BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 050001-EI

In the matter of

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

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VOLUME 5

Pages 660 through 851

PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN BRAULIO L. BAEZ COMMISSIONER J. TERRY DEASON COMMISSIONER RUDOLPH "RUDY" BRADLEY COMMISSIONER LISA POLAK EDGAR COMMISSIONER ISILIO ARRIAGA
DATE:	Wednesday, November 8, 2005
TIME:	Commenced at 9:00 a.m. Concluded at 6:38 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	MARY ALLEN NEEL Registered Professional Reporter (850) 878-2221
APPEARANCES:	(As heretofore noted.)

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I N D E X

WITNESSES

EXHIBITS

NUMBER		I.D.	ADMTD.
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P R O C E E D I N G S

(Transcript follows in sequence from Volume 4.)

CHAIRMAN BAEZ: We'll go back on the record. Mr. Horton, your witnesses.

MR. HORTON: Yes, Mr. Chairman. We have two pieces of testimony that I'm going to go through. Just for clarification, the first one is the panel testimony of Mr. Bachman, Mr. Cutshaw, and Ms. Martin that's styled in the docket, the 01 docket. And the second piece is the direct testimony of George Bachman, Cheryl Martin, Mark Cutshaw, and Robert Camfield, and it's titled "Fuel Cost Recovery and Phase-in Plan," just for clarification.

CHAIRMAN BAEZ: Wait, wait, wait. Okay. And I know that you tried to explain this to me. The two pieces -- now, I have -- there's separate testimony for Cheryl Martin, et al.?

MR. HORTON: No, sir. No. That's all included in the panel testimony.

CHAIRMAN BAEZ: In the panel testimony.

MR. HORTON: Yes, sir.

CHAIRMAN BAEZ: Okay. And then there's the other panel testimony.

MR. HORTON: And then there's the other, yes, sir.

CHAIRMAN BAEZ: Okay. Proceed.

MR. HORTON: And with respect to the 01 docket, on the second page there, and unfortunately it's not numbered, on line 13 we show Mr. Bachman as being the respondent. That should Mr. Bachman and Mr. Camfield.

CHAIRMAN BAEZ: I'm sorry. Where are you looking at?

MR. HORTON: It's the second page in, line 13, that says, "Answer. Bachman: FPUC feels." It should be Mr. Bachman and Mr. Camfield both.

CHAIRMAN BAEZ: I see.

MR. HORTON: Sorry for the confusion, but --

CHAIRMAN BAEZ: No, that's all right.

MR. HORTON: And the next step is that unfortunately my witnesses were all mingling around outside yesterday, so none of them have been sworn.

CHAIRMAN BAEZ: None of them have been sworn. Shame on you all. All right. Are all your witnesses in the room at this point?

MR. HORTON: Yes, sir, they're all over there.

CHAIRMAN BAEZ: Okay. If you would stand and raise your right hand.

(Witnesses collectively sworn.)

Thereupon,

GEORGE BACHMAN, CHERYL MARTIN, MARK CUTSHAW,

and ROBERT CAMFIELD

were called as a panel of witnesses on behalf of Florida Public Utilities Company and, having been first sworn, testified as follows:

DIRECT EXAMINATION

BY MR. HORTON:

Q. Mr. Bachman, Mr. Cutshaw, and Ms. Martin, would you all please state your names, address, and by whom are you employed?

A. (By Mr. Bachman) My name is George Bachman. I am the chief financial officer for Florida Public Utilities Company located in West Palm Beach, Florida.

A. (By Mr. Camfield) My name is Robert Camfield. I am vice president for Christensen Associates. We operate in Madison, Wisconsin. The address is 4610 University Avenue, Madison, 53705.

A. (By Ms. Martin) I'm Cheryl Martin. I'm the controller for Florida Public Utilities. My address is 401 South Dixie Highway, West Palm Beach, Florida, 33401.

A. (By Mr. Cutshaw) My name is Mark Cutshaw. I'm the director of the Northwest Florida Division in Marianna for Florida Public Utilities Company. The address is P.O. Box 610, Marianna, Florida.

Q. Now, Mr. Bachman, Mr. Cutshaw, and Ms. Martin, have you prepared and prefiled direct testimony in the 01 proceeding?

A. (By Mr. Bachman) Yes, we have.

Q. Do you have any changes to make to that portion of your testimony?

A. None other than what you've already stated.

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

A. Yes.

MR. HORTON: Mr. Chairman, I would like to ask that the testimony in the 01 docket be inserted into the record as though read.

CHAIRMAN BAEZ: Without objection, show the prefiled testimony of witnesses Martin, Bachman -- Bachman and Cutshaw?

MR. HORTON: Yes, sir.

MS. CHRISTENSEN: Commissioner, can I ask for clarification? On the testimony that was filed on September 21st as part of -- originally filed in the 050317 docket, it's also panel testimony. The questions in that -- the questions and answers in that testimony do not identify the individual or individuals that are responding to the specific questions. And I think for clarity of the record, since they did identify the individuals answering the specific questions in the 01 testimony, if they could go ahead and file or identify in a separate document, maybe to be late-filed, who is responding to which questions. It's not clear in that testimony.

CHAIRMAN BAEZ: Is there --

MR. HORTON: Commissioner, we haven't gotten to that testimony yet, but I can provide some clarification.

CHAIRMAN BAEZ: Then let's hold off on that.

MS. CHRISTENSEN: Okay.

CHAIRMAN BAEZ: Let's get the prefiled in the 01 docket, and that is by Martin, Bachman, and Cutshaw. Without further objection, it's entered into the record as though read.

MR. HORTON: Thank you, sir.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 050001-EI
CONTINUING SURVEILLANCE AND REVIEW OF
FUEL COST RECOVERY CLAUSES OF ELECTRIC UTILITIES

Direct Testimony of
George M. Bachman, Mark Cutshaw,
Cheryl M. Martin
On Behalf of
Florida Public Utilities Company

Q. Please state your names, employer and business addresses.

A. George M. Bachman, Florida Public Utilities, Company, 401 South Dixie Highway, West Palm Beach, FL 33401.

A. Mark Cutshaw, Florida Public Utilities Company, 2825 Pennsylvania Avenue, Marianna, Fl 32448.

A. Cheryl M. Martin, Florida Public Utilities Company, 401 South Dixie Highway, West Palm Beach, FL 33401.

Q. Have you previously testified in this Docket?

A. Bachman, Cutshaw, and Martin: Yes.

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

A. Martin: I will briefly describe the basis for the computations that were made in the preparation of the various Schedules that we have submitted in support of the January 2006 - December 2006 fuel cost recovery adjustments for our Consolidated Electric division and for informational purposes, the two separate electric divisions. In addition, I will advise the Commission of the projected differences between the revenues collected under the levelized fuel adjustment and the purchased power costs allowed in developing the levelized fuel adjustment for the period January 2005 - December 2005 and to establish a "true-up" amount to be collected or refunded during January 2006 - December 2006.

Q. You are also proposing that the Commission allow FPUC to consolidate their Fuel Cost Recovery Clause and fuel rates for their two operating divisions (Northeast Florida-Fernandina Beach, and Northwest Florida- Marianna) aren't you?

A. Martin: Yes we are. FPUC should be allowed to consolidate their Fuel Cost Recovery Clause and fuel rates for the two operating divisions. This would be consistent with the Commission's practice within the State of Florida of other investor owned utilities. Moreover, fuel consolidation is consistent with the Commission's recent action to consolidate base and conservation rates for FPUC's customers in 2004. We also feel this would also be beneficial to all FPUC customers in the long term.

Q. Why does FPUC feel it is appropriate to allow consolidation of the Fuel Cost Recovery Clause for their electric operations?

A. Bachman: FPUC feels it is appropriate to consolidate their Fuel Cost Recovery Clause and fuel rates for several reasons.

First, as Cheryl previously mentioned, the consolidation of fuel rates for all customers in a Company's operating divisions within the State of Florida is consistent practice within the State of Florida for all other investor owned electric utilities. All electric utilities in the State of Florida have one set of fuel rates for all retail customers regardless of the actual costs associated with obtaining fuel for those individual customers. Even if there is only one fuel contract to serve all customers in their operating areas, those contracts have more than likely been developed by averaging the actual cost to serve their customers living in different areas into one set of weighted average rates.

Second, the Commission has allowed consolidation of FPUC's base and conservation rates for many of the same reasons that apply to the fuel rates. In our recent base rate proceeding, the Company offered support for consolidation of all rates. See Docket No. 030438-EI and Docket No. 030002-EI for additional details on the consolidation of these two rates.

Third, the consolidated fuel factor for FPUC will provide additional savings to the FPUC ratepayers by reducing the cost associated with preparing and filing the fuel adjustment factors. The savings will include corporate accounting costs to prepare one filing rather than two, division costs to prepare to file one tariff revision rather than two and the legal costs to make one filing rather than two. The quantifiable cost savings associated with these activities are as follows:

Corporate Accounting Savings -	$1,000
Division Savings -	$1,250
Legal Savings -	$ 500

Furthermore, one can reasonably expect that the FPSC and its staff would experience savings in the areas similar to our savings mentioned above relating to the review, audit, and administrative work associated with the fuel filings. While we do not have a basis to assess or measure these savings, the FPSC staff may be able to guide the Commission in the assessment of the direct savings in the on-going costs of this reduction that may materialize on the regulatory agency side.

The final reason to consolidate fuel is the mitigation of price risk inherent to wholesale markets. As discussed by our consultant in our testimony in support of the Phase in of expected prices of new contracts for fuel, price risk is costly to retail consumers, and it is appropriate to mitigate price risk where possible. The level and volatility of wholesale electricity prices are, to a substantial extent, determined by the level and volatility in the prices of primary fuels, particularly natural gas. In turn, price volatility of fuels is determined by the level of scarcity of supply in comparison to the level of demand. Although natural gas volatility is also sensitive to seasonal weather patterns - e.g., a cold snap in the Northeast - and unexpected supply shocks - e.g., Hurricane Katrina - natural gas has also been relatively scarce beginning in the third quarter of 2005 as a result of continued pressure on supply. In summary, natural gas prices can be unusually volatile during periods of relative scarcity, in this is manifested directly in wholesale spot price volatility.

An historical perspective is always useful, and shown below observed prices and volatility at commercial hubs within the Eastern Interconnection.

	PJM West		Florida-Ga Border		In-State Florida		SERC	
Year	*Average Daily Prices*	*Variation In Daily Prices*	*Average Daily Prices*	*Variation In Daily Prices*	*Average Daily Prices*	*Variation In Daily Prices*	*Average Daily Prices*	*Variation In Daily Prices*
1996	$0.00	$0.00			$25.36	$3.15	$24.85	$3.52
1997	$0.00	$0.00			$28.59	$6.45	$26.23	$8.33
1998	$28.39	$9.96	$61.14	$93.66	$44.79	$47.15	$47.10	$49.78
1999	$38.79	$20.78	$49.52	$43.96	$54.57	$54.40	$50.60	$50.71
2000	$40.40	$11.97	$48.01	$10.75	$50.59	$11.29	$42.99	$11.79
2001	$40.39	$12.49	$41.75	$7.41	$46.23	$7.53	$38.08	$8.48
2002	$35.89	$9.33	$34.95	$5.41	$40.41	$6.64	$30.55	$4.77
2003	$48.63	$10.13	$45.12	$8.50	$52.58	$9.12	$42.00	$7.96
2004	$53.50	$6.41	$51.31	$3.76	$55.69	$4.49	$48.71	$3.73
Average	$40.85	$11.58	$47.40	$24.78	$49.27	$20.09	$42.86	$19.60

Currently prices are sharply higher than the prices shown above, and there appears to be little immediate relief in sight.

This means that short-term volatility in primary fuel prices and thus wholesale power prices are likely to remain for some time. Accordingly, wholesale power suppliers are increasingly reluctant to engage in long-term contracts without the appropriate mechanisms to hedge risks. These mechanisms imply that it is likely that FPUC will, within its new contracts, be shouldering some of costs of price hedging, as incorporated within the commercial terms of the new contracts. As envisioned, the provisions of the new contracts will vary from one contract to another, and thus the integration of the contracts under a common fuel clause umbrella means that retail consumers can better hedge the price risk inherent in fuel contracts, to the benefit of all.

Q. Please describe the regulatory treatment that FPUC would implement for the true-up amounts that exist for each division at the end of the last month prior to consolidating the two division's factors.

A. Martin: It is the intention of FPUC to incorporate the true up amounts that exists for each division at the end of the last month prior to consolidating the two division's factors into the consolidated rate calculations. An alternative course of action would be to exclude the respective true-up amounts from the consolidated rate calculations then adjust the resulting consolidated factor by each true up amount for the respective divisions. The company would then collect from/refund to the customers for a one year period or until the end of 2006.

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

A. Martin: Yes.

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

A. Martin: We have filed Schedules E1, E1A, E2, E7, E8 and E10 for our Consolidated Electric division. They are included in Composite Prehearing Identification Number CMM-6. For informational and analysis purposes only, we have filed Schedules E1, E1A, E2, E7, and E10 for Northwest Florida (Marianna) and E1, E1A, E2, E7, E8, and E10 for Northeast Florida (Fernandina Beach). They are included in Composite Prehearing Identification Number CMM-3. We have also prepared and filed Schedules E1 for our Consolidated Electric division, Northwest division (Marianna) and Northeast division (Fernandina Beach) with the special fuel surcharge requested in Docket 050317-EI as Composite Prehearing Identification Number CMM-5. Additional support for the surcharge amount has been filed as Composite Prehearing Identification Number CMM-4 (CONFIDENTIAL) as well as within this testimony and the testimony filed in Docket No.050317-EI.

Schedule E1-B and E1-B1 for both Northwest Florida (Marianna) and Northeast Florida (Fernandina Beach) were filed last month in Composite Prehearing Identification Number CMM-2. These schedules support the calculation of the levelized fuel adjustment factor for January 2006 - December 2006. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period January 2005 - December 2005 based on 6 Months Actual and 6 Months Estimated data.

Q. In derivation of the projected cost factor for the January 2006 - December 2006, period, did you follow the same procedures that were used in the prior period filings?

A. Martin: Yes, with the exception that we are now requesting one consolidated electric Fuel Cost Recovery Clause and set of fuel rates for both of our electric operating divisions. We are also requesting permission, through Docket No. 050317-EI filed in May 2005, to include a fuel surcharge as an additional add-on to the fuel factor to help minimize the significant future effects of fuel contracts that are expiring at the end of 2007.

Q Why has the GSLD1 rate class for Northeast Florida (Fernandina Beach) been excluded from these computations?

A. Martin: Demand and other purchased power costs are assigned to the GSLD1 rate class directly based on their actual CP KW and their actual KWH consumption. That procedure for the GSLD1 class has been in use for several years and has not been changed herein. Costs to be recovered from all other classes are determined after deducting from total purchased power costs those costs directly assigned to GSLD1.

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

A. Martin: The demand cost recovery factors for each of the RS, GS, GSD, GSLD, GSLD1 and OL-SL rate classes will become one element of the total cost recovery factor for those classes. All other costs of purchased power will be recovered by the use of the levelized factor that is the same for all those rate classes. Thus the total factor for each class will be the sum of the respective demand cost factor and the levelized factor for all other costs.

Q. Please address the calculation of the total true-up amount to be collected or refunded during the January 2006 - December 2006.

A. Martin: We have determined that at the end of December 2005 based on six months actual and six months estimated, we will have under recovered $285,297 in purchased power costs in our Consolidated Electric division. We will have under-recovered $702,270 in purchased power costs in our Northwest Florida division (Marianna). In our Northeast Florida division (Fernandina Beach) we will have over-recovered $416,973 in purchased power costs.

Based on estimated sales for the period January 2006 - December 2006, it will be necessary to add .04204¢ per KWH to collect this under-recovery in our Consolidated Electric division during the January 2006 - December 2006 period (excludes GSLD1 customers). For informational purposes, Northwest division's (Marianna) separate factor would have been to add .21568¢ per KWH to collect the under recovery, and Northeast division's (Fernandina Beach) separate factor would have been to subtract .11814¢ per KWH (excluding GSLD1 customers) to refund the over recovery. Page 3 and 10 of Composite Prehearing Identification Number CMM-3 and page 3 of Composite Prehearing Identification Number CMM-6 provides a detail of the calculation of the true-up amounts.

Q. What are the final remaining true-up amounts for the period January 2004 - December 2004 for both divisions?

A. Martin: For our Consolidated Electric division, the final remaining true up amount was an under-recovery of $1,433,132. In our Northwest division (Marianna) the final remaining true-up amount was an under-recovery of $966,951. The final remaining true-up amount for our Northeast division (Fernandina Beach) was under-recovery of $466,181.

Q. What are the estimated true-up amounts for the period of January 2005 - December 2005?

A. Martin: For our Consolidated Electric division, the estimated true up amount was an under-recovery of $735,918. In our Northwest Florida division (Marianna) the estimated true-up amount was an under-recovery of $246,528. The estimated true-up amount for our Northeast Florida division (Fernandina Beach) was under-recovery of $489,390.

Q. What are the total true-up amounts to be collected or refunded during the period January 2006 through December 2006?

A. Martin: In our Consolidated Electric division, there is an estimated under recovery of $285,297. In our Northwest Florida division (Marianna), there is an estimated under-recovery of $702,270. The Northeast Florida division (Fernandina Beach) has an estimated over-recovery of $416,973.

Q. What will the total fuel adjustment factor, excluding demand cost recovery, be for the Consolidated Electric division and for informational purposes, both separate divisions for the period?

A. Martin: For our Consolidated Electric division, the total fuel adjustment factor as shown on Line 43, Exhibit CMM-6, Schedule E1, is 2.278¢ per KWH. In the Northwest Florida division (Marianna) the total fuel adjustment factor as shown on Line 33, Exhibit CMM-3, Schedule E1, is 2.819¢ per KWH. In the Northeast Florida division (Fernandina Beach) the total fuel adjustment factor for "other classes", as shown on Line 43, Exhibit CMM-3, Schedule E1, amounts to 1.857¢ per KWH.

Q. What will the total fuel adjustment factor, excluding demand cost recovery be for the Consolidated Electric division and for information purposes; both separate divisions for the period if the fuel surcharge is approved (Docket No. 050317-EI) and allowed to be added to the fuel adjustment factor in 2006.

A. Martin: If the fuel surcharge is approved and allowed, the total fuel adjustment factor for the Consolidated Electric division as shown on Line 43, Exhibit CMM 5, Schedule E1, is 2.532¢ January 2006 through June 2006 and is 2.804¢ July 2006 through December 2006. The fuel adjustment factor for the Northwest Florida division (Marianna) as shown on Line 33, Exhibit CMM5, Schedule E1 is 3.074¢ January 2006 through June 2006 and is 3.346¢ July 2006 through

December 2006. The fuel adjustment factor for the Northeast Florida division (Fernandina Beach) as shown on Line 43, Exhibit CMM5, Schedule E1 is 2.111¢ January 2006 through June 2006 and is 2.383¢ July 2006 through December 2006.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January 2006 - December 2006 including base rates, conservation cost recovery factors, and fuel adjustment factor and after application of a line loss multiplier.

A. Martin: For our Consolidated Electric division, a residential customer using 1,000 KWH will pay $64.79, a decrease of $4.76 in our Northwest Florida division (Marianna) from the previous period, and an increase of $2.58 in our Northeast Florida division (Fernandina Beach). For information purposes, if the separate fuel factors were used then in our Northwest Florida division (Marianna) a residential customer using 1,000 KWH would have paid $71.48, an increase of $1.93 from the previous period. In our Northeast Florida division (Fernandina Beach) a customer would have paid $58.97, a decrease of $3.24 from the previous period.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January 2006 - December 2006 including base rates, conservation cost recovery factors, and fuel adjustment factor and after application of a line loss multiplier if the fuel surcharge is approved.

A. Martin: If the surcharge is allowed and added to the cost of fuel for our Consolidated Electric division, a residential customer using 1,000 KWH will pay $67.39 from January 2006 through June 2006 and they will pay $70.18 from July 2006 trough December 2006. For informational purposes if separate fuel factors were used with the surcharge added, a residential customer using 1,000 KWH would pay

$74.09 from January 2006 through June 2006 and would pay $76.88 from July 2006 through December 2006 in our Northwest Florida division (Marianna). In our Northeast Division (Fernandina Beach), a residential customer using 1,000 KWH would pay $61.58 from January 2006 through June 2006 and would pay $64.37 from July 2006 through December 2006.

Q. You have included a fuel surcharge in the fuel adjustment factor. Could you explain that?

A. Bachman: Yes. Since the Company does not have any generating capability we purchase all of the power which we provide customers. Currently we have contracts to purchase power from JEA and the Southern Co. ("Gulf Power"). Both of these have very favorable rates which have benefited our customers for the past 8 years; in fact, the contract rates are significantly below current market rates. Both of these contracts expire on December 31, 2007, and we know that there will be a sharp increase in power costs so we have proposed a surcharge to be added to the adjustment factor to mitigate those expected sharp increases.

Q. How would this surcharge be implemented?

A. Martin: The surcharge would be added to the cost of fuel for two years and when the new contracts are effective the accumulated amounts would be credited back to customers over a three-year period.

Q. Would there be a separate account for the surcharge?

A. Bachman: All of the revenue collected from the surcharge would be held in an interest bearing account and all of the accumulated amounts plus interest would be flowed back to the customers. The Company will not receive any of these revenues and the accumulated surcharge would not be part of the working capital.

Q. How will this benefit customers?

A. Bachman: We know that there will be a sharp increase in the fuel adjustment factor beginning January 1, 2008 and this proposal would mitigate that increase. By collecting the surcharge now and incurring the additional interest and then crediting these amounts back to customers the increase can be phased in and we can mitigate the rate shock to our customers.

Q. What is the amount of the surcharge for 2006 that has been added to the fuel rates?

A. Bachman: Effective January 1, 2006, the Company will add a surcharge of $.00254 per KwH to the cost of fuel. Effective July 1, 2006, the Company will add a surcharge of $.00526 per KwH to the cost of fuel. This surcharge has been incorporated into our requested fuel rates and schedules.

Q. Have you entered into new contracts that result in these amounts?

A. Bachman: No, we do not have the final contracts in place at this time.

Q. What is the status of those contracts?

A. Bachman: We are reviewing and analyzing proposals at the present.

Q. Explain the process you established.

A. Bachman: We began looking at our options several months ago. We recognize the importance of these contracts and we involved Christensen Associates to assist in looking at our options and helping with the RFP and negotiations. With their help, we invited interested parties to provide proposals and we received a number of responses and those are being evaluated. We expect to have discussions with several of the responding parties and our objective is to negotiate the most favorable contract that we can for our customers.

Q. When will that be completed?
A. Bachman: Probably sometime in 2006.
Q. What is the basis for the surcharge you have proposed?
A. Bachman: We have detailed projections supporting expected future price increases that more than justify the use of these conservative fuel surcharge factors. Since we are still in the process of negotiations for fuel contacts, our future fuel expectations are confidential in nature. We have provided this projection on a confidential basis, as Exhibit _____ (CMM-4). We feel there is sufficient evidence to support the use of this surcharge in 2006. Even without finalization of our fuel contracts and completion of the bidding process, we are able to estimate what market fuel costs are expected to be in the future, and fuel costs are expected to be well above the amount of our requested 2006 surcharges. Since the surcharge is a gradual increase and a phase in of the future expected price increases, the surcharge for 2006 is appropriate and is expected to provide for a gradual increase in the fuel costs to our customers.
Q. Have you requested approval of this proposal in a separate petition?
A. Martin: Yes, we have. We have filed a petition and testimony for approval of the surcharge in Docket No. 050317-EI but we think it appropriate to consider it in this docket since it is a component of the fuel adjustment factor.
Q. You mentioned that you used Christensen Associates to assist in this process. Have those costs been included in the calculation of the proposed fuel adjustment factor?
A. Martin: Yes, they have.
Q. Should the Commission allow FPUC to recover fees paid to

Christensen Associates to perform FPUC's request for proposals for wholesale capacity and energy commencing 2008 and develop a rate smoothing surcharge for 2006 and 2007?

A. Martin: Yes. As I discussed, FPUC retained the consulting group, Christensen Associates, to develop and manage the bidding process for power supply beginning in 2008 for FPUC's electric operations. This process organized by our consultants is a highly structured process that casts a wide net in search of the best overall power supply arrangement for our retail customers. The level of interest in, and market response to, the Company's RFP has been good and, as intended, a substantial level of contestability has developed. Our company is not large enough to have this type of resource on staff and the experience, knowledge, and expertise that they contribute to the process helps us to obtain more favorable results. If we were to expand our staff to include similar resources, the customer impact would be great.

Q. How do the customers benefit from your use of the consultants?

A. Martin: By using a consultant in this process, we are able to supplement our in-house resources with the experience and knowledge the consultants have of the broad process. We believe that having this resource available to us will result in a more favorable power supply arrangement. Any reduction in the cost of fuel over the life of the contract benefits the customers. For example, a $.0001 per kWh reduction in the cost of fuel results in savings of over $400,000 in just five years and this well exceeds the cost for the consultant in this process. We feel that the savings will be much greater than this over the life of contracts through lower fuel prices.

Q. Couldn't you negotiate new contracts with Company resources?

A. Martin: We could, but the market now is very different than it was when the current contracts were negotiated and there may be more options available to us now than there were then. Having the advice and assistance of consultants who work with this process more frequently strengthens our efforts and enhances our ability to obtain contracts favorable to our customers.

Q. Are these consultant's costs included in your base rates?

A. Martin: No. These costs have not been recovered through our base rates as they directly relate to the fuel and fuel costs. Since these costs directly relate to our fuel costs and will likely result in lower fuel costs to the customers, they are appropriate to recover through the fuel cost recovery clause. These costs are not the normal procurement and administrative costs that would be associated with ongoing fuel purchases. It is possible upon award of our new fuel contracts that administrative personnel will be needed to manage and procure our fuel on an ongoing recurring basis; however, we cannot determine whether this will be necessary with our new fuel contracts at this time. The costs for the services of Christensen Associates are nonrecurring special costs associated directly with the cost of fuel and these probably would not have been allowed for recovery through base rates since they would not be in the test year and would not be recurring expenditures. To disallow the recovery of these costs would penalize the Company for acting in a prudent manner on behalf of the customers for savings in their fuel costs.

If the Commission feels it would be more appropriate to recover these costs through base rates, we would like to request permission to defer these until our next rate proceedings and amortize the costs at that time with the associated recovery of the costs.

Q. The audit report of the Fuel and Purchased Power Cost Recovery Clause conducted by Staff contained a disclosure regarding payments to Gulf Power for a transformer agreement that commenced in November 2004. Can you explain that agreement?

A. Cutshaw: Yes. As previously discussed, FPUC currently purchases all wholesale capacity and energy from Gulf Power/Southern Company for the Northwest Division. At each of the delivery points, Gulf Power provides all transmission, substation and transformer facilities and associated equipment. FPUC only provides the distribution facilities at each delivery point. In 2004, additional facilities were needed to service a new "Family Discount Distribution Center" and FPUC and Gulf Power entered into an amendment to the current contract where Gulf Power provides a transformer and associated equipment necessary to establish an additional delivery point at our Marianna substation. The terms of the five year agreement calls for Florida Public Utilities Company to pay Gulf Power $3,678 a month commencing November 2004. The "South Marianna delivery point" was constructed to match the facilities at the other delivery points in order to maintain the integrity of the current contract.

Based upon the fact that the new transformer and associated equipment at the "South Marianna delivery point" are owned and operated by Gulf Power Company who currently provides wholesale capacity and energy, it seems reasonable that these costs to FPUC should be included for recovery through the fuel clause. Since this delivery point was not included in the existing wholesale power contract and was not included in the development of those rates, it was determined that the cost to provide power to this delivery point was not justified by the current contract price. This resulted in the necessity for a facilities charge being added to the current contract energy cost.

Q. Does this conclude your testimony?

A. Martin, Bachman, and Cutshaw: Yes.

BY MR. HORTON:

Q. Now, with respect to all four of you with respect to the fuel cost recovery and phase-in plan, have you prepared and prefiled direct testimony in that proceeding, or in this proceeding?

A. (By Ms. Martin) Yes, we have.

Q. Do you have any changes to make to that, to your portion of that testimony?

A. Yes. The surcharge factor has been updated to reflect a consolidated factor as shown in the 01 testimony filed on September 9th, and those factors have also been changed to two factors per year to allow a more gradual increase.

Q. With that clarification, if I were to ask you the questions contained in that testimony today, would your answers be the same?

A. Yes, they would.

MR. HORTON: Mr. Chairman, I would request that the prefiled testimony, fuel cost recovery and phase-in plan, be inserted into the record as though read.

CHAIRMAN BAEZ: All right. Now, before I do that, this is the testimony that you're referring to, Ms. Christensen?

MS. CHRISTENSEN: I believe this is the testimony that I'm referring to. It's panel testimony, but it does not identify which individuals are responding to the individual questions.

CHAIRMAN BAEZ: And how are we going to address that, Mr. Horton?

MR. HORTON: Questions with respect to a discussion of the company historical data, historical arrangements, the concepts for the proposal that we've presented, design principles, and efficiencies of the proposal should be directed to Mr. Bachman. And when you're asking -- if you've got questions with respect to the markets, market expectations, projections, outlook for the fuel prices, calculations, that would be Mr. Camfield. And Ms. Martin may also have some responses to the calculations. And I think our testimony pretty much follows in that line.

CHAIRMAN BAEZ: Ms. Christensen, to the extent that you're referring to questions in the prefiled testimony directly, you can -- we can try and ascertain who was responsible for the response ahead of time. It's going to be a little messy, I know, but if we're going to get this testimony, or if we're going to get this part of the hearing in, I think we have to shift on the fly on this one.

MS. CHRISTENSEN: Well, I'll do the best that I can, sir.

CHAIRMAN BAEZ: No, that's fine. We all will.

Very well. Without objection, show the direct testimony of Bachman, Martin, Cutshaw, and Camfield entered into the record as though read.

DIRECT TESTIMONY

OF

GEORGE BACHMAN

CHERYL MARTIN

MARK CUTSHAW

ROBERT CAMFIELD

IN

FLORIDA PUBLIC UTITITIES COMPANY

PETITION OF
FLORIDA PUBLIC UTILITIES COMPANY

FUEL COST RECOVERY AND PHASE-IN PLAN

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

A. Witness Bachman. My name is George Bachman. I am the Chief Financial Officer and Treasurer of Florida Public Utilities Company. My business address is 401 South Dixie Highway, West Palm Beach, Florida, 33401.

Witness Martin. My name is Cheryl Martin. I am Controller for Florida Public Utilities Company. My business address is 401 South Dixie Highway, West Palm Beach, Florida, 33401.

Witness Cutshaw. My name is Mark Cutshaw. I am the Director of the Northwest Florida Division for Florida Public Utilities Company. My business address is 2825 Pennsylvania Avenue, Marianna, Florida 32447.

Witness Camfield. My name is Robert Camfield. I am a Vice President with Christensen Associates Energy Consulting LLC (CAEC). My business address is Suite 700, 4610 University Avenue, Madison, Wisconsin, 53705.

Q. What is the scope of your testimony?

A. The scope of our testimony is twofold. First, we provide evidence in support of the costs of power supply (generation and transmission services) of Florida Public Utilities Company (FPU or Company), for use in determining the retail price of the Company's fuel cost recovery mechanism. Second, our testimony presents the Company's proposed phase-in of costs associated with sharply higher power supply costs beginning in January 2008, as anticipated. In the course of presenting the proposed phase-in plan, we review current conditions of wholesale power markets and the implications for power procurement; and we present the Company's overall procurement strategy.

Q. Please review your professional background and experience that qualifies you to provide such recommendations.

A. Witness Bachman. I have Bachelor of Science Degree in Business Administration from Indiana University in 1981, with a concentration in Accounting. I subsequently joined Southeastern Public Service Company, and served as the Assistant Controller at the time of my departure in January 1985, when I joined Florida Public Utilities Company. My positions through 1998 included General Accounting Office Manager, Accounting Manager, and Controller.

In 1999 I was appointed to my current position, Chief Financial Officer and Treasurer of Florida Public Utilities Company. As the senior financial and accounting official of the Company I have overall fiduciary responsibility and oversee the accounting and finance department with all related functions. The accounting and finance staff maintains the accounting systems and carries out day-to-day functions such as revenue accounting, cost accounting, cash management, tax accounting, and payroll. Our area maintains the financial records of the Company and reports financial results. The accounting and finance department is also responsible for various studies in support of accounting activities, such as determination of depreciation rates. As Chief Financial Officer, I represent the Company before the investment community including investment and commercial banks. Finally, I am responsible to the Chief Executive Officer for the development of financial policy, and I am involved in determination of overall business strategy at the highest level.

I have been an expert witness in numerous fuel, purchased gas, and rate relief proceedings before the Florida Public Service Commission for electric, gas, and water.

Witness Martin. I have been employed by FPU since 1985 and I have worked within numerous accounting functions Company. I assumed the position of Corporate Accounting Manager in 1995. In this position, I managed the Corporate Accounting Department including regulatory accounting (Fuel, PGA, conservation, rate cases, surveillance reporting, and general regulatory reporting), tax accounting, external reports, and various special projects. In January 2002, I assumed the position of Controller of the Company where, in addition to the above duties, I also have responsibilities in purchasing, general accounting, and Securities and Exchange Commission (SEC) reporting. I have been an expert witness in numerous proceedings on behalf of FPU before the

Florida Public Service Commission (FPSC), including rate relief in Docket Numbers 881056-EI, 930400-EI, and 030438-EI for retail electricity service, and 900151-GU and 940620-GU for retail natural gas service. I graduated from Florida State University in 1984 with a Bachelor of Science degree in Accounting. I am a Certified Public Accountant in the State of Florida.

Witness Cutshaw. I joined FPUC in May 1991 as Division Manager in the Marianna Division. In 2001, my title was changed to Director, Northwest Florida. My work experience and responsibilities at FPUC include all aspects of budgeting, customer service, and operations and maintenance in the Marianna/Northwest Florida Division. In 2003 – 2004, I testified before the Florida Public Service Commission in Docket 030438-El on rate design and related matters. In 1993, I participated in the Cost of Service study for the Marianna Division Rate Case Filing and testified during the proceeding. I have also been involved with numerous proceedings and matters of Florida Public Utilities Company before the Commission, including filings, audits, and data requests for the FPSC. I graduated from Auburn University in 1982 with a B.S. in Electrical Engineering and began work with Mississippi Power Company in June 1982. I left Mississippi Power Company in May, 1991 while in the position of Supervisor, Electric Operations. While at MPC, I was involved in the budgeting, operations and maintenance activities in the Hattiesburg, Laurel and Pascagoula Districts.

Witness Camfield. I am a graduate of Interlochen Arts Academy, and hold a Bachelor of Science Degree in Business Administration from Ferris State

University with an emphasis in Management, graduating in 1969. I earned a Master of Arts Degree in Economics at Western Michigan University in 1975, with a concentration in Monetary Theory and Policy. I joined the Michigan Public Service Commission in 1976 as a staff economist. During my tenure with the Michigan Commission, I was involved in several retail electricity and natural gas pricing issues, and I testified in several rate case proceedings regarding cost of capital and retail gas prices. I joined the New Hampshire Public Service Commission in 1979 as the senior economist, and held the position of chief economist beginning in 1981. In these positions, I was responsible for the development, administration, and training of the economics staff. I oversaw economic analysis and the development and delivery of testimony, and provided policy advice to the Commission on a variety issues such as construction work in progress, financial planning, and the determination of PURPA Section 133 rates. I joined Southern Company in 1983, and held positions in several departments including Pricing and Economic Analysis at Georgia Power Company, Costing Analysis at Southern Company Services, and Southern Company's Strategic Planning Group. In 1994, I joined Laurits R. Christensen Associates, Inc. as senior economist, and currently hold the position of Vice President. My experience covers a gamut of issues facing regulated industries. I have represented agency staff, consumer advocates, independent generation companies, utilities, and transmission companies before nine regulatory agencies regarding cost of capital, cost benchmarking, forecasts of electricity demand, retail rates, cost of service allocation, generation planning, and transmission issues. I have been involved in the negotiation of power supply contracts and the terms for franchise licenses. My overseas assignments are several, and I recently managed a large market restructuring project in Central Europe. I have served on national and regional advisory panels, and I have advised electric companies on numerous policy and technical issues. Innovations include two-part tariffs for transmission services, web-based self-designing retail electric products, marginal cost-based cost-of-service methods, and efficient pricing of distribution services. I have published chapters in books, reports, and articles in noted journals such as *The Electricity Journal, CIGRE,* and *IEEE Transactions on Power Systems*. Currently, I am the Program Director of EEI's Market Design and Transmission Pricing School. My resume, including the list of formal appearances before regulatory agencies, is attached.

Q. Can you please review the market context and situation of Florida Public Utilities Company?

A. Yes. The electricity business unit of Florida Public Utilities Company is a distribution utility that serves two retail markets of northern Florida. These markets are referred to as the Northeast and Northwest divisions. During 2004, the Northeast division, also known as Fernandina Beach, served 15,100 customers with gross electricity sales of 449,464 MWh. The Northwest division, also known as Marianna served 15,000 customers with gross electricity sales of 316,884 MWh.

The Northeast division distribution system is interconnected with JEA (formerly the Jacksonville Electric Authority) transmission network at one delivery point with 150,000 kVA of transformer capability and 138 kV primary feeders. The Northwest division interconnects with Southern Company's transmission network at five delivery points with 130,000 kVA of capability and 12.5 kV primary feeders.

Q. What are the Company's current arrangements for the power supply?

A. Both divisions of the Company are wholly dependent upon external purchases of generation and transmission (G&T) services to satisfy the needs of the Company's retail markets. Accordingly, FPU has, for a number of years, engaged in full requirements contracts for G&T services with suppliers in the southeast region. Full requirements refers to an umbrella or package of services covering the total loads of FPU, and includes energy (balancing or spot energy), reserve service categories of regulation, spin, non-spin, and backup, ancillary services of voltage support and black start, and the transmission services of network transport services and transaction scheduling. Full requirements services have been and are currently provided to FPU under long-term contracts with JEA in the case of the Northeast division, and with Gulf Power Southern Company (Gulf/SoCo) in the case of the Northwest division. Both contracts date to 1997 and expire in December 2007. The Company is currently implementing its strategy for power supply for 2008 and beyond. This involves the recent release of the Company's all-source RFP.

Q. Have the current contracts been favorable overall, and in the general interest of the Company's retail customers?

A. Yes. The current full requirements power supply arrangements have been wholly successful. Both suppliers, JEA and Gulf/SoCo, have served Florida Public Utilities Company and its retail electricity customers well from a broad perspective including reliability, counterparty risk, and commercial terms of sale. The contract terms and prices of the current contracts were negotiated in good faith by the contracting parties within an environment of increasing contestability in wholesale markets. The negotiation process resulted in commercial terms that have been fair to the contracting parties including JEA, Gulf/SoCo initially. However, wholesale prices rose substantially during 1998 and 1999, and with the exception of 2002, the terms have been generally favorable to the Company in all years thereafter. It is useful to reference Exhibit BMCC-5, which shows compiled day-ahead spot prices for energy for the relevant regions of the North American Reliability Council regions include the Southeastern Electric Reliability Council (SERC) and the Florida Reliability Coordinating Council for individual months of the years 2000 – 2004. As observed, these prices range from $33 to $49 for SERC and from $43 to $52 for the FRCC over these years. A similar story is revealed for the early contract years, in part due to a large and unanticipated run-up in short-term prices during 1998 and 1999. However, it is important to recognize that *ex post* comparisons of spot prices with respect to contract prices agreed to at the start of a period simply describe the outcome of events beyond the contracting parties' control or influence. Ex post prices can reside outside the range of expectations held by the counter parties at the time that the contracts were agreed to.

The Company's successful arrangements for power supply coupled with its cost efficiency in distribution services mean that the retail customers of FPU have enjoyed and continue to enjoy low-cost and reliable retail power services. Indeed, Exhibit BMCC-6 shows that customers of Florida Public Utilities Company currently enjoy about a 20% cost advantage with respect to peer groups.

Q. What is Florida Public Utilities Company's strategy for power supply beyond December 2007?

A. The Company has issued a *Request for Proposals for Wholesale Power Supply* (RFP), and is in the midst of receiving and assessing offers to provide wholesale power supply including generation and transmission services. The anticipated offers by bidders will be assessed according to the dual objective of minimizing prices and overall risks to retail consumers, where risks include price volatility, delivery, and counterparty risks.

The Company is pursuing all possible avenues and measures to obtain the lowest possible prices in order to sustain its competitive price advantage in retail markets. The RFP is the first major step in the Company's transparent and open procurement process. The procurement process is geared to building contestability by facilitating the maximum level of bidder participation. Accordingly, the Company's RFP has been delivered to a fairly large number of suppliers that have expressed interest in responding to the RFP.

The procurement strategy is set up in a manner that provides the basis to diversify risks by building a contract portfolio that includes multiple suppliers and contract laddering for the two divisions. To this end, the RFP seeks to obtain three types of offers to supply: Full Requirements, Partial Requirements, and Energy Service (block energy). Bids will be assessed according to objective, value-based criteria. Nonetheless, the full success of the RFP is somewhat dependent upon the level of participation of bidders, and the offers themselves.

The Company has been remarkably successful as a low-cost service provider, particularly in view of the absence of potential scale economies at all levels and areas of its operations. From the perspective of the RFP and power supply, the Company is mindful of possible limits occasioned by its comparatively small-sized electricity operations in terms of risk diversification. Also, the Company remains concerned about the timing of the release of the RFP, which is taking place at a time of high cost wholesale market prices. Thus, it is essential that the term and the structure of the commercial terms of the resulting contract match up with the overall market outlook at the time that power supply contracts with winning bidders are finalized, and do so in a way that captures benefits in the form of lower prices should wholesale prices subsequently decline.

Q. What are the likely results of the Company's power procurement process?

A. It is likely that the contemporary conditions of electricity markets will translate into sharply higher prices for generation and transmission services beginning in

2008. As we mentioned, wholesale electricity prices have risen to exceptionally high levels since 2004. This contemporary experience affects expectations of the future; that is, forward prices reflect commitments conditional upon expectations of the future. In turn, expectations of future spot prices reflect recent price experience of wholesale markets.

As with all forward markets including commodities, currencies, and financial markets, expected electricity market conditions and spot prices are implicit in market participants' willingness to supply (sell) and willingness to pay (purchase) over future periods. That is, bids and offers reflect the expected future short-run marginal costs/spot prices of the region as such costs/prices reflect opportunity cost – essentially, the highest-valued use of resources, otherwise known as market worth. As observed, prices of New York Mercantile Exchange (NYMEX) futures (standardized forward contracts) for delivery at various locations across the Eastern Interconnection as well as in the West over the ensuing two or three years, are trading within the range of roughly \$58 to \$75 per MWh. Not surprising, futures prices are lower during off-peak months than during peak months. Also, futures contracts for off-peak hours trade lower, ranging around \$40 per MWh. Of particular concern are the high prices of off-peak periods, which are driven largely by exceptionally high costs of primary fuels, the major input to the process of producing and generating electricity, and to a lesser extent by the increased frequency that gas-fired generators are on the margin.

Q. What are the implications of high forward wholesale prices for retail consumers?

A. The implications for retail consumers are twofold. First, customers of Florida Public Utilities Company face substantial likelihood of sharply higher retail prices for power supply. While the Company is committed to obtaining the best outcome from its procurement process, the resulting prices reflect the realities of wholesale markets, and are properly incurred costs and wholly prudent in all aspects. The higher prices of the succeeding contracts for power, as expected, will bring the retail prices of the Company to an overall level that approaches that of other service providers in the region. Nonetheless, the Company believes that, through its efficient power procurement process and ongoing business operations, it will remain the price leader within the Florida region over the foreseeable future, particularly in view of the significant upward pressure that higher primary fuel prices will have on all utilities within the region and at the national level.

Second, under the current regulatory framework, retail prices will rise abruptly when the new wholesale supply contracts come into force in January 2008. The abrupt transition to the higher price level constitutes a needless and burdensome shock to customers that can be eased with mitigating policy and action. Transitioning to the high prices is an issue of vital importance to retail consumers, and Florida Public Utilities Company wishes to enlist the assistance of the Florida Public Service Commission. Through appropriate regulatory policy, the Commission and the Company can help retail consumers to bridge the ensuing and difficult timeframe.

Q. What strategies are available to mitigate the abrupt change in wholesale power costs on retail customers?

A. As commonly recognized, sudden abrupt bill changes and volatility (variation) is costly to consumers. While high prices are evidence of the contemporary markets that we face, the Florida Public Service Commission and the Company can take progressive action to largely mitigate what is likely to otherwise be a clear-cut case of rate shock. To this end, the Company proposes to phase in the impact of higher expected wholesale power costs to retail customers over the 2006 – 2010 timeframe. The effect of the phase-in plan is to soften the impact of the large price rise on customer bills, as anticipated. In so doing, the overall welfare of customers will be improved.

Q. What are the design principles that underlie Florida Public Utilities phase-in plan?

A. The proposed phase-in plan and framework is premised on a central design principle. That is, the recommended plan should improve welfare while also satisfying a *"hold harmless"* constraint. In the immediate context, hold harmless means that the retail customers of the Company are left indifferent in money flows, regardless of the approach taken. That is, the plan is bill neutral in terms of discounted money flows for customers as a whole. The proposed phase in plan obtains improvements in overall welfare by mitigation/ elimination of rate shock while also satisfying hold harmless criteria.

Q. What are the main elements of the proposed phase-in plan?

A. The Company's proposed plan has several key features. First, the proposed plan incorporates a *surcharge*, a special and temporary charge to retail customers on fuel costs during the two years previous to the effective date of the new contracts. The surcharge amount would be implemented in two steps during these two years, 2006 and 2007. The second step, 2007, is somewhat higher in absolute terms than the first step, 2006, as the surcharge ramps up and approaches the anticipated contract prices, which are effective in early 2008.

The second feature is *interest accrual*. That is, the surcharge amounts accrue interest monthly at 2.8 per cent interest, which is the current cost of commercial paper. The total accrual amount including principal and interest accumulate in an escrow account. The accumulated surcharge and interest should also be excluded from the company's working capital for purposes of surveillance and base rate making in order to hold the company harmless as well as customers.

The third feature of the plan is referred to as *flow-back credits*, where the escrow balance at year-end 2007 is flowed back as credits (reductions) to the retail charges for the new contracts, in three steps over the years 2008, 2009, and 2010. The flow back credits diminish over time, with the amount of the credit for 2008 greater than that of 2009, and with 2009 greater than that for 2010. The surcharge amounts, escrow accrual, and flow-back amounts are subject to full accounting audits and checks, and review by the Florida Public Service Commission.

The fourth feature of the Company's proposed plan is referred to as *within-process adjustment and reconciliation*. That is, the surcharge amounts will be adjusted as market expectations change, as actual energy sales deviate from forecast sales, as offers are received, and as contracts for new power supply are reached. Finally, we wish to mention that the baseline point used to determine the surcharge amounts are, by design, out-of-market in order to preserve incentive compatibility.

Q. Given current expectations of the Company, please describe the surcharge amounts and the implied revenue and escrow amounts obtained with the proposed phase-in plan.

A. The proposed surcharge amounts for 2006 and 2007 and the resulting revenues and escrow balances are shown on pages 1 and 2 of Exhibit BMCC-1, for the Northeast and Northwest divisions of FPU respectively. As shown for the Northeast division (page 1), the 2006 surcharge is 0.644 cents per kWh, while the surcharge for 2007 is 1.418 cents per kWh. These surcharge values are applied to energy sales during the months of January – December of 2006 and 2007.

For the Northeast division, the surcharges revenues resulting from the implementation of the phase-in plan are expected to be $3,147,560 and $7,191,467 for 2006 and 2007, respectively, stated in nominal terms. With the inclusion of the accrual of interest, the resulting escrow balance at December 2007 is expected to be $10,560,025. As proposed, interest is compounded monthly.

As mentioned above, the escrow amount is flowed back as a credit to customer bills during 2008 – 2010. The flow back credit amounts received by customers are equal to $5,586,226 during 2008, $3,338,752 during 2009, and $1,995,523 in 2010. Escrow balances accrue interest over the course of the flow back period, 2008 – 2010.

The surcharge and flow back credits are less for the Northwest division because of lower sales quantities and higher contract prices for power supply currently, than for the Northeast division. Specifically, the 2006 surcharge is 0.321 cents per kWh, while the surcharge for 2007 is 0.676 cents per kWh. The expected surcharge revenues obtained by the phase in plan in the Northwest are $1,024,210 and $2,196,775 for 2006 and 2007, respectively, stated in nominal terms. With the inclusion of the accrual of interest, the resulting escrow balance at December 2007 is expected to be $3,291,077.

The escrow amount flowed back as credits to customers in the Northwest division during 2008 – 2010 are equal to $1,711,652 during 2008, $1,049,566 during 2009, and $643,623 in 2010.

Q. Please describe the size the rate shock impacts facing customers absent the phase in plan.

A. As mentioned, the increases in prices are large without the implementation of the phase in plan. Exhibit BMCC-1 page 3 shows the anticipated rate impacts on customer bills beginning in the year 2008 without the presence of the plan. As can be seen, the percentage change in the customer bills of residential, commercial, and industrial consumers range from 22 to 78%. Abrupt change in customer bills of these magnitudes are of major concern, and evidence of the substantial burden placed on retail consumers in the absence of the phase in plan.

In addition, the bill impacts differ significantly among customers and it is useful to review the differential impacts. Without the phase in plan, customers of the northeast division face significantly larger increases than customers of the northwest division. This is because the current contract prices for wholesale power supply for the northwest division are higher than the corresponding prices for the northeast division. As observed, the percentage change in customer bills range from 22% to 45% for the northwest division, whereas the impacts for the northeast division are larger still, ranging from 35% to 78%. As a general rule, the change in the electricity bills facing customers rises progressively with an increasing share of the current bill composed of costs of wholesale power. For this reason, the larger customers of the northeast division in particular face very large bill impacts.

The bill impacts clearly demonstrate the need to phase in the costs of the Company's new contracts.

Q. Can you please elaborate on and briefly discuss fairness and efficiency aspects of the proposed phase in plan?

A. Yes. The proposed plan has both fairness and market efficiency aspects. From a social efficiency perspective, the path of the phase in prices more closely matches wholesale prices, which reflect societal marginal costs of power, over the years of the surcharge, 2006 and 2007. Overall efficiency is improved and the level of retail sales will be somewhat less than otherwise during these years. Conversely, phase in prices experienced by consumers depart from wholesale prices during the period of the flow back credits. Accordingly, retail sales levels will be somewhat greater than otherwise during these latter years.

The first order welfare impacts of the proposed plan, measured as consumer surplus and as reflected in expected electricity sales impacts, are significant for individual years but small overall for the several years over which the plan is in effect. However, our main concern and the purpose of the proposed phase in plan is the benefits obtained by introducing a degree of gradualness in price changes – essentially, second order benefits realized through of stability of prices. By attenuating rate shock, a form of risk, the proposed plan reduces harm caused by a sudden increase in prices. It is predominantly this reason rather than market efficiency that underlies the Company's petition to the Commission to implement the phase in plan as proposed.

Q. Do customers prefer reduced risk, and does the phase-in plan add value?

A. Yes. Cursory observation, intuition and common sense, and formal empirical evidence across a broad range of markets suggest that risk and uncertainty are costly and that economic agents, both firms and households, prefer less risk all other factors constant. A large number of examples of risk aversion in the behavior of agents are readily available:

1. The comparatively large-scale participation and steady growth of futures markets and over-the-counter forward contracts for wholesale commodities including energy, agriculture, and metals, as well as the steady expansion of the products that are traded forward.

2. The longstanding presence of comparatively long-term debt instruments in financial markets, the growth in financial options including complicated compound features.

3. The appearance of weather-related insurance to mitigate financial losses attributable to crop damage, and insurance to guard against damaged goods and cargo while in transit.

4. The growth in the volume of transactions in forward currency markets.

5. The expansion of consumer insurance markets beyond life, auto, and home insurance categories and products. Insurance coverage is commonly available for health, consumer electronics, boats, automobile repair and service, tires, theft, and appliances. In addition, the range of coverage of insurance menus and options has expanded vastly.

6. The appearance of forward retail contracts for home heating oil and propane gas.

7. The vast expansion of specialized insurance products for business that cover a broad range of contingency events such as physician malpractice, and disability and physical incapacity for athletes and artists, as well as insurance for highly valued art and musical instruments.

8. Strong consumer preferences for fixed-price open-quantity tariff design for regular telephone service in lieu of measured service.

9. Equity share prices, as traded on major financial exchanges worldwide, are ordered according to perceptions of risks. If equity A has equivalent expected cash returns to capital but higher perceived risks vis-à-vis the cash returns and risks of equity B, A will trade at market prices lower than that of B. The lower prices of A provide the means for the realization of higher expected market returns to shareholders of A than to the shareholders of B, thus compensating for the higher risks implicit in holding the shares of A.

Risk management mechanisms and insurance tools are the vehicles of markets to mitigate risks and the costly effects of uncertain events associated with the many aspects of business and life. In so doing, a broad spectrum of markets are made more complete. A window to the expanding opportunities to hedge risk is Robert Shiller's recent book entitled "The New Financial Order: Risk in the 21st Century" published in 2003. The range of possible products and applications of risk management principles is vast. The essential point is that there exists a broad base of market experience to affirm the intuitive notion that risk is costly and that economic agents are willing to compensate third parties willing to assume the costly burden of and responsibility for risk. In short, agents prefer less risk to more, and market processes can be expected to implement many new innovations to mitigate risk.

Q. What about retail electricity markets? Is there explicit evidence and examples of risk aversion in the choices of consumers?

A. Yes, examples of risk aversion behavior by participants in electricity markets are readily at hand. For example, the fast expansion of fixed bill products at the retail level, and the wide scale participation in financial and physical transmission rights at the wholesale level are immediate examples. The fact that fixed bill products, which hedge quantity risks, are typically offered at premium prices suggests that many consumers are willing to pay higher *expected* prices for the risk hedging features of fixed bill products. In essence, consumers make value-improving choices, and by selection of premium-priced fixed bill options, retail consumers can improve welfare. This means that, for those customers that self select fixed bill products, the inherent quantity risks of the standard offer tariff, as perceived, is more costly the price premium attending the risk management feature of the option.

A second example of the costly nature of risk is the selection behavior of retail customers that are confronted with bill-neutral time-of-day options. To a substantial degree, customers prefer conventional non-varying price open quantity tariffs, which are common and prevalent among retail tariffs of service providers, to the TOU option. Generally, the TOU option is selected only when customers are capable of substantially shifting load to the lower-priced off peak periods – thus reducing the total electric bill – *or* where the customer bill on the TOU option is somewhat below that of the conventional tariff, holding quantities constant.

A third example is the self-selection of curtailable service load control options. To a large extent, customers will only chose such options when they are attended by rather substantial discounts in comparison with the firm service of standard offer tariffs. Essentially, the uncertainty associated with non-firm supply is costly, and sufficient discounts are necessary to obtain customer participation in non-firm power supply.

Q. What are the policy lessons and principles that we can draw from market experience and the behavior of agents regarding risks?

A. First, it is quite clear that risk is costly, and that the Commission and Florida Public Utilities Company should take the necessary action to reduce risks in a cost effective manner where possible. Second, the Commission should support the Company's plan to phase in the anticipated higher prices for power supply. In so doing, the Commission mitigates the costly impacts of rate shock, thus improving the welfare of the retail customers of Florida Public Utilities Company.

Q. Is there precedent for the phase-in of sharply rising costs for power supply?

A. While the reasons, situation, and market context were unique to the earlier era, a number of incumbent utilities phased in large-scale and costly base load power plants during the 1980s. Utility sponsors and regulators allowed and fully supported the phase-in of prudently incurred costs over several years in order to ease the burden of what would have otherwise been serious rate shock events.

It is useful to mention that the situation during this previous timeframe is in sharp contrast to that of the Florida Public Utilities Company in several important respects. Back then, large-scale base load plants were the primary cause of rate shock, and their utility sponsors had in several cases breached the confidence of retail customers and regulators, as manifest in costly overruns of construction budgets. As a result, the plants and their sponsors sometimes faced serious regulatory issues related to the need for additional resources, technology choice, and plant costs that were significantly out-of-market.

In contrast, the situation of the Company contains none of these issues. Rather, Florida Public Utilities Company faces higher costs simply because of the contemporary realities of wholesale markets.

Q. Would you please describe the workings of power markets in the Southeast, and the implications for power procurement?

A. Wholesale power markets were opened to new entrants with the passage of the national Energy Policy Act of 1992. Provisions of the Act called for incumbent transmission service providers, most of which were and continue to be vertically integrated electric companies, to allow access to transmission networks to buyers and sellers of wholesale power. Authority for implementation, oversight, and enforcement of the wholesale electricity market provisions of the Energy Policy Act was assigned to the Federal Energy Regulatory Commission (FERC).

The market mechanisms and procedures for obtaining access to power networks and scheduling wholesale transactions were not formalized, and the process was encumbered by burdensome scheduling, procedural, and institutional inefficiency. Arguably, accessibility to networks was effectively denied by procedural burdens for several years. A defining moment in the organization of wholesale markets was the Open Access Transmission Tariff as established in 1996. In April of that year, the FERC issued two landmark orders:

- Order 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities;* and,
- Order 889, *Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct.*

In addition to functionally separating the generation and transmission functions and activities of incumbent utilities, these two companion orders define categories of wholesale services, define the basis for determining the prices for wholesale services, and set forth fairly definitive procedures regarding the scheduling of wholesale transactions among control areas of the Nation's transmission grid using web based services (OASIS).

While the FERC has authorized the further unbundling of wholesale markets with the formation of ISOs and RTOs in California and the northern regions of the Eastern Interconnection, FERC Orders 888 and 889 constitute the authority for the conduct of power markets in much of the U.S. and under which a large volume of short- and long-term power transactions occur.

The growth in wholesale market transactions has precipitated the implementation of OASIS sites by service providers in order to facilitate the scheduling of wholesale transactions. Also, regional markets have formed commercial hubs at various locations and interfaces throughout the U.S. Hubs play an important role in price discovery.

These various procedural mechanisms and market provisions serve to facilitate and enable market processes. Buyers and sellers can engage in a variety of near-term transactions using more-or-less standard market products such as energy service and bundled packages of energy and transmission (including reserves) for same-day and day-ahead hourly and 16-hour periods, as well as for weekly and monthly peak-period and all-hours supply. Furthermore, market participants can schedule long-term transactions across seasons and years. In most regions, wholesale market participants are numerous and include rural cooperatives, local distribution companies, power trading subsidiaries of investor-owned utilities, trading authorities and merchant traders, merchant generators, and municipalities. While nettlesome impediments to competition remain wholesale electricity markets are reasonably contestable in most regions and within most timeframes.

This wholesale market environment is quite suitable for competitive power procurement, although serious challenges may be present in some areas and locales because of accessibility to transmission and so-called "pancaked" pricing of transmission services across multiple control areas. While these issues are encumbering and are not to be minimized, buyers including local distribution companies such as Florida Public Utilities Company, can organize well-structured procurement processes and often obtain competitively priced power supply.

Q. What are your expectations regarding future electricity prices and the reasons that underlie future price levels?

A. The U.S. electricity industry has entered an era of sharply higher wholesale prices for electricity beginning in late 2003. The contemporary high power prices are a national phenomenon, and are a result of three main factors. First, primary fuel prices including coal, natural gas, and oil have all risen to very high levels. Current fuel prices are largely a result of a sudden and seemingly sustained tightening of supply-demand balance for fuels; supply margins are fairly tight and inventories are exceptionally low from time to time over recent years in the case of natural gas and oil.

Second, transmission networks have experiencing substantially higher levels of congestion in recent years, which is manifest as increased frequency in transmission load relief (TLR) calls, and expanded differences in locational and zonal prices for power. Third, the aggregate demand for electricity service, as reflected in observed peak loads and energy consumption, has advanced over the past three years to levels that better balance with and more fully utilize generation supply. Fourth, and to a lesser extent, concerns about global warming and other environmental considerations have caused the electricity industry to increasingly embrace renewable resources, as evidenced by the adoption of Resource Portfolio Standards policy in several regions of the U.S. While renewable resources may reduce total emissions including sulfur dioxide (SO_2), mercury (including elemental, vapor, and particulate bound components), nitrogen oxides (NOX), particulate matter, and carbon dioxide (CO_2), such resources will raise the total costs of power supply, as far as the internal and direct resource costs are concerned.

Q. Please provide projections of future prices.

A. Exhibit BMCC-2 presents a projection of spot power prices for the Southeast region over the 2005 – 2012 timeframe. We include tables of average spot prices for three timeframes including all-hours, peak periods, and off-peak periods. These prices are a result of market simulations developed by CAEC and used regularly to prepare forecasts of regional prices. The prices reflect simulations of a range of possible market outcomes for energy, and the implicit reserve services of regulation, spin, non-spin, and backup reserve categories. The composite power prices are marginal cost-based prices for regions and incorporate scarcity rents. However, the prices do not include black start or reactive power, nor do they reflect the marginal cost of delivery services including transmission network service, connections services, and scheduling.

While we have also developed prices for Florida, the North American Electric Reliability Council (NERC) region known as the Florida Reliability Coordinating Council (FRCC), we believe that the more relevant region for the purposes herein is the NERC region known as the Southeast Electric Reliability Council (SERC), which encompasses the states of Alabama, Georgia, Mississippi, North Carolina, South Carolina, Tennessee, and Virginia, as well as the southern and northeastern areas of Louisiana.

The regional price projections are developed by applying a structural analysis approach to the markets represented by a so-called compressed SERC region. The development of projected wholesale price involves projections in regional economic activity, hourly loads for the region, the region's generation portfolio including units under construction as well as possible new generators in the future, and a range of possible future primary fuel prices. Exhibit BMCC-3, pages 1 – 3, shows supporting details that underlie the wholesale market price projections. Page 1 shows summer demand and generation capacity over the 2005 – 2012 timeframe for the compressed SERC region for low, moderate, and high demand growth scenarios. Of particular interest are the capacity reserve margins, where reserves stay tightly bundled around fifteen percent. These reserve levels reflect expected reserves for the surrounding regions of the Eastern Interconnection, and are not specific to SERC. Imposing non-SERC specific reserves on the simulations for the SERC region is necessary in order to reflect the natural behavior of power markets. Namely, regions that are a little long in capacity or otherwise have cost advantages – and thus have comparatively low marginal costs – will export power to regions that are relatively short. Hence, it is appropriate to utilize non-SERC specific reserve margins in the determination of the projections of regional power prices.

Exhibit BMCC-3 pages 2 – 3 contain the three scenarios of primary fuel prices and generation expansion for the moderate demand case, respectively. Page 2 presents a plausible set of alternative long-term paths for primary fuel prices in the Southeast over the 2008 – 2012 timeframe. These primary fuel price paths are obtained through a combination of analysis and intuition, and represent a combination of current forward prices converted to spot, as well as long-term trends. The fuel prices are utilized to project future electricity prices, also for the Southeast, and incorporate transportation costs as well as, in the case of coal, the costs of environmental compliance for sulfur dioxide. It is worthwhile to mention that SO_2 allowance prices have risen fourfold over the most recent eighteen month period.

As observed, we expect that price pressure for primary fuels will ease somewhat, before assuming the long-term path that roughly follows general inflation. The scenarios of fuel prices reflect possible long-term paths of prices and do not reveal the full range of short-term uncertainty and volatility inherent to primary fuels.

The modeling approach develops hourly prices (marginal costs) for six day-types for the months of each forecast year. The approach uses Monte Carlo methods to determine generator downtime for maintenance and unit availability. The approach obtains numerous realizations of prices/marginal costs for each hour of the various day types. The day-type analyses are then mapped to the various days of a weather normalized year, where the days of the year have been categorized according to day type and month. The result is a range of possible hourly prices. The prices embody implicit rents for scarcity, market power, and various market inefficiencies and friction that cannot be otherwise explicitly accounted for.

The modeling approach obtains prices for reserve services using optimization techniques (linear programming methods), based upon assumed operating parameters of generating units within the region.

As noted above, Page 1 of Exhibit BMCC-2 presents the expected value of wholesale electricity prices over all hours, while page 2 presents the expected prices for peak and off-peak hours. The projected prices are shown by month and year. As can be seen, the analysis suggests that wholesale electricity prices will generally recede from the current highs to levels of about $55.00 per MWh, and to then rise as primary fuel prices assume trajectories that conform with the respective long-term historical path roughly equivalent to overall expected inflation. Also, the long-term path reflects the gradual evolution in the generator unit portfolio of the region. Model simulations suggest, and market experience confirms, that as a general rule wholesale electricity prices are higher during summer months than non-summary periods. Although not shown, simulated and observed wholesale prices reveal higher variation (volatility) and risk during summer periods than non-summer periods. This result follows from the generally tighter supply margins of the summer, where unexpected demand-side events (such as weather) and supply-side events (such as generating unit and transmission line outages) translate into comparatively larger upside risk than during non-summer periods. Also, summer wholesale market prices for electricity can reveal distinct up-side skewness in the underlying statistical distributions.

Q. Please discuss the primary fuel prices and the outlook for fuels, as utilized in the projected wholesale prices.

A. In the case of coal, supplies are plentiful although rising demand for coal has been precipitated by high natural gas prices. Essentially, coal and gas are substitutes, with fairly substantial substitution elasticity. This means that generation companies – mainly electric utilities – will tend to utilize coal-based generation more intensively with rising prices for gas relative to coal. In addition, the costs of transportation of coal from locations where it is extracted to locations where it is consumed as fuel (coal-fired generators) has been recently constrained as a result of bottlenecks in railroad lines in key locations, of (as reported) some shortages of locomotives and coal cars and, we suspect, the exercise of market power by major railroads in key areas of the U.S. Also, there are reports that expanded U.S. coal exports are being used to produce steel worldwide.

Natural gas supply in the U.S. is constrained in the short run because of limits of economically viable wells and fields at market prices of less than $3 — $4 dollars per MCF (MMBTU) within the continental U.S. Second, inventories at various locations in the U.S. have been limited such that, when coupled with limited extraction capability, wholesale prices of natural gas can show high sensitivity to short-run changes in demand and expectations of future weather patterns and forecasts.

Unlike the difficult years of the 1970s, oil plays a rather insignificant role in electricity supply currently, particularly in the Southeast, and thus need not be considered in the context of the immediate issues at hand. Nonetheless, we wish to mention in passing that oil prices are currently driven by steadily increasing demand for transportation worldwide, mainly automobiles. Second, the retail prices of oil-derived products such as fuel oil for heating are affected by the apparent limits of refinery capacity in the U.S.

Pages 1 – 4 of Exhibit BMCC-4 present forward contracts for primary fuels for deliveries over future months, as reported by NYMEX during late 2004. It is important to recognize that *forwards* represent composite expectations of traders, both hedgers and speculators, regarding future spot prices for fuels. In essence, these forward prices suggest that traders in late '04 implicitly expected high primary fuel prices to be present over the ensuing months. Page 4 of Exhibit BMCC-4 presents coal price futures for deliveries during 2005 and 2006, as of February '05. As can be seen, the more current expectations reveal somewhat lower coal prices prospectively, than that of late 2004.

It is useful to view the current high levels of primary fuel prices within the context of long-term history. Accordingly, we present on pages 1 – 2 of Exhibit BMCC-7 primary fuel prices for crude oil, coal, and natural gas for 1973 – 2004 period for the consideration of the Commission. As can be seen, while primary prices are exceptionally high currently, such prices are not unprecedented. Specifically, primary fuel prices reached current levels during the 1980 – 1984 timeframe, stated in real terms.

Q. Please describe transmission congestion and the impact of congestion on wholesale prices.

A. Congested network facilities, including specific flowgates and key interfaces among control areas, separate markets. Congestion raises prices for some areas and lowers prices for others. Congestion is a particular issue for load centers that are downstream from constrained flowgates and interfaces, such as the various load centers of the Florida peninsula, as they now face higher costs for wholesale services. Congestion along key flowgates and interfaces leads to the realization of higher profits by downstream generators (constrained on) and lower profits by upstream merchant generators (constrained off).

Q. Please discuss supply-demand balance, reserve margins, and the effects of reserve margins on wholesale prices.

A. Supply-demand balance in the U.S. and Southeast is shown on page 2 of Exhibit BMCC-5. As mentioned earlier, supply-demand balance has tightened somewhat. In the case of electricity markets, changes in supply margins operate together with the characteristic of non-storability to produce instances in which small changes in supply margin often translate into fairly sizable impacts on power prices. Overall for the Eastern Interconnection, we would guess that the brief excess supply bubble of 2002 – 2003 is largely exhausted. And while the current large-scale volume of wholesale transactions is not altogether new, it is not as if the electricity industry has decades of experience; learning is a key element of market experience and it is reasonable to opine that the bubble of recent years is an infrequent phenomenon that will not be revisited often.

In summary, the supply-demand balance of markets is currently in approximate long-run equilibrium with capacity reserve levels near 16%, perhaps a little higher. For the present, we have no reason to expect overall capacity reserves in the future to deviate much from this level over the long run, aside from periodic variations largely attributable to random weather phenomena. One thing that could change long-term optimal capacity reserve margins is a rise in customer participation in reserve markets (curtailment programs) and other demand response programs such as real-time pricing.

Q. Please summarize your testimony and recommendations for the consideration of the Commission.

A. Florida Public Utilities Company takes very seriously, at the highest level, its duty to provide continued and uninterrupted power supply to its retail customers at reasonable cost. To this end, the Company is in the process of implementing a least cost long-term procurement strategy for power supply beginning in 2008. However, contemporary wholesale markets and market prices, in the Southeast and nationally, reveal sharply higher costs for power as a direct result of a roughly twofold increase in the costs of primary fuels, of increasingly constrained networks, of a steady tightening of supply-demand balance and reduced supply margins, and of environmental considerations being increasingly manifest in policy at the regional and national level.

These market conditions are affecting expectations of market participants over future years and, at this time, the Company and retail customers in all likelihood will face and be burdened with sharply higher prices for power beginning in 2008.

FPU's retail prices will change abruptly under standard ratemaking mechanisms of the current regulatory framework, and absent needed policy intervention by the Florida Public Service Commission. Accordingly, it is both necessary and appropriate for the Company, with the approval and full support of the Commission, to phase in the much higher prices for power as anticipated. The phase-in plan, as presented herein, has been designed in a manner that improves consumer welfare by mitigating the rate shock that would otherwise occur. Our phase-in plan contains important safeguards and features including interest accruals, accounting audits, regulator checks, and the provision for changes as market expectations evolve. Thus, the plan as proposed is in the general interest of retail consumers and provides the Commission with the necessary level of confidence that facilitates its approval and support.

Q. Does this conclude your Direct Testimony?

A. Yes.

MR. HORTON: And there are also --

CHAIRMAN BAEZ: Mr. Horton, I'm sorry. You were going to talk about exhibits?

MR. HORTON: Yes, sir, I was.

CHAIRMAN BAEZ: All right. Just to cut it short, I'm showing 21 through --

MR. HORTON: Twenty-one through 26 in the 01.

CHAIRMAN BAEZ: In the 01. And then 27 through 33?

MR. HORTON: Yes, sir.

CHAIRMAN BAEZ: Okay.

BY MR. HORTON:

Q. Do you have any corrections to make to any of those exhibits?

A. (By Ms. Martin) No, we do not.

MR. HORTON: Then I would offer the exhibits.

CHAIRMAN BAEZ: They've been already marked?

MR. HORTON: Yes, sir.

CHAIRMAN BAEZ: Okay.

MR. HORTON: I want you to know I had a brilliant opening statement, but I'm going to skip it.

CHAIRMAN BAEZ: You're going to forgo the opening statement? You're scoring points already, Mr. Horton.

MR. HORTON: And what we did agree,

Mr. Chairman, is that we would have one of the witnesses, one of the panel members to summarize the testimony, and Mr. Bachman would offer that summary.

CHAIRMAN BAEZ: Very well. Mr. Bachman?

MR. BACHMAN: Good afternoon, Commissioners. Our testimony today will pertain to the fuel calculations that are addressed by Witness Martin.

In addition to the normal items that go into fuel calculations and projections, we've got three unordinary items, which is primarily the reason for us being here today, the first of which is a fuel surcharge. And we kind of regret using the word "surcharge," but for lack of another way of saying that, that will gradually ease our fuel prices to market prices versus having a dramatic increase at the beginning of '08.

The second item is recovery of expenses that directly relate to obtaining new fuel contracts for 2008 and this phase-in program.

The third item centers around consolidating our fuel rates for our two geographic areas to be consistent with the one rate that we now have for base rates for all electric customers.

The first item, the proposed surcharge, is a result of a contract that was signed in 1996. It expires at the end of 2007. This contract -- both of these contracts have fixed prices. And what that translates to today is prices for electricity that are substantially less than the market price of electric. We estimate that we will still have this substantial difference at the end of '07.

The proposal is to gradually increase prices over the contract prices for the next two years -- and at the end of two years, our rates will still be substantially lower than market -- and then over the next three years, refund that collection with interest. The net result is to prolong the benefit that we have on fuel rates for five years, or an additional three years, versus taking it all deeply discounted here in two years and facing a dramatic increase in our fuel rates within 30 days. What we're asking for is approval in this, to have the surcharge and to take this and extend to five years our under-market rates for electricity.

The second item is, we're requesting recovery of expenses that we have incurred and will incur to obtain new fuel contracts and for developing this phase-in plan. Due to the small size of our company and the complexity in the fuel contracts today, we felt it best to have a consultant with the expertise come in, conduct our request for proposals, conduct the negotiations, and try to come up with the best price possible for our customers starting with '08. To disallow the expenses that we feel we've prudently incurred we feel would penalize our company for being prudent in trying to minimize the fuel costs that we will have under contracts beginning in '08.

The third item is the consolidating of the two geographic areas, as I've mentioned, for our fuel. This would be consistent with how our base rates are set up. We have one base rate for all electric. We've got one conservation rate. And as far as I'm familiar with, the other investor-owned utilities in the state all have one rate for their electric customers.

This does benefit us to the point where, with a larger base of customers, over 30,000 versus 15, it averages out any shock of additional expenses that may be incurred in one unique area. As opposed to isolating those costs and having to recover it from 15,000 customers, you get an averaging effect, because you have a larger pool of customers, and thereby it levelizes the cost effect on individual customers.

We do recognize we are the smallest investor-owned utility in the state. We do not have the normal resources available to some of the larger companies. And we do have some unique challenges because of our size, and we do try to come up with solutions that are fair to the customers as well as the company.

And that concludes my remarks.

MR. HORTON: The panel is available.

CHAIRMAN BAEZ: Ms. Christensen.

CROSS-EXAMINATION

BY MS. CHRISTENSEN:

Q. Good afternoon. I'm going to go ahead and direct these questions I guess at Mr. Bachman, and then I'll identify any of the other panel members as appropriate, unless you're unable to answer the question, and if you could direct me to whom would be more appropriate.

A. (By Mr. Bachman) Sure.

Q. And I think maybe that will help make this run a little bit smoother.

Now, Mr. Bachman, does FPUC have any of its own generation?

A. No, it does no.

Q. So I'm correct that all of your power is provided from third parties?

A. This is correct.

Q. Okay. And FPUC's customers pay for the purchased power contracts through a fuel charge; correct?

A. Yes.

Q. And your current purchased power agreements have fixed fuel components; correct?

A. That's correct.

Q. You anticipate that the future purchased power contracts will flow through the cost of fuel for generating the power at market prices; is that correct?

A. Could you rephrase that?

Q. Do you anticipate that when you enter into these new contracts that the price of fuel will be passed on to your customer at current market prices? That's what you're anticipating; correct?

A. We are anticipating those prices will be within the broad band of market prices, yes.

Q. Okay. And currently your rates are around the mid 60s per thousand kilowatt-hours for both of your divisions under the fixed price fuel purchase contracts; am I correct?

A. Correct.

Q. Okay. And you anticipate when the new purchased power contracts go into effect, your rates will increase by approximately $30 per thousand kilowatt-hours to around the mid-90s, the mid-$90 range? Am I correct in that?

A. That's correct.

Q. Now, is it true that the current contracts expire December 31st, 2007?

A. Yes.

Q. And your proposal is to impose a surcharge over the next two years to be flowed back over a three-year period to offset the impact of the one-time $30 increase in January of 2008; am I correct? Is that a general summary?

A. Flowed back with the interest, yes.

Q. Okay. So with interest collected, it would be flowed back, but this is to mitigate that $30 increase?

A. That's correct.

Q. Now, you would agree that the purpose of FPUC's proposal is solely for the benefit of the customers from the company's point of view?

A. I would say it's primarily for the benefit of customers, and the company would benefit, I guess, through PR, not having as many upset customers in January of '08, so kind of an intangible benefit.

Q. Right. But this is not for the company's financial benefit, is what you have --

A. That's correct.

Q. -- indicated in the past. And this rate shock would result because under the current contracts, the fuel cost component is fixed, but you expect that any contract for purchased power will have a fuel provision that will set the fuel prices at the market rate, so any future contracts will set the prices closer to market rates.

A. I will have to defer to Witness Camfield.

Q. Mr. Camfield?

A. (By Mr. Camfield) Well, it depends upon the contracts and the commercial terms of the contracts as they are signed prospectively. And it's certainly possible that the components -- the commercial terms would have components that, yes, reflect current market elements and prices as far as primary fuels are concerned, but not necessarily. That is to say, we have current offers as options before us that constitute fixed prices as well for the 2008-2012 time frame.

Q. But those are going to more accurately reflect current markets, correct, current market prices for gas?

A. Should I say that they reflect current expectations by bidders about current prices.

Q. But you have -- Mr. Camfield, am I correct in my understanding that you have not signed any contracts for purchased power in 2008?

A. That's correct.

Q. Okay. And would you agree that the surcharge rate is based on FPUC's estimate of the future market fuel costs in the 2008 through 2010 time frame?

A. We're at a point in the RFP process where we're reaching closure, and it's quite possible that we will have firm prices reflecting the prospective contracts to use in the development of the surcharge plan.

Q. But currently, as the surcharge plan is proposed, you anticipate -- your anticipation of what the surcharge will be is based on your anticipation of what those fuel costs will be in the 2008-2010 time frame; correct?

A. That's correct.

Q. Okay. And you would agree that the justification for the surcharge price is that your surcharge request for 2006 is less than what you estimate the future fuel costs will be?

A. That's correct.

Q. Okay. But your estimation of future fuel costs could be over or under what you used in your estimation; is that correct?

A. That's correct. So at this point, we anticipate that the actual contract prices will be higher than anticipated at the time that we proposed and filed the plan.

Q. Well, let me make sure that I understand. You have yet to file the purchased power contracts, so at this point, you don't know the exact terms or conditions of the purchased power contracts that will come into effect as of January of 2008; is that correct?

A. That's correct.

Q. And you won't have those contracts finalized --

my understanding from your testimony is that would be sometime in 2006. Is that still the current time frame that you anticipate?

A. It's coming ahead quickly, and it's just possible that we will know, as I say, the firm prices, or should I say the contract prices, effective 2008 within the very short term here, prior to the end of the current year, 2005. It's possible that we will not have signed contracts until early 2006.

Q. Okay.

A. In other words, we may know the contract terms and have finalization on contract terms prior to signing contracts.

Q. Okay. But your proposed surcharge that you've put in the testimony today of .00254 per kilowatt-hour for the cost of fuel effective January 1st and the subsequent increase to .00256 per kilowatt-hour starting July 1st is not based on any current contract that you have in -- that you will have in effect as of 2008, but are based on your estimates; is that correct?

A. That's correct.

Q. Okay. And so you're asking that the Commission approve a plan to collect the surcharge for the two-year period in 2006, which is included in your testimony, and 2007, which is not included in the testimony. In other words, we don't know what the fixed price of the 2007 increase will be.

A. At this point in time, that's correct.

Q. Okay. Now, let me make sure. I'm asking a clarifying question. Is FPUC asking the Commission to approve all the surcharge factors based on Exhibit CMM-4 or just the 2006 surcharge factor? Do we know?

A. (By Mr. Bachman) We are asking -- because it is in this '06 docket, we're asking for the '06 fuel, for the '06 portion.

Q. Okay. But if the Commission were to approve the plan, they would be approving a surcharge in 2007, but not knowing exactly what that surcharge would actually end up being in 2007; is that correct?

A. That's correct. Our plan would be to see what the market rates were and adjust that accordingly.

Q. Okay. So then the testimony on page 15 of the September 21st testimony -- and I think that was Mr. Camfield's statements -- lines 2 through 5, that state that the surcharge amounts will be adjusted as market expectations change, and I assume also as the contracts get finalized, as actual energy sales deviate from forecast sales, and as offers are received, and as the contracts for net power supplies are reached, is correct?

A. (By Mr. Camfield) That's correct.

Q. Okay. So at this point, all the Commission and customers can know for certain is that the amount of the surcharge usage rate, that it will increase in 2007; am I correct?

A. That's correct.

Q. Okay. And that if the Commission were inclined to approve the plan, they will have no definitive information as to what the 2007 usage rate will be; correct?

A. Well, I think the word there, definitive, is a little bit troubling, and perhaps we should clarify.

Q. Well, at this point, if the Commission were --

A. Precisely.

Q. -- to approve the plan, they would not have the 2007 factor that they were approving? Am I correct in that?

A. They would not know it exactly.

Q. Okay. I'm going to continue with Mr. Camfield. And, Mr. Bachman, if you care to add anything, please let me know.

Under the plan, the collection of the surcharge, we established, begins in January of 2006; correct?

A. That's correct.

Q. Okay. And all of the customers who are on the system at that time will be charged the surcharge based on their usage; right?

A. That's correct.

Q. Now, as customers continue to come on to the system during the two years, they will pay the surcharge based on their usage; am I correct?

A. That's correct.

Q. Okay. So if a customer comes on to the system in July of 2006, he will start contributing to the fund beginning from that date forward; correct?

A. That's correct.

Q. Okay. And this customer who comes on the system in July 2006, he will not be charged the surcharge for the period he was not on the system, i.e., from the January 2006 time frame to the July 2006 time frame; correct?

A. That's correct.

Q. Okay. And after the two-year collection period, the amount collected will be flowed back to the customers over the three-year period; right?

A. That's correct.

Q. And the flow-back of the total amount collected will be based on the customer groups, such as residential customers. Am I understanding that correctly?

A. The flow-back amounts will utilize several parameters in the determination of what the flow-back amounts actually are as a price or a credit per KWH.

Q. But residentials would be one distinct group of customers. You're going to keep the funds that you collect from residential customers separate and then flow them back to residential customers based on that customer group?

A. That's not our plan, no. We would put it in a general fund, and it would treat all energy sales and across all customer classes the same.

Q. Okay.

A. It doesn't distinguish between classes.

Q. All right. However, when you flow back the money that we're talking about that was collected over the two years, it will be flowed back on a customer usage basis; am I correct about that?

A. That's correct.

Q. Okay. And under this plan, monies are not tracked on an individual customer basis, so I am correct about that?

A. That's correct.

Q. And under the plan, if a customer leaves the system before the expiration of the plan, he will not receive a refund?

A. As the plan is currently proposed, that is correct.

Q. And under this plan, some customers may pay into the plan and won't get a refund and won't get back the full amount that they paid into the plan. That's a possible scenario; correct?

A. That's possible.

Q. Okay. And under this plan, it's also possible that there may be instances where a customer comes on to the system after the two-year collection period, yet they would receive the benefit of reduced rates until 2010. Am I correct about that?

A. That's correct.

Q. And since the plan does not track based on an individual customer basis and will be collected and flowed back on an usage basis, if a customer's usage changes over the period of the plan, he may end of being subsidized or subsidizing others; is that correct?

A. I have difficulty with the use of the word "subsidization." I would interpret subsidization -- I interpret and attach meaning to the term "subsidization" in a narrow sense, not the broader sense that I think is suggested.

Q. Well, let me see if I can break that down more. If a customer changes his usage -- let's assume he uses a thousand kilowatts of energy for a billing period, and he pays based on that thousand hours' worth of usage for the two years, and then when the increase comes, his usage drops to 800 kilowatts per billing cycle. He would not be receiving the full amount of the monies he paid in; is that correct? Mathematically, he would not be receiving -- if he paid for a thousand hours' worth of usage but his usage dropped to 800, it is possible that he will not be getting the full amount of the monies that he paid in back over the three years.

A. That's correct.

Q. Okay. And conversely, if he was using a thousand kilowatt-hours per billing cycle and his usage increased to 1,200, somebody else would be paying for that 200 kilowatt-hour increase?

A. I would disagree with that. I would suggest -- I have trouble with the term "someone else would be paying for it."

Q. Well, it would be coming out of the pot of money collected from all of the ratepayers; correct?

A. What we can say is that there's an imbalance between the amounts that would be paid in versus the amounts that were claimed during the payback period in some cases where there are changes, significant changes in usage by an individual customer.

Q. Okay. And would you agree that in the scenario where a customer for whatever reason were to increase his usage, he would not have paid for that increase in usage in the two-year plan? If for two years he used a thousand hours and then increased after the three years to 1,200, he himself would not have paid for that increase in usage into the plan?

A. That would be the sort of imbalance that I mentioned.

Q. Okay. You would agree, or am I correct that if the plan is not approved, the current customers will only pay for the electricity that they use today based on the current cost; correct?

A. That's correct.

Q. Okay. And any future electricity that he uses, he will be paying for the fuel related to that future energy usage; correct? The customer would be paying for what he actually in fact uses?

A. That's correct.

Q. Okay. Now, in your assumptions -- I think you had a table attached to your September 21st testimony. In the assumptions that you used to generate the surcharges from 2006 through 2010, was growth in customers as well as seasonal changes in consumption patterns included in that surcharge calculation?

A. Yes.

MR. HORTON: Excuse me, Mr. Chairman. Could we get a reference to that?

MS. CHRISTENSEN: I'm speaking in general to the exhibit that was attached to the back of the September -- I think it was the back of the September 2001 testimonies.

CHAIRMAN BAEZ: 2001, you said?

MS. CHRISTENSEN: I'm sorry. 2005, September 21st, 2005.

Well, let me clarify that. I believe that was actually referring to Exhibit CMM-4, but I believe -- that's the testimony that I'm referring to, the exhibit I was referring to.

MR. HORTON: I'm sorry. That was CMM-4?

MS. CHRISTENSEN: Correct.

CHAIRMAN BAEZ: That would be Exhibit 24, Commissioners.

MR. HORTON: Thank you.

BY MS. CHRISTENSEN:

Q. Now, if you have more growth in the payback years than in the surcharge years, doesn't customer growth lessen the amount of the rate reduction per kilowatt-hour to be paid back?

A. That's correct.

Q. So let me make sure I'm understanding this correctly. Just by including a growth factor, an individual customer gets less of what he paid in; is that correct?

A. If the growth in the payback years is greater than anticipated in the development of the phase-in plan, then the amount of money that would be realized by individual customers would be less than anticipated.

Q. Okay. How does the company anticipate that it will address the changes to its projections in the retail price of purchased power fuels in the years 2006 and 2007 regarding the surcharge payback cycle? Mr. Bachman?

A. (By Mr. Bachman) Could you reword that?

Q. I think in earlier testimony, it was stated that you anticipate adjusting the surcharge based on changing factors. And the question refers to that, which is how does the company anticipate that it will address those changes to its projections in the retail prices of purchased power fuel in 2006-2007 regarding the surcharge and payback cycle?

A. In case of significant changes to market price over our estimate? Is that what you're referring to?

Q. Yes.

A. I guess I'll have to defer that one to Witness Camfield also.

A. (By Mr. Camfield) Could I hear the question again, please? I'm sorry.

Q. Assuming there was a significant change to market prices over what was utilized in coming up with the surcharge projections, how would that be addressed in the 2006-2007 projections?

A. That would have no impact on the projections. And that's because the plan, should the plan be approved by the Commission, would be insulated to fuel prices during the years 2006-2007.

Q. How would you -- if my understanding was correct that you were planning on adjusting the surcharge based on market conditions, that if there were a significant change in market conditions, you would be adjusting the surcharge to more accurately reflect what the market prices would be in the 2008-2010 time frame; am I correct?

A. That's correct.

Q. Okay. And I guess what I'm asking you is, how do you plan on doing that in the projections?

A. During the years 2006-2007?

Q. Correct, or do you?

A. When we were developing the plan? Well, let's imagine that we have established contracts now and have them in place for the beginning of 2006, so those contracts are in place. They have a variable -- let's imagine that one contract, and there could be several contracts, has a variable component, so that that component would vary as a price element, as expectations for the 2008 to 2012 time frame. We would recognize changes in the expectations of that variable component of the contract terms within the surcharge calculations for the 2006-2007 time frame.

Q. So am I correct that if major changes occur in the company's projections, say one year the company's projected cost of fuel decreases from today's projections, doesn't adjusting this mechanism become quite complex and uncertain to administer, thus raising the cost for customers?

A. We think it's appropriate for the plan to be flexible and accommodate changing expectations for the 2008-2012 time frame. We don't think it adds unnecessary complexity.

Q. Would it add additional cost to make those adjustments?

A. To administration, administrative costs associated with the plan itself?

Q. Okay.

A. I would say, no. It would be minuscule.

Q. Let me refer to Mr. Bachman. You were present at the customer meetings held on October 5th and 6th in 2005 in Fernandina Beach and Marianna; correct?

A. (By Mr. Bachman) Yes.

Q. And at those customer meetings, you heard the comments made by the customers; correct?

A. That's correct.

Q. Okay. Would you agree that most of the comments made by the customers at this meeting were negative?

A. I would agree with that.

Q. And is it correct that, let's say, out of the four people who spoke at the Fernandina Beach meeting, at least three of those customers had a negative reaction to the proposed plan? Would you agree subject to check?

A. Subject to check, yes.

Q. And would you also agree subject to check that at least -- out of the eight people who spoke at the Marianna customer service meeting, at least six of those customers had a negative reaction to the proposed plan?

A. Yes.

Q. Okay. And have you had the opportunity to review the written comments that were submitted regarding the plan?

A. I have not.

Q. Okay. Let me address Mr. Cutshaw very briefly. Mr. Cutshaw, we had an article that was passed out earlier. I believe it's Exhibit -- I want to say 81.

CHAIRMAN BAEZ: Eighty-one.

BY MS. CHRISTENSEN:

Q. The article is 81. I believe in that article, am I correct, it quotes you as saying that FPUC will abide by its customers' wishes on this matter; is that correct?

A. (By Mr. Cutshaw) That's correct.

Q. Okay. And you've heard Mr. Bachman's testimony, and you were also present at those customer meetings. And you would agree that all the customer comments at those meetings were negative in objecting to the plan; correct?

A. Yes, I would agree that those that attended the meetings did have negative comments.

Q. Okay. Now, would you agree that based on that -- would you agree, based on the customer comments that were received at those meetings and the customer comments here today, that if you were to abide by your statement in here that the company would adhere to the customers' wishes, that FPUC would withdraw its petition in this matter?

A. I think the comment I made was that if the majority of the customers were against this, then we would abide by their wishes. I'm not sure that's the case.

Q. Okay. Has FPUC submitted any positive customer comments here today for the Commission's consideration?

A. No, we haven't.

Q. Okay. Let me ask -- I would like to ask a clarifying question of Mr. Cutshaw -- or Camfield, I'm sorry.

FPL and Progress customers have, on average, somewhere around -- or pay somewhere around $100 per thousand kilowatt-hours of energy. If your plan is not approved, what is your estimate of what the average FPUC residential rate per thousand kilowatt-hours of use will be in 2008? Will it be around $100?

A. (By Mr. Camfield) I would guess that it's about -- we can expect that it's about $97 monthly for 1,000 KWH consumption.

Q. Thank you. Mr. Bachman, I would like to ask you some questions regarding Christensen Associates and the fees. I think it's probably more appropriate for the company to address these.

In your testimony or in the panel testimony, you are proposing to collect from the customers the fees associated with Christensen Associates; am I correct?

A. (By Mr. Bachman) That's correct.

Q. Okay. I guess this is addressed to Ms. Martin, who may have provided a direct statement on this.

Ms. Martin, in your testimony, you claim that FPUC is entitled to seek recovery because Christensen Associates has developed and managed the bidding process for the power supply beginning in 2008 and has helped develop the surcharge plan; correct?

A. (By Ms. Martin) Correct.

MR. HORTON: Mr. Chairman, I appreciate the effort to move forward, but could we have some references to where -- to the testimony so that we can at least take a look?

MS. CHRISTENSEN: Page 13 of the 01 testimony.

MR. HORTON: Thank you.

CHAIRMAN BAEZ: Thank you.

MS. CHRISTENSEN: However, I'm not asking specific questions regarding lines or whatever so I would refer you to those, but in general about her testimony.

BY MS. CHRISTENSEN:

Q. Ms. Martin, am I correct that most of the fee you're requesting for reimbursement is based on Christensen Associates' work on the bidding process? Is that correct?

A. That's correct.

Q. Okay. And as stated earlier in the panel testimony, the bidding process has not concluded related to those 2008 contracts; am I correct in that?

A. That's correct.

Q. So at this point in time, Christensen Associates has not completed the work related to the 2008 contracts; correct?

A. Correct.

Q. Do you know what portion of the fee for Christensen Associates is associated with the work on the surcharge plan, if you had to provide a percentage of the hours that they've submitted for you, 50 percent, 20 percent, 10 percent, as opposed to the bidding process? And Mr. Camfield, maybe if he knows --

A. I can give you an estimate --

Q. That would be fine.

A. -- that it's less than 25 percent.

Q. Less than 25 percent?

A. Uh-huh.

A. (By Mr. Camfield) It's by my calculation 23 percent.

Q. Thank you for being very accurate.

Now, you imply in your testimony, I think, Ms. Martin, that it is likely that the use of the consultants will result in lower costs to the customers; is that correct?

A. (By Ms. Martin) That's correct.

Q. But isn't it true that at this point in time, you cannot quantify the savings because you have yet to secure the final contracts?

A. I would say that you will not be able to quantify it. It gets back to economics and fair, competitive -- the competitive process that is inherent in any type of -- in that type of a process.

Q. But your testimony does not attempt to quantify the dollar amounts; correct?

A. We do feel that the savings will be much greater than the costs that we have incurred for our consultant, in the neighborhood of -- I believe we feel it could be millions of dollars saved to our customers.

Q. Right. But that number or what you're quoting today was not included in your testimony; correct? I think if you --

A. I do believe we had something in it, if you'll give me a minute.

Q. Certainly.

A. What we stated in the 01 testimony on page 14 was that we felt the savings would be above what the costs would be. And if you want it word for word, we felt that the cost of fuel would result in savings well over 400,000 in just five years, and that well exceeds the cost for our consultant in this process.

Q. Okay. But you would agree that you would have a better idea of what the savings will be once you actually procure the new contracts and once those actually come into being, and that won't be until, as of the testimony date, the beginning of 2006? Am I correct about that?

A. We would never know what the exact savings would be, because you can't do both things at once, so there would be no way to know what the exact savings would be by using a consultant versus not using it, unless we did two separate processes and we went out for contracts without the use of a consultant versus going out for new contracts with the use of a consultant.

A. (By Mr. Bachman) And even then you would only have two observations. You couldn't generalize that to general benefits.

Q. Well, let me ask this. In your testimony at page 15, it appears -- lines 26 through 29, it appears that you concede that it may be more appropriate for this type of cost to be collected through a base rate proceeding, and that at least at this point you would be asking --

MR. HORTON: I'm going to object to that characterization. That's not what that says.

MS. CHRISTENSEN: The witness has the opportunity to agree or explain or deny in responding.

CHAIRMAN BAEZ: Well, can you point at least to the -- can you point us to the testimony at least?

MS. CHRISTENSEN: I'll repeat that, certainly. Page 15, lines 26 through 29.

CHAIRMAN BAEZ: Which testimony?

MS. CHRISTENSEN: I'm sorry. The 01 testimony.

CHAIRMAN BAEZ: And that's the panel testimony?

MS. CHRISTENSEN: That is correct.

CHAIRMAN BAEZ: Page 15?

MS. CHRISTENSEN: Page 15, lines 26 through 29.

CHAIRMAN BAEZ: Ask your question again.

MS. CHRISTENSEN: Okay.

BY MS. CHRISTENSEN:

Q. In your testimony, you talk about if the Commission feels that it's more appropriate to recover these costs through base rates, you would just request permission to defer these until the next rate proceeding and have them amortized at that point in the future. And I guess my question goes, based on that testimony, isn't it are correct that this type of cost is more appropriate for a base rate proceeding?

A. (By Ms. Martin) That is not correct. We definitely feel this is directly related to fuel costs, that it most appropriately belongs to be recovered through the fuel recovery clause. We do recognize that sometimes the Commission prefers alternatives, and we do recognize that there was some opposition to recovering these costs through the fuel cost recovery clause.

We also recognize that there was an order that the staff felt that maybe disallowed those through the fuel cost recovery clause, but we disagree, because in great detail we have analyzed that order and most definitely feel that these costs that we've incurred do not fit into those definitions. The costs that we incurred are again directly related to our fuel RFP process, and these costs are not annually recurring. They're not ongoing administrative costs. They are not fixed costs. We have not recovered these through our base rates, and therefore, they don't meet that definition, we feel, of that order that would require those type of costs to be recovered through base rather than the fuel cost recovery clause.

And we simply offered that in a way not to penalize the company for these prudently incurred costs, that if they did feel that the fuel wasn't the place to recover those, we offered an alternative that would not penalize the company and allow us to recover those through base rates upon our next rate proceeding.

Q. Let me ask you a few questions regarding your consolidation proposal. And I'm not sure if -- Ms. Martin, are you the appropriate person, or Mr. Bachman? In this proceeding, you're asking to consolidate the price for the fuel component for your two divisions; am I correct?

A. (By Mr. Bachman) This is correct.

Q. Okay. And in Docket 031135-EI, the company also asked the Commission to consolidate the rates for the two divisions; correct?

A. That's correct.

Q. And in that docket, in Order PSC-04-0417-PAA-EI, isn't it correct that the Commission denied the company's request to consolidate the fuel component for the two divisions?

A. That's correct.

Q. And in that order, the Commission had already considered the reasons that were put forth in your testimony in the 01 docket regarding minimizing rate shock and minimizing regulatory administrative costs; right?

A. I'll defer that to Witness Martin.

A. (By Ms. Martin) We feel that that order back then could not have taken into account the facts that are available to us today with respect to the fuel prices that we expect in the future years. And so, no, that order would not have taken into account all of the facts that are put forth to support our request to consolidate.

Q. You have not as of today's date changed the purchased power contracts that the company is operating under; correct?

A. Correct.

Q. And in Order PSC-04-0417-PAA-EI, the Commission found that the consolidated fuel rates would be unduly discriminatory, and any regulatory administrative cost savings would be minimal; is that correct?

A. That's correct.

MS. CHRISTENSEN: Okay. I have no further questions.

CHAIRMAN BAEZ: Colonel, do you have questions?

LT. COLONEL WHITE: (Shaking head negatively.)

CHAIRMAN BAEZ: Mr. Wright?

MR. WRIGHT: Ms. Christensen asked all the ones I would have asked, Mr. Chairman.

CHAIRMAN BAEZ: All right. Staff?

CROSS-EXAMINATION

BY MS. VINING:

Q. Good afternoon. I'm not going to direct these to any particular witness. You guys can tell me who's the most appropriate witness by your answer.

A. (By Mr. Bachman) Okay.

Q. Now, on Exhibit CMM-4 to the testimony that you filed in the 01 docket on September 9th, you indicate that the total amount that FPUC proposes to collect through the surcharge is $11,482,542; is that correct?

A. (By Mr. Camfield) Just a moment, please.

Q. Sure.

A. That appears to be correct.

Q. Okay. And on what basis did FPUC determine that that's the amount of revenue that it needed to collect under the surcharge?

A. May I have the question read back, please?

Q. Sure. How did FPUC come up with that $11.4 million amount as the amount that was appropriate for collection under the surcharge?

A. We constructed a simulation, and the simulation took into account and was, should we say, parameterized by key factors. Those factors include the current prices paid for generation services and transmission services by FPU. It takes account of expected growth in energy sales to retail consumers during the 2006-2007 years reaching out to 12, 2012. And it also includes a key element, the expected wholesale price for power supply beginning in 2008. That simulation was generated during the April-May 2005 time frame, and so by today's standards perhaps is a bit dated. But those are the essential elements.

Q. Okay. And that wholesale amount that you said was one of the parameters, in your response to staff's interrogatory number 12, which is at Bates stamp 162 to 164 in staff's composite, which you should have over there, you said that that wholesale price you estimated to be $60 per megawatt-hour; is that correct?

A. That's correct.

Q. Okay.

A. That includes, by the way, just generation services.

Q. Okay. What else would be appropriate for us to get what a real value would be then beyond that?

A. Excuse me. I have misspoken. Let me refer to another place in my testimony. Wait just a moment.

The $60 includes transmission as well.

Q. Okay.

A. So, in other words, that would be the contract price to FPU for the purchase, wholesale purchase of both generation and transmission services.

Q. Okay. And looking at the exhibit that was prepared with the testimony from the 050317 docket, which was BMCC-2 --

A. Yes.

Q. At the time that was prepared, the $60 was sort of on the high rage for all the parameters you listed there. Would you say that's true?

A. If you are on page 1 of BMCC-2, those prices shown are just for generation services.

Q. Okay.

A. It does not include transmission.

Q. Okay.

A. And that's the key distinction.

Q. Now, you said earlier that these projections were done in April or May of this year; is that correct?

A. That's correct.

Q. And you would agree that the market prices have gone up since that time?

A. Yes.

Q. Do you have a sense of what an appropriate estimate would be for the wholesale purchase price at this point per megawatt-hour?

A. Beginning in 2008?

Q. Yes.

A. I would guess that it would be $70.

Q. $70?

A. Including generation and transmission. So it's directly comparable to the $60, which is vintage April-May 2005.

Q. Can you repeat what you just said?

A. The $70 is comparable in the service bundle to that of the $60 that we've been talking about.

Q. Oh, I thought you just said 70 including transportation. Is that what you said?

A. I did, and that's comparable to $60, which also includes transport or transmission charges as used in the simulation for the phase-in plan developed in April-May.

Q. Okay. My question then is, if you think that based on current market prices you think a more appropriate wholesale price is $70 per megawatt-hour starting in January 2008, is it more likely now that the surcharge amount that was proposed by FPUC is less likely to capture enough monies to really ameliorate the potential rate shock that might come about in January 2008?

A. Well, if we rely upon today's expectations for the 2008-12 time frame, it's pretty clear that the April-May projections understate today's expectations, and so would be by any reasonable standard, I think, low.

Q. Okay. Now, FPUC has proposed a fuel surcharge of .254 cents per KWH for the period of January through June of 2006, and then it will go up to .526 cents per kilowatt-hour for the period July through December 2006; is that correct?

A. (By Mr. Bachman) Yes.

Q. Now, those proposed factors apply to both divisions; is that correct?

A. Yes.

Q. And will all customer classes, both residential and commercial, be assessed this surcharge?

A. That's correct.

Q. So the GSLD-1 rate class for both divisions would also be paying the surcharge?

A. That's correct.

Q. Now, in your original proposal as filed in

050317, you had -- well, strike that. For 2007, your CMM-4 shows a surcharge increase to .776 cents per kilowatt-hour for January through May of 2007, and then going up in June through December of 2007 to 1.086 cents per kilowatt-hour. Now, I'm just curious. Why did you have a break in July in 2006, but then the break was in June in 2007?

A. (By Mr. Camfield) Because I made a mistake.

Q. So I guess we get to some of the questions that Ms. Christensen asked you earlier. Really, you're not asking for the 2007 surcharge to be approved in this proceeding, just to affirm what you had said earlier? I think Mr. Bachman said that.

A. (By Mr. Bachman) Yes, correct.

Q. So essentially, you would correct that oversight in next year's filing to have the amount ratcheted up in July of 2007 if this was approved?

A. Yes.

Q. Okay.

A. (By Mr. Camfield) Regarding this error, and I appreciate you bringing it to my attention, I will provide you with a corrected exhibit.

Q. Thank you. Now, this is on page 2 of CMM-4. For the Northeast Division, FPUC has proposed to collect $6,982,859 in 2006 and 2007 through the surcharge that's proposed. Now, on page 2 of CMM-4, FPUC proposes to refund $7,304,838, which would be more than is collected, and both of those amounts presumably are with interest. So I'm wondering what the difference is between the amount collected and the amount that's proposed to be refunded. And I'll say that there is a similar discrepancy for the Northwest Division, but it's a much smaller differential.

A. The difference that you see, it is a discrepancy, but it's a discrepancy that we built into the scenario. We can construct a scenario so it balances out exactly --

Q. Okay. And --

A. -- if that's -- go ahead.

Q. Why wouldn't you do it so it balances out exactly? I mean, what is the differential there?

A. The differential was as a matter of presentation to show and demonstrate the sincerity of the company to refund the total monies collected, so we set it up in the scenario design to pay back. As recognized, as you observe here, it's slightly more than the collected.

Q. So where does that extra money come from?

A. That would come from FPU.

Q. Okay. Now, Ms. Christensen asked before about where the money would be placed, and I think it was an interest-bearing account. And I'm wondering, is that going to be at the commercial paper rate, that account?

A. (By Mr. Bachman) I apologize. Would you repeat the question?

Q. Sure. The monies will be placed an interest-bearing account. That was said earlier, either on cross or in your summary.

A. That's correct.

Q. Is that going to be at the commercial paper rate?

A. It definitely would be at an investment grade, and I believe what we have in the testimony was the commercial paper rate.

Q. Okay. Which currently is around 4 percent?

A. That's correct.

Q. Okay. Now, referring again to CMM-4, it has credits listed that you're proposing to refund back to the customers in 2008 through 2010. Are you requesting Commission approval of those credits at this hearing, or is it going to be similar to your 2007 surcharge amount, you'll wait until those respective years and then ask for approval?

A. It is our intention again to true this up to where the market fluctuates, and we would run through another iteration at that point to say, well, what will it take for offsetting credits to smooth the increase to market over those three years. So in answering the question, yes, those would be adjusted.

Q. Okay. And I'm curious. If the total amount that's collected through the surcharge at the end of 2007 differs from what was projected to be collected, will that credit be subject to an adjustment, or you'll just sort of -- you'll have more in the pot to be refunded back through 2008 through 2010?

A. That again would go through the other iteration. You would have the market change. We would find out the exact number of dollars that we had available, including the interest. And again, we would look at the projected costs for those three years, assuming Christensen would run that through the model again for a smoothing effect. So, yes, it would be trued up for whatever amount of money is there at that point in time.

MS. VINING: Okay. Those are all the questions I have. Thank you.

CHAIRMAN BAEZ: Commissioners, questions?

COMMISSIONER DEASON: Mr. Chairman, I have a few questions.

CHAIRMAN BAEZ: Go ahead, Commissioner Deason.

COMMISSIONER DEASON: I'm looking an exhibit which is labeled BMCC-1, and it's three pages. I think this is attached to some testimony that was filed on

September the 21st, and it's labeled "Phase-in Plan Summary."

CHAIRMAN BAEZ: Commissioner, which page of that?

COMMISSIONER DEASON: Well, it's three pages. I'll just start on page 1.

CHAIRMAN BAEZ: Okay.

COMMISSIONER DEASON: I have questions on each page.

Do the witnesses have this exhibit?

MR. CAMFIELD: We have the exhibit, Commissioner.

COMMISSIONER DEASON: Okay. I know this is a summary of the plan. Is the information contained here the most current information, or has this been updated somewhere?

MR. CAMFIELD: The information on these exhibits would show separate surcharges for the Northeast and Northwest Divisions of FPU rather than show the results on a consolidated basis.

COMMISSIONER DEASON: I'm sorry. There's an exhibit -- page 1 is the Eastern Division, and page 2 is the Western Division. This is what's still being proposed at this point?

MR. CAMFIELD: We would propose to phase in on a consolidated basis.

COMMISSIONER DEASON: I'm sorry. Could you repeat that? To phase in what?

MR. CAMFIELD: We would propose to phase in -- if we're going to consolidate fuel, then we would want to phase in -- a phase-in plan that is common to both divisions.

COMMISSIONER DEASON: Well, this exhibit assumes that there is not to be a phase-in plan, I mean, not to be a --

MR. CAMFIELD: It assumes that there's a phase-in plan, but --

COMMISSIONER DEASON: But not a consolidation?

MR. CAMFIELD: That's correct.

COMMISSIONER DEASON: On page 1 of this exhibit under the column "Retail Fuel Prices," there's numbers there for the years 2006 through 2010. And I assume that the numbers there for 2006 and 2007 are under the current contracts; correct?

MR. CAMFIELD: That's correct.

COMMISSIONER DEASON: Okay. And the same for the Western Division. Those amounts listed there for 2006 and 2007 are under current contracts?

MR. CAMFIELD: Yes.

COMMISSIONER DEASON: Now, the amounts listed for the years 2008 through 2010 are the same for both the Eastern Division and the Western Division; correct?

MR. CAMFIELD: They would be different and are different for the Schedule BMCC-1, pages 1 and 2.

COMMISSIONER DEASON: Well, my exhibit shows the same numbers for each division. This is under the first column entitled --

MR. CAMFIELD: I'm sorry, Commissioner. I was on the wrong column. You are correct. They are the same.

COMMISSIONER DEASON: Now, is this -- is it anticipated that the -- I know the contracts are yet to be signed, but is it anticipated that the general market conditions for wholesale energy are going to be approximately the same for both the Eastern and the Western Division?

MR. CAMFIELD: Current evidence suggests that the Northeast Division will face higher prices than the Northwest Division. This is in contrast to the current prices of the current contracts, where the Northeast has lower prices than the Northwest. We anticipate that beginning in '08 with the new contracts that that will be reversed, with the Northeast being the higher.

COMMISSIONER DEASON: And this is supported by the responses you've received from your RFP; is that correct?

MR. CAMFIELD: That's correct.

COMMISSIONER DEASON: Now, the -- that's fine. I want to refer to some different testimony. And this is testimony that was filed on September the 9th, and I'm looking at page 16 of that testimony. This testimony addresses an additional delivery point that is in the Western Division, and it was necessary in order to serve the Family Discount Distribution Center. And if I understand this, there is a -- you're requesting the inclusion of some $3,700 a month for leasing of equipment from Gulf Power to be flowed through the fuel clause; is that correct?

MR. CUTSHAW: That's correct.

COMMISSIONER DEASON: Okay. The question that I have is, how can you assure me that the additional revenue from the new large customer is not sufficient to cover the additional cost of this leased equipment, i.e., are you already recovering these costs through just your normal rates for this new customer?

MR. CUTSHAW: The new customer is under our standard GSLD rate class.

COMMISSIONER DEASON: And that means they are not recovering these type costs in their rates?

MR. CUTSHAW: When we constructed the additional facilities to serve that facility, there was not adequate capacity in the substation to supply that. Because of the lack of capacity, we requested that Gulf Power build an additional addition to the substation.

In turn, since that was not included in our original agreement with them for purchased power, there was a separate agreement signed for that particular substation, and there was a facilities charge added to the bill since that particular facility was not included in the rate determination for our original contract.

COMMISSIONER DEASON: But you agree that the lease on these facilities are not fuel costs in the pure sense of the term?

MR. CUTSHAW: In our specific situation with our contract with Southern Company, the substation charges, the capacity charges are all included in our purchased power costs. And we felt like that this additional capacity need was very much a need to serve this new customer. We feel like that this additional facilities charge is just the addition of the substation that -- if it were there today, it would be included in the purchased power cost and calculated in those base rates from Southern Company.

MR. HORTON: Commissioner Deason, could I -- this testimony that you just asked questions about was placed in here because initially staff had given us a list of areas of interest, which included an issue relating to this, and we provided them information. That's not actually an issue, but this was filed before that was taken out as an issue. So there's really no -- I'm not speaking for staff, but --

COMMISSIONER DEASON: Well, Mr. Horton, staff may not have an issue with it, but this Commissioner may.

MR. HORTON: I understand, sir, but I needed to throw that in there.

COMMISSIONER DEASON: I appreciate the explanation.

MR. HORTON: Because it has been reviewed by them.

COMMISSIONER DEASON: That's all I have, Mr. Chairman.

CHAIRMAN BAEZ: Commissioners, any other questions?

Mr. Horton, redirect?

MR. HORTON: Yes, sir, a few.

REDIRECT EXAMINATION

BY MR. HORTON:

Q. Mr. Bachman, Ms. Christensen was asking some questions with regard to customers who move in and out of the territory, your service area, and whether -- the effect of the additive on them. Do you remember those questions?

A. (By Mr. Bachman) Yes, I do.

Q. Okay. With your current fuel adjustment factor, is that always from year to year in equilibrium? Some years do you overrecover, and some years you underrecover?

A. That's correct.

Q. If you had a customer in your service area during a year, a period of time when there was an overrecovery on the fuel adjustment factor, would that be addressed in the subsequent year? Would there be an adjustment made to recognize that underrecovery -- overrecovery, excuse me?

A. If there's an overrecovery in a particular year with the fuel, that overrecovery is put in and refunded the following year to all customers.

Q. Refunded in the sense that it's included in the calculation of the --

A. That's correct.

Q. And if there was someone in the service area during the year of that overrecovery that moved, would that individual receive a refund?

A. No, they would not.

Q. If there was a customer that did not live in your service area for that period but then subsequently moved in, would they receive the benefit of the reduced calculation?

A. Yes, they would.

Q. Isn't that the same way that your proposal is working for the phase-in?

A. Yes, it is, except the phase-in is covering a two-year charge and a three-year payback.

Q. I believe that between you and Mr. Camfield, you indicated that to the extent that the proposed amounts of the additive needed to be adjusted, that there would be a true-up at some point; is that correct?

A. Yes, that's correct.

Q. Ms. Martin, with respect to the consultant -- you were asked some questions with regard to the consultant. Do you know the amount that has been included in this proceeding for the consultant fees?

Let me ask it a different way. Rather than a specific amount, have you included the entire amount of the anticipated consultant fees in this proceeding?

A. (By Ms. Martin) Yes, we have.

Q. Okay. Mr. Cutshaw, you're hiding back there. I believe it was you that responded that GSLD-1 would be paying the surcharge, or was that Mr. Camfield?

A. (By Mr. Bachman) I believe that was Mr. Bachman.

Q. Well, Mr. Cutshaw, what is GSLD-1?

A. (By Mr. Cutshaw) GSLD-1 customers are the two paper mills in Fernandina Beach.

Q. Why would it be appropriate for them to -- and I guess now, Mr. Camfield, why would it be appropriate for them to pay the additive?

A. (By Mr. Camfield) Well, just as a matter of equity, we would suggest that all consumers pay a constant amount for fuel costs and contract prices. In the case of the paper mills, they may respond to these higher prices, and they may have cogeneration capability. At some point, the payments for cogen capability are at avoided cost, so that it's a net wash from the perspective of Florida Public Utilities Company and its other retail consumers.

Q. Ms. Martin, you were asked some questions with respect to the -- again, going back to the consultant. And I don't know if it was a question or in our response you made reference to an order number that is reflected in the staff's position. Do you recall that?

A. (By Ms. Martin) Yes, I do.

Q. Does Florida Public Utilities Company have a staff responsible for fuel procurement?

A. We do not have anyone on staff that would be responsible to negotiate and do the RFP process.

Q. And the costs paid to the consultant, were they for anything other than fuel procurement?

A. Yes, some work on the fuel surcharge.

Q. When you say fuel surcharge, are you referring to the proposal?

A. Yes, I am.

Q. So there's no -- none of the costs paid to the consultant for which you're seeking recovery through the fuel cost recovery factor is associated with rate case activity or anything like that?

A. No, they are not.

Q. Were the costs that you're seeking to recover in the fuel cost recovery included in your last rate case?

A. No, they were not.

Q. So they're not in your rate base?

A. No, they are not.

MR. HORTON: I believe that's all, Mr. Chairman.

CHAIRMAN BAEZ: Okay. We'll take exhibits.

MR. HORTON: I would move Exhibits 21 through 33.

CHAIRMAN BAEZ: Without objection, show Exhibits 21 through 33 admitted.

(Exhibits 21 through 33 were received into evidence.)

CHAIRMAN BAEZ: And I have a question. Mr. Camfield offered to provide a late-filed exhibit clarifying something for staff. Do we need -- I'm assuming we need to mark that.

MS. VINING: Sure.

CHAIRMAN BAEZ: Okay. We'll mark that 83, if you can just give me what to call it. And then, Mr. Camfield, how soon can you get -- is this a day thing or a -- I hope it is.

MR. CAMFIELD: Mr. Chairman, we will try to have this revised exhibit to you by the end of the day.

CHAIRMAN BAEZ: Great.

MS. VINING: I believe that would be a correction to the CMM-4.

CHAIRMAN BAEZ: Okay. And I don't know whether to hold this off, or subject to your review, Ms. Christensen?

MS. CHRISTENSEN: That's fine. We can -- as soon as it comes in, if we can have the opportunity to look at it.

CHAIRMAN BAEZ: Great.

(Late-filed Exhibit 83 was identified.)

MR. HORTON: May the panel be excused?

CHAIRMAN BAEZ: Yes, they may.

MR. HORTON: Thank you.

CHAIRMAN BAEZ: Thank you. And let's take five minutes.

(Short recess.)

CHAIRMAN BAEZ: We'll go back on the record.

Mr. Beasley, I have your witness up next.

MR. BEASLEY: Tampa Electric calls Mr. Smotherman.

CHAIRMAN BAEZ: Mr. Smotherman, you were sworn, sir?

THE WITNESS: Yes, I was.

CHAIRMAN BAEZ: Thank you.

Thereupon,

WILLIAM A. SMOTHERMAN

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

DIRECT EXAMINATION

BY MR. BEASLEY:

Q. Sir, would you please state your name, your business address, and your position with Tampa Electric Company?

A. My name is William A. Smotherman. My business address is 702 North Franklin Street, Tampa, Florida, 33602.

Q. Mr. Smotherman, have you read the prepared direct testimony of Mr. David R. Knapp that was filed in this proceeding on April 1 of this year?

A. Yes, I have.

Q. Do you adopt that testimony as your own?

A. Yes, I do.

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

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

BY MR. BEASLEY:

Q. Mr. Smotherman, do you also adopt and sponsor Exhibit DRK-1 that accompanied Mr. Knapp's testimony?

A. Yes, I do.

MR. BEASLEY: Mr. Chairman, I believe that has been marked as Exhibit 62 in the composite list.

CHAIRMAN BAEZ: I am struggling mightily to find it. I'm sorry. Exhibit what?

MR. BEASLEY: Seventy-two.

CHAIRMAN BAEZ: Oh. So it is.

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

A. Yes. On behalf of Tampa Electric, I testified before this Commission in Docket No. 040001-EI regarding the calculation of the Generating Performance Incentive Factor ("GPIF") targets.

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 GPIF for the period January 2004 through December 2004. I will also compare these results to the targets established prior to the beginning of the period.

Q. Have you prepared an exhibit to support your testimony?

A. Yes, Exhibit No. _____ (DRK-1), consisting of two documents, was prepared under my direction and supervision. Document No. 1, entitled "Tampa Electric

Company, Generating Performance Incentive Factor, January 2004 - December 2004, 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 2004 period.

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

A. Five of the company's units are included. They are Big Bend Station Units 1, 2, 3, and 4 and Polk Station Unit 1.

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during the January 2004 through December 2004 period?

A. Yes, I have. This is shown on Document No. 1, page 4 of 26. Based upon 1.323 GPIF points, the result is a reward amount of $729,534 for the period.

Q. Please proceed with your review of the actual results for the January 2004 through December 2004 period.

A. On Document No. 1, page 3 of 26, the actual average common equity for the period is shown on line 14 as $1,396,325,730. This produces the maximum penalty or reward amount of $5,514,963 as shown on line 21.

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

A. Yes. Operating data on each of the units is filed monthly with the 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 12 months provides the basis for the GPIF.

Q. Are the equivalent availability results shown on Document No. 1, page 6 of 26, column 2, directly applicable to the GPIF table?

A. No. 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 26. 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 2004. Actual outage activities required 662.4 planned outage hours. Consequently, the actual equivalent availability of 66.6% is adjusted to 67.9% as shown on Document No. 1, page 7 of 26.

Big Bend Unit No. 2

On this unit, 504 planned outage hours were originally scheduled for 2004. Actual outage activities required 651.9 planned outage hours. Consequently, the actual equivalent availability of 69.1% is adjusted to 70.4% as shown on Document No. 1, page 8 of 26.

Big Bend Unit No. 3

On this unit, 504 planned outage hours were originally scheduled for 2004. Actual outage activities required 689.6 planned outage hours. Consequently, the actual equivalent availability of 67.2% is adjusted to 68.8% as shown on Document No. 1, page 9 of 26.

Big Bend Unit No. 4

On this unit, 504 planned outage hours were originally scheduled for 2004. Actual outage activities required no planned outage hours. Consequently, the actual equivalent availability of 79.3% is adjusted to 74.8% as shown on Document No. 1, page 10 of 26.

Polk Unit No. 1

On this unit, 384 planned outage hours were originally scheduled for 2004. Actual outage activities required 279.3 planned outage hours. Consequently, the actual equivalent availability of 90.5% is adjusted to 89.4%, as shown on Document No. 1, page 11 of 26.

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 26, column 4. This number is entered into the respective Generating Performance Incentive Point ("GPIP") table for each particular unit on pages 20 of 26 through 24 of 26. Page 4 of 26 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 and Polk Unit 1 are shown on Document No. 1, page 6 of 26. 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 26. The heat rate value is entered into the respective GPIP table for the particular unit, shown on pages 20 of 26 through 24 of 26. Page 4 of 26 summarizes the weighted heat rate and equivalent availability points to be awarded.

Q. What is the overall GPIP for Tampa Electric for the January 2004 through December 2004 period?

A. This is shown on Document No. 1, page 26 of 26. Essentially, the weighting factors shown on page 4 of 26, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 26, column 4, are substituted within the equation. The resulting value, 1.323, is then entered into the GPIF table on page 2 of

26. Using linear interpolation, the reward amount is $729,534.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MR. BEASLEY:

Q. Mr. Smotherman, did you also prepare and submit the prepared direct testimony of William A. Smotherman filed in this proceeding on September 9, 2005?

A. Yes, I did.

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

A. Yes, they would.

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

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

BY MR. BEASLEY:

Q. And, Mr. Smotherman, did you prepare the exhibit marked WAS-1 that accompanied your prepared direct testimony?

A. Yes, I did.

MR. BEASLEY: Mr. Chairman, I believe that has been marked as Exhibit 73.

CHAIRMAN BAEZ: Correct.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM A. SMOTHERMAN

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

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

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

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

Q. What is the purpose of your testimony?

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

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

A. Yes, Exhibit No. _____ (WAS-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 2006 period.

GPIF Calculations

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 through 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 2005 projected GPIF. Similarly, Tampa Electric requests approval of its 2006 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 2006 period. A range of potential improvements and degradations were 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 2006 period, the projected Equivalent Unplanned Outage Factor for Big Bend Unit 4 is 22.37 percent, and the Planned Outage Factor is 5.75 percent. Therefore, the target equivalent availability factor for Big Bend Unit 4 equals 71.88 percent or:

$$100\% - [(22.37 + 5.75\%)] = 71.88\%$$

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:

$$EAF_{MAX} = 100\% - [0.8\ (22.37\%) + 0.95\ (5.75\%)] = 76.64\%$$

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,

$$EAF_{MIN} = 100\% - [1.4\ (22.37\%) + 1.10\ (5.75\%)] = 62.36\%$$

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 2006 through December 2006 are shown on page 17 of Document No. 1. Two GPIF units have a major outage (28 days or greater) in 2006; therefore, two Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 4 is scheduled for a planned outage from March 20, 2006 to April 9, 2006. There are 504 planned outage hours scheduled for the 2006 period, and a total of 8,760 hours during this 12-month period. Consequently, the Planned Outage Factor for Big Bend Unit 4 is 5.75 percent or:

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

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 9.59 percent. Polk Unit 1 has a Planned Outage Factor of 4.38 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 2005, was used as a basis for the projection. All projected factors are based upon historical unit performance. These target factors are additive and result in an Equivalent Unplanned Outage Factor of 22.37 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

$$EUOF = \frac{(1{,}931 + 29.0)}{8{,}760} \times 100 = 22.37\%$$

Relative to Big Bend Unit 4, the EUOF of 22.37 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 21.03 percent. The unit will have a planned outage in 2006, and the Planned Outage Factor is 15.34 percent. Therefore, the target equivalent availability for this unit is 63.63 percent.

Big Bend Unit 2

The projected Equivalent Unplanned Outage Factor for this unit is 18.89 percent. The unit will have a planned outage in 2006, and the Planned Outage Factor is 3.84 percent. Therefore, the target equivalent availability for this unit is 77.27 percent.

Big Bend Unit 3

The projected Equivalent Unplanned Outage Factor for this unit is 34.21 percent. The unit will have a planned outage in 2006, and the Planned Outage Factor is 9.59 percent. Therefore, the target equivalent availability for this unit is 56.20 percent.

Big Bend Unit 4

The projected Equivalent Unplanned Outage Factor for this unit is 22.37 percent. The unit will have a planned outage in 2006, and the Planned Outage Factor is 5.75 percent. Therefore, the target equivalent availability for this unit is 71.88 percent.

Polk Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 35.28 percent. The unit will have a planned outage in 2006, and the Planned Outage Factor is 4.38 percent. Therefore, the target equivalent availability for this unit is 60.33 percent.

Q. Please summarize your testimony regarding Equivalent Availability Factor.

A. The GPIF system weighted Equivalent Availability Factor of 65.0 percent is shown on Page 5 of Document No. 1. This target is similar to the July 2004 through June 2005 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 load units, 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 the months of January, February, and May 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 March and April, the 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 2006 period.

A. The heat rate target for Big Bend Unit 1 is 10,848 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±514 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,518 Btu/Net kWh with a range of ±436 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,904 Btu/Net kWh, with a range of ±718 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,672 Btu/Net kWh with a range of ±595 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,497 Btu/Net kWh with a range of ±1,167 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 $959,068,300 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 $47,304,788 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 12.33 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 76.6 percent equivalent availability, fuel savings would equal $6,443,000, 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, or $47,304,788. 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 2006 is $1,461,702,488. This produces the maximum allowed jurisdictional incentive of $5,802,787 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):

$$\begin{aligned} GPIP: = (\; & 0.1233 \; EAP_{BB1} + 0.1147 \; EAP_{BB2} \\ & + 0.1905 \; EAP_{BB3} + 0.1362 \; EAP_{BB4} \\ & + 0.1020 \; EAP_{PK1} + 0.0549 \; HRP_{BB1} \\ & + 0.0589 \; HRP_{BB2} + 0.0645 \; HRP_{BB3} \\ & + 0.0849 \; HRP_{BB4} + 0.0700 \; HRP_{PK} \end{aligned}$$

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 2006 - December 2006 period?

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

Maintenance Planning

Q. What does Tampa Electric do to complete planned maintenance outages on schedule and within budget?

A. To complete planned maintenance outages on schedule and within budget Tampa Electric: (1) develops a comprehensive scope of work before every planned outage that identifies time, material and manpower requirements; (2) procures materials and contractor labor; (3) assigns outage coordinators, project managers and business plan managers to manage and coordinate the various aspects of the outage; and (4) holds regular meetings with the appropriate personnel prior to and during the planned outage to ensure that the outage schedule is being met, issues are resolved, and costs are being appropriately managed.

Q. What actions does Tampa Electric take to minimize the occurrence, duration and magnitude of unplanned outages?

A. To minimize the occurrence, duration and magnitude of unplanned outages Tampa Electric: (1) uses a Preventative Maintenance ("PM") program that incorporates the Original Equipment Manufacturer's maintenance specifications, vibration analysis, oil sampling, temperature monitoring, and thermograph equipment; (2) reviews historical equipment unplanned outages; (3) assigns project managers and outage coordinators to manage outages; and (4) schedules planned outages on equipment incorporating a review of the outages during the prior year that result in the largest reduction in unit generation. These tools allow Tampa Electric to determine appropriate actions needed to develop equipment repair strategies, predict future maintenance requirements, appropriately manage the impact of unplanned outages, and return units to service as soon as practicable.

Q. How does Tampa Electric optimize the equivalent availability factors and heat rates of its GPIF units?

A. Above I described actions to complete planned maintenance on time and to minimize the occurrence and duration of unplanned maintenance that directly affect the unit equivalent availability factors. While planned maintenance decreases equivalent availability factors in the short-term, in the long run, maintenance work helps Tampa Electric manage unit performance and availability by decreasing the likelihood of future unplanned outages due to the failure of equipment repaired during the planned maintenance. Tampa Electric optimizes the equivalent availability factors of its units by predicting future maintenance requirements and developing advantageous equipment repair and unit operating strategies using the tools, processes and procedures outlined above.

Tampa Electric optimizes GPIF unit heat rates by: (1) running these units at relatively higher load levels for long periods of time, as the system allows, to avoid the inefficiencies associated with starting and cycling a unit and operating a unit at minimum load levels that are less efficient; and (2) incorporating a review of the largest unit heat rate impacts in the outage planning process.

Polk Unit 1 Outage

Q. What is the status of Tampa Electric's investigation of the failure that caused an extended unplanned outage at Polk Unit 1?

A. Tampa Electric consulted with its service provider, General Electric International ("GE"), with regard to the Polk Unit 1 unplanned outage that began on January 18, 2005. Tampa Electric has been advised that the outage was the result of a physical failure that resulted in extensive damage to the unit's air compressor. The investigation determined the compressor discharge case experienced higher than designed creep, which is high temperature progressive deformation of a material at constant stress. The higher than designed creep resulted in reduced clearances between fixed and rotating air compressor components. When the design limits of the fixed components were exceeded, the fixed vane and rotating blades made contact, causing extensive compressor damage.

Q. Has Tampa Electric evaluated all avenues of redress for replacement fuel and purchased power costs for the air compressor failure at Polk Unit 1?

A. Yes, Tampa Electric has been and continues to be in communication with insurers and GE, who is both the manufacturer and service provider for the air compressor. However, under the company's insurance policy and the contract for purchase of the equipment, Tampa Electric is not entitled to recovery for consequential damages such as replacement fuel and purchased power costs. In my experience at Tampa Electric, indirect damages of these sorts are not typically covered by insurance, construction contracts, or service agreements because covering the risk of indirect damages would be cost-prohibitive or impracticable.

Q. Does this conclude your testimony?

A. Yes.

BY MR. BEASLEY:

Q. Mr. Smotherman, would you please summarize your direct testimony?

A. Yes. My name is William A. Smotherman. I am Director of Tampa Electric's Resource Planning Department.

For this hearing, I have adopted the prepared testimony and Exhibit DRK-1 of Tampa Electric witness David Knapp concerning the calculations of the GPIF reward for Tampa Electric's unit operations during 2004. The calculations for 2004 result in a reward of $729,534, which is reflected in the 2006 projected fuel factor.

My direct testimony presents for the Commission's review and approval Tampa Electric's proposed 2006 GPIF targets and ranges against which actual performance for 2006 will be measured. The 2006 targets and ranges were developed in accordance with the procedures in Section 4.3 of the Commission's Generation Performance Incentive Implementation Manual as previously approved by the Commission. The 2006 targets and ranges are set forth in Attachment A in the Prehearing Order.

That concludes my summary of the testimony.

MR. BEASLEY: Thank you. We would submit Mr. Smotherman for questions.

CHAIRMAN BAEZ: Ms. Christensen.

CROSS-EXAMINATION

BY MS. CHRISTENSEN:

Q. Good afternoon, Mr. Smotherman. Your testimony addresses the GPIF performance of TECO; correct?

A. Correct.

Q. Okay. Can you please tell us what GPIF stands for?

A. Basically, it stands for generation performance incentive factor.

Q. Okay. And which of TECO's generating plants are included in the GPIF calculation for this year's factors?

A. The units included in our factor for this year are the Big Bend Station units, Big Bend Station Unit 1, 2, 3, and 4 -- those are coal-fired generators -- as well as our Polk Unit 1, which is an IGCC coal-fired generator.

Q. And by -- is that IGC -- I'm sorry. Is that --

A. It's an integrated gasification combined cycle unit.

Q. Okay. So that uses coal?

A. It uses coal as a feedstock to create syngas, which is burned in the combined cycle.

Q. Okay. And the Polk plant is located at Bayside in Tampa; am I correct?

A. The Polk plant is actually located in Polk County. Bayside is our combined cycle unit, natural gas-fired. It's not in the GPIF presently.

Q. Okay. So you have natural gas generation at Bayside?

A. That is correct.

Q. And that was put into service in 2004; correct?

A. 2003 and 2004.

Q. Okay. Now, the Big Bend coal plants, do they account for approximately half of TECO's generation?

A. Approximately, yes.

Q. And let me ask you, you eliminated Bayside from this year's calculation; correct?

A. Bayside is not included in this year's calculation; that is correct.

Q. And it's excluded because?

A. It is excluded because we have not received enough historical data to include that unit as of yet. We expect that Bayside 1 would be included in the 2007 factor, because it was brought on in 2003. And the following year, in 2008, in fact, we expect potentially to include Bayside Unit 2.

Q. Okay. Would you agree that the GPIF formula is used to provide an incentive to the companies for good performance in generating plants?

A. It's used as an incentive for performance improvements.

Q. And the formula for calculating GPIF also provides penalties for poor performance; is that correct?

A. Yes, it does provide penalties for a reduction in performance.

Q. And those calculations are based on formulas found in the GPIF manual; correct?

A. That is correct.

Q. And can you tell us what is the source of the manual?

A. The source of the manual? The manual was developed, I believe, back in 1981 during a hearing with this Commission, and that was the feed for the development. If I -- I was not at the company at the time, but I know it was a long hearing. It started in -- I believe it was in April or May and ran through like September.

Q. Okay. But that is not -- it's not codified in a rule; correct?

A. I don't -- I wouldn't be the appropriate person to answer that.

Q. The GPIF manual sets the conditions for including and excluding certain plants; is that correct?

A. That is correct.

Q. And it shows how to make the calculations to measure performance; right?

A. That is correct.

Q. And the GPI measurements of performance are the EAF and the heat rate; right?

A. That is correct.

Q. What does EAF stand for?

A. EAF stands for equivalent availability factor.

Q. Now, am I correct that if you have no outages during a given time period, the measurement time period, the EAF for that period would be 100 percent? Is that correct?

A. That would be correct.

Q. And the EAF is calculated by subtracting the planned outage factors and the equivalent unplanned outage factors from 100 percent to determine the target EAF; is that correct?

A. That is correct.

Q. Okay. Looking at pages 9 through 10 of your testimony, you have listed the plants that are included in the GPIF calculation for this year; correct?

A. Yes.

Q. And would you agree that for Big Bend Units 1 through 4 and Polk Unit 1, your have more unplanned outage -- your unplanned outages are greater than your planned outages; is that correct?

A. That would be correct.

Q. Okay. And for Big Bend 1, your unplanned outages is 21.03 percent, and your planned outages is 15.34 percent; correct?

A. Yes. The unplanned outage factor for Big Bend 1 is 21.03, and the planned outage factor is 15.34.

Q. Okay. And for Big Bend 2, the unplanned outages is 18.89 percent, whereas the planned outages is 3.84 percent?

A. That is correct.

Q. And for Big Bend 2, the unplanned outage percentage was 34.21 percent, and the planned outages is 9.59 percent; correct?

MR. BEASLEY: Big Bend Unit 2, you said, or 3?

MS. CHRISTENSEN: Three.

THE WITNESS: That is correct.

BY MS. CHRISTENSEN:

Q. And Big Bend 4 is 22.37 percent for unplanned and 5.75 for planned; correct?

A. That is correct.

Q. And for Polk, the unplanned outage is 35.28 percent, and planned is 4.38 percent; correct?

A. Correct.

Q. Okay. Now, wouldn't you agree that it would be more efficient to deal with the maintenance needs of a given plant on a planned basis?

A. The unplanned outage rates that are shown there, or the targets that are shown there are based on historical data, not on how we plan on dealing with the outages.

Q. Right. But if you were planning -- for planning, the most efficient means of operating a plant is to try and have planned outages as opposed to unplanned outages? You would agree with that?

A. You would like to have very few unplanned outages, I agree, but essentially, you cannot plan for every eventuality.

Q. And am I correct that when you take down a plant, you try and fix everything possible and do all your preventative maintenance and replacement of all the worn out piece parts at one time during that planned outage?

A. When you do a planned outage, essentially, it requires that you have a good understanding of what you're going to do during that outage, because you've got to order equipment and replacement parts, et cetera, prior to actually doing the outage itself. So from that perspective, you can only do certain things. And there's also a time element related to that, because you've got a system with multiple units on it, and you can only have so many units down at one time. So it will limit the amount of time and the amount of what you know is wrong versus what crops up that you didn't know about.

Q. Right. But you try and take care of everything that you know about as much as possible during planned outages; correct?

A. To the extent that we can.

Q. Okay. And when you take one of these plant units down for major outages, how long on average are those units usually out of service?

A. For a major outage, which we do our major outages roughly once every four years, and those are normally about eight weeks in span.

Q. Now, you could also do your plant maintenance just by fixing the units on an as-needed basis, but you would agree that that would be the least efficient method for maintaining your plants; correct?

A. It depends on the situation. If you're in a situation where you have something come up that you weren't aware of, you may be in a situation where you've got to repair, because you want to make sure you stay online or maximize your time online to generate as much power as possible. To the extent that you know about a problem, you would do a planned outage to address that. But if you don't know about it and it were to crop up on you, you would have to do what you could to get the unit back online.

Q. But I guess conversely, you could have a plan where you just fixed the units as problems cropped up; correct?

A. You could.

Q. But that would be less efficient than having planned outages; am I correct?

A. I don't know if that would be less efficient or not less efficient. It would be less desirable from my perspective.

Q. Okay. But either way you maintain your plant, the company budgets and spends on O&M to keep the plant working; correct?

A. That is correct.

Q. And you would agree that generally the amount of O&M spent on a plant impacts that plant's efficiency?

A. Over time it will impact the plant's efficiency, or could.

Q. Can you explain how the heat rate is calculated?

A. Heat rate is a measure of the power plant's efficiency. So a heat rate that we generally show in the GPIF is Btu, or fuel in, fuel energy in, divided by KWH, or power that is actually produced by the plant out. So a lower heat rate means that a plant has a better efficiency. A higher heat rate means a plant has a worse efficiency.

Q. Okay. Am I correct that the Commission is being asked to approve TECO's requested GPIF targets for EAF and heat rate for the 2006 time frame; correct?

A. That is correct.

Q. Now, looking at your testimony, on page 2 of your exhibit, it appears from this exhibit that if you meet your targets for 2006, you incur no reward or penalty; is that correct?

A. That is correct.

Q. And under this exhibit, under the GPIF you're proposing for this year, the maximum reward and penalties in 2006 are 5.8 million; correct?

A. That is correct.

Q. Now, on page 4 of the exhibit, it shows the EAF targets for all the plants; correct?

A. Correct.

Q. And if you add those numbers together, the total GPIF for the system is 66.67 percent; is that correct?

A. The 66.67 is the weighting factor for the EAF.

Q. And most of that 66.67 percent is comprised of the Big Bend coal units; correct?

A. Yes, it is.

Q. Now, is the EAF target for TECO's Big Bend coal units higher or lower than Gulf's coal units' target -- coal unit targets requested in this docket?

A. I do not know what Gulf's units' targets are.

Q. Okay. Subject to check, would you agree that Gulf's EAF targets, which are greater than 80 percent, are higher than the target set that's being requested for TECO in this proceeding?

A. Subject to check, yes.

Q. Okay. And are you familiar with what Progress's requested GPIF targets are?

A. No, I'm not familiar with Progress's targets.

Q. Subject to check, would you agree that Progress's GPIF targets that are greater than 80 percent are higher than what TECO is requesting for GPIF targets in this docket?

A. Subject to check, yes.

Q. Now, you provided a late-filed deposition exhibit, I believe, that shows -- I think it's Late-filed Deposition Exhibit Number 3, page 2 of 2. Do you have that, or I can -- if I can approach the witness, I'll pass out the diagram.

(Document distributed.)

BY MS. CHRISTENSEN:

Q. Mr. Smotherman, are you familiar with this graph?

A. Yes, I am.

Q. Okay. And this is a graph representing the 1999 through 2004 Big Bend Station historical EAF; is that correct?

A. That is correct.

Q. Now, can you tell me, what was the EAF, the historical EAF for 1999?

A. The historical EAF for 1999 was approximately 75 percent.

Q. And according to the graph, what was the EAF for 2000?

A. The EAF for 2000 was approximately 81 percent. I'm just judging by the graph that's on here.

Q. Okay. Do you recall from your memory what your EAF was in 1998, although it's not on the graph?

A. No, I do not.

Q. Okay. Now, would you agree based on the graph that TECO's historical EAFs for the Big Bend units have been over 70 percent for the years 1999 through 2001?

A. Yes, I do.

Q. Now, what are the EAFs for 2002 and 2003, according to the graph?

A. The EAFs for 2002 and 2003 are approximately 65 percent.

Q. And in 2004, would you agree that the EAF has risen again above 70 percent?

A. Yes.

Q. Now, looking at the graph, it appears the 2002 and 2003 years have an anomaly and show a negative trend. Would you agree with that?

A. They are lower than the rest of the numbers on the graph. I would not agree that they're necessarily an anomaly. What occurred in 2002 and 2003, essentially, in the year 2000 relatively we began a lot of our compliance efforts on the Big Bend Station associated with our consent decree, and you see some of the impact of that on the EAFs that occurred subsequent to that period and -- as we have suffered a little bit on our reliability because we added complexity to the operation of those plants.

Q. Are you familiar with the Commission staff member Sid Matlock's direct testimony related to GPIF --

A. Yes.

Q. -- for TECO this year?

A. Yes.

Q. And would you agree that his basic recommendation is to account for the increased negative trend in forced and maintenance outages for the past five years? Let me rephrase that. Would you agree that his testimony recommends that in setting the targets, that the Commission take into account the negative trends created by the increase in forced and maintenance outages over the past five years?

A. I don't know. I can't speak to whether his testimony directly says it's to address those trends. I know his testimony essentially suggests the exclusion of particular forced outage, equivalent forced outage rate months or equivalent maintenance outage rate months.

Q. And would you agree that he's recommending that since the increase in the forced outages and maintenance outages, especially in the 2002 and 2003 time frame, are likely to -- unlikely, excuse me, to continue in the near future, that the 2006 targets be set higher by excluding outages greater than 40 percent?

A. I know he suggests that they be excluded. I don't know that it suggests that it be higher. But from a practical standpoint, when we modified those units, which we have modified those Big Bend units, the potential still exists for that to occur. It does not mean that it will not occur ever again. In fact, we have some more environmental-related projects that we will be pursing subject to the 2007 to 2010 time period.

Q. Now, isn't it correct that the adjustment that's recommended by Mr. Matlock is an adjustment that is contemplated by the GPIF guideline for TECO, 4.3.1, the equivalent availability targets, which says in part that this average may be modified due to numerous circumstances, such as recent trends, equipment modifications or changes, unit rating changes, et cetera?

A. I believe the application of that suggested language as you put it there is in reverse of how it should be applied. The GPIF is pretty straightforward in its applications of when you should make modifications. The general rules would be as stated in the manual, natural disasters, planned outages, reserve shutdown hours, or situations where the unit has been shut off or been required to run longer due to regulatory agencies' requirements.

Now, generally when we've made changes associated with a recent trend -- and not that we have ever on availability, but we have on heat rate -- those changes are always related to history. So, for example, if we didn't have a history and we made a major modification to a unit like the modifications that we did when we did the scrubbers for Big Bend 1 and Big Bend 2, we would make that change to history as well as to projections.

I would suggest that the changes associated with what we're talking about now are things that have already occurred, and we have paid penalties or received credits under the GPIF methodology. These are not new changes. They didn't happen yesterday. They've been occurring over a five-year period of time.

Q. Well, let me provide you with a copy of the language from the GPIF rule, if I can approach and provide copies.

CHAIRMAN BAEZ: Go ahead.

THE WITNESS: Thank you.

CHAIRMAN BAEZ: Ms. Christensen, I failed to ask, the late-filed depo exhibit that you provided us with, do we need that marked?

MS. CHRISTENSEN: I'm sorry?

CHAIRMAN BAEZ: Do you need the late-filed depo exhibit that you were asking questions on marked?

MS. CHRISTENSEN: Yes, Commissioner, if I could have that marked, as well as the --

CHAIRMAN BAEZ: Show that as Number 84. And then the two pages, pages 4.403 and 4.404 of the GPIF manual?

MS. CHRISTENSEN: Correct. These are excerpted pages from that.

CHAIRMAN BAEZ: Got it. Show those marked as composite 85 -- 86. No, 85. I'm sorry.

(Exhibits 84 and 85 were marked for identification.)

BY MS. CHRISTENSEN:

Q. Mr. Smotherman, are you familiar with this portion of the GPIF manual?

A. Right. This is Tampa Electric's detail for the GPIF manual.

Q. Okay. And at the bottom of the page, the first page that we have under Rule 4.3.1, it talks about how to determine the target equivalent availability for each unit; correct?

A. That is correct.

Q. And that target is generally set based on historical information; correct?

A. That is correct.

Q. And within that, if you turn over to the top of the following page, is where it talks about modifying the historical average; correct?

A. That is correct.

Q. And that's where it talks about modifying those historical averages due to recent trends, equipment modifications or changes, unit rating changes, et cetera; correct?

A. That is correct.

Q. Okay. And you would agree that in this case, TECO has not made any modifications to its historical EAF?

A. No, we have not. And I might want to point out that this is our detail of the GPIF manual. The overriding or the general text for the GPIF manual is on Sheet 3.4.04. And that's where it states natural disasters or externally caused disasters, the unforeseen shutdown, rescheduling, planned maintenance, reserve shutdown hours, et cetera, and this is the detail behind when you do that. So it essentially is contemplating what would be explained under the larger heading of those items.

Q. But isn't it true the explanation you provided today regarding the decrease or the negative trend on the graph starting in 2000 was that you were modifying your units because of equipment? Is that correct?

A. We were modifying our units in conjunction with the consent decree order that we had received.

Q. Right. But that was due to putting on equipment?

A. That was due to putting on new types of environmental equipment.

Q. Correct. And that was a modification to those units; correct?

A. That is correct. But according to this manual, what that would suggest would be that we would change our history and change our projections in accordance -- like we have done in the past on heat rates, so we would reflect out or take out those items that we could identify. We did not do that in the five years that we've done this.

Q. Okay. Now, is it also true that TECO has a chance for a bigger reward, so to speak, if your targets are set lower?

A. I don't know if we have a chance for a bigger reward or not. To the extent that we are able to improve the operation of our units, we have an incentive to do so according to the methodologies.

Q. Yes. But wouldn't you agree, and isn't it true that if you set your targets lower, it's easier to achieve improvements and thereby get rewards?

A. Well, we do not set our targets lower or higher. Our targets are determined by history, because history is the best indicator of future performance.

Q. If the Commission accepts your proposed target of 66.67 percent, is it more likely that you will receive a reward than if the targets are adjusted to exclude the negative trends related to the forced and maintenance outages?

A. The 66.67 you're referring to is not the target value. But to the extent that our targets are set higher, history would suggest that it would be more difficult to reach that number, merely because we've not done that in recent history.

Q. And am I correct that it's TECO's belief that the EAF performance for the Big Bend units went down in

2002 and 2003 due to modifications made due to environmental equipment?

A. That -- excuse me. That is correct.

Q. Now, when we asked for a late-filed exhibit showing how many outages and the length of those outages that were caused by the environmental equipment, would I be correct in saying that you were unable to identify that specifically?

A. Right. And the reason why we were unable to identify that specifically is, the outages that were created from that are not necessarily categorized in that fashion. So, for example, if we have additional tube leaks due to a change in the combustion of our coal, which is one of the items that we've seen, it's not like you can say, "Okay. This number came from the environmental equipment, and this number came directly from normal wear and tear on the unit." So it's very difficult to separate some of those items.

Q. Let me ask you this. In the 2003 time frame, did TECO decrease or increase its O&M budget related to the maintenance work on the Big Bend units?

A. Say that again. I didn't catch the whole question.

Q. In the 2003 time frame, did TECO increase or decrease its O&M budget related to maintenance work on the

Big Bend units?

A. I believe the O&M budget was lower from Tampa Electric in 2003, although we ended up, I believe, exceeding that budget amount.

Q. And has TECO subsequently increased its budget, O&M budget related to maintenance work on the Big Bend units in 2004 through the 2006 time frame?

A. Yes, we have. Our budgets are essentially driven by what we think we have to do to maintain and operate the units reliably. So as we see trends of increasing outages, we will obviously increase our budgets to make sure we can maintain the reliability of our plants, similar to what I was referring to before for planned outages. When you know you've got problems and you can see them coming up, you go ahead and you plan and you spend the money to do those things.

Q. So isn't it true that the anomaly related to the 2002-2003 time frame may also be attributable to the decrease in maintenance O&M?

A. As I said before, when we see problems that we have, we don't just not let the unit run. We go ahead and we spend the money. We have a budget that we try and keep to. But to the same extent, if you end up in a situation where you know you're going to have problems, you go ahead and you spend the money and you fix the units.

Q. And since TECO has increased its O&M budget for maintenance, isn't it correct that it is unlikely that the negative trends of 2002 and 2003 will reoccur?

A. We have, as I said before, many other environmental projects that we are getting read to embark on with these units, so there is no guarantee that we will not see the same types of things happen again.

Q. But to the extent that any of the EAF was negatively impacted by the decrease in O&M maintenance budget, that's unlikely to occur, because you have increased the maintenance budgets in the near future; correct?

A. Yes, we have increased the maintenance budgets.

Q. And isn't it also true that if the EAF targets suggested by Mr. Matlock are approved that the anomaly related to the 2002-2003 time frame would be removed from the 2006 targets?

MR. BEASLEY: Mr. Chairman, I think the witness has indicated a couple of times that he doesn't consider there to be an anomaly with respect to 2002 and 2003.

CHAIRMAN BAEZ: What's your objection exactly?

MR. BEASLEY: Improper characterization of the witness's prior testimony.

CHAIRMAN BAEZ: Ms. Christensen, ask the question again.

BY MS. CHRISTENSEN:

Q. Isn't it true that if the targets suggested by Mr. Matlock are approved, that the downward trend in the numbers shown on the graph that brought the EAF down to 65 percent in 2002 and 2003, in the 2002-2003 time frame, would be removed from the 2006 targets?

A. That's not true. The way the targets are set, they're set based on the 12-month prior history. So if you look at 2004 and 2000 -- through June 2005 is where they're being set from. So the targets that are presented for 2006 setting, the data starts July of '04 and runs through June of '05. So the data reflected in 2002 and 2003 was not included in the development of the targets for 2006.

Q. So that's not included as part of the historical data?

A. The historical data is based on the past 12-month period, and the 12-month periods roll from July through June of prior years.

MS. CHRISTENSEN: I have nothing further.

CHAIRMAN BAEZ: Do any of the other intervenors have questions for this witness?

LT. COLONEL WHITE: (Shaking head negatively.)

CHAIRMAN BAEZ: No? Ms. Vining.

CROSS-EXAMINATION

BY MS. VINING:

Q. Good afternoon, Mr. Smotherman.

A. Good afternoon.

MS. VINING: I've handed out four different exhibits. And, Mr. Chairman, I think just for ease, if we could go ahead and premark these exhibits.

CHAIRMAN BAEZ: You want them in any particular order, or do you want to take them as a composite?

MS. VINING: I would think -- and this would be 86 through 89. Eighty-six should be the selected pages from the GPIF manual; and 87, selected pages from Appendix A of Order No. 9558; and 88, page 9 from Mr. Smotherman's direct testimony filed in Docket 030001. And then 89 would be selected pages from Tampa Electric Company's GPIF filings in Dockets 000001, 010001, and 020001 for Gannon Unit 6.

CHAIRMAN BAEZ: So marked.

(Exhibits 86, 87, 88, and 89 were marked for identification.)

BY MS. VINING:

Q. Now, Mr. Smotherman, if you could turn to Bates stamp page 166 in staff's composite exhibit, which is the green cover page right there.

CHAIRMAN BAEZ: What page was that?

MS. VINING: 166.

A. I'm there.

Q. Do you have it? Okay. And that is a chart that's entitled "Comparison of TECO 2006 EUOF Targets with Previous Years' Targets and Actuals"? That's that you have?

A. That's correct.

Q. Can you define -- well, tell us what the acronym EUOF stands for.

A. The acronym EUOF stands for equivalent unplanned outage factor, which essentially is the unplanned outage hours divided by the total hours in any particular year.

Q. And what does that generally show, this factor?

A. That factor generally shows the amount of time during a year that a unit would be out for unplanned outages.

Q. Now, if you can refer to columns 11, 9, 7, and 6 on the chart, those list the targets for the units for 2002 through 2005; correct?

A. Correct.

Q. Now, looking at the targets for 2006, which are in column 2, can you explain why Polk Unit 1's target is substantially different from what it was in columns 6, 7, 9, and 11?

A. Yes. Polk Unit 1's target is different, and it is a higher number than what appears in the other targets, merely because we've had a fairly substantial outage on that unit which occurred this year. And that has been rolled into the GPIF calculation.

Q. And how long was that outage?

A. I don't remember the exact time frame. It started in roughly January -- I believe January 18th was when it started, and it finished April 29th, I believe.

Q. So around four months?

A. Approximately.

Q. And do you know what the cause of that outage was?

A. Yes, I do.

Q. Can you please tell us?

A. Yes. The cause of the outage was, essentially, we had a failure of a blade in the air compressor section of the turbine. That failure essentially wiped out all the blades after that blade and required a long outage to fix that air compressor section of the turbine.

Q. And do you believe that a similar outage is going to happen in 2006?

A. No, I do not.

Q. But yet you included an outage of a similar time frame in your target setting for 2006; is that correct?

A. That is correct. The GPIF methodology as set forth essentially would suggest that we would include that, and according to the methodology, we will probably end up paying a maximum penalty associated with that unit also related to that outage.

Q. Now, while the unit was down for those four months, did you do any extra planned maintenance because it was down for so long than you would have normally done otherwise?

A. Yes, we did.

Q. So in actuality, perhaps the unit would perform better because you were able to do planned maintenance earlier than you had planned?

A. We think it was a prudent thing that we went ahead and did the maintenance since we were going to be down for such a long period of time. Otherwise, we would have had to take additional outage time on the unit, which would have reduced our coal-fired generation output of that plant.

Q. Now, the target for Big Bend 4 appears to be higher than it had been in the past, higher than any previous target since 2002. Why is that number higher in the target for 2006?

A. We had some boiler tubes fail on the floor, on the floor of that unit, and that is suspected to be related somewhat to the environmental changes that have been made on that unit. We put in some fixes as well during the Big Bend -- during this year, roughly in March. And we're waiting to see how well those fixes hold up.

Q. Okay. How about for Big Bend 3? It looks like that target is higher than any previous target since 2002 except for 2005.

A. Big Bend 3 has had a variety of different issues. And again, a lot of those have been related to some of the environmental changes on that unit.

Q. Okay. Now, if you can turn to what has been marked as Exhibit 86 and look at sheet number 3.100.

A. Exhibit 86?

Q. Yes, the one -- selected sheets from the GPIF manual.

A. Yes, ma'am.

Q. Okay. And sheet 3.100 should be the first one.

A. I'm there.

Q. Okay. If you can go down to the fourth paragraph on that page and read for me the second sentence in that paragraph.

A. Starting with "these"?

Q. Yes, please.

A. "These targets reflect how each unit is expected to perform during the six-month period encompassed by the projected fuel adjustment clause."

Q. Okay. And then continuing to the second sentence, the next sentence after that, please.

A. "For each target, a maximum reasonable attainable range of potential improvement and degradation are determined. Weighting -- "

Q. So -- that's it. That's good.

A. Okay.

Q. So would you say based on those two sentences that targets should be set to reflect how each unit is expected to perform during the projected fuel period?

A. I would say that this is a -- what is being done is, this is used as a proxy for what is expected to be done, but the methodology clearly provides for both penalty and incentives.

Q. And you had said earlier in response to Ms. Christensen's questions that history is the best barometer for how a unit is expected to perform?

A. Yes.

Q. But you would agree too, though, that history may not be reflective of how it will perform in the future?

A. Yes, but it provides a balanced approach for both penalty and incentive. So from the standpoint, if you do better, then you get an incentive. From the standpoint, if you do worse, you do get a penalty. So the methodology has been in play for multiple years, and I believe that it's valid and it works well.

Q. So you think in the case of Polk Unit 1, it's appropriate to include this four-month outage at the beginning of the year in setting targets?

A. I do, unless we were to not include that outage as part of the history.

Q. Even though you don't think it will reflect the unit's performance in the year 2006?

A. No, merely because it provides the symmetry associated with the methodology. The methodology provides for a penalty and for a reward. And to the extent you're able to make something perform better, you get a penalty -- I mean a reward, and vice versa. It has been in place for a long time, and we've had that occur. This is not the first time we've had a situation like this. We've had outages. For example, on Gannon 6, we had a fairly large explosion. We incurred a penalty associated with that explosion, and that set the target that we were to beat for the next year.

Q. Now, Mr. Smotherman, if you can take a look in that same exhibit at pages -- or sheets, rather, 4.403 and 4.404, these are the pages that had you had a discussion Ms. Christensen on earlier. And you did indicate earlier that these are from the TECO-specific section of the GPIF manual.

A. Yes, ma'am.

Q. And these are the guidelines for setting the targets; correct?

A. These are the guidelines for setting the targets, yes.

Q. Okay. Now, you also had a discussion with Ms. Christensen about -- you had listed some other items that you thought should be taken into account when setting the targets. And you addressed them in your rebuttal testimony and listed them explicitly, but because you answered them with regard to Ms. Christensen, I'll go ahead and ask you questions on that then.

If you can look then at sheet 3.403 again. Well, actually, we haven't looked at that, 3.403 and 3.404.

A. Yes, ma'am.

Q. Now, at the top of 3.404, those are the factors that you talked about your rebuttal testimony and that you also expressed to Ms. Christensen earlier.

A. That is correct.

Q. Okay. Now, which section of the manual are these from? In other words, are these general guidelines for GPIF?

A. These are general guidelines for GPIF that are set overriding ones that -- for every company to follow.

Q. Okay. Do you feel that this list that's on page 3.404 does not support Mr. Matlock's proposed method for adjusting the 2004 EAF targets?

A. Yes, I feel it does not.

Q. Okay. Now, this list sets adjustments to performance indices, does it not?

A. Yes, it does.

Q. Okay. If you could look at 3.403, the very last sentence, if you could read that for me, on that page, starting with "Since performance targets."

A. "Since performance targets are set prospectively in the GPIF, certain circumstances may arise during the six-month period which warrant adjustments to be made in the final GPIF calculation."

Q. Wouldn't you agree then that the factors you listed in your rebuttal testimony, which are itemized on 3.404, go to the final adjustment of the GPIF with regard to whether or not a penalty or reward should be given versus setting the actual targets prospectively based on historical information?

A. Well, I believe they go for the final, but I would think for the prospective they would apply as well.

Q. Even though it says warrant adjustments to be made in the final GPIF calculation?

A. Yes.

Q. So you don't think that the items listed on 4.404 apply to target setting? It's only the list that's on 3.404?

A. No. I think the list on -- the other list does apply as well. These lists that are shown on 3.404 is the overriding list. But what that also says is, it says generally, and it provides flexibility for other things to be done. But those other things essentially would have to be approved by the Commission as outlined in the TECO-specific section.

Q. I'm confused then, because you just said that the manual gives flexibility for those things to be adjusted. That doesn't --

A. What I said is, essentially, under the -- these are the general overriding guidelines on 3.404 that would be applied. Now, anything outside of that, the language that is written, it says generally adjustments. So it provides for -- other reasons for that to happen.

And the reason why I bring that up is, not using it under EAF, but under heat rate, we have done other things, and we've always come to the Commission prospectively for approval of those items. So I would say this is the general, and I think it's set this way to show that it needs to be something fairly large before you would come and change your targets.

Q. The manual doesn't say how large it has to be before it's changed, though, does it?

A. It does not speak to specifics, no.

Q. These specific sections also do apply to TECO, correct, in addition to the general sections?

A. That's correct. Those specifics, though, would be overridden by what's in here unless we got Commission approval, as it says. At the end of that language, it basically says we would go to the Commission and ask for approval of that, and it basically says it's pending Commission approval. So these are the overriders. Those are the items if we were going to do something outside of that, and we would need to do that seeking Commission approval.

Q. Okay. But the manual does not foreclose the type of adjustments that Mr. Matlock has proposed?

A. No, it does not.

Q. Okay. And they're within the scope of the manual?

A. Well, I would say the way that he proposed it is different from the scope of how the manual proposes, because when it says recent trends, I would propose that that looks at recent trends of what's happening. So if you have higher outages occurring on a recent basis, you would have a worse target.

So, for example, if in the last six months of a 12-month period it's a lot worse, you could make an argument, "I want a worse target." Or if I have a lot better in the last six months, I can make an argument, "I want a better target." But to me, that's a recent trend change, not that it's getting worse, so I'm going to set it higher. That seems counter to what you would expect for a recent trend change.

Q. Well, then couldn't you also make the argument that it's a recent trend that the Polk Unit 1 had a four-month unplanned outage which you don't expect to happen again, so it seems appropriate that that would be adjusted out?

A. I think to maintain the symmetry of that, I would expect to adjust that out in the final true-up for the '06 of this. But if you were to do it on both sides of it, I would say yes.

Q. Let's talk a little bit more about that doctrine of symmetry. Now, again, this is in your rebuttal testimony, but because you've answered on it, we'll go ahead and talk about it. On page 2, lines 13 through 15 of your rebuttal testimony, I'm going to quote from it. You say, "The GPIF program benefits the ratepayers and utilities by providing a fair and symmetrical sharing of improvements or declines in unit performance"; is that correct?

A. That is correct.

Q. Now, does this concept of symmetry appear in any orders of the Commission addressing GPIF?

A. I don't know if it is specifically stated in the order, but it is something that is definitely reflected in the methodology as set forth.

Q. Okay. So that would be a no then?

A. It's not specifically stated, no, but I think it is reflected in the way the methodology is set forth.

Q. Does your statement then that you made in your rebuttal testimony imply then that in order to be fair, the penalties incurred in one period should be evened out by rewards in another period?

A. No. Basically, all I'm saying is that if the history is such, then you do reflect the history. If you're going to change the history, then you should also reflect that change in the projection.

Q. Okay. Let's move on to Exhibit 87, which are selected pages from the appendix to Order No. 9558. If you can look at page D-8. That's what's listed in the bottom of the page. Do you have it?

A. Yes, I do.

Q. If you can read for me the second paragraph on that page.

A. "At the end of the six-month fuel adjustment period, actual equivalent availability and average heat rates are compared to pre-established targets. Based on this comparison, a monetary reward is awarded for improvements from the performance targets; a monetary penalty is deducted for degradation from the performance targets."

Q. Okay. Do you agree with the second sentence that a reward is awarded for improvements from the performance targets or for improvements from how a unit is expected to perform rather than for improvements from the previous period?

A. When you say expected to perform, I don't believe I read that. I believe it said pre-established targets.

Q. Well, I thought we discussed earlier that those targets are set on how the unit is expected to perform.

A. But those targets are associated with history, and the history is the expectation for the future. So the improvement or degradation, reward or penalty, is based on the history of that particular unit and the pre-existing, preset targets.

Q. Did you just say that history is how it's expected to perform?

A. I said that the methodology as set forth by the GPIF uses history as an expectation for future performance.

Q. Okay. Let's move on to Exhibit 88, which is a page from your direct testimony filed in Docket 030001. Could you read for me the question that's on page 9 and the portion of the response that's also on page 9?

A. Okay. "How did you determine the forced outage and maintenance outage factors for each unit?"

"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 2003, was used as a basis for the projection. This value was adjusted by analyzing trends and causes for recent forced outage maintenance (sic). 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 unavailability factor of 27.11 for Big Bend 1."

Q. Thank you. Now, you state in your answer on lines 18 through 20 that this value was adjusted by analyzing trends and causes for recent forced and maintenance outages. So based on that, would you agree that a straight historical average is not the only basis for an outage factor projection, nor for a resulting availability factor projection?

A. I would agree that the methodology allows for that with the Commission approval. To state a fact, though, the 27.11 as shown here was a direct calculation of a historical number. The historical number utilized to determine that was just a straight basis of those numbers. No changes were made.

Q. But you did consider trends? You just decided that no adjustments were warranted?

A. Exactly.

Q. All right. Now, moving on to Exhibit 89, this has actual unit performance for calendar year 2000 as well as 2001, and then estimated unit performance data for calendar year 2002 for Gannon Unit 6. Are you aware that Gannon Unit 6 had a major forced outage in late 2000?

A. Yes, I am.

Q. Now, do you agree that the forced outage hours and maintenance outage hours, which are listed on lines 7 and 8 of the 2000 data, as well as the 2001 data, for late 2000 and early 2001 total 3,923.3 hours? And what I did was, I took the numbers for July through December of 2000 and for January through June of 2001.

A. Subject to check.

Q. Okay. So then based upon that, would you agree that the number of equivalent unplanned outage hours was at least 3,923.3 hours?

A. I would think so, yes.

Q. Okay. Now, would you agree that the 12-month period from July 2000 through June 2001 totals 8,760 period hours, which would be 365 days times 24 hours in a day?

A. Yes, I would.

Q. Okay. So if I take the 3,923.3 that we talked about earlier and divide by the period hours, I should get 44.8 percent, which would be the equivalent unplanned outage factor for that time period?

A. That is correct.

Q. Okay. Now, if you could look at the estimated data for 2003, please, which should be the third page in the exhibit, would you agree that the target EUOF, which again is the equivalent unplanned outage factor, for 2002 for Gannon Unit 6 was only 18 percent? And that's on line 3.

A. Yes, I do.

Q. So we had just calculated that the equivalent unplanned outage factor should have been 44.8 percent for that particular unit, but yet the estimated data says 18 percent for that unit. What's the discrepancy there?

A. The change would be that if you look at the planned outage factor that it shows up there, it's at 18.1 percent. So what we do when we actually calculate the numbers is, if we have additional -- or we have planned outages occur during a time period, we use not the factor, but we use the rate.

And then you can't have the same number of outage hours, because on a rate basis, if you have a planned outage, essentially, you've taken out a portion of the year. So a portion of the year is essentially gone, or 18.1 percent of the year, you can't have a forced outage. So that necessitates that the equivalent unplanned outage hours that you would expect for the upcoming year would be less.

Because that is a very large unplanned outage, 18.8 percent -- not unplanned, I'm sorry, planned outage of 18.1 percent, that dramatically reduces the total number of hours that would be reflected.

Q. Correct me if I'm wrong, but I thought that the 2002 target that's listed on line 3 was calculated based on the 12-month historical average, which would have been the period July 2000 through June 2001.

A. That is correct.

Q. Okay. I thought we had calculated that equivalent unplanned outage factor to be 44.8 percent.

A. Right. But the methodology also recognizes the fact that planned outages are not the same from one year to another. So the methodology essentially allows for increasing those unplanned outage hours or decreasing those unplanned outage hours based on whether you have a planned outage or not.

If you have -- say you go from a year where you have a zero unplanned outage, which is what I would expect shows in this data from the target period, to a year where you have a relatively high planned outage. It's not going to say, okay, we're going to have 3,000 hours and 3,000 hours of outage time, and you're only going to run for whatever is left over. The methodology recognizes that that really wouldn't work.

So to account for that, what the methodology does is, it ratios your equivalent unplanned outage hours associated with the amount of planned outage hours you have in any particular period, because essentially, if you take a large planned outage in a target period, it's very hard for you to say that you're going to have that same number of unplanned outage hours. In fact, you should have less, because part of your year is actually eaten up by the fact that you've actually done a planned outage, and the methodology accounts for that and allows for that shifting.

Q. So you're telling me that TECO did not exclude any of the unplanned outage hours in the historical period from the target for 2002?

A. That is correct.

Q. Even though there's almost -- well, at least almost a 30 percent discrepancy between the historical and the number you're targeting?

A. That is correct. And if you were to look at the addition of the planned outage and the unplanned outage hours, that represents roughly 36 percent outage.

Q. Right. And then we still have to get somewhere up to 45 percent.

A. Right. But it's not a factor that it's based on. It's based on a rate. So as you reduce the number of hours that it's seen over, the rate actually stays the same. The factor is what changes.

MS. VINING: Okay. Those are all the questions I have for you, Mr. Smotherman. Thank you.

CHAIRMAN BAEZ: Commissioners, questions of Mr. Smotherman? No questions?

Mr. Beasley?

MR. BEASLEY: I have no redirect, sir, and I would like to move the admission of Exhibits 72 and 73.

CHAIRMAN BAEZ: Without objection, show Exhibits 72 and 73 admitted.

(Exhibits 72 and 73 were received into evidence.)

CHAIRMAN BAEZ: Ms. Christensen, I have for you 84 and 85.

MS. CHRISTENSEN: I would ask to have Exhibits 84 and 85 moved into the record, please.

CHAIRMAN BAEZ: So moved.

(Exhibits 84 and 85 were received into evidence.)

CHAIRMAN BAEZ: And, Ms. Vining, I have 86 through 89 for you.

MS. VINING: Yes. I would ask that those be moved into the record.

CHAIRMAN BAEZ: Show them admitted without objection.

(Exhibits 86, 87, 88, and 89 were received in evidence.)

CHAIRMAN BAEZ: Mr. Smotherman, thank you.

Let's take a five-minute break, and then we'll be back with Mr. Stewart.

(Short recess.)

(Proceedings continued in Volume 6.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA:

COUNTY OF LEON:

I, MARY ALLEN NEEL, Registered Professional Reporter, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter translated under my supervision; and the foregoing pages numbered 660 through 850 are a true and correct record of the aforesaid proceedings.

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

DATED THIS 15th day of November, 2005.

Mary Allen Neel

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