available to me so that I could look at them and base some cross-examination questions on them.

CHAIRMAN BAEZ: Mr. Litchfield, I know you have got a response to that. I don't know what it is going to be, but I'm not sure that there is even that question before us at this point, so if you can just save -- is it fair to save this discussion if it comes up on cross-examination or do you want to address it now?

MR. LITCHFIELD: If a response is not required from me at this point, I will defer and wait until it is ripe.

CHAIRMAN BAEZ: Okay. We will save that fight for another time. Let's see if we can get Mr. Hartman on the saddle here.

And we were at the point of admitting the direct testimony of the witness into the record as though read. Mr. Litchfield, I notice this was his direct testimony.

MR. LITCHFIELD: This is his direct testimony, correct.

CHAIRMAN BAEZ: Go ahead.

BY MR. LITCHFIELD:

Q Mr. Hartman, are you also sponsoring any exhibits to your testimony?

A Yes, I am.

Q And those would be TLH-1 through 6?

A That is correct.

MR. LITCHFIELD: Mr. Chairman, I would note, for the record, that those exhibits have been prenumbered as 13 through 18 respectively.

CHAIRMAN BAEZ: That is correct.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TOM HARTMAN

DOCKET NO. 040001-EI

September 9, 2004

Q. Please state your name and business address.

A. My name is Thomas L. Hartman. My business address is 700 Universe Blvd., Juno Beach, FL 33408.

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

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as the Director of Business Management for Resource Assessment and Planning.

Q. What are your present job responsibilities?

A. My current responsibilities include: providing analyses and support to assist the Company in determining whether and on what terms to extend or replace expiring purchase power contracts; evaluating and identifying improvement opportunities and negotiating amendments to existing long term power purchase agreements; negotiating new power purchase agreements; and assisting in the development of draft purchase power agreements for future generation capacity purchases.

Q. Would you please give a brief description of your educational background and professional experience?

A. I received a Bachelor of Science Degree in Mechanical Engineering and Aerospace Sciences in 1974, and a Master's Degree in Mechanical Engineering in 1975 from Florida Technological University. I received a Masters of Business Administration degree from Georgia State University in 1985. I have been employed in my current position at FPL since July 2003. From 1994 until joining FPL, I was employed by FPL's unregulated affiliate, FPL Energy, LLC and its predecessor company. Throughout my employment at FPL Energy I held a number of positions in Business Management, where I had responsibility for various unregulated power projects, including responsibility for administering, negotiating, and modifying power purchase agreements. Prior to joining FPL Energy, I was with a number of consulting firms, providing management and technical consulting.

Q. What is the purpose of your testimony?

A. My testimony is provided in support of FPL's request for approval of three purchase power contracts with subsidiaries of the Southern Company, for purposes of cost recovery through the capacity cost recovery clause and the fuel and purchased power cost recovery clause. The capacity represented by the three contracts totals 955 MW. My testimony describes these contracts, identifies their principal benefits, and explains why the Commission should approve them for purposes of cost recovery.

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

A. Yes. It consists of the following documents:

Document TLH - 1 Contract for Scherer Unit 3

Document TLH - 2 Contract for Harris Unit 1

Document TLH - 3 Contract for Franklin Unit 1

Document TLH – 4 2003 Off Peak Price Spread between Florida and Southeastern SERC

Document TLH – 5 Summary of Merchant Plants in Southeastern SERC

Document TLH – 6 Summary Economic Analysis against 2003 RFP Plant

Q. Please describe each of the contracts and summarize its key elements.

A. FPL has negotiated three individual contracts for the purchase of power from three discrete units owned by one or more subsidiaries of the Southern Company, (sometimes referred to as "Southern Company" or "Southern").

The first contract is for approximately 165 MW (19.57% of unit capacity) of firm capacity and energy from the coal-fired Robert W. Scherer Unit 3 plant, located near Juliette, Georgia and jointly owned by Georgia Power Company and Gulf Power Company (the "Scherer Contract," my Document TLH - 1). Under this contract, FPL would make a fixed monthly capacity payment and an energy payment tied to the actual cost of fuel, emissions allowances, and variable O&M at the facility, as well as a fixed startup payment which escalates at a fixed rate.

The second contract is for 100% of unit capacity, up to 600 MW of energy and firm capacity from Southern Power Company's Harris Unit 1 combined cycle facility, located near Autaugaville, Alabama (the "Harris Contract," my Document TLH - 2). Under this contract FPL would make a fixed monthly capacity payment, variable O&M and startup payments that escalate at a fixed rate, payments for firm gas transportation to the unit, and payments for fuel supply tied to an established gas index and a fixed heat rate curve for the facility.

The third contract is for approximately 190 MW (35.1% of unit capacity) of firm capacity and energy from Southern Power Company's Franklin Unit 1 combined cycle facility, located near Smiths, Alabama (the "Franklin Contract," my Document TLH - 3). Under this contract, FPL would make a fixed monthly capacity payment, variable O&M and startup payments that escalate at a fixed rate, payments for firm gas transportation to the unit, and payments for fuel supply tied to an established gas index and at fixed heat rates based upon output.

All three unit outputs under the contracts are fully dispatchable by FPL within agreed-upon scheduling parameters. Additionally, all three contracts call for bonuses/penalties in the capacity payments based upon each unit's ability to meet or exceed target availabilities. All three contracts call for delivery of energy and capacity to FPL at the facility's interconnection point to the transmission system. After allowance for losses in transmission, the contracts will provide 930 MW of capacity at the FPL system. All three contracts call for delivery of energy and capacity starting June 1, 2010 and have a nominal termination date of December 31, 2015. The contracts for Harris and Franklin include an option for FPL to extend the term of the contracts by two years, exercisable by FPL until January 2010.

Q. What is FPL's purpose in entering into these contracts?

A. The purpose of these contracts is to allow FPL to continue cost-effectively many of the benefits provided by the current supply arrangements under the Unit Power Sales Agreement (the "UPS Agreement") between FPL and subsidiaries of the Southern Company, which provides energy and 930 MW of capacity, and expires May 31, 2010. Under the UPS Agreement, FPL has received coal-fired power from Scherer Unit 3 and Alabama Power Company's Miller Units 1, 2, 3 and 4. The Miller Units currently provide 720 of the 930 MW under the UPS Agreement. Alabama Power has indicated to FPL that, upon expiration of the UPS

Agreement, it is not willing to continue the wholesale sale of the Miller portion of the UPS agreement. In addition to providing energy and capacity, the current supply arrangement under the UPS Agreement provides FPL other benefits, including transmission rights out of the SERC region. With the UPS Agreement set to expire in 2010, it was necessary to seek alternative supply sources that would preserve these additional benefits associated with the UPS Agreement.

Q. Are there any contingencies or conditions precedent in the contracts that you wish to bring to the Commission's attention?

A. There are two important conditions precedent in each of the contracts that I would like to address. The first relates to the need to obtain firm transmission rights from each generating facility. If FPL is unable to obtain adequate firm transmission by a date certain, and at an acceptable cost, FPL has the right to terminate the contracts. The second condition precedent relates to FPSC approval of all three contracts for purposes of cost recovery. If the Commission fails to grant the requisite approval within six months (or before transmission rights are obtained, whichever is later), FPL will have the right to terminate the contracts. These conditions precedent are linked through all three contracts, in that termination of any one contract requires the termination of all three contracts. Thus, the contracts, although separate in form and relating to different generating units, in fact constitute a single, composite power purchase option for purposes of the Commission's review and approval.

Q. Please explain why these contracts are contingent upon FPL's ability to obtain firm transmission rights.

A. Firm transmission rights are essential to these contracts in order to deliver the power to FPL's system. The existing UPS Agreement has transmission service bundled into the contract. Continuation of bundled transmission service is no longer allowed under FERC Order 888. In order to move the energy and capacity to FPL's customers from units located within Southern's service territory, FPL must seek and obtain the needed transmission capacity. If FPL is unable to obtain the requisite firm transmission rights, the contracts will offer no value to FPL's customers and FPL will have the right to reject them.

Q. Does FPL believe that it will be able to obtain the requisite transmission rights?

A. Yes. Under FERC Order 888, long term (i.e., more than one year) firm transmission customers have the right to "roll-over" their transmission rights to other sources of energy and capacity. FPL has been a long-term transmission customer of the Southern Company and, therefore, expects to "roll-over" the transmission rights bundled in our existing UPS Agreement to meet customers' needs through these new contracts.

To roll-over its transmission rights, FPL expects that it will have to show that the changed delivery points (from the existing UPS Agreement to the new contracts) do not cause substantial changes in the transmission provider's system flows. The UPS Agreement currently provides energy and capacity to FPL from Scherer Unit 3 and Alabama Power Company's Miller Units 1, 2, and 3. The flow from Scherer Unit 3 will be essentially unchanged. The Harris and Franklin units are suitable replacements for the Miller output from a transmission standpoint because they are located on the flow path between the Miller units and the Florida border. Consequently, little change in the transmission provider's flows is expected under the Harris and Franklin Contracts. As a result of these considerations, FPL should be granted "roll-over" of its existing transmission rights under the UPS Agreement to these three replacement contracts.

Q. How does the capacity provided by these contracts relate to the Company's current Ten Year Site Plan?

A. FPL's current Ten Year Site Plan contemplates replacing the existing supply arrangement under the UPS Agreement with purchased power in the same quantity, starting in the summer of 2010. Entering into these contracts would be consistent with that plan. The Ten Year Site Plan, however, assumed that the replacement contracts would be based only upon natural gas fired generation, while the proposed contracts include a firm coal component.

Q. What are the key benefits of entering into these contracts?

A. The contracts offer several important benefits. In conjunction with these contracts:

1) FPL will maintain 165 MW of firm coal capacity in FPL's portfolio with the opportunity to purchase additional "coal-by-wire" on an as-available basis.

2) FPL will receive rights of first refusal for additional firm coal fired capacity and energy from Southern's Miller and Scherer units.

3) FPL also will retain 930 MW of firm transmission within SERC for future use, enabling it to procure energy and capacity when market terms are favorable.

4) FPL will obtain the equivalent of firm gas transportation adequate for 790 MW of generation, on a separate gas transmission network independent of the two that serve Florida, to meet FPL's power supply needs.

5) FPL's access to firm transmission capacity on the Southern system will enable FPL to obtain contracted firm capacity and/or purchase market energy from outside Florida, thus enhancing FPL's electric system reliability.

6) FPL will be able to defer making a long term commitment (self build or long-term purchase) which likely would be gas-based, thus preserving a certain amount of flexibility to consider new non-gas technologies over the next ten years.

Q. Please explain the importance of maintaining coal-fired capacity in FPL's resource portfolio.

A. The Scherer Contract represents the only available source of additional coal-based generation in the time frame contemplated. FPL believes in maintaining a diversity of energy sources, including natural gas, oil, nuclear and coal, the combined use of which benefits our customers by reducing volatility in energy costs for our customers. In addition, a diversity of energy sources increases system reliability because interruptions in one source are unlikely to occur simultaneously in others.

The Scherer contract, along with the transmission access associated with all three contracts, increase the diversity of FPL's energy sources. Without these contracts, FPL would need to add gas generation to its portfolio to meet its load requirements in 2010. Moreover, FPL will acquire a Right of First Refusal in conjunction with the contracts that potentially could add substantial additional coal-based generation to FPL's portfolio.

Q. Explain how FPL may be able to obtain additional coal-based capacity pursuant to the Right of First Refusal.

A. If Alabama Power ultimately chooses to sell the Miller units at wholesale on a long-term basis, FPL has the first option to purchase Miller energy and firm capacity and concurrently reducing the energy and capacity taken under the Franklin and Harris Contracts. Additionally, FPL will have the option to purchase a small amount of additional firm capacity from Scherer Unit 3 under some circumstances.

Q. Would the contracts generate additional opportunities for FPL to access coal-fired generation?

A. Yes. Operating subsidiaries of the Southern Company have a large proportion of base load coal and nuclear units in their portfolio of generation assets. Retention of the Miller units to meet Alabama Power's native load means that coal generation will be more frequently on the margin than it would otherwise be. As a result, power from coal units will be available more frequently in off-peak periods at attractive prices. FPL can use its firm transmission to wheel this inexpensive power to our customers. This is still "coal-by-wire," but on an as-available basis.

Essentially, the firm transmission rights in SERC allow FPL to arbitrage price differences between Southern's territory and Florida markets, for the benefit of FPL's customers. Comparing off-peak market clearing price projections in Southern's territory to prices in Florida indicates that the ability to purchase off-peak power could result in substantial savings to FPL's customers, ranging between $36 to $83 million (2004 NPV), or an average of $60 million over the contract term. Such estimates are based on the natural gas prices contained in FPL's current baseline projections. However, if gas prices should increase over the Company's baseline projections, the potential benefit of this arbitrage opportunity to FPL's customers is likely to increase because coal will still be on the margin in many hours and the spread between coal generation costs and gas will widen. My Document TLH - 4 shows publicly reported data for the spread in off peak power prices between Florida and Southern's territory, and illustrates the potential value of the arbitrage opportunity. Using 2003 prices, the arbitrage value of the transmission rights for that year would have been worth $10.87 million.

Q. Please describe any additional benefits to FPL's customers resulting from the transmission rights associated with these contracts.

A. In addition to enabling the delivery of the contracted energy and firm capacity, and additional coal-fired energy on an as-available basis, the firm transmission capacity itself enhances FPL's system reliability. Should the units under contract be unable to generate for any reason, FPL can use this firm transmission capacity to procure replacement power from the market to meet its customers' needs. Without these firm transmission rights, FPL would have no assured access to any capacity in the SERC region. In addition, preserving the firm transmission rights will allow FPL to pursue additional opportunities to purchase economic capacity and energy in the SERC region after these contracts have expired.

Q. Please explain how these contracts provide FPL the equivalent of access to an incremental source of firm gas transportation.

A. Under each of the Harris and Franklin Contracts, Southern will provide firm gas transportation to these plants under a contract between Southern and Southern Natural Gas Company. To the extent FPL is supplied energy from these facilities, Southern will give priority to scheduling FPL's gas with respect to the use of this firm gas transportation capacity. Southern cannot, as a condition of these contracts, cancel or replace the existing firm gas transportation contracts without FPL's consent. The Southern Natural Gas system is independent of the FGT and Gulfstream pipelines where FPL currently has firm gas transportation capacity.

This firm gas transportation commitment has several benefits for FPL's customers. First, an additional gas transportation capability increases reliability because it is independent of the in-state supplies (FGT and Gulfstream) used by FPL's gas-fired generation. Secondly, the ability to use this firm transportation to meet our customers' load defers the need for additional gas transportation to be obtained on FGT or Gulfstream, leaving that capacity available for later system additions, and deferring the need for gas transportation expansion within the state.

Q. Please explain how entering into these contracts will enhance FPL's electric system reliability.

A. First, as discussed above, the Harris and Franklin units use gas transportation facilities that are independent of FPL's current firm gas transportation paths. Therefore, the contracts for these gas-fired units, combined with that for coal-fired power from Scherer Unit 3, provide 930 MW (after allowance for transmission losses on Southern's system) into FPL's system that is independent of the existing gas infrastructure in Florida. This alone would increase our system reliability, by diversifying the risk due to gas pipeline interruptions.

Second, Southern has a financial incentive under the contracts to use other resources available to them to meet FPL's need if, for any reason, any of the units under these contracts is not available.

Third, in conjunction with these contracts, FPL will hold firm transmission rights within SERC into FPL's system. Should the contract units be unavailable, and should Southern be unable to provide alternate resources, FPL would still have the capability to use its firm transmission rights to import market energy it may purchase in the region to meet FPL's customers' requirements. While a single power plant is only one source of energy, transmission that will be held to implement these contracts will effectively provide two additional alternatives to concentrated generation: an alternate resource(s) if offered by Southern, or other units in a market that is geographically diversified from FPL's service territory.

Q. If these contracts are not approved, how would FPL meet the 930 MW need left by the loss of the UPS Agreement?

A. It is likely that FPL would either purchase power from one or more yet-to-be-built gas-fired facilities, or self-build a combined cycle unit to meet this need. The latter alternative would be equivalent to accelerating the self-build combined cycle additions shown in the 2004 Ten Year Site Plan.

Q. How do the costs of FPL's self-build option compare versus the cost of the contracts proposed for approval?

A. If we were to consider only the costs that can be readily quantified, accelerating FPL's self-build plan could result in lower costs of between $69 and $93 million (2004 NPV). However, this would ignore a number of the benefits of the Southern contracts that are not easily quantified but represent real opportunities and value for FPL's customers. First, the contracts provide approximately 165 MW of firm coal capacity, with the potential to obtain additional firm coal capacity as well as the opportunity to purchase additional coal-based energy on an as-available basis, which reduces our customers' exposure to natural gas price volatility. Second, the contracts are a short term commitment and therefore give FPL the option of moving to other fuels at their expiry when new solid fuel generation is possible, whereas a self-build option for 2010 would involve a long term commitment to additional gas-fired capacity. Third, they enhance system reliability through availability of additional firm gas transportation on a different pipeline system, as well as the ability to purchase energy outside Florida and transmit it to meet our customers' needs. Fourth, they enable FPL to maintain firm transmission capacity which will allow FPL to purchase cost effective capacity and energy in the SERC region after these contracts expire. Given these benefits, I believe that entering into these three contracts is in our customers' best interests.

Q. Putting aside the benefits you have described above, what have you done to satisfy yourself that the costs of the contracts are reasonable?

A. I have satisfied myself that the costs of these contracts would be reasonable based on my review of the market for merchant generation in the SERC region, recent publicly disclosed power purchase agreements for energy and capacity in the SERC region, and indications of interest from merchant generators. In addition, I oversaw an evaluation of the contracts against offers received by FPL in the last RFP conducted relative to FPL's 2007 need for incremental capacity.

Q. It has been reported in the trade press that there is a "glut" of merchant generation in the SERC region. Did you evaluate the potential for meeting FPL's firm capacity needs with purchases from merchant generation in that region?

A. Yes, I did. In assessing this alternative, I began by identifying thirty four merchant facilities with a combined capacity of over 26,000 MW. Of this total, I identified a total of 4,200 MW from eight simple cycle peaker units, eliminating this output from the total merchant capacity in the region. This is because the cost of firm gas transportation and firm transmission would be uneconomic for the anticipated run time of peakers in the market. Of the remaining 21,800 MW, I concluded that 16,400 MW would be from units that either are in locations where the transmission path to FPL would be constrained, or are not directly connected to The Southern Company system and consequently FPL's transmission roll-over rights would not be applicable. Of the remaining 5,800 MW, 620 MW is known to be under contract past 2010. The Franklin and Harris units represent 47% of the remaining merchant capacity in the SERC region. Document TLH - 5 summarizes the units examined.

In summary, while there is a large amount of merchant generation capacity in SERC, only a small percentage of this generation capacity could cost effectively be used to meet FPL's customer loads.

Q. How does the price of the proposed power purchase agreements compare to the prices of recent publicly disclosed power purchase agreements in the SERC region?

A. Publicly available information is very limited on merchant transactions. However, capacity prices were publicly available on contracts for three gas facilities. Quarterly sales of energy and capacity are reported to the FERC by all merchant generators. The Tenaska Lindsey Hill and Central Alabama units report prices that are higher than the prices reflected in the Harris and Franklin Contracts when the respective operating characteristics are taken into account. The most complete public disclosure was a transaction between Southern Power Company and Georgia Power in June, 2002. Disclosed in Docket ER03-713-000 at the FERC, the capacity price for the CCGT McIntosh Units 10 and 11 was $69/kW-year. After allowance for 3% per annum inflation between that time and 2010, when the contracts begin to deliver energy and capacity to our system, the Southern Power-Georgia Power capacity price would be $7.28/kW-month, which is higher than the contracts' comparable costs.

Q. Please explain how FPL's solicitation of indicative offers provided you with comfort that the Southern contracts' pricing is reasonable.

A. In connection with its effort to determine possible sources of replacement power for the UPS Agreement upon its expiration, FPL sought indications of pricing from several owners of existing merchant facilities that have no known transmission constraints. FPL received only one expression of interest, at an indicative price of $6.21/kW-month, but with a heat rate that is higher than Harris' or Franklin's contract heat rate. When the heat rate differences are considered, the Southern contracts are more cost-effective. I believe that we received such limited interest due to the timing of our interest. We are interested in meeting a 2010 need, while owners of existing merchant assets are not currently interested in time horizons that far in the future. The futures market for wholesale electricity transactions has only a two or three year horizon. If we were looking to purchase wholesale energy for 2006 or 2007, we may have solicited some interest. Alternatively, if we were to wait until 2007 or 2008 to solicit for our 2010 need, we may generate some interest. But by then, there is no assurance that the benefits of these contracts will still be available to FPL. To obtain the benefits I have described in my testimony, we must decide now.

Q. Please explain the analysis you oversaw to compare the costs of these contracts to the costs of other offers received in response to FPL's most recent RFP for supply options.

A. An economic analysis was performed to compare the costs of these contracts against the most comparable offer from the 2003 RFP (a 1,220 MW 15 year PPA), using methods consistent with those used in the RFP evaluation, but using the current economic assumptions. Depending upon the level of off-peak purchases from the market, on a straight economic comparison these three contracts are more cost effective for our customers by between $4 million and $51 million, net present value in 2004 dollars. These figures include arbitrage savings, transmission interconnection and integration costs, capacity losses, marginal energy losses, increased operating costs due to locational issues, and net equity adjustment. This difference does not reflect all the other benefits that FPL's customers receive as a result of the contracts. This analysis is summarized in my Document TLH - 6.

Q. Please summarize your testimony.

A. The Franklin, Harris and Scherer Contracts have been entered into for the purpose of replacing the 930 MW FPL currently receives under the UPS Agreement that terminates May 31, 2010. The benefits of these contracts are significant and include a reduction in energy price volatility due to the firm coal component, as well as the ability to purchase low cost base load energy from the SERC region during the off-peak periods. These contracts also provide increased system reliability due to the ability to purchase power from outside the State, as well as delivery of gas to these units via a pipeline that is independent of the two existing pipelines in Florida. The shorter term nature of the contracts allows us to broaden the range of generation options for the future as opposed to an accelerated commitment to additional natural gas generation in 2010. Further, these contracts enable FPL to retain firm transmission rights that will give FPL greater resource choices in the future. FPL believes that these benefits more than offset any perceived advantages associated with accelerating the construction of combined cycle self-build options listed in its Ten Year Site Plan, thus making the Scherer, Harris and Franklin Contracts the best alternative for FPL's customers.

To compare these three contracts to the "market," I assessed the availability of generating resources in the SERC region and determined that only a small portion of the total installed capacity in that region might be available to replace the UPS Agreement and also meet FPL's objective of preserving its firm transmission rights from the SERC region. I further determined that these "market" alternatives were less beneficial than the three contracts.

To test the reasonableness of the contracts' costs, I compared the contract pricing with the limited available information on market-based contracts in the Southern territory, and compared the economics to a competitive bid obtained in the 2003 RFP. Based on this review, I am satisfied that the costs of the contracts are reasonable. Given the benefits offered by the contracts and the reasonableness of the contracts' costs, I recommend that the Commission approve the contracts for purposes of cost recovery.

Q. Does that conclude your testimony?

A. Yes

BY MR. LITCHFIELD:

Q Mr. Hartman, have you prepared a summary of your direct testimony?

A Yes, I have.

Q Would you please provide that to the Commission.

CHAIRMAN BAEZ: Can I just interject one moment here. And this is a question, perhaps, that I should have asked earlier, but seeing -- I think it is only Mr. Hartman that actually has direct and rebuttal. We are not taking direct and rebuttal, am I to understand we are not taking direct and rebuttal together at this point?

MR. LITCHFIELD: That is correct.

CHAIRMAN BAEZ: So you anticipate having Mr. Hartman up again?

MR. LITCHFIELD: Yes.

CHAIRMAN BAEZ: Very well.

Go ahead, Mr. Hartman. I'm sorry.

A Good afternoon, Commissioners. FPL is asking the Commission to approve three power purchase agreements for recovery of costs from our customers. FPL has entered into those contracts to continue to provide our customers as many of the benefits as possible of the expiring unit power sales agreement in a cost-effective manner.

The existing UPS agreements expire in 2010 and provides 930 megawatts of energy and capacity from coal units owned by the Southern Companies. The new contracts include 165 megawatts of coal-fired capacity from the Scherer unit, 190 megawatts of capacity from the gas-fired Franklin unit, and 600 megawatts of capacity from the gas-fired Harris unit. All three units are owned by affiliates of the Southern Company. Energy and capacity would start flowing to our customers in June of 2010 and continue until the end of December 2015. We have an option to extend the Franklin/Harris contracts for an additional two years.

All three of the contracts are similar. In all three the energy is fully dispatchable by FPL to serve our customers, and the capacity payments are fixed over the term of the contracts. Variable operations and maintenance costs are a fixed number for the Harris and Franklin units, which escalates at a fixed rate during the contract period. Variable O&M is provided at cost for the Scherer contract.

Fuel for the Harris and Franklin units is priced at an index price and then charged based upon contractually established heat rates. Fuel for the Scherer plant is the priced at cost. The contracts provide for the delivery of fuel to the Franklin and Harris plants using firm gas transportation at Southern's cost of transportation. Additionally, we have filed to obtain firm electric transmission rights to bring the energy and capacity from the plants to our system. Transmission costs will be governed by Southern's open access transmission tariff.

There are two conditions which remain to be met under these contracts. The first is approval of these contracts by this Commission for recovery of costs. The second condition is obtaining the needed electric transmission capacity by December 2005. From a cost-effectiveness perspective these contracts compare well to available cost references. These contracts are below the costs that would result from publicly available PPA prices for other contracts in Southern's territory.

They are more cost-effective for our customers than the most relevant offer we received in our most recent RFP. While we might be able to build a self-built gas unit that could provide energy at 69 to $93 million lower cost on a net present value, we believe there are a number of benefits from these contracts that while difficult to quantify are nonetheless real and whose value outweighs this difference.

Let me briefly address these benefits. First, our customers will have the benefit of 165 megawatts of firm coal-fired generation in FPL's portfolio, with the potential for additional coal generation under the rights of first refusal. Second, our customers will benefit from firm transmission in Southern, providing the capability to purchase energy on the market when economically justified. Third, the contracts will enhance reliability for our customers through the capability of procuring energy from outside the state as well as the use of a third gas pipeline independent of the two existing gas pipelines in Florida. Lastly, we will be able to defer committing to a gas-based energy source, preserving a certain amount of flexibility to consider and implement other technologies.

Given the benefits offered by the contracts and the reasonableness of the contracts cost, I believe they are in our customers' best interest and recommend the Commission approve the contracts for the purposes of cost-recovery.

CHAIRMAN BAEZ: Mr. Litchfield, do you tender the witness?

MR. LITCHFIELD: Does that conclude your summary, Mr. Hartman?

THE WITNESS: Yes.

MR. LITCHFIELD: We would submit the witness for questioning.

CHAIRMAN BAEZ: I'm going to take OPC first.

MS. CHRISTENSEN: OPC has no questions at this time.

CHAIRMAN BAEZ: Okay. Ms. Kaufman and Mr. McGlothlin.

MR. McGLOTHLIN: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q Mr. Hartman, I'm Joe McGlothlin. With Ms. Kaufman I represent the Florida Industrial Power Users Group in this case. I want to refer you first to Page 6 of your direct testimony. At Line 9 this question appears: Are there any contingencies or conditions precedent in the contracts that you wish to bring to the Commission's attention. And in your summary you mentioned the condition of the transmission rights and also of the approval by the Commission, is that correct?

A That is correct.

Q But isn't it true, sir, that neither of those factors is a contingency or condition precedent in the sense of something that is required for the contracts to be effective and valid? In other words, each of these conditions enables FPL to take the affirmative act to terminate the contract, but if that decision is not made, then the contracts are effective, is that correct?

A That is correct.

Q Again, at Page 6, Lines 13 to 15, you state if FPL is unable to obtain adequate and firm transmission by a date certain, and at an acceptable cost, FPL has the right to terminate the contracts.

Now, the outside date contemplated by the parties for the receipt of firm transmission at an acceptable cost is December 1st, 2005, is that correct?

A That's correct.

Q And in the event that the firm transmission is either unavailable or is not at an acceptable cost, or both, FPL can terminate the contract at that point?

A That is not precisely correct, but let me explain just a minute. First of all, it is highly unlikely that that is going to occur. But there are some provisions in the contract where if we don't have, for example, we don't get from Southern Transmission enough transmission capacity to handle what we need under this contract, the seller of the contract, Southern Company, can make transmission available to us that they have in addition to what we have applied for. So there are some other provisions that we just wouldn't necessarily terminate.

Q Yes. I understand that you would not necessarily terminate, but if FPL is unable to obtain adequate firm transmission and at an acceptable cost by December 1st, 2005, the arrangements of the contract contemplate that FPL would have the right to terminate at that point, correct, whether it exercises that right or not?

A If we don't have enough transmission and the seller doesn't provide us enough transmission, under certain circumstances Southern would actually be the one terminating the contract.

Q Well, what does this phrase mean, Mr. Hartman, if FPL is unable to obtain adequate firm transmission by a date certain and at an acceptable cost, FPL, not Southern, FPL has the right to terminate the contracts? Is that a true statement?

A We would have the right to terminate the contract if we don't have it. There are also certain circumstances under which Southern would have the right to terminate the contract.

Q But, in any event, FPL has the contractual right to terminate the contract in that event?

A In that event, yes.

Q And if that scenario unfolded in that way, and FPL for whatever reason exercised its right to terminate the contract at about December 1st, 2005, is it true that at that point, December 1st, 2005, Southern Company would be in the position of placing this capacity represented by the UPS contracts on the market?

A Could you clarify what you mean by the UPS contracts?

Q I'm talking about the three proposed UPS contracts that you are sponsoring in this case.

A Absent this agreement, absent the agreements that we have signed with Southern Company, those units would be in the market in that period of time in any case. The Scherer unit has already been in the market for some of the capacity. The Franklin and Harris units are merchant units and would be in the market in any instance. So all we are doing is tying up units that were already in the market.

Q My question is, sir, is it true that the capacity associated with the three UPS contracts that you are sponsoring in this case, in the event that FPL exercised its right to terminate in December 2005, is it true that Southern would be in a position of placing the capacity on the market at that point?

A Yes, they would be.

Q And that is contemplated by the terms of the contracts that you are supporting, correct?

A The contracts that we are supporting contemplate the fact that we would wind up, if we can't get adequate transmission by December, not having contracts. To the best of my knowledge that wasn't being driven by Southern, it was being driven by our need to make sure that come 2010 we have capacity available for our customers. If we don't have firm transmission and a firm agreement for this capacity by December of 2005 we are in a position where we are going to have to come up with a self-build or something else, and we need to know what that is by the end of next year.

Q So to answer my question, the scenario that I described in which Southern Company would be in the position of placing this same UPS capacity on the market in December 2005 is contemplated by the terms of the contract you are supporting?

A What is contemplated is the contracts go away in December of 2005 if we don't have transmission and approval for recovery of these contracts by the FPSC.

Q So to answer my question specifically, is it true that the scenario in which Southern Company would be in the position of placing capacity on the market December 2005 is contemplated by the arrangements that you are sponsoring in this case?

A The arrangements that we are sponsoring in this case would result in Southern Company having this capacity on the market. Southern Company has several thousand other megawatts of capacity on the market. These units that we have currently tied up under contract would no longer be under contract at the end of December, that's correct.

Q I believe you answered that's correct to my question?

A The units would no longer be under contract to us in December. I would assume they would then be in the market.

Q As a consequence of the exercise of the rights under these contracts?

A As a consequence of the fact that the contracts would no longer exist.

Q Because you would have acted to terminate them?

A Because they have terminated.

Q Thank you, sir. At Page 9, Line 7, you state that under these proposed contracts FPL would maintain 165 megawatts of coal-fired capacity, is that correct?

A That's correct.

Q Would you agree with me that taking into account the total package that is 995 megawatts, the coal-fired component represents about 17.28 percent of the total?

A That's correct.

Q Beginning at Page 16 and through Page 19 of your direct testimony, you describe some activities with respect to comparing alternative sources in the SERC area. It's true, is it not, that FPL did not engage in any bilateral negotiations with anybody in SERC when comparing the proposed UPS contracts to alternatives?

A We did not get into bilateral negotiations with anyone.

Q As I understand it, you received one indicative price from a merchant in SERC, is that correct?

A That is correct. We sought several others, only one responded with an indicative price.

Q Now, is it true that an indicative price is a term used to describe what parties understand to be an opening round with the expectations that negotiations will follow?

A An indicative price is the beginning stage of negotiations.

Q So it is not by any means regarded by either party as the bottom line, is it?

A It is not a binding offer by either party.

Q At Page 19, beginning at Line 1, you describe this indicative price at 6.21 per kW month, and you state when the heat rate differences are considered, the Southern contracts are more cost-effective. Do I understand from that statement, sir, that on a pure price basis this 6.21 kW per month indicative price was competitive with the price of the UPS contract?

MR. LITCHFIELD: I will object to the form of the question. I think it is vague, Commissioner Baez. I don't know what he means by pure price basis.

CHAIRMAN BAEZ: Can you work on it a little, Mr. McGlothlin?

MR. McGLOTHLIN: Yes, sir.

BY MR. McGLOTHLIN:

Q Do I understand correctly that when one looks only at the indicative price of 6.21 per kW month and compares that only to the corresponding price of the UPS contracts, the indicative price is competitive?

A First of all, $6.21 a kilowatt month is an indicative capacity price. That has very little to do with the total cost to our customers. You are trying to compare one very small part. For example, there is scheduling, there is the amount of scheduling we can do, there is start-up cost, there is heat rate, all of which can have a bigger impact on our customers than just a 6.21 capacity price. There are units out there with much lower capacity prices than that that are much worse deals because the heat rates are very high. You can't just compare the one figure.

Q But for purposes of my question compare only the one figure. Would it be competitive?

A One figure is -- well, first of all, the 6.21 is competitive to what is in our contract numbers.

Q Okay.

A But as I pointed out, that is the same as trying to compare, you know, a rental car, one that gives you free mileage and one that costs you 50 cents a mile. Comparing the daily rental rate is not a valid comparison of the cost.

Q Well, let's look at your next statement. You say when the heat rate differences are considered, the Southern contracts are more cost-effective. Now, that statement takes into account more than the capacity price, does it not?

A It does.

Q And do I understand correctly from this statement that absent the application of the heat rate differences and adjustments, the Southern contracts would not be more cost-effective?

A No, you don't understand that. Okay. What I said was the 6.21, just looking at a capacity price, was competitive and very close to what we are looking at here, although the prices here are confidential. What I'm telling you is whenever you include the fact that we have a different heat rate, the Southern contracts are much more cost-effective.

Q But isn't it true, sir, that when you made this comparison, you were using the final negotiated price of the UPS contract?

A That's correct.

Q And you were comparing it to an indicative price which you had reason to believe was not the lowest best offer from the source, is that correct?

A You are looking at a capacity price. You also have to take a look at the heat rate and other aspects associated with it. I assume in final negotiations numbers would change, okay, but just because they change doesn't mean that they necessarily always go down. For example, dispatch rates. These units are sitting there at, for example, a minimum 16-hour dispatch, okay. If I have a shorter minimum dispatch, then I could expect the capacity price to go up because they are going to have to cover the difference in cost somewhere or the other.

You start looking at nonprice factors, and they can make a significant difference in what you are actually looking at in your term sheet. Did I expect their numbers to change? Yes. Which direction it would change? I don't know because the contract terms never were negotiated.

Q Well, a few moments ago you agreed with me that an indicative price was the opening round that both parties expected to be negotiated further.

A And I can negotiate -- prices can go in both directions. If I tighten up certain nonprice terms, I can wind up with higher prices. So, for example, if I tighten up financial concerns, the amount of security they have to put up, if I tighten up the dispatch flexibility that I want, I can wind up with numbers like this 6.21, or start costs, or other numbers that actually get higher, but might provide a net benefit to my customers.

Q Based on your response, are you saying that when you receive the indicative price of 6.21 per kW month you expected the price to go up in negotiations?

A Based on what they had in their indicative price against what I had with the Southern Company, if they were down to the same sort of terms I would expect their prices to have to go up as to what they had.

Q At Page 19, Lines 19 through 21, you state an economic analysis was performed to compare the costs of these contracts against the most comparable offer from the 2003 RFP, a 1,220 megawatt 15-year PPA, using methods consistent with those used in the RFP evaluation, but using the current economic assumptions.

Now, in your prefiled testimony you used the word the most comparable offer. In your summary I heard you say the most relevant offer. In what respect do you believe this offer was the most comparable; was it the size?

A No. It had to do with the configuration of the plant. Several of the other portfolios required that we had to build peaker units in order to support them. This was a stand-alone unit that we could compare.

Q A stand-alone unit.

A In the sense that we didn't have to also build additional assets to support the contract.

Q Was it a dispatchable proposal?

A Both proposals are fully dispatchable.

Q Was it located in SERC or in Florida?

A The last RFP, it was located in Florida.

Q Now, I have heard you say you used the most comparable offer and the most relevant offer. I haven't heard you say you used the most economical offer. Was this particular proposal the one that was viewed to be the most economical alternative of those that were submitted in the RFP?

A Actually, the most economical alternative in the last RFP was our unit, which was the Turkey Point unit.

Q Speaking of the proposals that were submitted for consideration.

A Of the proposals that were submitted, I don't know offhand. This one was very close. The trouble with any of the other units -- not any of the other units -- the trouble with some of the other offers is in order to have those proposals work, we would have to build 600 megawatts down at Turkey

Point. We can't do that because we are now building our unit down at Turkey Point. Whenever you take that out, this was the best offer that was on the table.

Q You say this particular proposal was for 1,220 megawatts. The proposed contracts, the UPS contracts total 955 megawatts, is that correct?

A That's correct.

Q And you expect to receive or net about 931 after losses?

A 930 megawatts at our border, that is correct.

Q The proposal to the 2003 RFP that you said was the most relevant was for 15 years, correct?

A That's correct.

Q These UPS contracts are five and a half years?

A That's correct.

Q Did you make any effort either with reference to the SERC area or in Florida to solicit proposals that would have been closer to the 930 or the five-year duration that you see as attractive in the UPS contracts?

A Well, first, we were looking in SERC in order to have a majority of the benefits of the existing UPS agreement, which is outside of the state, and many of those benefits are associated with having outside-the-state resources and transmission. So, we were looking outside of the state. And, no, we did not go out and specifically solicit. We did check what the market was in terms of looking at other units that were out there. And also the analysis takes care of -- the economic analysis that we used takes place over about a 30-year time frame. So the difference in the tenor of the UPS agreement versus this agreement over that 30-year time frame on a pure economic basis, without including the value of the flexibility that the shorter time gives us, was included in the economic analysis.

Q So the analysis was for 30 years?

A That's correct.

Q I would like for you to turn to -- I think it is Exhibit 18, is the Southern Company offer or economic comparison to the 2003 RFP plant. And does this exhibit display the results of the comparison between the proposal to the 2003 RFP and the UPS contracts?

A Yes, it does.

Q And you have got three scenarios there, the average arbitrage, minimum arbitrage, and maximum arbitrage. Do I understand correctly that those represent three different assumptions with respect to the amount of the economy energy that you would buy from the Southern area if you had the ability to dispatch the UPS contracts?

A That's correct.

Q Now, looking first at the minimum arbitrage scenario, if I read this correctly, the right-hand column indicates that the minimum arbitrage scenario is $4 million less expensive than the proposal, is that correct?

A No, I believe it indicates that it is -- oh, the proposal being the 2003 RFP plant? That's correct. So the UPS, the replacement UPS with our minimum estimated use of economy energy purchases would be a $4 million benefit against the numbers that we received in the 2003 RFP.

Q And looking at the average arbitrage, and, again, looking at the right-hand column, does this indicate that under these assumptions, the average arbitrage scenario of the UPS contracts would be $28 million less expensive than the proposal?

A That's correct.

Q Now, look at the column for the net equity adjustment. Do I understand correctly that for purposes of this comparison FPL attributed to the UPS contracts an equity adjustment, an equity penalty of $17 million?

A That's correct.

Q And FPL attributed to the 2003 RFP proposal an equity adjustment of $58 million?

A That is also correct.

Q So FPL's equity adjustment applied to the RFP submission exceeded that applied to the UPS contract by $41 million?

A Because of the difference in the tenor of the contracts.

Q But the number is $41 million?

A The net present value of the difference of the numbers is $41 million.

Q So does it follow, sir, that with respect to the average arbitrage scenario and the minimum arbitrage scenario, the conclusion that those two UPS scenarios are less expensive than the RFP 2003 submission is dependent upon the proposition that the equity penalty attributable to the RFP submission should be more than three times the amount of the equity penalty attributed to the UPS contract?

A It is dependent upon a number of differences. You will notice also that the transmission losses are much higher for the UPS agreement than what is in here for the RFP plant. We are taking care of that difference. Yes, you do have a difference in the equity adjustment in the cost because the contract is a longer term.

Q So a contract having a shorter duration would have received a lower equity penalty?

A That's correct.

Q But you do not solicit a shorter contract from any source, did you?

A No, we did not.

Q First of all, would you agree with me that the entire subject matter of the equity adjustment or equity penalty has been controversial in PSC proceedings over time?

A It is my understanding that it has been.

Q Would you agree with me that the application or derivation of an equity penalty requires some subjective judgments regarding such things as weighting factors to be incorporated in the calculation?

A No, sir, I would not.

Q Well, isn't it true that there is a requirement that one determine the percentage of the capacity payments to be regarded as the equivalent of debt?

A There is that determination. It is also my understanding that Standard and Poors has determined that and pretty much told everybody what the numbers are going to be. There isn't a determination as far as some of the regulatory characteristics of the state.

Q Are you saying that Standard and Poors has dictated that a hard and fast percentage be applied to the calculation of the debt equivalents?

A It is my understanding that Standard and Poors has established some guidelines for calculation of the equity adjustment, or actually the balance sheet implications of having the contracts with the company.

Q Are you familiar with the -- let me back up. You have indicated that the particular submission -- that the particular proposal being evaluated was one that was submitted to the 2003 RFP, correct?

A That's correct.

Q The 2003 RFP was the one that culminated in the selection of the Manatee and Martin units, is that correct?

A No, it is the one that has culminated in the selection of the Turkey Point unit. It is for our 2007 need.

Q I see. Are you aware that in the order approving the Manatee and Martin units the Commission declined to apply any equity penalty?

A No, I wasn't aware of that.

Q Would you accept that subject to check?

A Subject to check.

MR. McGLOTHLIN: And in conjunction with that question, Commissioners, I ask the Commission to officially recognize its Order Number PSC-02-1743-FOF-EI in Docket Numbers 020262 and 020263.

CHAIRMAN BAEZ: So noticed. Mr. McGlothlin, do you intend on referring to the orders as part of your cross?

MR. McGLOTHLIN: No, sir. When the witness agreed to accept subject to check, that's, I think, all I need.

CHAIRMAN BAEZ: Okay.

BY MR. McGLOTHLIN:

Q Mr. Hartman, the proposal for the 2003 RFP that was used to compare in this exhibit was for 1,220 megawatts. Was an adjustment made for the difference in megawatts in order to compare the cost of each?

A Implicit in the analysis that adjustment is made in the sense that we monitor, or actually we model the total cost to our customers of the units being on the system. So to the extent we had a 1,200-megawatt unit coming on and this is 930 at our border, it would then shift when we needed the next unit and what the cost would be, et cetera, on it.

Q In your testimony you also describe a comparison between the proposed UPS contracts and the company's self-build option, do you not?

A Yes, I do.

Q I have a series of questions that relate to a document that has already been identified as an exhibit. I believe it is Staff's Composite Stipulation Number 2. It's Question 46. The answer to Question 46 in staff's fifth set of interrogatories. I have some copies here if parties don't have it readily available.

Mr. Hartman, do you have that in front of you?

A Yes, I do.

Q My questions relate to the table at the bottom of Page 1 and the definitions on the following pages, primarily Page 2. First, I want to refer you in the table to the line item on the left-hand side called potential benefit of SERC transmission. And then referring to the definition or description on Page 2 of that, you state that FPL will be able to use the firm transmission obtained through the PPAs to purchase economy energy in SERC and wheel it to its customers in Florida, a practice referred to as arbitrage. FPL estimates the value of this arbitrage opportunity at a high of $83 million and an average of $60 million.

Do I understand correctly, Mr. Hartman, that the firm transmission rights that you are seeking in conjunction with the UPS contracts are point-to-point in nature?

A Yes, they are.

Q And the delivery points are located at the generating units that will be supplying the UPS capacity and energy, is that correct?

A That is correct.

Q Now, as I understand it, this line item for the potential benefit of SERC transmission comes into play during those hours in which there are opportunities to decrease the generation from the units identified in the UPS contracts and purchase cheaper energy elsewhere in the SERC area, is that correct?

A That's correct.

Q My question to you is this, sir. If the firm transmission rights are in the nature of point-to-point rights, and the economy energy is being obtained from units other than those identified in the contracts, would the firm transmission rights encompass all of the transmission costs associated with those transactions, or would there be additional wheeling costs incurred to get the power from the additional units to a point where you can put them on your transmission rights?

A No, the existing firm transmission rights that we are filing for would accommodate everything we need. There would be no additional cost.

Q And is that because the units that will be the source of economy energy are located on the path of the firm transmission rights?

A No, it is because once we have the firm transmission rights under Southern's tariff, we can redirect it firm 24 hours ahead at no cost.

Q You will have to restate that for me in less technical terms.

A The primary issue on the transmission rights and the reason why they are so valuable is there is restrictions on getting the power from Southern's territory into Florida. That is where a real bottleneck is and limited capacity. Under Southern's tariff, once we have firm transmission rights from the units under contract into Florida, we can then go ahead and a day ahead of time tell them we want it from a different unit and still get it firm, which means they will guarantee us the power. On an hour ahead of time basis we can get it on an interruptible basis and redirect it. So once we have the firm transmission rights, we have a great deal of flexibility as to where we can take the power from Southern's system.

Q Now look at the line item called marginal energy and capacity losses due to wheeling by others. And this amounts to $117 million? And if I am reading this correctly, this is a penalty item associated with the UPS contracts, is that correct?

A Well, you will see the same figure in two places, energy and capacity losses up above, and marginal energy capacity losses due to wheeling by others. In both cases it is a marginal energy loss on our system. And the reason why it is down here against the self-build also is we recognize the value of the transmission assets that we can make. Basically, it is worth $83 million on a net present value to us today. If we self-build, we lose that transmission. We also lose the firm transmission and somebody else now has the right to bring it in across our system also. So we don't anticipate that the losses that we would see on our system due to these contracts would just disappear if the contracts went away. Other people would be wheeling the power in and the losses would stay relatively unchanged.

Q On Page 2, looking at the description of that line item, you state, "If FPL were to elect a self-build unit instead of the PPAs, the transmission capacity FPL currently utilizes to supply our customers for the existing UPS agreement would become available. In such circumstance it is reasonable to expect that third parties would utilize the transmission capability to import power from SERC, and the losses associated with such a transaction would still be experienced."

And if I understand it correctly, the balance of the description there explains that while those third parties would be responsible for the average transmission losses associated with their usage, you would, in fact, incur higher marginal losses associated with the usage which FPL would absorb, is that correct?

A For comparison with the RFP units, and in accord with past practices, for evaluating this we use marginal losses on our transmission system. What we recover from customers that are wheeling on our system are average losses, so if we are comparing a self-build unit to the UPS agreement on a consistent basis with our other practice, we use a marginal loss calculation to represent the losses on our system and then we have to look at the recovery that we would get on an average.

Q I believe we said the same thing, but let me follow up for a second. I believe you said that under the tariff the third parties that would be using your transmission system because it is now freed up, you are self-build and you are no longer hauling energy from Southern to FPL's service area would compensate FPL only for the average value for losses in its tariff, is that correct?

A That's correct.

Q But that is not the only payment that you would receive from third parties who were using your transmission system, is it, sir?

A Which other ones are you referring to?

Q This is a self-build scenario. Because you are self-building and generating power within your service area, you are no longer using your transmission system to haul from Southern Company. That transmission system is freed up. You have to post it as available to other potential users. They come on board. They use it. They pay you more than the average losses associated with their use, don't they?

A It depends on the customer.

Q Well, you will have to explain that to me.

A We have network customers that are already taking service. We have customers already with firm service. To the extent that a network customer starts bringing in the power on our network along this path, they are already a network customer, they are already paying the tariffs for the network service and now we have the losses.

Q Okay. And are there customers other than network customer who would be using your system?

A There are customers other than network customers that use our system.

Q And, in that event, would there be incremental revenues associated with their use?

A Yes, there could be.

Q Has that been reflected on this schedule?

A No, it has not been.

Q To the extent that the decision to self-build frees up transmission and makes possible transactions in which third parties would be using your transmission and paying you incremental revenues, should that revenue figure be incorporated in this comparison?

A To the extent we had somebody with incremental revenues, yes. That is not necessarily the case, however.

Q Not necessarily the case. A moment ago I think you agreed that it is possible that users other than network users would use your system and pay you incremental revenues, is that a possibility?

A That is possible.

Q And that is not something you have attempted to estimate or incorporate into the schedule?

A No, it is not.

Q On Page 3 you have this final note, "It is important to note that this differential does not reflect any value for the other benefits of the PPAs that are not provided by a self-build alternative. These benefits include retention of some firm coal-fired capacity as part of the contracts."

Would not the quantification of generation costs associated with the UPS scenario incorporate the value of having firm in the arrangement, the value of having coal in the arrangement?

A Not the value of coal as opposed to any other energy source. It doesn't reflect the reduced volatility value to our customers of coal versus natural gas, for example. It doesn't reflect the physical capabilities of coal if you have a natural gas interruption. It doesn't reflect just the pure value to our customers of having a variety of energy sources rather than being dependent upon just one.

Q Looking at the line item called system generation model differential, is that a quantification of the cost of generation over the time period measured in this analysis?

A Yes, it is.

Q Would that capture the difference between the generation based on coal, that amount of coal incorporated in the UPS contracts as opposed to the self-build option?

A It would capture the pure economic numbers of the difference in energy price forecasts between coal and the rest of our system. As I mentioned, it doesn't capture the other benefits of fuel diversity to our customers.

Q You mention in this last note on Page 3 one of the benefits is the planning flexibility afforded by these short-term contracts, especially when combined with long-term commitments as part of an overall strategy. You are referring there to the duration of the five and a half years for the UPS contracts?

A That's correct.

Q But you would have that flexibility with any PPA of a duration of five, five and a half years, not necessarily limited to the UPS contracts, is that correct?

A That's correct.

Q You also mention enhanced system reliability through the geographic diversity of the PPA, excuse me, of the PPA units. One can achieve diversity, geographic diversity if it is desirable with units other than the three units in the UPS contracts, is that true?

A That's true.

Q And isn't it true that as recently as the most recent RFPs, FPL expressed a reference for units located near its load centers?

A Yes, we have. And these contracts were evaluated on exactly the same method as used in the last one. All the cost figures you are quoting, the difference in prices incorporate the same sort of analysis that was used in the last RFP.

Q I want to back up for a second to Exhibit 18, which is a comparison between the Southern Company UPS offer and the bid into the 2003 RFP. With respect to the UPS offer, in each scenario you have assumed some arbitrage of varying quantities, is that correct?

A That's correct.

Q I believe you said that the proposal into the 2003 RFP was a dispatchable unit, is that correct?

A That's correct.

Q And I believe you said earlier also that the ability to arbitrage is in large measure a function of the dispatchability of the units, is that correct?

A That's correct.

Q If you were to contract with the proposal into the 2003 RFP, wouldn't it be fair to assume that because that is a dispatchable unit there would be some arbitrage opportunities?

A No, because the arbitrage we are looking at here is a price difference between Southern's territory and Florida, and we would lose the transmission and the transmission is what allows us to have that value.

Q Do you believe there are opportunities for arbitrage within the State of Florida?

A If you are saying that there are, we would still have that even with these contracts. So even if we have the UPS, and you are saying that hypothetically there are additional arbitrage opportunities inside the State of Florida, we would have those also with this agreement.

Q No, I think you misunderstood my question. The question assumes that rather than enter the UPS contracts you have opted for this 2003 RFP proposal, which is a dispatchable unit located in Florida. Recognizing that the price differential between SERC and Florida is not at play, isn't it nonetheless likely that there are some arbitrage opportunities by backing off the generation from the RFP plant and buying elsewhere in Florida when the price differential makes that arbitrage possible?

A Well, first of all, the economic model that we use already dispatches the plant economically, at least against our system. So one of the issues is some of that is already incorporated in our economic analysis on both sides. Secondly, to the extent that there is additional arbitrage capabilities within the State of Florida, whatever they might be, and you attribute some additional value to the RFP plant, that same value would also be attributable to the UPS plant because nothing there keeps us from doing the same trading within the State of Florida also.

Q Yes, sir. But isn't it true that with respect to the UPS contracts you have assumed varying degrees of arbitrage in each of the three scenarios, whereas with respect to the 2003 RFP plant you have made no assumption regarding arbitrage?

A The arbitrage is between SERC, or Southern's territory, and our territory. That does not exist with the 2003 RFP plant.

Q One type of arbitrage exists between SERC and Florida. But I think a moment ago you agreed that even within

Florida there are some arbitrage opportunities. Aren't there some hours in which it is likely that there are some opportunities to purchase at prices cheaper than one generates with the RFP proposal?

A Potentially so. That same opportunity would exist also with the UPS agreement to arbitrage, as you said, within the State of Florida. So you would be looking at subtracting the same number from both sides of the analysis. It wouldn't make any difference.

CHAIRMAN BAEZ: Mr. McGlothlin, are you at a good breaking point?

MR. McGLOTHLIN: Certainly.

CHAIRMAN BAEZ: All right. We will take ten minutes. Before we recess, it is my plan to shut down as close to 6:00 as possible tonight and maybe we can get this wrapped up tomorrow morning. That is the plan, so be advised. Thank you. We will break for ten minutes.

(Recess.)

CHAIRMAN BAEZ: We are ready to go back on the record.

Mr. McGlothlin, you can proceed.

MR. McGLOTHLIN: Thank you. Mr. Hartman, I have only a few more questions for you.

BY MR. McGLOTHLIN:

Q Would you refer to Exhibit 16, which I believe is

TLH-4, the graph as captioned, "2003 off-peak price spread between Florida and southeastern SERC."

A Yes.

Q And my first question is simply would you take a moment and briefly describe what Exhibit 16 is intended to portray?

A Excuse me. Exhibit 16, TLH-4 is publicly available statistics as far as price differences for off-peak power between the southeastern part of SERC, which is basically Southern's territory, and reported pricing in the FRCC on a daily basis in terms of dollars per megawatt hour for the energy price. So if you take a look there is a date in there, say just before January, you will see that there is a price spike up there of about $10.50 per megawatt hour. So it is saying that you could buy energy for $10.50 a megawatt hour cheaper in Southern's territory than you could buy it in Florida.

Q Or said slightly differently, generators in the southeastern SERC have opportunities to sell at favorable prices in Florida?

A If you had the transmission, yes.

Q Do the bars reflect some averages that are calculated in a given day?

A No. These are the off-peak prices. So each day a price is reported off-peak and on-peak hours. So these would be the off-peak hours, so it would be averaged over that period of time.

Q Are there ever any occasions when the off-peak price in Florida is less than the corresponding off-peak price in SERC?

A Yes, there are.

Q And would this graph depict that?

A No, it doesn't. However, let me clarify one thing. You can see there is a couple of points in the graph, not too many, where there is basically no bar. And those are basically times whenever the off-peak power in Florida was less expensive than the off-peak power, basically, in Georgia or Alabama.

Q But on an overall basis, do I understand correctly that the purpose of the graph is to describe a situation which, generally speaking, the prices in Florida are higher than prices in Georgia?

A That's correct, off-peak at least.

Q That being the case, would you agree with me that generators located in the southeastern SERC have an incentive to enter transactions with buyers in Florida?

A If they had transmission. The value, this price difference between southeastern SERC and Florida is capable of being captured by those with the transmission access.

Q Yes. And assume for a moment for purposes of the next question that FPL is not the one that has the firm transmission rights that it seeks here. That being the case, wouldn't generators in the southeastern SERC attempt to obtain the transmission necessary to make these favorable transactions occur?

A Yes, they would.

Q And to the extent they can obtain the transmission rights and enter those transactions with FPL and others, the benefits would be the same irrespective of who owned those transmission rights, correct?

A The benefits go to the transmission owner. Whoever holds the transmission rights will achieve those benefits.

Q But in terms of the favorable, more favorably priced power, the benefits would enure to the purchasing utility, would they not?

A Could you clarify that a little bit?

Q Yes. Regardless of whether the transmission rights are controlled by FPL or perhaps by a merchant in SERC, when a generator in SERC sells to Florida at a price that is better than can be had in Florida, that advantage enures to the purchasing utility and its ratepayers regardless of who controls the transmission?

A Some potential benefit might enure to the benefit of the utility, but the maximum amount of the benefit is going to go to whoever has the transmission. If I am a merchant generator up in southeastern Georgia, and I have a $10 price advantage that I can capture due to the fact that I own the transmission rights, I'm going to pocket most of that $10 myself because I can sell for 50 cents under the market and sell all I want. So why would I sell it for less than that if I can pocket the $9.50 profit myself? The profit on transmission, on arbitraging the market belongs to the people that have the right to transfer that power and capture the price difference.

Q Well, the people who have the transmission rights have the ability to deliver their power to the purchasing utility in Florida?

A That's correct.

Q And at a price that will have been determined to be favorable by the parties to the transaction?

A That is correct.

Q And how is that different when the entity in SERC has the transmission rights for the transaction as opposed to when FPL has the transmission rights?

A I think I pointed out that the value of the arbitrage, the value of this price spread goes to the person that owns the rights to create that price spread, and that is the transmission owner. If an entity up in SERC has that right, they have captured the value. How much they share with our customers is a matter of negotiation. If we own the transmission rights, how much we share with our customers is a matter of the fact that they get all of it

Q All of the --

A All of the benefits of the transmission rights. So if we are looking at a $10 price spread, our customers see that $10 advantage, not some amount less whatever the person on the other side would be willing to pocket. Also, the transmission owner, if it is somebody other than us, they have the right to then redirect the transmission and choose other sources that would be cheaper, okay. And, again, that is something that we get to do for our customers. So the fact that there is a price spread is historic and it has been there. Who captures the value of that price spread depends on who can produce the economic results from it, and that is the transmission owner.

Q You state several times in your prefiled testimony that you are trying to continue the same or similar benefits that are associated with the existing UPS contracts, and to that end you proposed these new UPS contracts. And you identify the benefits associated with having the firm transmission rights, primarily, and then some others.

Would you agree that it is possible for a transaction to provide benefits that are different in nature and yet perhaps equally valuable to the benefits associated with the UPS contracts?

MR. LITCHFIELD: I will object to the question. I think it is vague. I'm not sure what different in nature means in reference to transmission rights.

CHAIRMAN BAEZ: Can you restate it, Mr. McGlothlin, in a way that is --

BY MR. McGLOTHLIN:

Q Well, for example, you have emphasized the firm transmission rights. Let's assume that there is a different type of transaction, not necessarily the SERC, that doesn't involve firm transmission rights, but has extremely favorable price, hypothetically. Aren't there some situations or aren't there some possibilities of transactions other than the UPS contracts which are different in nature, but have their own set of advantages that could be desirable?

A Well, you can always wind up with different transactions having different advantages. Fundamentally, if you were to use a hypothetical where there was somebody else, you know, inside the State of Florida that offers different power at a different price, et cetera, I'm all in favor of it. We have additional RFPs that are coming out, we have additional needs, I see no reason why not to do both. I mean, if we can capture the benefits of the transmission outside the state and get other benefits on another transaction, good.

MR. McGLOTHLIN: Those are all of our questions.

CHAIRMAN BAEZ: Mr. Moyle.

MR. MOYLE: Can we proceed?

CHAIRMAN BAEZ: I'm sorry?

MR. MOYLE: Do you want me to go on?

CHAIRMAN BAEZ: Yes; absolutely.

CROSS EXAMINATION

BY MR. MOYLE:

Q Mr. Hartman, Jon Moyle representing Mr. Churbuck. On a scale of one to ten, would you rank this deal for me, please?

MR. LITCHFIELD: I will object. That is a very vague question.

CHAIRMAN BAEZ: Let's try it again.

MR. MOYLE: I'm just trying to get a general understanding. Let me do this, let me lay a foundation.

BY MR. LITCHFIELD:

Q Mr. Hartman, you negotiate contracts on behalf of FPL, isn't that correct?

A That's correct.

Q And you have negotiated a lot of contracts?

A I have negotiated a fair number.

Q Like how many?

A For FPL, not very many. For FPL Energy, 20, 25.

Q As we sit here today, given your history in terms of negotiating contracts or whatnot, can you give this Commission an idea as to the relative ranking of this contract based on the ones that you have negotiated? And I will ask you to do it on a scale of one to ten.

MR. LITCHFIELD: I will object. I still think that is very vague. Counsel has not given the witness any firm reference or acceptable index or anything else to frame his answer.

CHAIRMAN BAEZ: Give him something to hang on to so he can tell you how difficult or complex. I'm assuming you are --

MR. MOYLE: Okay.

BY MR. LITCHFIELD:

Q Mr. Hartman, with respect to -- and I will say it for your frame of reference -- all the contracts you have negotiated or have been made aware of, aren't you made aware of other contracts that others negotiate if that information becomes either privately available to you or publicly available, that is information that you sometimes receive, is it not?

A Yes.

Q Do you consider yourself any kind of expert in contract negotiations?

A At least on these contracts, I'm an expert on them.

Q Are you able to rank this contract vis-a-vis other contracts you have negotiated in terms of giving us some insight as to is it a good deal, an okay deal, a great deal, a bad deal? And I was asking, well, those are kind of subjective terms, but I thought a one to ten scale might give you some kind of frame of reference. If you want, maybe use A, B, C, D.

Could you rank this contract vis-a-vis other contracts that you have experience with for me, please?

MR. LITCHFIELD: The same objection.

CHAIRMAN BAEZ: I'm going to let the witness take a stab at it.

A You know, every contract is relatively unique. They all have their own particular attributes. I can say in this case, quite honestly, recommending it for our customers. I am a customer, I'm very pleased with the contract. The company has nothing to gain in this, okay. We wouldn't be doing it if we didn't think it was good for the customers. And management, whenever we were negotiating this, made it quite clear that if we didn't think this was a good thing to do we could kill it at any time. We are bringing this to you because we think it is a very good contract and represents a very good value for our customers.

Q Okay. So one to ten, any numbers in there you can give me?

A No.

Q Okay.

A They are all unique.

Q A, B, C, D, or F, can you rank it with a letter?

A Still unique.

Q Mr. Hartman, have you had an opportunity to read the prehearing order in this case?

A No, I haven't.

Q And I will show you this if you would desire. On Page 4 of the prehearing order in the case there is a statement that says, and I quote, witnesses are reminded that on cross-examination responses to questions calling for a simple yes or no answer shall be so answered first, after which the witness may explain his or her answer. Are you familiar with that protocol that is often followed here at the PSC?

A Yes.

Q I would ask you to follow that protocol. Will you agree to do that?

A Yes.

Q I'm going to follow up on a couple of questions that Mr. McGlothlin had for you that I was trying to listen, I'm not sure I understood exactly the answers. You were asked some questions about an equity adjustment or equity penalty in reference to an exhibit, I guess it is TLH-6 to your testimony. Do you recall those questions and your answers?

A Yes, I do.

Q Do you know what percentage of capacity payments was used when you made that equity adjustment or equity penalty?

A I believe the equity adjustment was on approximately 30 percent of the capacity payments.

Q Do you know if it was 30 percent or approximately 30 percent?

A I don't know for a fact.
Q And you referenced S&P guidelines. Do you recall that answer?
A Yes.
Q Do you know if FPL adheres to these S&P guidelines when making equity adjustments?
A It is my understanding they do, yes.
Q Do you know what these S&P guidelines are?
A Yes, but I don't have them right in front of me.
Q So it is your belief that Florida Power and Light should adhere to the S&P guidelines when making equity adjustments, is that correct?
A It is correct that it is my understanding that whenever calculating the equity adjustments on evaluating the RFPs we use the methodology proposed by S&P, that is correct.
Q You have been in this hearing throughout the day, have you not?
A Yes, I have.
Q You were here for the argument that I made to the presiding officer about striking your testimony related to the right of first refusal. Let me ask you this, and I could refer you to your direct testimony. I think it is on Page 9, Line 10. You are asking this Commission, are you not, sir, to rely on FPL's right of first refusal for additional firm coal-fired capacity and energy from Southern's Miller and

Scherer units, are you not?

A Yes. That is one of the benefits that we believe these contracts bring.

Q Is that an important benefit?

A It's one of them.

Q Could you rank that benefit for me in terms of relative importance or significance?

A No. We haven't ranked the benefits; we have looked at them as a bundled package.

Q So as we sit here today, are you able to put any relative worth on these benefits, one through six that are found on Pages 9 and 10 of your testimony?

MR. LITCHFIELD: I will object to the form of the question. If I understood it correctly, you asked him to put some relative worth.

MR. MOYLE: I will rephrase it.

BY MR. MOYLE:

Q Can you rank the benefits found on Pages 9 and 10 of your testimony for the Commission?

A No, I can't.

Q You are incapable of doing that?

A I just haven't considered even doing it in the past.

Q Okay. And I asked you that question at your deposition, did I not?

A Yes, you did.

Q And you weren't able to do it then, were you?

A No, I wasn't.

Q And during that week or so have you given any more thought to that and made any effort to try to rank these benefits in any kind of proprietary order?

A No, I haven't.

Q So for the purposes of what you are asking the Commission to do, would it be fair to say that these benefits are all kind of part of a package, and it is a package deal that they need to consider, correct?

A That is correct.

Q The right of first refusal, those are represented in agreements that you have, are they not?

A Yes, they are.

Q And these are separate agreements with -- is it Alabama Power and Georgia Power respectively?

A Alabama Power, Georgia Power, and Gulf Power, all signed by Southern Company Services as agent.

Q So with respect to the agreement, who is a party to the agreement for your right of first refusal out of the Miller plant?

A Could you repeat that, please?

Q Who is a party to the agreement for your right of first refusal for firm coal-fired capacity and energy out of Southern's Miller plant, if you know?

A Alabama Power, with Southern Company Services signed as their agent on behalf of Alabama Power.

Q The same question with respect to Scherer?

A Gulf Power and Georgia Power with Southern Company Services acting as their agent.

Q Why is Gulf on that agreement, if you know?

A Gulf is a part owner of the Scherer unit.

Q Did you provide these agreements to the Commission?

A No, I did not.

Q Are these agreements in the building today as we sit here?

A I don't know if they are in the building. I don't have them.

Q You don't have them?

A No, I do not.

Q If you could locate them, would you have any objection to providing them to the Commission or to counsel for the parties?

MR. LITCHFIELD: Chairman Baez, let me address that as counsel for Florida Power and Light. This is probably something that we ought to speak to.

CHAIRMAN BAEZ: Go ahead.

MR. LITCHFIELD: We have no objection to furnishing the separate agreements as late-filed exhibits subject to confidential protection. I would note, for the record, that

Mr. Moyle, in fact, requested copies of these in discovery. Florida Power and Light Company sought a motion for protective order on the grounds that they were confidential. Mr. Moyle withdrew his discovery request, and there was no need to act on a motion for protective order. So I'm a little concerned now that Mr. Moyle is suggesting that he ought to get through the back door what he had agreed to give up through the front door, and to have those put before him today or at some point tomorrow. Having said that, we are completely amenable to providing them to the Commission under protective terms.

CHAIRMAN BAEZ: Well, in my ongoing education on protective orders, right, exactly what kind of protection were you seeking when you filed for protective order from having to provide them under confidentiality to Mr. Moyle, or was it a complete -- were you seeking to avoid having to provide them to Mr. Moyle at all?

MR. LITCHFIELD: We were seeking to avoid having to provide them to Mr. Moyle at all in light of whom he represents. Now, it is clear to us, and this is reflected in many pleadings that we have filed, that Mr. Churbuck is president of a subsidiary of Calpine. Mr. Rignari (phonetic) is a Calpine employee and he is Mr. Churbuck's co-representative with Mr. Moyle. Mr. Rignari, in fact, showed up at Florida Power and Light Company's offices to review discovery.

So there has never been any doubt in our mind as to who was behind this intervention. So this information, the terms of the rights of first refusal agreements are confidential to us, they are confidential to Southern Company, and at no point did we feel that we had an ability to share them with Mr. Moyle. So that was the basis for our motion for protective order.

CHAIRMAN BAEZ: Okay. Now, bring me up-to-date. Exactly what is it that you don't have -- exactly what is it that you don't have an objection to as providing them to staff, should they so request?

MR. LITCHFIELD: We would be willing to provide them, in fact, as a late-filed exhibit in this proceeding subject to the confidential protections under the Commission's rules.

CHAIRMAN BAEZ: And that would imply that no one else -- you are maintaining your reticence to release it to any of the other parties, even under a confidential agreement?

MR. LITCHFIELD: Correct. Even if we were willing to agree to it, we don't have the agreement of Southern Company for Mr. Moyle and his clients to review those materials.

CHAIRMAN BAEZ: Well, I think that complicates things. I'm not even going to entertain the offer now, because I'm not sure where Mr. Moyle is going with this at this point. But I will take it under advisement at this point, and then staff has some -- staff may have some thinking to do as to whether for their own benefit they would require or request the agreement, so we can take them up at that time.

Mr. Moyle, you can go ahead with your questioning.

MR. MOYLE: Can I just respond briefly? Mr. Litchfield made a lot of comments and allegations and whatnot. And Mr. Churbuck, we have gone over this issue. It is ground that has already been covered with respect to a petition to intervene. FPL opposed it on the grounds that Mr. Churbuck is president of Power Systems, which is in the power business, and have basically convinced themselves of the fact that a ratepayer who happens to also be in the energy business can't have interest.

I, for the purposes of this document, this right of first refusal, you know, if there are provisions that they consider confidential, redact them, and I will take the redacted version, just like they did with this big fat contract. But to just say no, we are not going it to you, Moyle, and then come in and ask this Commission to rely it just seems patently unfair to me.

CHAIRMAN BAEZ: You know, this is an interesting situation, because I think the prehearing order, the prehearing officer allowed intervention of the parties on a perfectly legitimate basis and the only complication is their parentage, if you will.

MR. LITCHFIELD: And we are no longer arguing about their interest, but we don't equate interest with the right to review and have access to competitively sensitive information.

CHAIRMAN BAEZ: But, Mr. Litchfield, I think you can also appreciate that as a -- again, I reiterate, it is a sensitive subject because as an intervenor, you know, that status as an intervenor has a significance to it and has certain rights that follow to it.

Now, again, neither am I going to entertain Mr. Moyle's request to produce these agreements. At this point in time I would like to learn a little bit more about the law on it and what we really have to -- if, in fact, that is a petition that is before us right now. Staff has their own questions to answer, and I appreciate your offer to provide it to staff should they feel it necessary.

As to the murkier questions of how we would treat Mr. Moyle's client as an intervenor to the fullest extent possible and yet respect your competitive -- you know, your competitive concerns, I'm not sure I have an answer for you at this point in time.

MR. LITCHFIELD: Fair enough.

MR. MOYLE: And as you consider that, as a suggestion, I mean, I am an officer of the court. You know, if he wants to give it to me --

CHAIRMAN BAEZ: I think we all are on some level, right? No? I appreciate what you are saying, but I can tell you I'm not going to decide that now. I would like to have some more time to, you know, really -- since I wasn't prehearing officer, I'm not familiar with the terms of the intervention. And I would at least like a chance, to the extent that the request is again before me, I think we are getting a little bit ahead of ourselves. I don't think the magic words have been uttered.

Nonetheless, to the extent that it does come before us and I have to consider it, I would like to go back and read up on the situation as much as I can. So I'm going to reserve whatever ruling is or isn't necessary at this point.

MR. MOYLE: And just so the record is clear, Mr. Chairman, you know, the magic words, I thought I had uttered them earlier when we are doing the motion to strike. I don't want to force you to make a decision right now. But for purposes of looking at the issue, we would ask that those documents be produced. So if that gets the magic words out there, then I would ask that --

CHAIRMAN BAEZ: Well, you were on a road, I think, asking him questions, and why don't you go ahead and lead up to it between the lines so that we are not arguing --

MR. LITCHFIELD: May I ask a clarifying question, though, of counsel? Then am I to understand that Mr. Moyle is now withdrawing his withdrawal of the discovery requests? Because I had understood he was withdrawing those discovery requests, and now it appears that he is reinstituting those today in open court and that concerns me. And I just want a clarification on that point.

CHAIRMAN BAEZ: And, again, I mean, Mr. Moyle, if that is the practical intent of your line of questioning, then I've got to tell you, sitting here I'm just not smart enough to tell you whether you can even do that. So, you know, we are testing the limits of my ability to get this hearing proceeding on schedule and not getting bogged down on creative legal arguments of the likes of which I am very sure are meritorious to no end. But, you know, if you have got a question, ask it. Let's hear the answer of the witness and see where that goes.

BY MR. MOYLE:

Q Mr. Hartman, just so we are clear now, these other agreements that we are referencing that contain the right of first refusals, they have not been filed with the Commission, is that correct?

A That is correct.

Q And do these agreements contain the full and complete terms as to the parties' rights and responsibilities and what FPL anticipates receiving pursuant to these rights of first refusal?

A Could you clarify that, please?

Q Sure. These two agreements, let's call them the right of first refusal agreements. Is it your understanding that they contain, in their entirety, the rights, terms, and conditions that FPL would receive from Southern with respect to buying coal-fired generation as a right of first refusal from the Miller and Scherer units?

A Yes, in the sense that they specify how the right of first refusal would work, how we would negotiate the responsibilities of one party against the other under the right of first refusal.

Q How many pages is the document?

A They are each about four.

Q Do you know how many sections they have, how many provisions?

A I don't remember offhand.

Q As we sit here today, are these rights of first refusal signed by all parties?

A Yes, they are.

Q Mr. Hartman, do you know what the projected load forecast in Alabama and Georgia for the period from 2010 to 2015 and the corresponding projected economic dispatch of Georgia Power and Alabama Power's generation assets are?

A No, I do not.

Q So with respect to Scherer, you don't necessarily know how that unit is projected to dispatch on a going-forward basis?

A On the Scherer unit that we have under contract, it will dispatch and we will get the power per how we dispatch it.

Q With respect to the question I asked you about the projected load forecasts, isn't it true that if you knew the projections that you could quantify for the Commission the value of this right of first refusal on a projected basis? If you could answer yes or no and explain if you need to.

A No, I don't believe so. First of all, you would have to look at all the provisions of the right of first refusal, which makes things a little bit more complicated. Secondly, you might have the issue of knowing what the load forecasts are. You also don't know what generation is going to be available, what the price is of coal, what the environmental attributes are going to be. It is impossible to project that right now.

Q I'm sorry, in response to that question I didn't hear, you said you would have to look at what, all the provisions of the --

A The provisions of the right of first refusal, and then the other issue is you are saying that, you know, a right of first refusal implies a value of coal versus natural gas that we are already getting, and loads, et cetera. Many of the things in addition to load go into it, such as environmental costs associated with coal plants versus gas plants, the price of coal versus gas, how many additional units get built. There is a lot of things besides Southern's load.

Q Have you made efforts to obtain these other things that you said are significant to try to value the rights of first refusal?

A No, we have not.

Q So you are asking this Commission to ascribe a value to the rights of first refusal, but you haven't taken these steps to try to determine for yourself their value, is that correct?

A The right of first refusal is an option.

Q I understand. I presume it is an option you would hope to exercise, is it not?

A The nice thing about an option is you don't necessarily have to hope. If coal becomes available from these units, if they are not, you know, if they are offered at wholesale, then we have the option at that point to decide whether we want to take it or not.

Q Okay. When I asked you the question I was trying to understand do you believe the right of first refusal is one that, if available, you would seek to exercise?

A I can't determine that at this time.

Q Why not?

A Because I don't know what the pricing will be and what the value of the coal will be at that point in time.

Q So it is fair to say that this is uncertain as to whether this right of first refusal would be exercised in 2010 to 2005, correct?

A That is one of the reasons why we have it listed as a difficult to quantify benefit. It could have a potential huge upside for us, it could also have no value at all.

Q And we just don't know at this point?

A We don't know at this point.

Q What we have to do is sort of speculate and hypothecate as to what it may be, is that correct?

A No, we are sitting there with -- we have a fuel diversity issue, we would like to have additional nongas in our portfolio, this is an option to get us there if certain things happen.

Q Mr. Hartman, given more time, the information that you just described as to things that could potentially be valuable in judging the right of first refusal, would that be something that you would want to look at closer to try to determine with more certainty the value of the rights of first refusal?

A No, I don't believe so. Too many of the uncertainties are too long into the future that we couldn't really determine them in any case.

MR. MOYLE: Mr. Chairman, I have asked my questions on the right of first refusal. He has referenced the document a number of times in his response, I believe, talking about various things. I would like to have the opportunity to look at the document. It may have a provision that I could use to say, well, isn't it true that this provision says this, that, or the other and effectively build my case better that this right of first refusal has really little value because it is based on things that may or may not happen in the future. With that I would like to utter the magic words.

CHAIRMAN BAEZ: Are you formally moving to compel discovery?

MR. MOYLE: I'm asking that either the testimony with respect to that issue not be allowed because it is not based on the best evidence, or if it is allowed that I be provided with the document itself that Mr. Hartman is testifying about and speaking to and asking this Commission to rely on.

CHAIRMAN BAEZ: Well, on the question of disallowing the testimony, I think there has already been a ruling on that, so that is outside the question. If you are formally moving to compel discovery of the agreement, then we have got a question before us that we are going to have to take up. I can tell you that we are not going to take it up today.

MR. MOYLE: That's fine.

CHAIRMAN BAEZ: There is not going to be a ruling on it today.

MR. LITCHFIELD: And we would reurge our motion for a protective order which we had agreed to dispense with on the understanding that Mr. Moyle had withdrawn his discovery.

CHAIRMAN BAEZ: We are back to the beginning. And maybe this question is inappropriate, but why was the discovery withdrawn, the motion withdrawn to begin with? And I don't want to put anybody -- I don't want you to give up argument or anything like that.

MR. MOYLE: No, I will tell you. I was speaking with staff, we were talking about preliminary matters, you know, what needed to be done. If you look at the record, you know, we asked for a lot of information. They objected to a ton of information. There was a lot of work to go through and rule on each issue and whatnot.

I think what I indicated was that I think this information is relevant and ought to be provided. But given the time frame involved, this kind of rush, that if it was all provided I would have difficulty getting through it. And I didn't want to force them to have to spend a lot of time doing this. I indicated that I would pull back the discovery that we had sought, and if the matter got spun out we could reserve it.

So, Mr. Litchfield is right, we withdrew it. I'm not intending to reserve it or whatnot, I'm asking on this one issue that is one of the six key benefits listed that we have a copy of it.

CHAIRMAN BAEZ: Well, I will tell you what, I think you have gotten -- you know, you have gotten a fair amount of testimony on it. And I'm more inclined, in order to serve everybody's interests, let the fact that you have drawn attention to it, attention to the agreement, and we would honor or accept Mr. Litchfield's offer to provide it to staff under confidential treatment. And let's let staff deal with the particulars of the agreement, and just rely on your good work in questioning and cross-examining the witness to actually cast whatever doubt is appropriate for the staff to take up with the benefit of the agreement.

And I think that we can keep this hearing moving, and the purpose of having the agreement will have been ultimately served. I'm offering that as a compromise between the two. If we have to get into flying paperwork, then, you know, that is going to be bad for everybody.

MR. MOYLE: I understand. And I think the record is clear. Let's do this, why don't I move on to another area of questioning. I can talk to Mr. Litchfield. You can consider the issue further and maybe --

CHAIRMAN BAEZ: But, Mr. Moyle, I've got to tell you, unless you all come out holding hands on something that I haven't heard already, I have already told you what my predilection is at this point on this issue. Because I think, you know, it may sound like half a sandwich, but at least it is in the hands of someone other than the company with which legal issues are not arising. And I think that that is the best for everybody at this point.

You all go ahead on a break, if you want, talk and see if you can come up with some other kind of solution. But I can tell you in advance that that is probably the way we are looking at things at this point. You had more questions?

MR. MOYLE: I do on another subject matter.

CHAIRMAN BAEZ: Okay. Go ahead.

MR. MOYLE: And I apologize, Mr. Chairman, I do have extensive cross and it is a lot of --

CHAIRMAN BAEZ: That's alright. I told you we wanted -- if you can look over your cross and find a natural breaking point, because we do need to get done by about 6:00 o'clock today, if that is all right.

MR. MOYLE: I have subject areas, I will just pick subject areas and try to do it that way.

CHAIRMAN BAEZ: That works.

BY MR. MOYLE:

Q Mr. Hartman, arbitrage, that is one of the benefits that you have asked this Commission to relay on, is it not?

A Yes, it is.

Q What is your understanding of arbitrage?

A For the purposes of our analysis, we define arbitrage as the capability of using the transmission to purchase lower cost economy energy in southeastern SERC and bring it to the use of our customers.

Q Isn't it true that the arbitrage value depends on the relative conditions in the SERC market vis-a-vis the Florida market?

A Yes, in the sense that arbitrage depends upon a price difference between the two.

Q And with respect to that price difference, you have made some projections about the value of arbitrage, correct?

A Yes, we have.

Q Isn't it true that the value that you have ascribed for this arbitrage depends on the relative conditions in the SERC market and the Florida market not materially changing?

A I don't know how to answer the question. What do you mean by the relative conditions?

Q Well, I'm trying to understand the value of this arbitrage. If I understand arbitrage, it is based on a difference in price in different markets, correct?

A That is correct.

Q And so if you put a value on it, but then something in one of the market changes, a condition changes and things move around, the value of the arbitrage is affected as well, correct?

A Yes.

Q And with respect to the arbitrage value that you have placed on this that you have asked this Commission to consider, doesn't that presuppose that the market conditions in SERC and Florida will be relatively unchanged from the years 2010 to

2015?

A No, it does not.

Q Why not?

A Because we had projections of market prices in SERC, southeastern SERC, and in the FRCC, and that is what we used as a basis for the arbitrage. So, for example, if you looked at the exhibit I have in here, I think it was, what, TLH-4 where it shows a great deal of price difference, you will notice that it even goes down in the summertime. The price differences that we are looking at for our arbitrage projections, for our price difference projections shows that decreasing in the summertime.

Q And you are referring to TLH-4, is that right?

A That is correct.

Q And that is a 2003 off-peak price spread?

A 2003 off-peak price. So the numbers we are projecting in 2010 through 2015 shows less of that to be available in the summertime.

Q Do you have similar charts such as this for 2010 to 2015?

A No, I do not

Q Would that information have helped in ascertaining the value of the arbitrage, running a similar analysis for 2010 to 2015?

A We did run an analysis for 2010 through 2015. What is reported in here for 2003 is actual prices, which obviously we don't have.

Q So the value of the 2010 to 2015 time frame, you would agree the arbitrage value depends on market conditions both in SERC and FRCC, correct?

A Yes, I would agree.

Q And you would expect, would you not, that the market conditions in SERC will change between now and 2010?

A Yes, I would.

Q And you would also expect, would you not, that the market conditions in FRCC will change between now and 2010?

A Yes, I would.

Q You would agree, also, would you not, that the actual value of arbitrage is based on projections?

A Yes, I would.

Q And some of those projections may be right or may be wrong, correct?

A That is correct.

Q So the arbitrage value is somewhat uncertain as we sit here today, is it not?

A That's correct. And let me explain that that is one of the reasons why in our analysis we used a range of arbitrage values.

Q As we sit here today, can you guarantee to the Commission that there will be arbitrage savings associated with the PPA agreements?

A No, I can't guarantee it, but it is going to be extremely unlikely that there won't be at least some arbitrage savings. For that to occur you would have to wind up with savings in -- with the costs in the southeastern region of SERC being at or higher than they are in Florida in basically all hours. They have a large amount of coal, they have a large amount of nuke, they have a large amount of base load capacity that doesn't cycle very well and we have a lot of gas. So in off-peak periods and shoulders months it is going to take a very unusual circumstance for them to be more expensive than us all the time.

Q So if I understood your answer, you didn't think it was likely because they have a lot of coal and Florida has a lot of gas, is that correct?

A That is one of the reasons.

Q Wouldn't the arbitrage value lessen considerably if the price of gas declined significantly, say $3, $3.50 for gas?

A Yes, it would.

Q And a couple of years ago, three or four years ago, wasn't gas at around three bucks, 3.50?

A Yes, it was.

Q Do you know if gas is going to go to $3.50 again say in year 2010?

A No, nor do I know whether it is going to go to $30 in

2010.

Q You just don't know one way or the other, is that correct?

A That's correct.

Q But if gas did go down to, say, three bucks and it was lower than the price of coal, the arbitrage value that you are asking this Commission to rely on would be significantly reduced, would it not?

A That's correct. That is one of the reasons why this transmission, even though we don't have firm coal for but a small part of it, this transmission represents effectively coal-by-wire. And to the extent that the difference in price between coal and natural gas goes away and natural gas is now cheaper, the value of the arbitrage goes away and the value of the transmission becomes less to us. Just like the value of a coal plant PPA would become less to us.

Q Do you have the answers to staff's interrogatories that was handed outed earlier, and I think staff handed out an exhibit that has a bunch of answers to interrogatories, a comprehensive exhibit?

A Yes, I do.

Q You were asked a question, and let me refer you to it, and I will read it into the record. This is Staff's Fifth Set of Interrogatories, Question Number 45. And it references Page 12, Lines 12 through 14 of your testimony identifying the arbitrage value of transmission rights for 2003 as 10.85 million. And you were asked to explain whether this value is net of the cost of transmission rights. Do you recall that question?

A Yes, I do.

Q And in response you indicated, and I will read this, yes, in the sense that the incremental cost for arbitrage of the transmission rights is zero. The cost of transmission is associated with the cost of the PPAs and has been reflected in the economic analysis as part of the cost of the PPAs. Since of the cost of the transmission must already be paid as part of the PPAs, the ability to arbitrage in the benefit to our customers has zero incremental cost associated with it. Was that your answer to this question?

A Yes, it is.

Q And it is true and accurate, is it not?

A Yes, it is.

Q So if I understand this, let me ask you some questions about this. There are costs associated with transmission, correct?

A That's correct.

Q And the arbitrage value of 10.87 million that you have said is of value, it doesn't reflect these transmission costs, correct?

A That is correct.

Q And that is because those transmission costs are booked not with respect to the arbitrage profit, if you will, but they are booked as embedded in the PPA, correct?

A What do you mean by booked?

Q Charged against or accounted for. I'm not looking for an accountant term, but I understood your answer to be, hey, we are not taking into account transmission cost in this arbitrage issue because it is already part of the contracts.

A The transmission costs are not part of the contracts However, whenever we are doing our economic analysis, the transmission costs are included in part of the economic costs of the PPAs. So in our economic analysis we have already accounted for the transmission costs with the PPAs, the arbitrage is an additional savings. So from the point of view of our economic analysis, the transmission costs for the arbitrage is zero.

Q But if I understand how these contracts work, if you are not taking power, you don't get charged for transmission at that point in time, correct?

A Yes, we do.

Q Whether you take it or not?

A Whether you take it or not, firm transmission is just like renting a power plant, okay. You have paid for it. You don't have the losses, but you still have to pay for the firm transmission.

Q Okay. All right. So 2003 we have 10.87 million in arbitrage savings, is that right?

A That is correct.

Q Do you know what the associated transmission costs are? I mean, can you give me a transmission cost to balance against this 10.87 million?

A Well, I think, as I just said, whenever we are doing our economic analysis and looking at the arbitrage, we are looking at all the transmission costs being associated with the PPAs. So the cost of the transmission associated with our arbitrage is zero. Now, we would just go out -- what are you asking me to do here?

Q Let me ask you this. Turn to your interrogatory to Staff's Interrogatory Number 42. You were asked to please identify the anticipated cost of transmission rights under the proposed contracts.

A Yes.

Q And you said that the cost is $1,753.52 per month plus a scheduling fee of $80.60 per month, correct?

A That's correct.

Q Can you take these numbers and balance them against the arbitrage numbers?

A I think I have already answered that these costs would be accumulated for the PPA. Whenever we are doing our economic analysis, all of these costs get associated with the

PPA. The arbitrage has no additional incremental cost other than losses.

MR. MOYLE: May -- can I approach?

MR. LITCHFIELD: May I have a copy, Mr. Moyle?

BY MR. MOYLE:

Q Mr. Hartman, I have handed you an exhibit that has some answers to interrogatories that Mr. Churbuck served. Would you please identify this document for the record? Let me do it this way. You would agree, would you not, that this represents Question Number 36, Question Number 39, Question Number 45, Question Number 57, and a copy of an affidavit that you signed in response to interrogatories served by Mr. Churbuck?

A They appear to, yes.

Q And I made an opening statement and made a few points and we are going to have an opportunity, I think, either later today or tomorrow to get into some of these issues in detail. But with respect to your answer to Question Number 36, isn't it true that when you were negotiating this arrangement with Southern that you were interested in the coal-fired facilities and being able to keep coal generated power and not particularly interested in gas-fired facilities from Southern, correct?

A Whenever we started off with this we wanted all the benefits of the existing UPS, which included 930 megawatts of coal.

Q So you had 930 megawatts of coal currently, correct?

A That is correct.

Q And at the end of the day you ended up with 165 megawatts of coal?

A 165 megawatts of firm coal, that's correct.

Q Did you run a calculation to figure out what percentage decrease this was?

A No, I didn't.

Q Can you estimate for me what percentage decrease that was?

A It is about 83 percent.

Q All right. And then to get that 165 megawatts, Southern wanted you to take gas-fired capacity, isn't that correct?

A Southern wanted us -- well, we still wanted the 950 megawatts of base load capacity to keep the transmission. If we couldn't get it with coal, we had to take it with gas, yes.

Q And Southern wasn't willing to given you the coal alone as 165 megawatts of coal, or give you any more than that, they wanted you to take the 165 megawatts combined with the nearly 800 megawatts of gas-fired capacity, correct?

A Except for the extent they give us a right of first refusal should they have additional coal come up on the market.

Q What is the value of the 165 megawatts of coal in your mind?

A I don't know. I haven't separately even considered it.

Q And without giving me a price, how about just in terms of a general description about why was retaining coal so important to FPL in these negotiations?

A Because we wanted to retain coal due to fuel diversities considerations. It has reduced volatility.

Q All right. And with respect to the amount of coal that you retained, I think the next interrogatory addresses this point. But you would agree with me, would you not, that 165 megawatts represents less than one percent of FPL's total generation portfolio?

A Yes, it does. And if the right of first refusal came through it would represent quite a bit more than one percent, so we could be looking at 950 megawatts of coal.

Q And your reference in the right of first refusal is what we have had all of this discussion about, is that right?

A That's correct.

Q So it is your understanding that the right of first refusal could take you up to how many megawatts of coal?

A The right of first refusal could give us 930 megawatts of coal at our border.

Q What would have to occur for that to happen?

A Alabama Power would have to decide to sell the existing Miller capacity that we have at wholesale, and we would have to decide to execute the right of first refusal against it, and the existing transaction that Southern has entered into apparently with regard to the Scherer capacity would have to not close, and we could exercise our right of first refusal there.

Q And with respect to that, you don't know how likely that is?

A No, I don't.

Q And I don't want to tread that ground again, but you would have to -- do you have any idea whether the regulators who oversee that Miller unit would be inclined to allow Southern to sell low-priced coal down into Florida?

A They did once already.

Q Do you know how they would act in the future?

A I have no idea.

Q Let me flip you to Question Number 45. It is true you all did an economic evaluation in which you looked at self-build options compared to the Southern proposal, isn't that correct?

A We did an economic analysis and looked at a self-build option against Southern, that is correct.

Q The next interrogatory, Question Number 57. And part of the reason, if I understand it, you can answer this for me, is that you are asking this Commission to act because some of the benefits that you list in your testimony may not be there in the future, correct?

A No, that is not correct.

Q You are not suggesting that you need to act now because some of these benefits that you are describing if you don't act now may go away; Southern may decide to go sell their output somewhere else?

A No. What we're asking the Commission to do is make a decision now. The reason is we know we have 930 megawatts that go away in June, or goes away effective June 1st, 2010. We have to do something to replace that. If you start backing up from that and you assume that we need to have the capacity, you start looking at a self-build option, the RFP process associated with it, the time frame to go ahead and get in the transmission with this UPS in order to assure we can get transmission you are looking at needing a decision now.

Q Okay. You would affirm for me, would you not, that SCSI, which I guess Mr. Litchfield said was an agent for the Southern entities, that they never communicated to you that the benefits you describe would not be available at some point in the future, isn't that correct?

A No, other than the fact that part of the Scherer unit was sold while we were negotiating.

Q So your answer in this interrogatory stands?

A Yes.

Q Let me switch gears to another subject area, and that is the comments you made about fuel diversity and coal being important. You would agree, would you not, that retaining even a small piece of the coal-fired generation from Scherer is important to FPL?

A I would agree it is important, yes.

Q FPL could develop a coal plant in Florida from soup to nuts in seven years, could it not?

A That would be extremely aggressive, but potentially so, yes.

Q Do you remember your deposition when I asked you that question and you said seven to eight years?

A That is what I said, yes.

Q And FPL has already started the process to develop a coal plant, has it not?

A FPL is doing some investigation of coal plants.

Q In fact, hasn't FPL been working on its own solid fuel project now for over a year in terms of investigations and whatnot?

A It is my understanding that FPL is doing some studies and investigation on solid fuel plants and will be providing a recommendation or at least a report to the Commission.

Q And when are they going to give that report, do you know?

A It is my understanding that the report is due in the first quarter of next year.

Q So with respect to the question I posed to you about hasn't FPL been looking at the issue of a solid fuel project of its own now for over a year, would that be a yes?

A I don't know that it is over a year, but they are investigating solid fuel.

Q So if I understood, if it could take seven years to develop a coal plant, FPL has been at it for awhile, FPL could conceivably have in place a large coal-fired generation unit in, say, late 2010, early 2011?

MR. LITCHFIELD: I will object to the question. I think it is mischaracterizing Mr. Hartman's testimony and attempting to mix two separate issues. One, prestudy phases of looking at coal, and secondly, actually siting and constructing a power plant. I object to the question.

CHAIRMAN BAEZ: Mr. Moyle, can you ask it again, because I think you skipped a step there. You know, ask him where does the clock start, perhaps.

MR. MOYLE: Okay.

BY MR. MOYLE:

Q We agreed seven to eight years to develop a coal plant, correct?

A Yes, that is correct.

Q And that clock has already started, correct? FPL has already started doing some investigations?

A I don't know that that clock has started. I know we have done some investigations, I don't know that you would say that the clock has started on us building a coal plant.

Q So do you know one way or the other whether they have or they have not?

A No, I do not know. What I know is that they are working on the study to prepare the report to provide to the Commission.

Q If the clock started today based on a seven-year time frame, you would agree, would you not, that a coal plant on a soup to nuts basis could be in service in November of 2011?

A If the clock started today, yes.

Q And this UPS agreement is scheduled to come in in the summer of 2010, correct?

A That's correct.

Q So you would have possibly a six-month gap that you would have to deal with, correct, in terms of power if you needed to -- if you wanted to defer a decision on this coal plant and build your own coal plant?

A Let me just clarify this. So you are saying that this UPS comes in place in the summer of 2010, we could have a coal plant on line in the winter of 2011, so that means there is a year and a half that we are kind of missing things.

Q Well, I think it depends on whether you use seven or eight years. I guess where I'm going with this, Mr. Hartman, is that isn't it true that FPL has taken a look at doing a coal plant of its own?

A Yes, FPL is looking at doing a coal plant.

Q And such a unit would likely be larger than 165 megawatts, would it not?

A Yes, it would.

Q Wouldn't you agree that it might make sense to consider accelerating FPL's solid fuel option project rather than agreeing to this UPS agreement which saddles FPL with 800 megawatts of gas-fired energy so that you can get 165 megawatts of coal-fired capacity?

A No, I would not.

Q And why not?

A The reason is a seven-year schedule is an accelerated schedule. As you just pointed out, we could get it on line in 2011. If you want to say we can get it on line in 2009, that is fine, but that doesn't mean that it can happen. Fundamentally, we have got about a year and a half gap. We would be short 930 megawatts. And the way we would have to do that is build a gas plant.

Q Do you know if there are peakers that are currently available for sale, capacity out of peakers in Florida?

A Yes.

Q Is it possible that you could consider bridging that year and a half period with a short-term purchase?

A That's not something I have looked at.

Q And just so the record is clear, when I asked you the question about how long it took to build a coal plant, you had indicated, did you not, in your deposition that seven to eight years was the appropriate time frame, soup to nuts?

A That's correct.

Q Do you know that if you built your own coal plant rather than buying this from Southern, do you know whether FPL shareholders would be given the opportunity to earn a return on investment based on the cost of FPL's coal plant?

MR. LITCHFIELD: I will object to the question to the extent that it requires the witness to offer a legal opinion or conclusion.

MR. MOYLE: I'm not asking for his legal opinion, just what he understands.

CHAIRMAN BAEZ: Mr. Hartman, you can answer the question and couch it in terms of a nonlegal opinion, if you wish.

THE WITNESS: It is clearly a nonlegal opinion.

CHAIRMAN BAEZ: That's all you have got to say.

THE WITNESS: You are assuming that the coal plant is the way to go, which I don't know is a decision that has been made. But if you assume the fact that we are going to build a coal plant, then I would assume that we are going to make some sort of return on the investment.

BY MR. MOYLE:

Q And with respect to this PPA agreement, are shareholders given an opportunity to earn a return on investment on this PPA?

A No, they are not.

Q And that is because it is a pass-through?

A That is correct.

Q Did FPL consider as an option self-building a coal facility rather than executing these PPAs with Southern?

A Not to my knowledge.

Q Let me switch you to another subject area and this is the timing of the request. Mr. Hartman, you would agree, would you not, that the main purpose of the fuel and purchased power recovery clause is for the PSC, after hearing evidence, to make rate adjustments for considering past year, present year, and future year fuel and purchased power adjustments?

MR. LITCHFIELD: Again, object to the extent that Mr. Moyle is attempting to have this witness describe the legal mechanical operations of the clause proceedings, something that I'm not sure that this witness is qualified to offer an opinion on.

MR. MOYLE: Again, just his understanding.

CHAIRMAN BAEZ: Can you simplify the question a little bit, because I'm not sure I understood it.

MR. MOYLE: Sure.

BY MR. MOYLE:

Q What is your understanding as to the purpose of the fuel and purchased power recovery clause in this docket that we are in today?

A It is my understanding, which is clearly not an expert opinion as far as the clause is, it is my understanding that this is a mechanism for the companies to recover from our customers costs that are passed through, such as fuel, such as purchased power, and adjustments are based on actuals last year, futures, and commitments of the company.

Q Do you know if there has ever been another situation where this Commission has been asked in the fuel clause to approve a PPA five plus years in advance of the actual delivery of the energy and capacity called for in that PPA?

A I don't know.

Q This is a docket that is open in January of every year, is it not?

A Again, I wouldn't know.

Q Your testimony, in part, describes reasons why FPL believes the Public Service Commission should approve the three contracts, does it not?

A Yes, it does.

Q And these contracts, they don't call for the delivery of power until June 1, 2010, correct?

A That is correct.

Q And these three power plants from which the power would be delivered, they are already built and in operation, correct?

A That is correct, they are.

Q Isn't it true that the first filing in this case which indicated FPL would seek PSC approval of these contracts, was made on September 9th, 2004?

A I believe the first filing was made then. I'm also aware of the fact that there were some discussions with staff before that.

Q And my question relates -- I was not a party to those discussions with staff, but with respect to a filing that was made, that was September 9th, 2004, correct?

A Correct.

Q Isn't it also true that FPL asked Southern to give the PSC a year to approve these contracts?

A Yes, that's correct.

Q And isn't it true that FPL at the negotiating table sought that year from Southern because FPL considered a year to be a reasonable time frame for the PSC to consider this matter and act on it, is that correct?

A Yes, in the sense that FPL considered a year an adequate time. I will also point out that whenever FPL proposed a year, it was in a counter to the 90 days that had originally been proposed by Southern.

Q What day are we at today from September 9th, day 60 or so?

A The 180 days we have for approval is from the date the contract was signed. The contract was signed August 11th.

Q But from the date that testimony was filed, how long has this matter been in front of the Commission?

A I don't know.

Q Southern refused to give FPL a year to have the PSC review this, correct?

A That's correct.

Q And FPL eventually agreed to provide the Commission with either six months or when FPL secured all firm transmission rights for these contracts, whichever occurred later, correct?

A No, that is a serious misstatement. What we said was we have from the time we signed the contract six months, 180 days to get approval. It isn't that the Commission has that long. So, our period ends whenever we need to have an answer, early February. It is from the contract became effective, which was August 11th.

Q Am I correct that FPL is now asking the Commission to approve these agreements from the bench at the end of the hearing, be it -- well, it won't be today, but tomorrow?

A I would be more than pleased if they would.

Q Is that what FPL is asking?

A I don't know.

MR. MOYLE: Mr. Chairman, we are getting close to 6:00. I have some other areas, but they may take some.

CHAIRMAN BAEZ: Well, this is probably a good time to stop then, if you have got some other lines of questioning?

We will pick it up at 9:30 tomorrow morning. Is there anything we need to take up before we adjourn for the day? Staff is not even -- I take that as a no. We will see you tomorrow morning. Thank you.

(The hearing adjourned at 5:57 p.m.)

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 17th day of November, 2004.

Jane Faurot

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