BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of — DOCKET NO. 060001-EI

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

PETITION TO RECOVER NATURAL GAS STORAGE PROJECT COSTS THROUGH FUEL COST RECOVERY CLAUSE, BY FLORIDA POWER & LIGHT COMPANY. — DOCKET NO. 060362-EI

PETITION FOR AUTHORITY TO RECOVER PRUDENTLY INCURRED STORM RESTORATION COSTS RELATED TO 2004 STORM SEASON THAT EXCEED STORM RESERVE BALANCE, BY FLORIDA POWER & LIGHT COMPANY. — DOCKET NO. 041291-EI

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VOLUME 2
Pages 188 through 406

PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN LISA POLAK EDGAR COMMISSIONER J. TERRY DEASON COMMISSIONER ISILIO ARRIAGA COMMISSIONER MATTHEW M. CARTER, II COMMISSIONER KATRINA J. TEW
DATE:	Monday, November 6, 2006
TIME:	Commenced at 9:30 a.m. Adjourned at 5:08 p.m.

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

REPORTED BY: MARY ALLEN NEEL, RPR, FPR

PARTICIPATING: (As heretofore noted.)

* * *

I N D E X

WITNESSES

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(Transcript follows in sequence from Volume 1.)

Thereupon,

GERARD J. YUPP

called as a witness on behalf of Florida Power & Light Company, continues his sworn testimony as follows:

CONTINUED CROSS-EXAMINATION

BY MR. McWHIRTER:

Q. A swap is a financial transaction; is that correct?

A. That's right.

Q. And a collar is a financial transaction?

A. Yes, it can be, yes.

Q. And when you engage in the hedging, do you do it in one of the commodity exchanges, or do you do it over the counter?

A. Predominantly over the counter.

Q. Do you deal over the counter with any affiliated companies of Florida Power & Light?

A. No, we do not.

Q. If the Commission had the duty to determine whether a hedging program was prudent or imprudent, give me an example of some kind of hedge that you would deem to be imprudent.

A. From a utility perspective, I think hedges that would be put in place purely at, let's say, trying to save the customer money, and as I explained in my summary, trying to outguess the market to return savings to the customers, those would be in my opinion imprudent hedging transactions.

The bottom line is, we don't know where the market is going to go. And in order to execute a prudent hedging program, you need to be well disciplined, you need to follow the plan, so to speak, and it does have to be independently controlled. But I think "well disciplined" is the right term.

And there may be indications that the market is heading in a different direction, and it's fine to take that into account, and I think your hedging program can be adjusted to take that into account with different types of instruments to limit your exposure.

But to see the market moving in a different direction and all of a sudden change your strategy I think could be, in reference to your question, Mr. McWhirter, deemed to be not prudent, because we cannot guess where the market is going to go. It could change tomorrow and start going back up again. So it's the transactions that are speculative in nature that I would say are not prudent.

Q. How do you determine whether a transaction was speculative or not speculative?

A. Well, I guess that's the difficult part. But I think probably -- and from what we file each year, I think you can see a certain pattern with our results where we weren't in and out of transactions on a frequent basis, in other words, changing the percentages of what we hedged. I mean, we develop our plan in the beginning of -- generally in the beginning of the previous year, and we execute that hedge program throughout the year to get to our desired percentages, and we don't vary a lot from that. Again, we're well disciplined in our approach.

And so it would be difficult to see -- I think it would be difficult to determine whether somebody was in the market purely speculating, but I think you would see a lot more swings in their percentages, maybe a lot more volume traded in their percentages as they try to beat the market. But again, it's probably difficult to determine that.

Q. Under your hedging program, do you have minimum and maximum percentages that you hedge at different times of the year for, say, delivery -- if you're hedging in August for delivery next June, do you have a specified minimum or maximum percentage you use in August 2006 for June 2007 acquisitions?

A. We generally will have a target percentage of what we determined through management approval and everything. We have a target percentage that we're looking at for the next recovery period. We generally will shape that.

Obviously, there are more volatile times than others, such as the winter period versus summer period, although with recent hurricane events and everything, summer has become very volatile also. But, yes, we do have target percentages that we're looking at and tolerance bands around those target percentages to where it's acceptable to be -- you are considered to be in line with what the plan was if you are within that tolerance band.

And the other point I'll make on that is -- or other note I'll make on that is that we do engage in rebalancing our hedge positions on a fairly frequent basis. Depending on where fuel prices are moving, we will look not necessarily to change percentages or to change what our plan is, but to rebalance our positions around where fuel prices are going and what our projections or new projections would be from a move in fuel price. And by projections, I mean fuel requirements.

Q. Would you look at Appendix 1 to your testimony, page 3? This is your September testimony.

A. Yes. Page 3?

Q. Yes, sir.

A. Yes.

Q. About --

MR. BUTLER: I'm sorry, Mr. McWhirter. Just to be clear, for me at least, you're referring to the page that begins, "FPL projected dispatch costs and projected availability of natural gas"?

MR. McWHIRTER: That is correct, January through December.

BY MR. McWHIRTER:

Q. Look at natural gas dispatch price. What does that mean?

A. That is the dispatch price of natural gas that we project. And by dispatch price, we meant it is the commodity cost with variable transport rolled into that. We do not dispatch our system with a fixed component of transportation included, so our dispatch price for natural gas includes commodity plus a variable transport component to the burner tube.

Q. What are the -- you don't hedge in your transportation costs, do you, or do you?

A. I'm not sure what I follow by hedging --

Q. Well, the NYMEX quotes prices at Henry Hub, and you have a cost to transport the gas from Henry Hub to wherever your generator is located, at the gateway.

A. Right.

Q. I call that the transportation price. What do you call it? Basis?

A. No. You are correct. That is the transportation cost. No, we do not hedge transportation.

And there are two types of transportation. There is obviously the fixed demand charge, which is a sunk cost, which is what we will pay the transporter or gas pipeline regardless of whether we use it or not. That is our firm transportation. And then there's a variable component of moving gas under firm transportation.

Q. Looking at those four lines for your different interstate pipelines, January through December, how do those numbers that you have in your testimony compare to the Henry Hub prices for the same periods? Are they more or less?

A. How do they compare to the Henry Hub price that was used to generate these prices?

Q. Yes, sir.

A. Or the NYMEX price, I should say.

Q. Well, you've got a commodity price and a transportation price, and I want to know how -- say your price for March is $11.25 on FGT per MM/Btu. How does that compare to the NYMEX plus your fixed transportation cost? Is that more or less?

A. That 11.25 would be more than the NYMEX commodity price. How much more I don't know off the top of my head here, but it would be more. Now, the other thing to keep in mind, these projected dispatch costs do not include the firm transportation demand charge, only the variable component.

Q. I see. I'm sorry, but I have to ask you to explain again the differential between the firm transportation and the variable component.

A. Well, as part of our firm transportation arrangements with either pipeline, FGT or Gulf Stream in our case, we pay a demand charge, which is a fixed fee for the amount of volume that we have as firm capacity on either pipeline. And then to move gas under firm transportation, there is variable transportation rates, which is commodity and fuel.

And so in this particular table here, what you see in firm FGT would be the commodity price, or our NYMEX price, with a variable component added to it, which would be our dispatch price. Now, under nonfirm FGT, there would be an additional transport component which we would consider interruptible transport.

So to the extent that I use all of the firm transportation capacity that I have on either pipeline to meet my requirements, my system requirements, we do project that there is interruptible transport that may be available on a day-to-day basis, and that's where you see higher prices. As compared in the example that you gave of 11.25 in March for firm FGT, dollar per MM/Btu, you can see that nonfirm is at 11.68.

So that would be a case where there's an interruptible transport rate that we're estimating what that would be, and we put that into our model to say, "Okay. Even given that extra interruptible transport rate, would the system dispatch economically," and take that additional gas.

Q. Do you use this number to lock in your hedge percentages?

A. We do not use -- well, let me ask for a clarification. Do we use what number to lock in our hedge percentages?

Q. Well, let's take the 11.25 for March of 2007. How do you use that number in connection with your hedging operations?

A. Well, basically, that number -- and as a footnote, this particular table was developed from

August 7th forward curve prices, which was the curve that went into our September 1st filing.

But where this number would be used is, as it would on a week-to-week basis, we develop projections on a week-to-week basis, given updated forward curve prices. And so these prices would go into developing our fuel requirements, natural gas and fuel oil, for the subsequent period or for the period that we're in. We continually rebalance. And that is then the main driver of our hedge percentage, so to speak. So as we update our fuel burn requirements on a weekly basis, our hedge percentages and whether we're in tolerance to what was approved by management as the hedge plan is based on those new requirements.

So I guess the long story, these prices are used to develop fuel burn projections, which then is what we are hedging based upon those fuel burn projections.

Q. So you use the 11.25 number as what you would go out into the over-the-counter market to buy --

A. No. We would -- I guess to clarify it better, assuming 11.25 was put in the model to dispatch our system and that resulted in a gas burn of 100,000 MM/Btu, if our hedge program bottom line intent for this period of time was to be 50 percent hedged, then in this case, the 100,000 MM/Btu that was generated by using this fuel price would result in a hedge program guideline of 50,000 MM/Btu, let's say, for March of the period. And so we would hedging up to the 50,000 MM/Btu to be within tolerance of our hedge program.

It has nothing to do with the price that is shown here. We hedge based on what the prices generate as our fuel requirements and what our agreed-upon hedge percentages are.

Q. But you would use that price to determine what you would pay -- if you were in the 50 percent criteria, what you would pay -- what you would look for to purchase gas in the futures market; is that correct?

A. Well, at that particular point in time, that may be the price that -- if we were to rebalance, or even were in the process of getting up to the original hedge percentages, that may in fact be the price that we would be hedging at. But it does take some time to rebalance and to actually get to the appropriate level of hedges for whatever the agreed-upon percentages were for us.

So price does change on a day-to-day basis, and it may not necessarily be at, in this case, whatever the commodity underlying 11.25 was. It may not be that price at the time that we execute the hedge.

But that's where we're not -- we are not price guessing or speculating. We have a target percentage to meet, and we are going to meet that. And depending on what the outcome or revised fuel burn projections are based on latest prices, we are going to go hedge to the right percentage given those requirements.

Q. And each month as you approach the consumption date, I would imagine each month your hedging percentage increases to a maximum?

A. When we are originally hedging -- and we can take 2006, for example, for 2007. Our original hedge program in the '06 period probably begins sometime in March, and we hedge across a pretty significant period, let's say an eight-month period through October, if that is in fact eight months. But once we agree on our target hedges for '07 period, then we would begin in early 2006, and we would begin hedging over a period of time to get ourselves to the appropriate level.

Q. Is the appropriate level confidential information, or can you give us some idea of what the percentages are?

A. All of our hedge percentages we do keep confidential.

Q. All right. You indicated on page 19 of your September 1 testimony at line 10 that through the month of July, you had realized losses of approximately $186 million to that point in time. Can you give us an update as to the realized losses to this point in time in 2006?

A. Yes. I do have an update through September. I do not have the final October numbers yet, but through September, we were at $262 million realized losses.

Q. And if you wanted to determine the impact on the customers, you would divide 262 million by what you -- 109 million megawatt-hour sales that you make each year, so your hedging losses would amount to -- well, I've got my calculator here.

MR. BUTLER: I would ask Mr. McWhirter to identify the source he's referring to for his kilowatt-hour sales.

BY MR. McWHIRTER:

Q. On E1 that Ms. Dubin talked about earlier, I believe your anticipated annual retail sales is in the area of 109 million megawatt-hours, is that correct?

A. (Examining document.)

Q. Look at page 38. There are a lot of -- the numbering system starts, but it's Schedule E1 on Appendix 2.

A. Appendix 2, Schedule E1?

Q. Yes. And on line 24, you anticipate system megawatt-hour sales to be 108.1 million megawatt-hours?

A. Yes, that is the number that is there.

Q. And so -- a megawatt-hour is the same as 1,000 kilowatt-hours?

A. Yes, sir.

Q. So if you divided $262 million by 108, according to my calculations, subject to check, for every thousand kilowatt-hours of consumption, it would cost $2.43 more because you hedged in 2006 than if you had not hedged; is that correct?

A. I'm not 100 percent sure about your calculation, but what I can say is, yes, with losses, with realized losses, it will cost more than it would have cost had we not hedged if you were buying purely at the spot price, yes.

Q. And that happens when the prices are going down, and when the prices go up, you achieve savings; is that correct?

A. That is correct. In fact, I think 2002 through 2005, we had realized savings associated with our hedge program of $926 million. So, yes. And that's what I alluded to in the beginning, is that we realize there are going to be gains and losses on a year-to-year basis associated with hedging, because we are trying to reduce the volatility associated with fuel prices.

Q. I saw that in your testimony. And the Commission didn't approve the risk management concept until October of 2002, so I presume that you had been hedging before the Commission approval came in place; is that correct?

A. We had been engaged in very minimal type hedging prior to the order coming out. The order addressed expanded hedging programs, and that is surely what we did after the order came out. But prior to the order, we did engage in some minimal type hedging.

Q. Did you have long-term fixed contracts for the purchase of gas and coal prior to 2002?

A. For natural gas, I believe actually in 2002, one of the first years I can recall, we did have a small contract in place for fixed price natural gas, physical side. Of course, we began utilizing natural gas storage as a hedging tool back in late 2000 on an interruptible basis, so we had been utilizing that, but again, very minimal prior to that. Now, coal, I believe we do have fixed price contracts, but that would be subject to check.

Q. At the present time, what is the maximum length of a hedging contract, a futures contract you enter into for natural gas?

A. Right now, currently, for natural gas, we are really up to one year out. We have not gone farther than that in our hedging program. We have stayed within the next recovery period.

Q. Enron would go 10 and 12 years out. Would you deem that to be imprudent?

MR. BUTLER: I object to that as calling for a legal conclusion.

BY MR. McWHIRTER:

Q. Is there a point beyond which you would think that the hedging would be imprudent for a number of years out into the future?

MR. BUTLER: Same objection.

MR. McWHIRTER: Would you state the rationale for your objection, please?

MR. BUTLER: You seem to be asking him to reach a legal conclusion about imprudence.

MR. McWHIRTER: What I'm -- his testimony is to demonstrate the success of the program, and it's also, I would presume, to determine whether the risk management -- what the parameters of prudence are. And he's the expert, and I would think that he would be aware of what the parameters of prudence are in hedging, so I don't understand what your objection would be.

MR. BUTLER: The objection is to the legal conclusion regarding prudence. I would not object to a question about reasonableness, although I'm not sure what the reasonableness of Enron's program has to do with FPL's practices.

MR. McWHIRTER: All right. I'll scratch Enron.

BY MR. McWHIRTER:

Q. But I would presume -- you are obviously the expert in the field, far more so than probably anyone in the room.

Well, I take that back. There are probably a lot more experts. But irrespective of that, do you know what is reasonable and what you would deem to be unreasonable with respect to time periods beyond which you should not hedge?

A. I would say that from that perspective, I'm not sure what would be unreasonable to hedge. I think that's all dependent upon the company, what they're hedging for, what their risk profile may or may not be. So it's difficult to make a conclusion that hedging 20 years out in advance is imprudent. I don't know that to be the case.

I know for Florida Power & Light that as of right now, we do hedge up to the next recovery period, which is a year out, and that's what we feel comfortable with at this point in time.

Q. And would it be fair to say that if over a period of time, some years you have losses and some years you have gains, but over a period of time, if your hedging program tracks the spot market that it has been a success?

A. I'm not sure I follow. If --

Q. Well, how do you define success in your hedging program?

A. Well, I think success really is in a reduction of volatility and greater price certainty. I think there's really no better way to show that than really to look at marked-to-market values of our hedge positions at any given point in time. And I can go back to 2005, December of 2005, and look at -- the marked-to-market position of our '06 portfolio was at $1.2 billion positive.

So, you know, we talk about fuel prices having come down throughout 2006, but there was a time shortly prior to that year where without our hedges, we were looking at $1.2 billion more in cost, and now that has obviously come down, as evidenced by the number I gave you of the $262 million realized.

But the success of the program is in sticking to what we agree upon, you know, is the intent of the program, which is to reduce volatility. And the only way you can do that is to develop what you believe your percentages should be, how much you should hedge, what types of instrument, and stick with it, and not speculate on where the market is going and adjust your plan according to that, because I think in the long run, that produces more volatility, because I have no better idea of where the market is going than you may or anybody else.

So, you know, the success of the program is in the volatility reduction. And I think we have seen that since its inception. You look at the savings that we generated up through 2005, and now obviously we're on the other side of that. And that is what we have said all along can happen with hedging. If you are going to hedge to reduce volatility, you will have gains, and you will have losses. There is no doubt about it. That is the only way that you can deliver greater price certainty. And so our program has done that since its inception.

Q. Your program is not designed to improve reliability, is it?

A. Reliability? From a reliability standpoint, the hedging that is done with option premiums, with swaps, with fixed price components, because predominantly it is financial, no. I will say that the physical aspect of our program, and that revolves around our natural gas storage, yes, that is designed to increase reliability.

Q. We're going to get to that later. But principally, hedging avoids volatility?

A. Yes, sir.

Q. And it does not -- from your viewpoint, it would be speculative if you're trying to save money on gas, because that way you would be trying to track -- speculatively track the market; is that correct?

A. That is correct.

Q. Wouldn't it be fair to say that if you bought gas at $5 above the NYMEX for the next year that you could guarantee that you're going to have no volatility? Isn't that correct?

A. I'm not sure you could guarantee that you would have no volatility if you bought it right now at $5 above the NYMEX. I'm not sure why you would do that. You know, we buy our gas at the NYMEX, so to speak, when we are putting hedge transactions on, so we are not, you know, above or below, so to speak. We are buying at the NYMEX.

Q. Okay. So when the NYMEX falls, do you try to balance out your account so that you more closely approach what the NYMEX is for, say, six months down the road?

A. Well, depending on how far along into the hedge program or into -- how close you are to your ultimate goal, your ultimate hedge percentage, to the extent the market falls and you are continuing to hedge, yes, your average hedge price will come down.

But to the extent that we have met our goal, so to speak, or our percentage goal for hedging, do we unwind positions because the market has come down? No, we do not do that. We stick with the positions that we have.

Q. But you're going to buy a greater percentage, so you buy more MM/Btu at a lower price, so that would tend to levelize your cost.

A. It would tend to average down our weighted average cost of hedges, yes.

Q. Ms. Dubin has projected that your fuel costs for the year 2007 will be $6.1 billion, so the fuel factor will be set on the basis of $6.1 billion. In order to have a mid-course correction under the Commission's procedure, as I understand it, your fuel costs would have to exceed your estimate by some $600 million.

Is there anything that you see on the horizon that would lead you to believe there's a possibility that gas prices will go up -- which is what? Fifty percent of your consumption of gas?

A. Uh-huh.

Q. That it will go up so much as to increase your overall fuel costs more than $600 million?

A. I think right now the level of uncertainty really would make me answer "I don't know." And I think that was a lot of the discussion prior to refiling and trying to determine was the current market and the drop in fuel prices, was it going to be a good indicator of what ultimately fuel prices would end up to be in 2007.

And as of right now, we have not gone through the winter period. We don't know what winter weather is going to bring. We have not been through next year's hurricane season. We don't know what that will bring. We don't know what will occur in the Middle East from a geopolitical stability type driver of fuel prices. So it's very difficult to predict.

Sitting here right now, the information is great. We are at all-time record levels of natural gas storage. There's a lot of reports out that winter weather is going to be fairly mild again, which is one of the drivers that started the decline in prices in 2006. So there's a lot of positives out there.

But to sit here and tell you that it could not change the other way wouldn't be prudent on my part, because I don't know. There is still a lot of uncertainty. There's a lot of unknowns that could change this market tomorrow. And given the amount of natural gas that Florida Power & Light burns and the amount of heavy fuel oil that it burns, it can change very quickly. Dollars can mount up when you talk about 10 percent of 6.1 billion.

And I'll go back to our marked-to-market positions, as I described before, where in early December we were at $1.2 billion positive. By January, after the weather was somewhat mild for that 30-day period, we were down to 700 million. So we swung $520 million in a 30-day period, and that was on the downside. That can happen on the upside, and it has.

So there is no level of certainty there. But at this time, the information that is in the market, it's reasonable, and we'll just really have to wait and see, but it can change.

Q. The price was gone down $520 million, but you only reduced your fuel factor or your fuel cost estimate by $300 million; is that correct?

A. Actually, what I'm describing was for the '06 period. For '07 -- and I don't recall the numbers off the top of my head, but you would be correct in what you're saying. Given the fact that there are hedge positions on now, we are done, our hedging for 2007. Yes, you cannot -- you will not experience the full decline in the spot market, so to speak, or in the forward price market to the extent that you have hedges in place that are locking in a price that is higher than that.

Now, as I said before, there are ways to mitigate that, and that may be to use more call options, but there's a cost associated with that, cost premiums, and that costs the customer money. However, it allows you to take advantage of a downturn in the market when those options would technically expire worthless. But you're buying fuel at a lower spot market cost or a lower prior to the month cost. So -- I've lost my train of thought. I apologize.

Q. Well, that's all right. Final question.

A. I was going somewhere with that.

Q. Well, it sounded very good before it went.

But anyway, final question. Irrespective of whether you hedge or totally ignore hedging and follow the spot market for your natural gas prices, it has no adverse impact on Florida Power & Light, because the costs are fully guaranteed by the Commission's procedures with respect to fuel cost recovery; is that correct?

MR. BUTLER: I'll object to the form of the question, and in particular object to the characterization that the cost is guaranteed.

MR. McWHIRTER: I'm going to restate the form of the question.

BY MR. McWHIRTER:

Q. Mr. Yupp, when your fuel costs are not fully recovered, under Florida Public Service Commission procedures, does that cost go to the shareholders of company to pick up, or is it recovered through your true-up procedures from customers?

A. When we do not recover fully what our fuel costs are in a certain recovery period?

Q. Yes, sir.

A. That is a cost that goes to the customers, with the caveat that as long as those cost were prudently incurred.

Q. And in addition to recovery of your fuel costs, you also recover interest on that from the customers; is that correct?

A. Yes, and likewise, the other way if we've overrecovered, give interest back.

Q. And when the company hedges its fuel purchases, the costs, the premium costs and the gains and losses on hedging, 100 percent of that cost is passed through to the customers through your fuel cost, is that correct, your fuel cost recovery clause?

A. If they are deemed to have occurred prudently, yes.

Q. Can you tell me a circumstance under which the company would be responsible without the opportunity to recover its fuel costs from customers, presuming that the purchase was prudent and the hedge was prudent?

A. No. Not as long as we were prudent in the actions we took, no, I cannot think of one.

Q. So in summary then, would it be fair to say that hedging is to avoid -- primarily to avoid volatility, it does not, should not be designed to speculatively safe on fuel costs, and hedging with financial institutions does not improve reliability?

A. That's true.

Q. Does the company receive any rewards or incentives under the Commission's hedging program as it is presently structured?

A. No, we do not.

MR. McWHIRTER: I tender the witness.

CHAIRMAN EDGAR: Are there any other parties with cross for this witness?

Seeing none, are there questions from staff?

MS. BENNETT: Yes, Madam Chair, I have a few.

CROSS-EXAMINATION

BY MS. BENNETT:

Q. Regarding the Southeast Supply Header pipeline project -- and if you want to take a minute to turn to -- I think it's on page 33 and 32 of your testimony.

MR. BUTLER: I'm sorry. Which one?

MS. BENNETT: The September 1st projection testimony.

MR. BUTLER: Thank you.

THE WITNESS: Okay. I'm there.

BY MS. BENNETT:

Q. FPL's participation in the SESH pipeline will result in additional gas transportation costs to get gas to the Mobile Bay area. That's what you said in your testimony; is that correct?

A. That is correct.

Q. And on page 32 of your testimony, you refer to the current premium of Mobile Bay prices above the NYMEX. I realize this can be somewhat difficult to quantify, but in general, what is that premium?

A. Generally, if we were to just look at on average, 2006 to date, the premium for FGT Zone 3 deliveries above the Henry Hub was on average around 32 cents in MM/Btu.

Q. Is there a range of prices?

A. There can be a pretty significant range. I've seen everything from being flat to -- during hurricane periods, as we experienced in 2005 with Hurricane Katrina in particular, that basis was as high -- I believe it was, subject to check, over $5 premium for FGT Zone 3 above the Henry Hub.

Q. The normal range I think you've testified to before was approximately 20 cents to up to 85 cents; is that correct? Is that the normal range?

A. Yes. I think we've seen that typically on a day-to-day basis, barring any severe weather events or events such as that.

Q. You believe that lower price gas from the Perryville area and more supply into the Mobile area allows for the possibility of savings that will offset the additional transportation costs; is that correct?

A. Yes, that is correct. We believe that we will be able to procure natural gas in the Perryville area at such price to offset the firm transportation that we are proposing to acquire on the Southeast Supply Header pipeline.

Q. As an alternative to the Southeast Supply Header project, isn't it true that you considered liquefied natural gas?

A. Yes, we did evaluate liquefied natural gas proposals as far back as 2004 when issued an RFP for liquefied natural gas. And also, as we answered in our interrogatory responses, we did look at four particular LNG facilities that were proposed in the Gulf Coast as alternatives, as well as two additional pipelines similar to Southeast Supply Header. We did also evaluate those as alternatives.

Q. And you began evaluating those in 2004; is that correct?

A. LNG was being evaluated in 2004 as a potential supply alternative. The Southeast Supply Header pipeline as well as the two alternate pipelines and the LNG facilities on the Gulf Coast I believe were sometime early in 2006 or late 2005, but that would be subject to check. I'm not 100 percent sure on that.

MS. BENNETT: I have no further questions of this witness.

CHAIRMAN EDGAR: Mr. Butler?

MR. BUTLER: Thank you. Just a couple of redirect questions, Madam Chair.

REDIRECT EXAMINATION

BY MR. BUTLER:

Q. Mr. Yupp, does FPL file with the Commission each year a report on its hedging program and the results of the program?

A. Yes, we do.

Q. Would you just briefly explain what is contained in that report?

A. In the yearly filing that we make, generally around April 1st, we provide a recap of all our hedging activity for the prior period or prior year. We list out of all the instrument types that we used and the volumes associated with those instrument types for natural gas, heavy fuel oil, and for power, as well as the dollar values for savings or -- gains or losses associated with each instrument. We do that by month, and then, obviously, it's rolled up into an aggregate total for the year.

Q. Thank you. You discussed this at some length with Mr. McWhirter, but would you just summarize succinctly what you consider the goal of FPL's hedging program to be?

A. Yes. The goal of our hedging program since day one has been to reduce volatility, to not engage in speculative trading, which I believe would increase volatility. Trying to outguess the market, I don't think any of us can do that. There are sometimes drivers of the market that are hard to understand. The market moves a certain direction when maybe the information says it really shouldn't move in that direction.

So again, we are going to execute a well disciplined, independently controlled program. We're going to continue to try to reduce volatility for our customers.

You know, the one thing that we do every year is, we do look at market trends. We can take them into account. We can modify the types of hedges that we use, the types of instruments we use to mitigate some of the potential movement in the market. But in a nutshell, we are trying to reduce volatility, is the bottom line.

Q. Given that goal, would you consider FPL's hedging program to have been successful to date?

A. Yes, I would.

MR. BUTLER: Thank you. That's all the redirect that I have.

CHAIRMAN EDGAR: Do we need to do exhibits?

MR. BUTLER: Yes. No Commission questions, I assume. Yes, I would move Exhibits 11, 12, 13, and 14.

CHAIRMAN EDGAR: Those exhibits will be moved into the record.

(Florida Power & Light Company Exhibits Number 11, 12, 13, and 14 were admitted into evidence.)

CHAIRMAN EDGAR: Commissioners, were there questions that I didn't see? No.

Okay. Then the witness is excused. Thank you very much.

MR. BUTLER: Thank you.

CHAIRMAN EDGAR: Let's take about seven minutes. I need to stretch. We will go on a very short break.

(Short recess.)

CHAIRMAN EDGAR: We are going to begin again. Mr. Butler.

MR. BUTLER: Madam Chairman, I believe that FPL's next two witnesses, first of all, Mr. Gwinn was previously excused, and that Ms. Sonnelitter's testimony concerning the subjects that would come up at this point, which are just the targets and results for GPIF, have been stipulated.

And if that is correct, we would move the admission of their testimony. And Ms. Sonnelitter has exhibits that I will also refer to for admission into the record. It would be her Exhibit PS-1 and her Exhibit PS-3, which are 15 and 17.

CHAIRMAN EDGAR: Okay. Ms. Bennett, don't we need to move -- although Witness Gwinn was excused, don't we need to move that testimony and --

MS. BENNETT: Yes.

CHAIRMAN EDGAR: -- exhibits into the record as well?

MR. BUTLER: He has no exhibits, so I just moved his testimony. But he does not have any exhibits.

CHAIRMAN EDGAR: Okay. So the prefiled testimony of Witness Gwinn is entered into the record as though read, and the prefiled testimony and exhibits of Witness Sonnelitter will also be entered into the record.

(Florida Power and Light Company Exhibits Number 15 and 17 were admitted into evidence.)

MR. BUTLER: And just for clarification, I should probably note that's her April 3, 2006, and September 1, 2006, testimony. She does have August 22, 2006 testimony that we'll get to when we do the GPIF policy issues later.

CHAIRMAN EDGAR: So she will be called and available for questions later in the proceeding.

MR. BUTLER: That's right.

CHAIRMAN EDGAR: Okay.

MR. BUTLER: Thank you.

CHAIRMAN EDGAR: Thank you.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF W.E. GWINN

DOCKET NO. 060001-EI

September 1, 2006

Q. Please state your name and address.

A. My name is Walter E. Gwinn. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company (FPL) as a Manager of Nuclear Finance in the Nuclear Business Unit.

Q. Have you testified in predecessors to this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. My testimony presents and explains FPL's projections of nuclear fuel costs for the thermal energy (MMBTU) to be produced by our nuclear units, the costs of disposal of spent nuclear fuel, and the costs of decontamination and decommissioning (D&D). I am also updating the status of certain litigation that affects FPL's nuclear fuel costs; plant security costs and new NRC security initiatives; outage events; and the inspections and repairs to the reactor pressure vessel heads since the issuance of NRC Bulletin (IEB) 2002-02. Both nuclear fuel and disposal of spent nuclear fuel costs were input values to POWERSYM used to calculate the costs to be included in the proposed fuel cost recovery factors for the period January 2007 through December 2007.

Nuclear Fuel Costs

Q. What is the basis for FPL's projections of nuclear fuel costs?

A. FPL's nuclear fuel cost projections are developed using projected energy production at our nuclear units and their operating schedules, for the period January 2007 through December 2007.

Spent Nuclear Fuel Disposal Costs

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2007 through December 2007.

A. FPL projects the nuclear units will produce 253,892,102 MMBTU of energy at a cost of $0.3611 per MMBTU, excluding spent fuel disposal costs, for the period January 2007 through December 2007. Projections by nuclear unit and by month are in Appendix II, on Schedule E-4, starting on page 16 of the Appendix II.

Q. Please provide FPL's projections for spent nuclear fuel disposal costs for the period January 2007 through December 2007 and explain the basis for FPL's projections.

A. FPL's projections for spent nuclear fuel disposal costs of approximately $21.2 million are provided in Appendix II, on Schedule E-2, starting on page 10a of the Appendix. These projections are based on FPL's contract with the U.S. Department of Energy (DOE), which sets the spent fuel disposal fee at 0.9312 mills per net kWh generated, including transmission and distribution line losses.

<u>Decontamination and Decommissioning Costs</u>

Q. Please provide FPL's projection for DOE Decontamination and Decommissioning (D&D) costs to be paid in the period January

2007 through December 2007 and explain the basis for FPL's projection.

A. Based on the Energy Policy Act of 1992 (EPACT) requirements, FPL's final payment for these costs will be made in 2006. There are no projected D&D costs for 2007.

<u>**Litigation Status Update**</u>

Q. Is there currently an unresolved dispute under FPL's nuclear fuel contracts?

A. Yes.

<u>Spent Fuel Disposal Dispute</u>. This dispute arose under FPL's contract with the Department of Energy (DOE) for final disposal of spent nuclear fuel. In 1995 FPL, along with a number of electric utilities, states, and state regulatory agencies filed suit against DOE over its obligation to accept spent nuclear fuel beginning in 1998. On July 23, 1996, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) held that DOE is required by the Nuclear Waste Policy Act (NWPA) to take title to and dispose of spent nuclear fuel from nuclear power plants beginning on January 31, 1998.

On January 11, 2002, based on the D.C. Circuit's ruling, the Court of Federal Claims granted FPL's motion for partial summary judgment in favor of FPL on contract liability. There is no trial date scheduled at this time for the FPL damages claim.

The Court of Federal Claims ruled on May 21, 2004 that another nuclear plant owner, Indiana Michigan Power Company, was not entitled to any damages arising out of the Government's failure to begin disposal of spent nuclear fuel by January 31, 1998. On appeal, the U.S. Court of Appeals for the Federal Circuit upheld the Court of Federal Claims decision. This decision could impact FPL's claims against the Government. The impact on FPL's claims is unknown at this time.

Nuclear Plant Security Costs

Q. Please provide an update of the nuclear plant security costs to comply with NRC's requirements.

A. As mentioned in prior testimony, FPL expected to complete its initial Design Basis Threat (DBT) related modifications in 2005. However, a portion of the DBT modifications have been delayed. These delays resulted partially from discovering issues with the as-found material condition and configuration of the Intrusion Detection System panels and camera poles, as well as from unrelated plant events such as the Turkey Point main transformer fire and recovery from Hurricane Wilma. Additionally, shortfalls were discovered with the vendor design of the new security computer concerning its ability to integrate with and test the existing system. Resolution of this issue delayed the start of the installation of the new system to March 2006. FPL now expects to complete all initial DBT modifications by the Fall of 2006.

Q. What is FPL's projection of the incremental security costs for the period January 2007 through December 2007?

A. FPL presently projects that it will incur $26.5 in incremental nuclear power plant security costs in 2007.

Q. Please provide a brief description of the items included in this projection.

A. The projection includes adding security personnel as a result of implementing NRC's Order EA03-038, which limits the number of hours security personnel may work in a week; additional personnel training; cyber security, which assesses the communication vulnerabilities of nuclear systems and identifies appropriate risk reduction measures; additional regulatory initiatives for fires, aircraft threat strategy; protection of spent fuel pools and containments; and the purchase of new security search equipment for Turkey Point.

Q. Please provide a brief description of the new Turkey Point security search equipment.

A. FPL will replace the existing metal and explosive detection devices and X-ray machines with new enhanced technology to comply with evolving NRC threat-detection requirements.

Q. What is the projected cost for this equipment?

A. FPL projects an estimated cost of $4.8 million to replace the security search equipment.

Q. Was the cost of this new equipment included in the 2006 MFRs filed in Docket No. 050045-EI?

A. No, none of this security search equipment was included. FPL was not aware of the need to replace the equipment at the time it prepared the MFRs.

Q. Why is the estimated cost to replace the security search equipment at St. Lucie not included in the 2007 projection?

A. As a result of Hurricane Wilma, St. Lucie sustained substantial damage to its security search equipment. FPL has filed an insurance claim for the cost of the search equipment and anticipates it will be covered by insurance. However, in the event the entire cost is not reimbursed by insurance, FPL will request recovery of the uninsured amount in the Capacity Clause in a subsequent filing.

Q. Is there a possibility of further NRC security-related initiatives in 2007 and beyond, in addition to those included in FPL's projection?

A. Yes. As FPL has explained in prior testimony to the Commission, FPL is aware of new NRC regulatory initiatives to revise requirements regarding fires, propose aircraft-threat strategy revisions, make potentially significant changes in requirements for protection of spent fuel pools, conduct a study in conjunction with The Department of Homeland Security to evaluate potential threats to nuclear facilities from land, sea and air attacks, and conduct a study of buffer zones around nuclear sites.

In addition, there is a new NRC initiative to review and update the Enhanced Adversary Characteristics (EAC) of the Design Basis Threat (DBT). The DBT is the measure that all nuclear stations are designed to defend against. Some of these EAC/DBT enhancements would require extensive engineering support and significant modifications to station security defensive positions. Depending on the extent of the EAC/DBT enhancement, additional security personnel may be necessary in addition to upgrades to security hardware and/or equipment. While FPL cannot predict what future EAC/DBT enhancements might be, based on past experience it is reasonable to expect that they will come. If so, this would require a response from FPL in the form of security program upgrades.

It is not feasible for FPL to estimate at this time the future costs that will be required to comply with these various developing regulatory requirements, but the Commission should be aware that nuclear security costs could increase significantly based on the issues mentioned above.

Outage Events

Q. Please provide a brief description of the cause of the Condenser Tube leak at St. Lucie Unit 2 that caused an outage in January 2006.

A. The tube leak resulted from the failure of a tube in the 2B2 waterbox. The tube split lengthwise, resulting in an approximately five inch long crack.

Q. What was the duration of the St. Lucie Unit 2 outage related to this issue?

A. The outage duration was approximately 4 days.

Q. What corrective actions did FPL initiate to avoid this problem in the future?

A. FPL performed Eddy Current Testing (ECT) to detect tube defects on 100% of the condenser tubes during the refueling outage in April 2006. Condenser tubes with defects were plugged to prevent future tube leaks. Periodic condenser tube ECT is conducted to monitor tube degradation and plug affected tubes prior to failure.

Q. Please provide a brief description of the cause for the outage extension at Turkey Point Unit 3 in March and April of 2006.

A. As part of a series of tests and inspections being conducted to ensure that equipment was operating properly prior to plant heat-up and restart, FPL personnel identified a small drilled hole in the pressurizer piping.

Special teams from FPL corporate security, the NRC and the FBI went to Turkey Point to review and evaluate the circumstances concerning the damage. The NRC and FBI are conducting investigations into this potential tampering event. The NRC Augmented Inspection Team issued a report on this incident with no findings in April, 2006.

The affected pressurizer piping was repaired and the plant was restarted on April 10, 2006 without further incident.

Q. What was the duration of the Turkey Point Unit 3 outage extension related to this issue?

A. The outage extension duration was approximately 5 days.

<u>**Reactor Pressure Vessel Head Inspection Status**</u>

Q. What is the status of the reactor heads for the St. Lucie and Turkey Point Units?

A. As FPL has explained in prior testimony to the Commission, the NRC issued IEB 2002-02 on August 9, 2002 to address concerns related to visual inspections of the reactor heads. This NRC Bulletin resulted in all four FPL units being categorized as high susceptibility, requiring ultrasonic testing in addition to visual inspections until the reactor heads are replaced.

St. Lucie Unit 1 replaced the reactor vessel head during the refueling outage beginning on October 17, 2005.

St. Lucie Unit 2 performed ultrasonic inspections during the refueling outage beginning on April 23, 2006. No indications were detected on the reactor vessel head and no repairs were needed. The total cost of the inspections was approximately $5 million. The St. Lucie Unit 2 reactor vessel head will be replaced in the Fall of 2007 at the same time the Unit 2 steam generators are replaced.

The Turkey Point Unit 3 and 4 reactor vessel heads were replaced during the refueling outages beginning on September 26, 2004 and April 10, 2005 respectively.

Does this conclude your testimony?

A. Yes it does.

BEFORE THE PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF PAMELA SONNELITTER

DOCKET NO. 060001-EI

APRIL 3, 2006

Q. Please state your name and business address.

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

Q. Would you please state your present position with Florida Power and Light Company (FPL).

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

Q. Have you previously testified in the predecessor to this Docket?

A. Yes, I have

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to report the actual performance relative to the Equivalent Availability Factor (EAF) and Average Net Operating Heat Rate (ANOHR) for the thirteen (13) generating units used to determine the Generating Performance Incentive Factor (GPIF). I have compared the actual performance of each unit to the targets that were approved in Commission Order No. PSC-04-1276-FOF-EI issued December 23, 2004, for the period January through December 2005, and I have performed the reward/penalty calculations prescribed by the GPIF Manual based on this comparison. My testimony presents the result of my calculations, which is an incentive reward for the period.

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

A. Yes, I have. It consists of one document, PS -1.

Page 1 of the document is an index to the contents of the document.

Q. What is the incentive amount you have calculated for the period January through December, 2005?

A. I have calculated a GPIF incentive reward of $8,478,098.

Q. Please explain how the GPIF reward amount is calculated.

A. The steps involved in making this calculation are provided in my Document PS-1. Page 2 of Document PS-1 provides the GPIF Reward/Penalty Table (Actual), which shows an overall GPIF performance point value of +3.23 corresponding to a GPIF reward of $8,478,098. Page 3 provides the calculation of the maximum allowed incentive dollars. The calculation of the system actual GPIF performance points is shown on page 4. This page lists each GPIF unit, the unit's performance indicators (ANOHR and EAF), the weighting factors and the associated GPIF points.

Page 5 is the actual EAF and adjustments summary. This page lists each of the thirteen (13) units, the actual outage factors and the actual EAF, in columns 1 through 5. Column 6 is the adjustment for planned outage variation. Column 7 is the adjusted actual EAF, which is calculated on page 6. Column 8 is the target EAF. Column 9 contains the Generating Performance Incentive Points for availability as determined by interpolating from the tables shown on pages 8 through 20. These tables are based on the targets and target ranges submitted to, and approved by, the Commission prior to the start of the period.

Page 7 shows the adjustments to ANOHR. For each of the thirteen (13) units, it shows, in columns 2 through 4, the target heat rate formula, the actual Net Output Factor (NOF) and the actual ANOHR. Since heat rate varies with NOF, it is necessary to determine both the target and actual heat rates at the same NOF. This adjustment is to provide a common basis for comparison purposes and is shown numerically for each GPIF unit in columns 5 through 8. Column 9 contains the Generating Performance Incentive Points as determined by interpolating from the tables shown on pages 8 through 20. These tables are based on the targets and target ranges submitted to, and approved by, the Commission prior to the start of the period.

Q. Has FPL made any adjustments to the actual equivalent availability factor (EAF) of the GPIF units as a result of the hurricanes that hit FPL's service territory during 2005?

A. Yes. The GPIF Manual, Section 3, Paragraph 4.3.1, states:

"Adjustments to the equivalent availability performance indicator will be considered by the Commission on a case by case basis. Generally, adjustments to the equivalent availability performance indicator which will be considered by the Commission are categorized as follows:

- Natural or externally caused disaster.
- Unforeseen shutdown or continued operation of a unit pursuant to the actions of a Regulatory agency.
- Rescheduling of planned maintenance into or out of the review period.
- An identifiable and justifiable change in the work scope of a planned outage affecting total outage time.
- A difference between actual and forecast reserve shutdown hours, if reserve shutdown hours are used as part of the equivalent availability target setting methodology"

Consistent with the provision of the GPIF Manual to adjust for "natural or externally caused disaster," FPL proposes to adjust the actual EAF of St. Lucie Units 1 and 2 and Turkey Point Units 3 and 4 to remove the impact of the shutdowns of these units that resulted from hurricane Wilma.

Q. Please describe the effect of hurricane Wilma on St. Lucie Units 1 and 2.

A. Unit 1 was already offline for a planned refueling outage when Hurricane Wilma first threatened the plant site on October 24, 2005. This threat required FPL to demobilize plant equipment and materials staged for outage support, in order to secure the unit before the storm made landfall. For example, large cranes were dismantled and heavy equipment was moved and secured. Numerous site personnel were involved in completing these tasks in the short time frame before the storm arrived. This demobilization and subsequent remobilization of equipment and material resulted in the unforeseen extension of St. Lucie Unit 1 refueling outage by just over six days. No other delays were experienced at Unit 1 due to hurricane Wilma.

As required by St. Lucie's procedures, Unit 2 was brought offline on October 24, shortly before the site began experiencing hurricane-force winds from hurricane Wilma. It began normal power ascension on October 27.

Q. Please explain why St. Lucie Unit 2 remained shut down for several days as a result of hurricane Wilma.

A. A series of factors contributed to the amount of time St. Lucie Unit 2 remained shutdown. The unit was shut down at 00:01 on October 24, before hurricane-force winds were first experienced on Hutchinson Island. The last hurricane force winds passed the island later that afternoon, after which both onsite and offsite damage assessments commenced. FPL must have the NRC's and FEMA's approval after the offsite emergency preparedness is able to properly and timely carry out a public protective action (such as an evacuation) of the areas surrounding the St. Lucie plant before FPL is allowed to restart the units following a natural disaster. On October 26, FEMA completed its post disaster review and advised the NRC that it could give reasonable assurance for the restart of Unit 2. The NRC then gave FPL authorization to restart Unit 2. FPL began normal power ascension for Unit 2 on October 27 at 22:40 hours after the appropriate personnel shift was in place and made sure plant equipment was lined up to support start up procedures,

Q. Please describe the shutdown of Turkey Point Units 3 and 4 due to hurricane Wilma.

A. As required by Turkey Point's procedures, Units 3 and 4 were brought offline in the early hours of October 24, before the site began experiencing hurricane-force winds. Unit 3 began normal power ascension on October 27 at 17:39 hours after undergoing the same sort of post-hurricane restart process as St. Lucie Unit 2.

Unit 4 was also taken offline due to hurricane Wilma in the early hours of October 24, but it did not return to service until November 13. FPL was ready to begin normal power ascension for Unit 4 on October 28 at 04:18 hours but experienced additional restart delays. The additional restart delay beyond October 28 was due to electric grid instability issues, loss of offsite power, grass intrusion into secondary plant systems, and salt water intrusion due to a tube sheet plug failure. FPL is not treating the time between October 28 and November 13 as hurricane-related, and thus is not including that time in Unit 4's EAF adjustment for "natural or externally caused disasters".

Q. Please explain the regulatory requirements for the restart of a nuclear unit following a natural disaster.

A. The criteria for restarting the nuclear units following a hurricane are based on reviews performed by the NRC and the Federal Emergency Management Agency (FEMA) regarding the ability of FPL, the State of Florida, and local governments to effectively implement their emergency plans. The standard used by the NRC and FEMA to evaluate the ability to restart the plant following an event such as a hurricane is whether there is reasonable assurance that both FPL and the state and local government can protect the health and welfare of the public in the event of a nuclear power plant accident.

Q. What specific adjustments to the actual EAF for St. Lucie Units 1 and 2 has FPL made to remove the effects of hurricane Wilma?

A. The unforeseen outage extension of St. Lucie Unit 1 and shutdown of St. Lucie Unit 2 due to hurricane Wilma resulted in increments to the forced outage factors of St. Lucie Units 1 and 2 of 1.75% and 1.15%, respectively. FPL has removed those increments from the 2005 EAF calculation.

Q. What specific adjustments to the actual EAF for Turkey Point Units 3 and 4 has FPL made to remove the effects of hurricane Wilma?

A. The unforeseen shutdowns of Turkey Point Units 3 and 4 due to hurricane Wilma resulted in increments to the forced outage factors of 1.35% and 1.19%, respectively. FPL has removed those increments from the 2005 EAF calculation for Units 3 and 4.

Q. Are there any changes to the targets approved through Commission Order No. PSC-04-1276-FOF-EI?

A. No, the approved targets have not changed.

Q. Please explain the primary reason or reasons why FPL will be rewarded under the GPIF for the January through December, 2005 period.

A. The primary reason that FPL will receive a reward for the period was that Scherer 4, St. Lucie Nuclear Units 1 & 2, and Turkey Point Nuclear Unit 3 adjusted availability was better than targeted.

Q. Please summarize the effect of FPL's nuclear unit availability on the GPIF reward.

A. Turkey Point Unit 3 operated at an adjusted actual EAF of 94.7% compared to its target of 93.6%. This results in a +3.67 point reward, which corresponds to a GPIF reward of $1,196,275.

Turkey Point Unit 4 operated at an adjusted actual EAF of 69.6% compared to its target of 75.8%. This results in a -10.00 point penalty, which corresponds to a GPIF penalty of $2,742,693.

St. Lucie Unit 1 operated at an adjusted actual EAF of 83.5% compared to its target of 77.2%. This results in a +10.0 point reward, which corresponds to a GPIF reward of $3,264,941.

St. Lucie Unit 2 operated at an adjusted actual EAF of 98.7% compared to its target of 93.6%. This results in a +10.0 point reward, which corresponds to a GPIF reward of $3,357,867.

Q. Please summarize each nuclear unit's performance as it relates to the ANOHR of the units.

A. Turkey Point Unit 3 operated with an adjusted actual ANOHR of 11,029 Btu/kWh. This ANOHR is within the ± 75 Btu/kWh deadband around the projected target; therefore, there is no GPIF reward or penalty.

Turkey Point Unit 4 operated with an adjusted actual ANOHR of 10,947 Btu/kWh. This results in a +4.16 point reward, which corresponds to a GPIF reward of $403,643.

St. Lucie Unit 1 operated with an adjusted actual ANOHR of 10,876 Btu/kWh. This ANOHR is within the ± 75 Btu/kWh deadband around the projected target; therefore, there is no GPIF reward or penalty.

St. Lucie Unit 2 operated with an adjusted actual ANOHR of 10,991 Btu/kWh. This results in a -10.0 point penalty, which corresponds to a GPIF penalty of $9,219.

In total, the nuclear units' heat rate performance results in a GPIF reward of $394,424.

Q. What is the total GPIF incentive reward for FPL's nuclear units?

A. $5,470,814

Q. Ms. Sonnelitter, would you summarize the performance of FPL's fossil units?

A. Yes. Regarding EAF performance, eight (8) of the nine (9) fossil generating units performed better than or equal to their availability targets, while the remaining unit performed worse than its target. The combined fossil units' availability performance results in a GPIF reward of $1,978,201.

Regarding ANOHR, three (3) out of the nine (9) fossil units were below the ± 75 Btu/kWh deadband around their projected targets, resulting in a reward. One (1) unit out of the nine (9) fossil units operated with an ANOHR that was above the ± 75 Btu/kWh deadband resulting in a penalty. The remaining five (5) units operated with ANOHRs that were within the ± 75 Btu/kWh deadband, and they will receive no incentive reward or penalty. The combined fossil units' heat rate performance results in a GPIF reward of $1,029,083.

Q. What is the total GPIF incentive reward for FPL's fossil units?

A. $3,007,284

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF P. SONNELITTER

DOCKET NO. 060001-EI

SEPTEMBER 1, 2006

Q. Please state your name and business address.

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

Q. Would you please state your present position with Florida Power and Light Company (FPL).

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

Q. Have you previously submitted testimony in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the target unit equivalent availability factors (EAF) and the target unit average net operating heat rates (ANOHR) for the period of January through December, 2007, for use in determining the Generating Performance Incentive Factor (GPIF).

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

A. Yes, I have. It consists of one document, PS-3. The first page of this document is an index to the contents of the document. All other pages are numbered according to the GPIF Manual as approved by the Commission.

Q. Please summarize the 2007 system targets for EAF and ANOHR for the units to be considered in establishing the GPIF for FPL.

A. For the period of January through December, 2007, FPL projects a weighted system equivalent planned outage factor of 7.8% and a weighted system equivalent unplanned outage factor of 7.0%, which yield a weighted system equivalent availability target of 85.2%. The targets for this period reflect planned refueling outages for three nuclear units. FPL also projects a weighted system average net operating heat rate target of 9,010 Btu/kWh for the period January through December, 2007. As discussed later in this testimony, these targets represent fair and reasonable values when compared to historical data. Therefore, FPL requests that the targets for these performance indicators be approved by the Commission.

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

A. Yes, I have. Exhibit PS-3, pages 6 and 7, contains the information summarizing the targets and ranges for EAF and ANOHR for the 13 generating units which FPL proposes to be considered as GPIF units for the period of January through December, 2007. All of these targets have been derived utilizing the methodologies adopted in the GPIF Manual.

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

A. The GPIF Manual requires that the EAF target for each unit be determined as the difference between 100% and the sum of the equivalent planned outage factor (EPOF) and the equivalent unplanned outage factor (EUOF). The EPOF for each unit is determined by the length of the planned outage, if any, scheduled for the projected period. The EUOF is determined by the sum of the historical average equivalent forced outage factor (EFOF) and the equivalent maintenance outage factor (EMOF). The EUOF is then adjusted to reflect recent unit performance and known unit modifications or equipment changes.

Q. Please summarize FPL's methodology for determining ANOHR targets.

A. To develop the ANOHR targets, historic ANOHR vs. unit net output factor curves are developed for each GPIF unit. The historic data is analyzed for any unusual operating conditions and changes in equipment that will materially affect the predicted heat rate. A regression equation that best fits the data is calculated and a statistical analysis of the historic ANOHR variance with respect to the best fit curve is also performed to identify unusual observations. The resulting equation is used to project ANOHR for the unit using the net output factor from the POWERSYM model. This projected ANOHR value is then used in the GPIF tables and in the calculations to determine the possible fuel savings or losses due to improvements or degradations in heat rate performance. This process is consistent with the GPIF Manual.

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

A. The GPIF units were selected in accordance with the GPIF Manual using the estimated net generation for each unit taken from the production costing simulation program, POWRSYM, which forms the basis for the projected levelized fuel cost recovery factor for the period. The 13 units which FPL proposes to use for the period of

January through December 2007 represent the top 82.2% of the total forecasted system net generation for this period excluding three units: Martin Unit 8, Manatee Unit 3, and Turkey Point Unit 5. These three units were excluded from the GPIF calculation because there is insufficient historical data to include them yet. The conversion of Martin Unit 8 to combined cycle in 2005 constitutes a major design change affecting both the generation capacity and the performance of this unit. As a result, its future performance will not be comparable to its historical performance. Manatee Unit 3 and Turkey Point Unit 5 are new units for 2005 and 2007 respectively. Consistent with the GPIF Manual, the above mentioned units will be excluded from the GPIF calculations until we have enough operating history to use in projecting future performance.

Q. Do FPL's EAF and ANOHR performance targets represent a reasonable level of generation efficiency?

A. Yes, they do.

Q. Does this conclude your testimony?

A. Yes, it does.

CHAIRMAN EDGAR: Mr. Horton.

MR. HORTON: Yes, ma'am. Florida Public Utilities would call Mr. George Bachman. And, Madam Chairman, all four of the FPUC witnesses have been sworn.

Thereupon,

GEORGE BACHMAN

was called as a witness on behalf of Florida Public Utilities Company, and, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. HORTON:

Q. Would you state your name and address for the record, please, sir.

A. Yes. George Bachman, 401 South Dixie Highway, West Palm Beach, Florida.

Q. And by whom are you employed, Mr. Bachman?

A. Florida Public Utilities Company.

Q. Have you prepared and prefiled direct testimony in this docket consisting of three pages?

A. Yes, I have.

Q. Do you have any changes or corrections to make to that testimony?

A. No.

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

A. Yes, they would.

MR. HORTON: Madam Chairman, I would request that Mr. Bachman's testimony be inserted in the record as though read.

CHAIRMAN EDGAR: The prefiled testimony will be inserted into the record as though read.

BY MR. HORTON:

Q. And you had no exhibits, did you, Mr. Bachman?

A. No, I did not.

Q. Do you have a brief summary to present at this time?

A. Sure. Florida Public Utilities has two divisions that we serve electricity. We distribute electricity in northern Florida, our Northwest Division, which serves Marianna, and Northeast Division, which serves Fernandina Beach. We have purchased power contracts to purchase the electricity, two of the contracts, one for each of those divisions. Those contracts expire at the end of 2007.

Back in 2005, anticipating these contracts and their expiration, we went out and decided to hire a consultant. We did that for two reasons: (1) The contract would be expiring; and (2) because of the complex nature of fuel contracts, we needed an expert in that field.

We hired Christensen & Associates -- Robert Camfield is here today -- to do the analysis for us. Also, they handled the RFP process. They handled the negotiations and came up with final recommendations for awarding the contracts.

We have concluded this process for our Northeast Division, which serves again Fernandina Beach. We have entered into an amended contract with JEA to provide that power beginning in 2007. That new pricing has been put into our fuel projections.

That concludes my summary.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 060001-EI
CONTINUING SURVEILLANCE AND REVIEW OF
FUEL COST RECOVERY CLAUSES OF ELECTRIC UTILITIES

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

Q. Please state your name and business address.

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

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Have you previously testified in this Docket?

A. Yes.

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

A. To briefly explain our process to procure new fuel contracts for the purchase of electricity in our two electric divisions.

Q. When do the current contracts expire for purchase of electricity?

A. The current contracts for the purchase of electricity in our Northwest and Northeast divisions both expire December 31, 2007.

Q. When did the company begin the process to obtain new contracts?

A. The company began the process to obtain new fuel contracts during the first quarter of 2005 by hiring the consulting firm of Christensen Associates.

Q. When did the Company finalize the fuel contracts?

A. We anticipate a final contract for the purchase of electricity in our Northeast division, effective January 1, 2007 sometime in September 2006 prior to the fuel hearing in November 2006. We anticipate a final contract for the purchase of electricity in our

Northwest division effective January 1, 2008 before the end of 2006.

Q. What was the nature of the engagement with the consulting firm, Christensen Associates and one of their employees Robert Camfield?

A. The company obtained a firm with the proper expertise to handle the entire process of obtaining fuel contracts, from the initial Request for Proposals (RFP), to the final contracts for the purchase of electricity. Robert Camfield is the primary consultant in charge of this project for the consulting firm.

Q. Why did the Company engage a consulting firm to procure new fuel contracts?

A. Due to the size of our Company we did not have the expertise necessary in house to procure fuel contracts. We prudently engaged a Consulting firm, Christensen Associates, to procure our new fuel contracts. They have the necessary expertise to assist us in this endeavor.

Q. What role did the Company play in the process to obtain new fuel contracts?

A. The Company worked along with the consulting firm and reviewed, discussed and approved measures taken within the process from the initial RFP process to the final contract terms.

Q. Does the Company feel that the appropriate measures were taken to prudently obtain fuel contracts?

A. Yes the Company feels that we took the necessary steps to obtain prudent fuel contracts for the procurement of future electricity.

Q. Did the Company review the necessity to obtain a new fuel contract effective January 1, 2007 in our Fernandina Beach (Northeast division)?

A. Yes the Company concurs with our expert consultant, Christensen Associates, that a new fuel contract in our Northeast division was necessary January 1, 2007 to obtain the most favorable option for the procurement of fuel. See Robert Camfield's testimony for additional details in support of our fuel procurement process.

Q. Does this conclude your testimony?

A. Yes.

MR. HORTON: Mr. Bachman is available.

CHAIRMAN EDGAR: Ms. Christensen.

MS. CHRISTENSEN: No questions.

MR. McWHIRTER: No questions.

CAPTAIN WILLIAMS: No questions.

CHAIRMAN EDGAR: Are there questions on cross for this witness by any other parties? No?

Are there questions from staff?

MS. BENNETT: No questions of this witness.

CHAIRMAN EDGAR: Commissioners, any questions? All right.

MR. HORTON: May Mr. Bachman be excused?

CHAIRMAN EDGAR: He may.

MR. HORTON: I don't think I have any redirect for him.

CHAIRMAN EDGAR: Thank you, Mr. Bachman.

THE WITNESS: Thank you.

MR. HORTON: We would call Mr. Robert Camfield.

Thereupon,

ROBERT CAMFIELD

was called as a witness on behalf of Florida Public Utilities Company and, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. HORTON:

Q. Would you state your name and address for the record, please, sir.

A. My name is Robert J. Camfield, and my business address is 4610 University Avenue, Madison, Wisconsin.

Q. And by whom are you employed, Mr. Camfield?

A. Christensen Associates Energy Consulting.

Q. Mr. Camfield, did you prepare and prefile in this docket direct testimony consisting of 27 pages?

A. I did.

Q. Do you have any changes or corrections to make to that testimony?

A. There are no changes or corrections.

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

A. They would.

MR. HORTON: Madam Chairman, may I have Mr. Camfield's direct testimony inserted in the record as though read?

CHAIRMAN EDGAR: The prefiled direct testimony will be entered into the record as though read.

BY MR. HORTON:

Q. Mr. Camfield, you had no exhibits attached to your testimony either, did you?

A. There are no exhibits.

Q. Do you have a summary of your testimony at this time?

A. Yes. As Mr. Bachman mentioned, Florida Public Utilities has current separate contracts for power supply for its Northeast and Northwest Divisions. Those contracts terminate in 2007, year-end, and thus the company decided, with our advice, to enter into an open solicitation for power supply and to initiate that power supply solicitation in midyear 2005.

We did that in the form of an April request for power supply proposal, an RFP, and we solicited letters of intent from a number of parties that provide power supply in the Southeast region. We obtained letters of intent to provide offers for power supply offer packages from nine entities, and we took offer packages, submitted offer packages in May of 2005 from seven entities, potential power suppliers.

So that essentially kicked off our 2005 RFP process that subsequently gave rise to an evaluation of the offers that we had in front of us for both the Northeast and Northwest Divisions.

We then conducted a quasi-auction for what we refer to as qualified offer packages for qualified bidders, and through a three-round auction came up with a set of offers that were really overall, considering all factors, fairly close and competitive.

We thus conducted a second iteration of evaluation of the final offer packages and provided recommendations on those packages to Florida Public Utilities using known criteria for evaluation. And the company then decided on the winning bidder to its RFP solicitation process. It was Southern Company. More specifically, Southern Power Company was the winning bidder to the Northeast Division, and Gulf Power Company was the winning bidder to the Northwest.

The difficulty, of course, with bidders to the north of FPU is that the transmission interface can get congestion that's problematic along the Georgia-Florida interface. And as a result of that, we in the process of the solicitation, knowing that a number of the bidders were from the north, engaged in two different power transport -- should I say transmission supply strategies, one of which was the consideration of a separate radial line to link Fernandina Beach, the Northeast Division, to the Southeast Reliability Council, known as the SERC.

So the effect of that potentially would have been, should it succeed as a transmission strategy, was to remove the Northeast Division from the FRCC region, the benefit being that the benchmark wholesale prices to the north of Florida, the Florida peninsula, because of the transmission constraint, are lower substantially from that of the FRCC. So that long-term strategy was part of the alternative power supply arrangements that were being considered at the time.

Because of the asset concentration, the investment requirements for the radial line, the uncertainty associated with the completion of the line in the time frame required to get the permits and build and construct the line, plus reliability issues with a dual circuit line -- we simultaneously knew these things, of course, ahead of time and proceeded to consider an alternative transmission strategy, which was to obtain access to the transmission network, specifically the interface itself, through the OATT of JEA.

The constraints are well known on the Georgia-Florida interface and, of course, because of the constraints and so forth, firm service was not available to us, and thus we were essentially precluded from completing the power supply arrangement for the winning bidder, Southern Power Company, and thus have proceeded to negotiate a power supply contract with JEA, who was the incumbent supplier for the Northeast Division.

And it is that power supply contract, as Mr. Bachman mentioned, that is determining the prices for the 2007 time frame. Those prices are, as I state in my testimony, overall, for both generation and transmission services, at $45 per megawatt-hour under the amended contract, the current contract with its amendments.

The commercial terms give rise to increases in the prices for power supply over the 2008 and 2009 time frame, with the prices for 2008 at $59 per megawatt-hour, including transmission, and at $73, which is the full price level at cost of service, cost of service based prices for power supply, given JEA's embedded cost for generation services. And that price beginning in 2009 forward is at $73, but will escalate over the future years of the contract, which run through the year 2017.

And that concludes my summary.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 060001-EI

CONTINUING SURVEILLANCE AND REVIEW OF

FUEL COST RECOVERY CLAUSES OF ELECTRIC UTILITIES

DIRECT TESTIMONY

OF

ROBERT J. CAMFIELD

ON BEHALF OF

FLORIDA PUBLIC UTILITIES COMPANY

Q. PLEASE STATE YOUR NAME, ADDRESS.

A. My name is Robert J. Camfield, and my business address is 4610 University Avenue, Madison, Wisconsin 53705.

Q. WITH WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed with Christensen Associates Energy Consulting, LLC, where I serve in the position of Vice President.

Q. WOULD YOU BRIEFLY DESCRIBE YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. 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 rate case proceedings regarding cost of capital and retail gas tariff design. I joined the New Hampshire Public Service Commission in 1979 as the senior economist, and held the position of chief economist beginning in 1981. As Chief Economist, I was responsible for the administration of the economics department of the Commission staff. I oversaw the analysis of regulatory issues, the coordination and guidance of staff participation in regulatory proceedings, the preparation and development of testimony, and I provided policy advice to the Commission on a variety of 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 of Southern Company Services, and Southern Company's Strategic Planning Group. In 1994, I joined Laurits R. Christensen Associates, Inc. ("Christensen Associates") as a senior economist, and currently hold the position of Vice President with Christensen Associates Energy Consulting LLC., a subsidiary consulting group of Christensen Associates.

My experience covers a gamut of issues facing regulated industries. I have been involved in the negotiation of power supply contracts and the terms of franchise licenses. My overseas assignments are several, and I have managed a large market restructuring project in Central Europe. I have served on national and regional advisory panels, and I have advised integrated electric utilities, independent power producers, transmission and distribution companies, utility associations, offices of consumer advocate, and regulatory agencies 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 principles for efficient pricing of distribution services. I have published chapters in technical books, reports, and articles in noted journals such as *The Electricity Journal, IEEE Transactions on Power Systems*, and *CIGRE*. Currently, I serve as Program Director of the Edison Electric Institute's Market Design and Transmission Pricing School.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS?

A. I have represented regulatory staff organizations, consumer advocates, independent generation companies, distribution companies, transmission companies, integrated utilities, and utility associations in proceedings before a number of regulatory agencies regarding a host of issues including cost of capital, performance assessment and benchmarking, electricity forecasting, retail rates, cost-of-service allocation, generation expansion planning, and transmission issues.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. For the consideration of the Florida Public Service Commission, the testimony reviews Florida Public Utilities Company's ("FPUC" or "Company") long-term arrangements for wholesale power supply beginning in 2007 and extending through 2017. These contractual arrangements are new, and succeed FPUC's current power supply agreements. The testimony discusses the wholesale market context and situation of FPUC particularly as regards to transmission services, FPUC's procurement process, and the results of that process including the implications for retail electricity consumers.

The process of power procurement for Florida Public Utilities Company has proved to be unusually arduous for service for the Northeast Division. The electrical flow constraints attending the Georgia-Florida Interface facilities, when coupled with key interpretations of market rules regarding transmission access, severely limit Florida Public Utilities Company's options for power supply from the regional pool of relatively plentiful generation resources situated to the north of the Florida Peninsula. As a consequence, the Company is unable to take delivery of power supply from the selected and winning bidder to its 2005 Request for Proposal (RFP) process for service to the Northeast Division. Transmission service limitations thus constitute a serious complication, and have forced the Company to engage in a cost-based supply arrangement with the incumbent supplier to the Northeast Division. Fortunately, the commercial terms of the Company's new contract for service beginning in 2007 with its incumbent supplier are favorable and generally comparable to the offer prices obtained through the competitive solicitation process initiated through the Company's 2005 RFP.

Q. COULD YOU DESCRIBE THE ELECTRIC SERVICE TERRITORY OF FLORIDA PUBLIC UTILITIES COMPANY?

A. Florida Public Utilities Company is a small diversified distribution utility providing electricity, natural gas, and propane services in the State of Florida. The Company's electric operations consist of two divisions in northern Florida, referred to as the Northeast and Northwest Divisions. These two divisions provide bundled retail services to residential, commercial, and industrial consumers in two non-contiguous service territories. During 2005, the Northeast Division, also known as Fernandina Beach, served 15,099 customers with gross electricity sales of 495,370 MWh, while the Northwest Division, also known as Marianna, served 15,147 customers with gross electricity sales of 356,704 MWh. The Northeast Division is interconnected with the JEA (previously referred to as Jacksonville Electric Authority) transmission network at one delivery point with 150 MVA of transformer capability and 138 kV primary feeders. The Northwest Division interconnects with Southern Company's (Gulf Power Company) transmission network at six delivery points with a total of 130 MVA of capability and 12.5 kV primary feeders.

Q. DOES FPUC GENERATE ANY OF THE POWER WHICH IT SELLS TO RETAIL CUSTOMERS IN THESE TWO SERVICE DIVISIONS?

A. No. The Company is a distribution utility, and purchases all generation and transmission services from regional wholesale service providers.

Q. WHAT ARE THE COMPANY'S CURRENT ARRANGEMENTS FOR POWER SUPPLY AND PLANS FOR THE FUTURE?

A. The Company purchases bundled generation and transmission services under long-term supply contracts that date from 1997 and are scheduled to expire on December 31 of 2007. More specifically, the Company's Northeast Division is served by the JEA, and the Northwest Division is served by Gulf Power Company, where both contracts provide full requirements services including energy and reserve services, and also cover transmission services. As a consequence of the current contractual arrangements nearing expiration, the Company is in the process of finalizing contracts for power supply for both electric divisions over the ensuing years.

Q. WHAT ARE THE POWER PROCUREMENT OBJECTIVES OF FLORDA PUBLIC UTILITIES COMPANY?

A. The Company's power supply objectives align with the Company's longstanding goal of providing, over the long term, high quality service at the favorable prices to its retail customers. Stated more explicitly, the Company's underlying power procurement objectives are to obtain long-term power supply at favorable terms and prices, while assuming an acceptable level of risk. To this end and as I have documented elsewhere before this Commission, Florida Public Utilities Company is currently a low-priced service provider within the region, with very favorable retail electricity prices. The Company's costs of generation and transmission services, as provided under the Company's current wholesale supply contracts, are very low with reference to wholesale power prices within the region. In addition, the Company provides comparatively low-cost distribution services and, although of small scale, the Company has realized substantial gains in productivity in distribution services over recent years.

Q. WHAT POWER PROCUREMENT STRATEGIES DID THE COMPANY PURSUE FOR POWER SUPPLY BEYOND 2007?

A. In view of the pending expiration of the Company's current supply contracts, Florida Public Utilities Company engaged in a deliberate process that began by exploring alternative procurement approaches. The Company then initiated an open solicitation for power supply, referred to as a Request for Proposal, during 2005. Specifically, the Company released a formal *Request for Proposals to Provide Wholesale Power Supply* on April 21, 2005 ("2005 RFP").

An open solicitation for supply is one of several procurement formats that are potentially available to the Company. Alternative formats were initially explored by the Company including sequential short-term purchases that could involve contract laddering, as well as self-supply where FPUC owns and operates generation resources. Because power generation resources are sizable facilities involving large investment in specialized capital, self-supply would likely involve a jointly owned facility. In addition, the Company could engage in several forms of bilateral contracts including, for example, a tolling agreement with a power generation entity where the Company would purchase primary fuels that would then be transformed to electricity and transmitted to the Company's designated delivery points (points of withdrawal of power from transmission networks). The contractual arrangements for power supply under a tolling agreement would involve three separate contracts covering primary fuel inputs, power transformation, and transmission services.

The solicitation of power supply by others can be approached in a variety of ways, and several formats are possible. As mentioned, FPUC currently takes power under two bundled power supply contracts covering full requirements generation services (energy and reserves) and transmission services. Alternative solicitation formats include the two general categories of sealed bid and auction procedures. In the case of a so-called sealed bid solicitation, the solicitation—which can be as simple as a one- to two-page letter requesting power services or a formal RFP that is highly specific as regards to information requirements, process including pre-qualifying, engagement rules, and timetable—can involve a limited number of pre-identified potential suppliers, or can be an open invitation seeking offers from interested parties.

Auctions for electric power supply first appeared, at least in recent years, within the unbundled wholesale markets of California (CAISO), PJM, and New York (NYISO). Auctions are, literally, markets that operate under highly specific rules. For electricity, auctions can be organized as short-term sequential or simultaneous market procedures involving related services such as energy and reserves which are provided over same-day and day-ahead timeframes. These short-term auctions can include pay-as-bid and uniform-price auction formats. Because these auctions are repeated with high levels of frequency, they are organized electronically as a matter of necessity. Long-term auctions for standard offer service ("SOS") have recently been organized in the Eastern and the Midwest regions of the U.S. (e.g., New Jersey, Maryland, Ohio, and Illinois). In these auctions, pre-qualified candidate bidders provide offers to serve load shape shares. A type of auction recently implemented in wholesale electricity markets is referred to as a declining clock auction, where the market price follows a schedule of pre-defined decrement steps at periodic intervals (rounds) over the course of the auction. Electricity auctions usually cover very large loads, enjoy wide participation by many candidate suppliers, and can involve numerous auction rounds (i.e., 50 iterations or more).

Q. PLEASE DESCRIBE THE COMPANY'S APPROACH AND POWER PROCUREMENT FORMAT?

Of the various alternative procurement formats that are potentially available, the Company settled on the open solicitation format, where bidders are free to propose a variety of service arrangements and terms. The open solicitation format, manifest as the 2005 RFP, was designed in a manner to facilitate participation in order to increase the level of contestability and supply options available to the Company.

Q. DID THE POWER PROCUREMENT STRATEGY OF THE COMPANY CONSIDER DIVERSIFICATION OF CONTRACTS?

A. Yes. The Company's 2005 RFP provided bidders with options to submit offer packages with multiple offers covering full requirements, partial requirements, and energy only services. Energy offers could be submitted for a variety of timeframes such as, for example, specific hours of weekdays of defined seasons for individual years. The Company sought offers for a five-year term, although offers of shorter duration would also have been considered. In addition, the Company's 2005 RFP requested ten-year offers as options. Finally, the 2005 RFP provided bidders with considerable flexibility regarding the proposed commercial terms; bidders could submit offers with fixed charges, demand charges, energy charges, or energy charges indexed to primary fuel prices and wholesale electricity prices.

The approach taken, the open solicitation format, provides two main advantages. First, multiple offers covering a variety of forms provide a basis for the Company to potentially build a portfolio of supply including laddered contracts to hedge risks. Second, by allowing for a broad range of potential services and structure of terms, the 2005 RFP design to the extent possible held to a minimum the level of constraints and impediments to participation by serious, potential bidders. As a result, participation by bidders, at least conceptually, is enhanced thus increasing the potential level of competition and contestability, all in the interest of obtaining the lowest possible prices.

Q. WOULD YOU DESCRIBE THE IMPLEMENTATION OF THE PROCUREMENT PROCESS?

A. The Company's 2005 procurement process began with the identification of power suppliers and power marketing entities operating within the Southeast and Midwest regions. Selected potential suppliers situated toward the west were also identified. Potential suppliers were then surveyed in order to gauge their interest in taking receipt of the Company's formal RFP. The 2005 RFP was released on April 21 to suppliers that expressed interest in participation. The RFP explicitly defines several procedural steps, and the necessary information and data to be included in the offer packages submitted by bidders.

Q. CAN YOU BRIEFLY DISCUSS THE POWER SUPPLY SERVICES ASSOCIATED WITH THE RFP?

A. Yes. As a result of the unbundling of wholesale markets into separable transmission and generation services beginning in 1996, the Company's 2005 RFP process involves generation services including energy and certain ancillary services. Bidders were free to offer various bundles of services within offer packages. The implication is that, for example, a selected bidder could provide a service bundle including energy and load following service, such that the Company would be required to self-supply or contract for transmission and other ancillary services not covered under the bundle provided by the energy service provider (winning bidder).

Transmission services would be provided under separate contracts between the selected generation service provider (on behalf of the Company) and the relevant control areas, or between the Company and the control areas directly.

Q. BRIEFLY REVIEW THE DATA AND INFORMATION INCLUDED IN THE OFFER PACKAGES OF BIDDERS RESPONDING TO FPUC'S RFP FOR POWER SUPPLY.

A. In addition to the commercial terms and defined services, several information items were requested to be included in offer packages submitted by bidders. First, bidders were requested to provide a summary statement or business overview with a focus on the bidder's activities in wholesale markets and the generation technologies available to them. A business overview provides a means to gauge the full range and extent of the business activities of bidders, as bidders are often subsidiary organizations within the diversified business activities of very large firms—for example, a commodity group of an investment banking firm, a merchant supply business unit of an independent power producer, or an energy company involved in oil and gas exploration. Where relevant, bidders were requested to list their wholesale market certification.

The RFP requested bidders to provide statements of financial condition and credit worthiness and identified financial surety in the form of letters of credit.

The 2005 RFP also imposed non-disclosure obligations on bidders including confidentiality agreements and signed submission agreements.

Q. PLEASE DESCRIBE THE RFP PROCESS.

A. The RFP identified specific procedural steps with an accompanying schedule, as follows. First, *Response Window for Inquiries and Questions* (April 22 – May 16) provided candidate bidders with the opportunity to obtain additional information to assist them in deciding whether to prepare an offer package and in the preparation of such packages. Responses to questions were circulated to all candidate bidders. Bidders were requested to indicate their *Intent to Submit Offer Packages* on May 17, and *Offer Packages Were Due* on June 2. The Company conducted an *Initial Screen of Offers* and provided *Notice of Status* to bidders on June 22. Specifically, offer packages of bidders were reviewed for completeness and conformance with the delineated information requested within the 2005 RFP. Bidders were advised of non-conforming conditions of offer packages, and were provided one week to correct or provide additional information as identified. Under the original schedule of the 2005 RFP process, the Company then conducted an initial assessment of offer packages, identified qualifying bids, and noticed qualifying bidders by July 29 of their status. The Company then proceeded to interview qualifying bidders during early September 2005.

Q. HOW WERE BIDS SOLICITED AND HOW MANY RESPONSES WERE OBTAINED?

A. The Company contacted numerous potential suppliers, and thirty-five entities expressed interest in taking receipt of the 2005 RFP. Nine entities provided Letters of Intent to submit offer packages following the release of the RFP. Seven offer packages were submitted.

Q. WITH RESPECT TO THE SUBMISSIONS RECEIVED, WERE THE OFFERS BY BIDDERS TO SERVE ONE OR BOTH DIVISIONS?

A. Three bidders provided offers to serve either or both electric divisions of the Company. Other offer packages focused on one of the two divisions.

Q. OF THE OFFER PACKAGES RECEIVED, WERE ANY PACKAGES SUBMITTED BY ENTITIES AFFILIATED WITH FPUC?

A. No entities providing offer packages, or for that matter participating in the RFP process, are affiliated with FPUC in any way.

Q. ONCE THE RESPONSES WERE RECEIVED AND QUALIFIED BIDDERS IDENTIFIED, WHAT WERE THE NEXT STEPS?

A. At the time that the RFP was released, the schedule would have placed the Company in the position of selecting bidders during August and subsequently negotiating contracts during the September-October timeframe. However, the overall level of participation was greater than anticipated, and several viable bidders for both the Northeast and the Northwest Divisions were identified. Also, it became evident that, at least potentially, the Company could induce lower prices through an auction-style market procedure. Thus, the Company's 2005 RFP concluded with a quasi-auction involving three rounds, where bidders were invited to provide revisions to the price terms of offers. The relative standings of the offers of bidders were noticed to bidders following the first and second rounds.

Q. WHAT FACTORS WERE INCLUDED IN THE EVALUATION?

A. The criteria for evaluation of offers of bidders, as stated within the Company's 2005 RFP, included overall price level, counterparty risk, environmental quality of the underlying resources used to provide services, and delivery risks. To the extent possible, the analyses involve quantitative assessment and utilize multi-criteria analysis methods. Particular attention was given to the implied level of price risks, as some of the terms of the offer packages of bidders contained variable price terms. In fact, one specific offer package with highly favorable terms stated on an expected value basis, would involve a contract for differences with a major financial institution in order to hedge much of the inherent price risk associated with the commercial terms of the offer, should the offer be selected.

Q. HOW WAS THE EVALUATION CONDUCTED?

A. The evaluation was conducted independent of the Company by Christensen Associates Energy Consulting, and the results of the evaluation were presented to the Company as an outside study result. The evaluation included unit-specific and total bills criteria, where the commercial (price) terms are converted to an equivalent price basis, stated as net present value over the term of the potential contract.

An evaluation of the final terms of the offers, as obtained during the third round, was conducted during late 2005. The evaluation of terms, when combined with the assessment of non-price factors, provided the basis for the recommendations provided to the Company. The Company selected the winning bidder and bidders were advised of the outcome during late January 2006.

Q. PLEASE IDENTIFY THE SERVICE PROVIDERS SELECTED THROUGH THE 2005 RFP PROCESS.

A. Through the 2005 RFP process, the Company selected Southern Company as its prospective service provider, including Southern Power Company ("Southern Power") to serve the Northeast Division over the 2008 – 2017 period, and Gulf Power Company to serve the Northwest Division from 2008 through 2012.

Q. IS IT YOUR PROFESSIONAL VIEW, THAT AS A RESULT OF THE 2005 RFP PROCESS, THE SELECTION OF SOUTHERN COMPANY TO SERVE BOTH THE NORTHEAST AND NORTHWEST DIVISIONS WOULD BE IN THE BEST INTEREST OF RETAIL CUSTOMERS.

A. Yes, given the offer packages and potential suppliers available to the Company through the 2005 RFP process, and providing that a satisfactory resolution to the transmission delivery issue with respect to the Northeast Division could be reached. As I will discuss, the Company encountered and continues to encounter technical and institutional obstacles that, as a practical matter, preclude the delivery of service by Southern Power for the Northeast Division.

Southern Company is a well recognized, established electricity service provider with attending low levels of counterparty risks. Through conservative resource management and a focus on the markets that it serves, Southern Company provides very high levels of customer satisfaction to electricity consumers through high service quality and innovative products at favorable prices. These attributes were tested over the course of the Company's 2005 RFP.

Q. **AT THE OUTSET OF YOUR TESTIMONY, YOU MENTION THE LIMITATIONS OF TRANSMISSION CAPABILITY, AND THE COMPLICATIONS THAT TRANSMISSION HAS PRESENTED FOR POWER DELIVERY TO THE COMPANY'S NORTHEAST DIVISION. PLEASE ELABORATE.**

A. In the case of the Company's Northwest Division, the Company is recognized as an entity serving native loads and is thus entitled, as a matter of the market rules regarding transmission access rights, to Network Integration Transmission Service. Essentially, the Company over many years has drawn upon system-wide generation resources situated at various locations across the network. Because of its longstanding status as native load, the Company is entitled to continued access to the network transmission resources of its service provider, Southern Company (Gulf Power Company). For its new contract with Gulf Power for generation services, the Company *rolls over* (continues) the transmission service provided under the current agreement with Gulf Power. Going forward, however, the Company assumes the position of a direct transmission customer of Southern Company and, under the transmission service agreement with Southern Company, will pay transmission charges monthly, where the level of those charges are set by the Federal Energy Regulatory Commission (FERC).

The Company's Northeast Division resides within the JEA control area. The initial selection of Southern Power for service for the Northeast Division involved two control areas, JEA and Georgia Transmission Company ("GTC"). The implementation of a power contract between the Company and Southern Power—or other bidders with generation resources situated north of Florida—implied pancaked transmission charges for the transmission services provided by JEA and GTC (on behalf of members), *if* the Company were to schedule power delivery from Southern Power's resources in the north across the Georgia-Florida Interface to the delivery point for the Northeast Division. The scheduling of firm power across the interface involves a key issue: the Company's transmission access rights, as native load, where the designated resources have changed from the generation plants within the JEA control area to generators within the Southern Company/GTC territory and under the control of Southern Power.

At the outset, the Company's status regarding transmission service for the Northeast Division was unclear, and thus the Company engaged in two alternative transmission strategies in support of potential contracts with bidders to the north. First, the Company pursued transmission service with JEA/GTC involving network flows over the George-Florida interface. Second, the Company pursued the development of a radial transmission service line that would interconnect the Northeast Division with the Southern Company/GTC control area. This second alternative removes the Northeast Division from the FRCC region and the JEA control area such that, prospectively, the Company's generation supply and resource options are benchmarked to the sharply lower wholesale electricity market prices within the Southeast region, with respect to wholesale prices in the Florida Peninsula.

Q. WHERE ARE MATTERS CURRENTLY AND WHAT ARE THE RESULTS OF THE PROCUREMENT PROCESS?

A. At this point, it appears that the Company may not obtain transmission access rights with the designation of redirected resources. The Company and its legal team are reviewing this situation currently. Further exploration of the second transmission alternative, the radial interconnection to SERC, requires additional power flow analysis—initial studies were sponsored by Southern Power Company and carried out by Southern Company Services—an engineering assessment, facility siting and permitting, arrangements for facility financing, and construction.

Both transmission alternatives involve considerable expenditure of resources and time and, in view of the upcoming 2007 expiration of the current contract and precisely because of transmission limits, the Company is forestalled from implementing a power supply agreement with Southern Power for service for the Northeast. In addition, the expiration of the current contracts and the power procurement process are taking place within an unusually difficult and challenging timeframe. Currently, primary fuel supplies at the national level are unusually tight, a direct consequence of high worldwide demands for fuels and fairly high levels of uncertainty in several dimensions including random weather-induced supply disruptions (e.g., natural gas, oil, and Powder River Basin coal supplies). Accordingly, wholesale electric prices reside at fairly high levels and remain sensitive to unplanned events.

Together, these factors caused the Company to pursue additional supply options within the Florida Peninsula for the Northeast Division. These discussions developed outside of the 2005 RFP process, and involved expressions of interest as well as in-depth negotiations of two options with JEA, the incumbent supplier. Indeed, the new arrangement with JEA is a long-term power supply contract for service for the Northeast Division beginning January of 2007 and ending in December 2017.

As a result of the enormous gap (with corresponding economic losses for JEA) between the commercial terms of the Company's current power supply contract with JEA (about $31/MWh including transmission service, ancillary services, and reserve services), and contemporary regional wholesale electricity prices ($87/MWh since June 2005 and $72/MWh since January 2006 absent transmission, ancillary services, or reserves), JEA offers the embedded cost-based service option with a start date of January 1, 2007 only.

With the exception of voltage control and reactive power, the services provided under the new contract with JEA include energy and the full complement of ancillary services, as defined by the Open Access Tariff (OATT) first established by Order 888 of the FERC.

Q. FOR THE NORTHEAST DIVISION, WHAT ARE THE TERMS OF THE POWER SUPPLY CONTRACT WITH JEA?

A. As mentioned, the commercial terms of the new contract are based upon JEA's embedded costs of generation resources. The commercial terms include three elements: a non-fuel energy charge ($/MWh), a fuel charge ($/MWh), and a demand charge ($/kW-month). The non-fuel price terms will be based on the results of prospective cost of service allocation studies. The fuel charge of the new contract is set at a price equal to the fuel charge within JEA's retail tariff. All price terms vary periodically over the course of the contract term, and are subject to the review and approval of the JEA Board.

The Company will engage in a separate transmission service agreement with JEA for Network Integration Transmission Service (NITS). JEA's transmission tariff largely follows the OATT established by the FERC, and the invoice amounts for transmission services are based on $/kW-month charges. Demands are measured on an annual coincident peak load basis.

Q. FOR THE NORTHEAST DIVISION, HOW DO THE NEW CONTRACT PRICES COMPARE TO THE PRICES RESULTING FROM THE RFP PROCESS?

The expected all-in prices for power supply are $45.16, $59.47, and $73.17 for 2007, 2008, and 2009, respectively. These prices include transmission charges of $3.17, stated on a $/MWh basis, for 2008 and 2009. For purposes of comparison, it is useful to gauge the new contract prices with reference to the average of the 2008 and 2009 offer prices resulting from the Company's 2005 RFP process. Specifically, the offer prices average $79.94/MWh for these years including transmission charges, although the final offer price of the winning bidder selected by the Company is somewhat below this near-$80/MWh price level. Thus, the price level of the new JEA contract is favorably positioned when viewed from the perspective of long-term wholesale prices, where the 2005 RFP serves to provide a benchmark for the costs of long-term supply. Market context is important, and the low levels of market liquidity for the Florida region limit the long-term supply options available to the Company.

In addition to the embedded cost-based 10-year contract option, the Company also negotiated a 2-year incremental-cost based option with JEA. The all-in prices of this second option, stated with the inclusion of transmission charges, are $79.79/MWh and $82.09/MWh for 2008 and 2009, respectively.

Q. WILL CUSTOMERS IN THE NORTHWEST DIVISION EXPERIENCE ANY CHANGES IN 2007, AS A RESULT OF THE NEW CONTRACT?

A. No. Retail customers of the Company's Northwest Division will experience no change in the level of customer bills during 2007 as a result of the pending contract with Gulf Power Company. However, the overall contract prices for the Northwest may change slightly as a result of small changes in the price terms of the current contract, and changes in the billing determinants from 2006 levels.

Q. HOW WILL THE FUEL COSTS PAID BY CUSTOMERS IN THE TWO DIVISIONS COMPARE, FOR 2007?

A. Historically, the overall retail price level for the Northeast Division has been below the corresponding prices of the Northwest Division because of the differences in the commercial terms of the power supply contracts for the Northeast and Northwest Divisions. The contract price difference is about $9/MWh currently. The new power supply contract for the Northeast will bring the overall cost of generation and transmission services for the Northeast Division to a level somewhat above that of the Northwest Division during 2007.

Q. PLEASE SUMMARIZE THE STATUS OF THE POWER SUPPLY CONTRACTS FOR THE NORTHWEST AND NORTHEAST DIVISIONS FOR 2007.

A. The pending new contract for power supply for the Northwest Division with Gulf Power Company is under negotiation; the contract will become effective in January 2008 and extend through 2017. The new Northwest Division contract will have no impact on the retail prices of the Company's Northwest Division during 2007, as mentioned above.

The 10-year embedded cost-based option of the new contract for the Northeast Division is effective January 1, 2007 and will cause retail electricity prices (excluding GSLD1) during 2007 to increase to a level that approaches that of the Northwest Division.

Q. IN YOUR PROFESSIONAL OPINION, IS THE COMPANY'S SELECTION OF THE EMBEDDED COST-BASED OPTION WITH JEA FOR THE NORTHEAST DIVISION THE MOST PRUDENT ARRANGMENT FOR RETAIL CUSTOMERS OVER THE SHORT- AND LONG-TERM?

A. Yes, when the limits of transmission delivery, low levels of market liquidity, and underlying levels of uncertainty are accounted for, the embedded cost-based contract with JEA, the incumbent supplier, for service for the Northeast

Division, is the best long-term least cost power supply option and choice available to the Company and its retail consumers at this time.

The commercial terms of the new contract with JEA are based on embedded costs and, while the prices will be adjusted from time to time, such prices are likely to demonstrate high levels of stability. The outlook for the overall level of the contract prices are favorable though it is possible that future wholesale electricity prices within the region may be somewhat below (or somewhat above) the terms of the new contract with JEA. JEA is a well known and established municipal electricity service provider. Like Southern Company, JEA has obtained high levels of credit worthiness and provides good service quality. JEA's generation supply mix is well balanced and draws upon a substantial amount of coal-fired resources that utilize petroleum coke fuel supply and fluidized bed technologies, which are complemented by combined cycle gas generators.

It is perhaps useful to mention that the design features of wholesale electricity markets matter a lot. Alternative market arrangements in the Southeast can potentially realize much higher levels of transparency at all levels that, in turn, can give rise to improved market liquidity, higher levels of exchange, and expanded opportunities for trade. As it is, particularly for Florida, transmission constraints, generation resource limits, and institutional and market design impediments of various dimensions limit power supply options and availability.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

MR. HORTON: Mr. Camfield is available.

CHAIRMAN EDGAR: Are there questions on cross?

MS. CHRISTENSEN: No questions.

MR. McWHIRTER: No questions.

CAPTAIN WILLIAMS: No questions.

CHAIRMAN EDGAR: Okay. Are there questions on cross for this witness from any of the other parties?

Seeing none, are there questions from staff?

MS. BENNETT: Yes, Madam Chair.

CROSS-EXAMINATION

BY MS. BENNETT:

Q. I think I understood you to say that for the Northeast Division, FPUC could not contract with the winner of the 2005 RFP process because of transmission constraints; is that correct?

A. That's correct.

Q. For the Northeast Division, isn't it true that the existing power supply contract with JEA expires at the end of 2007?

A. That's correct.

Q. And would you agree that FPUC is proposing to forgo the last year of its power supply arrangements with JEA so that FPUC can obtain the proposed long-term contract with JEA?

A. That's correct.

Q. In your direct testimony on page 23, you talk about the Northeast Division and the new power supply contract with JEA which result in higher prices for customers in 2007, 2008, and 2009, and I believe I heard you testify to those numbers. They will be increasing each year; is that correct?

A. That's correct.

Q. On page 23 again of your testimony, on line 9, you note the average offer price of $79.94 based on the RFP process. Is that a correct number?

A. That's correct.

Q. Is it your belief that the new contract with JEA has favorable price terms compared to the request for proposal process that you previously described?

A. That is my expectation. Over the longer term forward period, as well as the current time frame here that we're talking about, 2007 and 2009, I feel that these embedded cost based contract prices with JEA are very favorable with regards to both the offer prices as received in response to the 2005 RFP of Florida Public Utilities, as well as projections of long-term wholesale prices in their region.

MS. BENNETT: Madam Chair, I have no further questions of this witness.

CHAIRMAN EDGAR: Commissioner Arriaga.

COMMISSIONER ARRIAGA: Sir, you mentioned the Georgia-Florida interface constraints as one of the reasons for going the route of contracting with JEA at higher rates. Could you explain that a little bit, because there have been times here that we have spoken about these interface constraints. I think the Department of Energy has pointed out some issues regarding that interface constraint.

What moved you to accept this contract versus considering a potential solution, or is there no solution to that Georgia-Florida interface constraint?

THE WITNESS: Well, as I discussed in the testimony, Commissioner, the interface constraints are well known. And the two issues that Florida Public Utilities faces with regards to transmission is, number one, can it obtain access rights for transmission under JEA's open access transmission tariff, which is modeled after the FERC OATT first established in 1996. And that tariff has two main transmission service types, network service and point-to-point service.

For the most part, wholesale power transactions over the interface to the peninsula of Florida service providers are point-to-point service arrangements utilizing the tariff and priced at the posted tariff prices of the JEA OATT.

The other transmission service type is known as network integration transmission service, and that service is for incumbent service providers like Florida Public Utilities that would utilize multiple generation resources within the control area, in this case, JEA.

So the issue as far as transmission access is concerned is whether or not FPU would be entitled to access rights of the interface facilities because it is an incumbent service provider, an incumbent customer of FPU, where under the rollover provision, and thus giving you access rights, you can redesignate the generation resources to the new supplier, in this case, Southern Power Company.

Southern Power resources, of course, are to the north of JEA, and thus we would need to have that access right, those transmission access rights in order to obtain the power over the interface. And that's the key interpretation issue as far as access, transmission access rights are concerned.

And as I discussed, the other transmission option available to FPU, at least potentially, would be the construction of a radial line in both options. The use of the existing transmission interface, should we be -- should I say should we obtain transmission access rights, as well as the radial line, were considered in the -- or should I say along with and parallel to the 2005 RFP process.

My apologies for that long-winded answer.

COMMISSIONER ARRIAGA: No, that's fine.

I think I am as concerned as you are about the transmission interface.

THE WITNESS: Oh, yes.

COMMISSIONER ARRIAGA: I've been talking to staff about it, and --

THE WITNESS: It's a serious issue.

COMMISSIONER ARRIAGA: It is a serious issue.

Your contract, I understand, with JEA is for three years. I'm sorry, ten years, 2017. But I see right here for the next three years only. What is it going to be in 2017?

THE WITNESS: The prices, should I say the commercial terms of the current contract amendment for the period 2008 and 2009 and all forward years will be determined by cost of service allocation. And specifically with the amendment are cost of service principles that define the methodology in general terms under which JEA will conduct a cost of service allocation study and determine essentially the share of total embedded cost of generation resources of JEA that would be allocated to FPU as a wholesale customer of

JEA. And that cost of service process will determine the nonfuel-related costs for the -- of the commercial terms of the contract amendment for all forward years, 2008 forward.

COMMISSIONER ARRIAGA: Just one last statement. I guess what I'm concerned about, and probably you are too, and the company is also, that you will find yourselves eventually with one supplier and being slowly choked. Do you have any other alternative to continuously having to negotiate a contract that is going to be higher and higher and higher as the years go by because you have no other source of supply?

THE WITNESS: Well, the company -- if the contract prices, the resulting contract prices, the commercial terms themselves of the amendment were not favorable, that would be a major concern. In fact, the contract amendment allowed Florida Public Utilities Company to elect one of two options.

The shorter term option was an incremental cost based option. It was a set of commercial terms known as Option A, where those terms were determined on the basis of incremental costs, the internal incremental costs of JEA to provide resources. Of course, I've had a chance to look in detail at the underlying costs of both Option A and Option B, the longer term embedded cost option selected by FPU. I've had a chance to review the financial forecasts of JEA and the fuel costs and the way it does things.

And so taken as a whole, Commissioner -- and, frankly, I share your concerns. But taken as a whole, I think it's quite favorable, and I don't feel that there is great danger for a price escalation that would put FPU in a position of having, or paying, should we say, noncompetitive wholesale prices for generation and transmission services.

COMMISSIONER ARRIAGA: All right. Thank you very much.

THE WITNESS: Yes, sir.

CHAIRMAN EDGAR: Mr. Horton.

MR. HORTON: No redirect. May Mr. Camfield be excused?

COMMISSIONER CARTER: The witness may be excused. Thank you.

THE WITNESS: Thank you.

MR. HORTON: And I would call Mr. Cutshaw.

Thereupon,

MARK CUTSHAW

was called as a witness on behalf of Florida Public Utilities Company and, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. HORTON:

Q. Would you state your name and address for the record, please, sir.

A. My name is Mark Cutshaw, Florida Public Utilities Company. My address is 911 South Eighth Street, Fernandina Beach, Florida, 32034.

Q. What is your position with Florida Public Utilities?

A. I am the general manager for the Northeast Florida Division.

Q. Did you prepare and prefile in this docket direct testimony consisting of three pages?

A. Yes, I did.

Q. Do you have any changes or corrections to make to that testimony?

A. No, I don't.

Q. 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: Madam Chairman, I would ask that his prefiled direct testimony be inserted into the record as though read.

CHAIRMAN EDGAR: The prefiled testimony of the witness will be inserted into the record as though read.

BY MR. HORTON:

Q. And you had no exhibits to your testimony either, did you?

A. No, I didn't.

Q. Do you have a summary to present at this time?

A. Yes, I do. During 2005, we realized that the impact on our customers beginning in what we had thought at the time to be 2008 would be significant. We began to explore different alternatives to try to mitigate this significant rate increase that would occur at that time. We looked at alternatives.

We filed formal proceedings that, although they were not approved, did allow public hearings to occur. It did bring information to this venue to go out to the public. We had media releases in the communities during 2005 that informed them things would change going forward. They were used to very, very favorable pricing, and that would come to an end.

As I mentioned, those alternatives were not approved. However, in 2006, as we moved through the process of getting a new power contract, we also retained a firm that worked with us to provide additional communications to our customers to inform them that, yes, prices would increase. We also provided them with information on conservation techniques that they could use when the prices went up to help avoid significant cost to them.

So we have been continuing. We will continue after the results of this docket are closed in informing our customers exactly what to expect going forward and will do whatever we can to assist them in making preparations to do so.

That concludes my summary.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 060001-EI
CONTINUING SURVEILLANCE AND REVIEW OF
FUEL COST RECOVERY CLAUSES OF ELECTRIC UTILITIES

Direct Testimony of
Mark Cutshaw
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. Mark Cutshaw, 911 South 8th Street, Fernandina Beach, FL 32034.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Have you previously testified in this Docket?

A. No.

Q. What is the purpose of your testimony relating to the fuel docket?

A. I am here to explain the measures we have taken and plan to take with respect to educating our customers on the upcoming expected fuel increases.

Q. What is the company going to do to alert and prepare customers of the expected rate impact?

A. The following is a list of past events that have informed customers of what will occur going forward regarding electricity cost, plus other items that are planned.

1. On May 6, 2005, FPU filed a petition (Docket #050317-EI) to begin gradually increasing prices in preparation for the increased cost of wholesale power.
2. During September 2005 public notices were published concerning the petition, projected prices and customer hearings to be held in both divisions.
3. During October 2005 customer hearings were held in both divisions in which customers were provided information

regarding planned future increases and customer comments were taken. Media coverage of these meetings was published in newspaper in each division.

4. At the November 2005 FPSC agenda conference, company and customer testimony was presented to the commission in this matter. The Public Service Commission denied the rate request.
5. In January 2006 the company contracted for public relations assistance with Curley & Pynn, Maitland, Florida. Curley & Pynn has vast experience within the power industry and has provided assistance with developing a plan for communicating this issue to our customers.
6. During May and June 2006, a customer survey of electric customers in both divisions was completed. One of the areas included in the survey was how customers would prefer to see an increase occur (i.e. gradually or all at once). The survey also included a more detailed survey of specific community leaders in each division.
7. Media releases have occurred during the first half of 2006 regarding energy usage and how customers can reduce their power costs.
8. A communication strategy has been developed to provide more detailed information to customers prior to the increase in electric costs. The strategy will be finalized after confirmation of the extent and timing of the rate increases.
9. The communication strategy will include finalizing the internal infrastructure to provide needed information to customers, educating employees to accurately communicate information to customers, communicating with community leaders and

organizations, and utilizing the media to communicate to customers. A customer outreach program that will involve other entities in the community is also being considered.

Q. What was your involvement with the procurement process on the new fuel contracts?

A. I was involved on the team that reviewed and made the fuel decision with the assistance of an outside Consulting firm for our new fuel contracts.

Q. Does that conclude your testimony?

A. Yes.

MR. HORTON: Mr. Cutshaw is available.

CHAIRMAN EDGAR: Ms. Christensen.

MS. CHRISTENSEN: No questions.

MR. McWHIRTER: No questions.

CAPTAIN WILLIAMS: No questions.

CHAIRMAN EDGAR: Okay. Questions on cross from any other parties for this witness?

Seeing none, questions from staff?

MS. BENNETT: Yes, Madam Chair.

CROSS-EXAMINATION

BY MS. BENNETT:

Q. Mr. Cutshaw, I understand you've begun to provide notice to your customers about the increased rates. If the Commission were to approved your company's proposed cost recovery related to the power supply contract with JEA, can you describe briefly what the company will do to notify your customers of the Northeast Division of the proposed increases for 2008 and 2009?

A. Given that the prices would go into effect beginning in January, we have already begun informing the customers that prices will increase. We have -- we were kind of in the middle of, "Do we tell them what we think will occur, or do we tell them nothing until it's approved?" We made the choice to go ahead and tell the customers that we anticipate approval.

We've talked to large commercial customers. We've talked to the industrial customers. We've sent bill inserts to residential customers. We've provided conversation tips to all the customers. So we have informed them that we anticipate, based on approval today, that their prices will increase, and that will continue up through January.

MS. BENNETT: That answers the questions I have for this witness. Thank you.

CHAIRMAN EDGAR: Commissioners, any questions? No?

Mr. Horton.

MR. HORTON: No questions. May Mr. Cutshaw be excused?

CHAIRMAN EDGAR: The witness may be excused. Thank you.

THE WITNESS: Thank you.

MR. HORTON: And I would call Cheryl Martin.

Thereupon,

CHERYL MARTIN

was called as a witness on behalf of Florida Public Utilities Company and, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. HORTON:

Q. Would you state your name and address for the record, please, ma'am?

A. Cheryl Martin, 401 South Dixie Highway, West Palm Beach, Florida.

Q. And by whom are you employed?

A. Florida Public Utilities Company.

Q. And did you cause to be prepared and prefiled in this docket direct testimony dated February 26th consisting of two pages?

A. Yes.

Q. August 8th, consisting of two pages, and revised direct testimony on October 26th consisting of four pages?

A. Yes.

Q. Do you have any changes or corrections to make to that testimony?

A. No, I do not.

Q. 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: I would ask that Ms. Martin's direct testimony dated February 26th, August 8th, and the revised direct dated October 26th be inserted into the record as though read.

CHAIRMAN EDGAR: The prefiled testimony will be inserted into the record as though read.

BY MR. HORTON:

Q. Ms. Martin, did you also prepare exhibits that have been identified CMM-1, CMM-2, and CMM-3, which are identified as Exhibits 20, 21, and 22?

A. Yes, I did.

Q. And did you submit a revised a schedule CMM-3 on October 26th with respect to Fernandina Beach?

A. Yes, I did.

Q. And those were prepared by you or under your supervision?

A. Yes, they were.

Q. Do you have a summary of your testimony to present at this time?

A. Yes. My testimony and the related exhibits provide the computations for the proposed fuel factors for 2007 for both our Northeast and Northwest Divisions. I've also included testimony and related exhibits relating to the true-up contained in those same 2007 projections. I summarized the various fuel factors by rate class, the true-up amounts, and the impacts to the residential customers that are using 1,000 kWh. I've also incorporated the impact of the new fuel contract in our Northeast Division into our 2007 fuel projections. I revised the original projections filed in September 2006 for the Northeast Division on October 27, 2006, and included the related testimony and exhibits for those revisions.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 060001-EI
Fuel and Purchased Power Cost Recovery Clause

Direct Testimony of
Cheryl M. Martin
on behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. Cheryl M. Martin, 401 South Dixie Highway, West Palm Beach, Florida 33401.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Could you give a brief description of your background and business experience?

A. I graduated from Florida State University in 1984 with a BS degree in Accounting and I am a Certified Public Accountant in the state of Florida. I have been employed by FPU since 1985 and performed numerous accounting functions until I was promoted to Corporate Accounting Manager in 1995 with responsibilities for managing the Corporate Accounting Department including regulatory accounting (Fuel, PGA, conservation, rate cases, Surveillance reports, reporting), tax accounting, external reports and special projects. In January 2002 I was promoted to my current position of Controller where my responsibilities are the same as above with additional responsibilities in the purchasing and general accounting areas and Security and Exchange Commission (SEC) filings.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the calculation of the final remaining true-up amounts for the period Jan. 2005 through Dec. 2005.

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

A. Yes. Exhibit_______ (CMM-1) consists of Schedules M1 and F1 for the Marianna and Fernandina Beach Divisions. These schedules were prepared from the records of the company.

Q. What has FPUC calculated as the final remaining true-up amounts for the period Jan. - Dec. 2005?

A. For Marianna the final remaining true-up amount is an under recovery of $53,882. For Fernandina Beach the calculation is an under recovery of $153,867.

Q. How were these amounts calculated?

A. They are the difference between the actual end of period true-up amounts for the Jan. - Dec. 2005 period and the total true-up amounts to be collected or refunded during the Jan. - Dec. 2006 period.

Q. What was the actual end of period true-up amount for Jan. - Dec. 2005?

A. For Marianna it was $742,173 under recovery and for Fernandina Beach it was $283,221 over recovery.

Q. What have you calculated to be the total true-up amount to be collected or refunded during the Jan. - Dec. 2006 period?

A. Using six months actual and six months estimated amounts, we calculated an under recovery for Marianna of $688,291 and an over recovery of $437,088 for Fernandina Beach. (Ref. CMM-1, revised schedule EI-B of 1st true-up filing and testimony)

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 060001-EI
CONTINUING SURVEILLANCE AND REVIEW OF
FUEL COST RECOVERY CLAUSES OF ELECTRIC UTILITIES

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

Q. Please state your name and business address.

A. Cheryl M. Martin, 401 South Dixie Highway, West Palm Beach, FL 33401.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities.

Q. Have you previously testified in this Docket?

A. Yes.

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

A. I will briefly describe the basis for our computations that were made in preparations of the various schedules that we have submitted to support our calculation of the levelized fuel adjustment factor for January 2007 - December 2007.

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

A. Yes

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

A. We have filed Schedules E1-A, E1-B, and E1-B1 for Marianna and E1-A, E1-B, and E1-B1 for Fernandina Beach. They are included in Composite Prehearing Identification Number CMM-2. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period January 2006 - December 2006 based on 6 Months Actual and 6 Months Estimated data.

Q. Please address the calculations of the total true-up amount to be collected or refunded during January 2007 - December 2007.

A. We have determined that at the end of December 2006 based on six months actual and six months estimated, we will under-recover $316,591 in purchased power costs in our Marianna division. In Fernandina Beach we will have under-recovered $892,682 in purchased power costs.

Q. What are the final remaining true-up amounts for the period January 2005 - December 2005 for both divisions?

A. In Marianna, the final remaining true-up amount was an under-recovery of $53,882. The final remaining true-up amount for Fernandina Beach was an under-recovery of $153,867.

Q. What are the estimated true-up amounts for the period January 2006 - December 2006?

A. In Marianna, there is an estimated under-recovery of $262,709. Fernandina Beach has an estimated under-recovery of $738,815.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 060001-EI
CONTINUING SURVEILLANCE AND REVIEW OF
FUEL COST RECOVERY CLAUSES OF ELECTRIC UTILITIES

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

Q. Please state your name and business address.

A. Cheryl M. Martin, 401 South Dixie Highway, West Palm Beach, FL 33401.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Have you previously testified in this Docket?

A. Yes.

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

A. I will briefly describe the basis for the computations that were made in the preparation of the various Schedules that we have submitted in support of the January 2007 - December 2007 fuel cost recovery adjustments for our two electric divisions. In addition, I will advise the Commission of the projected differences between the revenues collected under the levelized fuel adjustment and the purchased power costs allowed in developing the levelized fuel adjustment for the period January 2006 - December 2006 and to establish a "true-up" amount to be collected or refunded during January 2007 - December 2007.

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

A. Yes.

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

A. We have filed Schedules E1, E1A, E2, E7, and E10 for Marianna

(Northwest division) and E1, E1A, E2, E7, E8, and E10 for Fernandina Beach (Northeast division). They are included in Composite Prehearing Identification Number CMM-3. Schedule E1-B and E1-B1 for both Marianna (Northwest) and Fernandina Beach (Northeast) were filed last month in Composite Prehearing Identification Number CMM-2.

These schedules support the calculation of the levelized fuel adjustment factor for January 2007 - December 2007. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period January 2006 - December 2006 based on 6 Months Actual and 6 Months Estimated data.

Q. In derivation of the projected cost factor for the January 2007 - December 2007 period, did you follow the same procedures that were used in the prior period filings?

A. Yes.

Q. Have there been any changes to the fuel contracts used to purchase electricity.

A. Yes, we will have a new contract in our Fernandina Beach (Northeast division) for the purchase of fuel beginning January 1, 2007. The contract for our Marianna (Northwest division) does not expire until December 31, 2007.

Q. Do the projections for fuel in the Fernandina Beach (Northeast division) reflect the anticipated prices of this new fuel contract?

A. Yes, the projections for Fernandina Beach (Northeast division) have utilized anticipated fuel costs in our fuel factors from our anticipated new fuel contract. See additional testimony from Robert Camfield and George Bachman regarding the new fuel contracts.

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

A. 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. 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 2007 - December 2007.

A. We have determined that at the end of December 2006 based on six months actual and six months estimated, we will have under-recovered $316,591 in purchased power costs in our Marianna (Northwest division). Based on estimated sales for the period January 2007 - December 2007, it will be necessary to add .09464¢ per KWH to collect this under-recovery.

In Fernandina Beach (Northeast division) we will have under-recovered $892,682 in purchased power costs. This amount will be collected at .25633¢ per KWH during the January 2007 - December 2007 period (excludes GSLD1 customers). Page 3 and 10 of Composite Prehearing Identification Number CMM-3 provides a detail of the calculation of the true-up amounts.

Q. What are the final remaining true-up amounts for the period January 2005 - December 2005 for both divisions?

A. In Marianna (Northwest division) the final remaining true-up amount was an under-recovery of $53,882. The final remaining true-up amount for Fernandina Beach (Northeast division) was under-recovery of $153,867.

Q. What are the estimated true-up amounts for the period of January 2006 - December 2006?

A. In Marianna (Northwest division), there is an estimated under-recovery of $262,709. Fernandina Beach (Northeast division) has an estimated under-recovery of $738,815.

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

A. In Marianna (Northwest division) the total fuel adjustment factor as shown on Line 33, Schedule E1, is 2.709¢ per KWH. In Fernandina Beach (Northwest division) the total fuel adjustment factor for "other classes", as shown on Line 43, Schedule E1, amounts to 3.412¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January 2007 - December 2007 including base rates, conservation cost recovery factors, and fuel adjustment factor and after application of a line loss multiplier.

A. In Marianna (Northwest division) a residential customer using 1,000 KWH will pay $70.14, a decrease of $1.12 from the previous period. In Fernandina Beach (Northeast division) a customer will pay $77.47, an increase of $18.95 from the previous period.

Q. Does this conclude your testimony?

A. Yes.

MR. HORTON: Ms. Martin is available.

CHAIRMAN EDGAR: Questions on cross?

MS. CHRISTENSEN: No questions.

MR. McWHIRTER: No questions.

CAPTAIN WILLIAMS: No questions.

CHAIRMAN EDGAR: Questions on cross for this witness from any other party?

Seeing none, questions from staff?

MS. BENNETT: Staff has no question for this witness.

CHAIRMAN EDGAR: Commissioners? No?

Mr. Horton.

MR. HORTON: I would move entry of Exhibits 20, 21, and 22.

CHAIRMAN EDGAR: The exhibits will be moved into the record.

(Florida Public Utilities Exhibits Number 20, 21, and 22 were admitted into evidence.)

MR. HORTON: Thank you. And may Ms. Martin be excused?

CHAIRMAN EDGAR: The witness may be excused. Thank you.

MR. HORTON: That concludes Florida Public Utilities.

CHAIRMAN EDGAR: Mr. Badders.

MR. BADDERS: We would call Rusty Ball to the stand.

Thereupon,

H. R. BALL

was called as a witness on behalf of Gulf Power Company and, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. BADDERS:

Q. Mr. Ball, were you present this morning when the witnesses were sworn in?

A. Yes, I was.

Q. Could you please state your name and your business address for the record?

A. My name is Herbert R. Ball. My business address is One Energy Place, Pensacola, Florida, 32520.

Q. By whom are you employed, and in what position?

A. I'm employed by Southern Company Services, Inc. as fuel manager for Gulf Power Company.

Q. Are you the same H. R. Ball who prefiled direct testimony on March 1, 2006, consisting of ten pages, August 8, 2006, consisting of 11 pages, and on September 1, 2006, consisting of ten pages?

A. Yes, I am.

Q. Do you have any changes or corrections to that testimony?

A. Yes, I do have one change. On page 5, line 7 of my March 1st testimony, I need to change the word "increase" to "decrease."

Q. With that correction, if I were to ask you the same questions today, to your answers be the same?

A. Yes, they would.

MR. BADDERS: We would ask that the prefiled direct testimony of Mr. Ball be inserted into the record as though read.

CHAIRMAN EDGAR: Excuse me. The prefiled testimony of this witness will be inserted into the record as though read with the correction as noted by the witness.

MR. BADDERS: Thank you.

BY MR. BADDERS:

Q. Mr. Ball, did you also have two exhibits attached to that testimony?

A. That's correct.

Q. And those are labeled HRB-1. And we need to make a correction to the second one. It is incorrectly listed as HRB-1, but it's HRB-2, and that would be to the September 1 testimony. And with that correction, do you have any other changes or corrections to your exhibits?

A. No, I did not.

MR. BADDERS: We ask that that exhibit be identified. I believe they were preidentified as 23 and 24.

COMMISSIONER CARTER: So noted.

MR. BADDERS: Thank you.

BY MR. BADDERS:

Q. Mr. Ball, please summarize your testimony.

A. Yes. My responsibility at Gulf Power is to manage the fuel program in a manner that assures a reliable supply of fuel at the lowest practical cost to Gulf's customers over time.

Gulf's primary source of fuel for generation of electricity is coal. Gulf purchases coal using a combination of short- and long-term supply agreements. The short-term agreements are priced at market, and the price is fixed over the term of the agreement. Long-term agreements are priced using a competitive bid process, and the price-certain nature of these agreements provide a physical cost hedge to protect against large increases in market prices.

Natural gas is a secondary fuel for Gulf, but represents a significant cost or a significant percentage of the cost of the fuel program to Gulf's customers. Gulf's strategy for the procurement of gas is to contract for supply using long-term agreements at market price. The goal is to provide gas suppliers market price to assure supply during normal supply periods and to rely on natural gas storage to provide supply during supply disruptions.

Gas hedges -- Gulf hedges the price of a percentage of these of purchase agreements using financial hedges. These financial hedges accomplish the same objective as the physical price hedge of Gulf's long-term coal supply agreements by protecting against large increases in the market price of natural gas and providing price certainty for a portion of Gulf's gas purchases.

We believe that these coordinated coal and gas procurement strategies prudently deliver the primary objectives of Gulf's fuel program.

And that concludes my summary.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
H. R. Ball
Docket No. 060001-EI
Date of Filing: March 1, 2006

Q. Please state your name, business address and occupation.
A. My name is H. R. Ball. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Fuel Manager for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.
A. I graduated from the University of Southern Mississippi in Hattiesburg, Mississippi in 1978 with a Bachelor of Science Degree in Chemistry and graduated from the University of Southern Mississippi in Long Beach, Mississippi in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power's (MPC) Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Fuel Department as a Fuel Business Analyst. I was promoted in 1987 to Supervisor of Chemistry and Regulatory Compliance at Plant Daniel. In 1988, I assumed the role of Supervisor of Coal Logistics with Southern Company Fuel Services in Birmingham, Alabama. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the Southern Electric System. I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. My responsibilities include the management of the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's Intercompany Interchange Contract (IIC).

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

A. The purpose of my testimony is to summarize Gulf Power Company's fuel expenses, net power transaction expense, and purchased power capacity cost, and to certify that these expenses were properly incurred during the period January 1, 2005 through December 31, 2005. Also, it is my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel expenses.

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

A. Yes, I have.

Counsel: We ask that Mr. Ball's Exhibit consisting of two schedules be marked as Exhibit No. _____(HRB-1).

Q. During the period January, 2005 through December, 2005 how did Gulf Power Company's recoverable total fuel and net power transaction expenses compare with the projected expenses?

A. Gulf's recoverable total fuel cost and net power transaction expense was $352,566,865 or 12.60% above the projected amount of $313,107,510. Actual net energy was 12,307,374,624 KWH compared to the projected net energy of 12,205,476,000 KWH or 0.83% above projections. The resulting actual average cost of 2.8647 cents per KWH was 11.67% above the projected cost of 2.5653 cents per KWH. The higher total fuel and net power transaction expense is attributed to higher market fuel prices on all fuel types for the period and a greater amount of purchased power at higher cost than projected for the period. The higher fuel cost is reflected in both the fuel cost of generation and the cost of purchased power. This information is from Schedule A-1, period to date, of the Monthly Fuel Filing for the month of December, 2005.

Q. During the period January, 2005 through December, 2005 how did Gulf Power Company's recoverable fuel expenses compare with the projected expenses?

A. Gulf's recoverable fuel cost of net generation was $432,955,311 or 1.54% above the projected amount of $426,383,424. Actual generation was 15,024,296 MWH compared to the projected generation of 16,049,720 MWH or 6.39% below projections. The resulting actual average fuel cost of 2.8817 cents per KWH was 8.47% above the projected cost of 2.6566 cents per KWH. The higher total fuel expense is attributed to the higher market fuel prices on all fuel types for the period. Fuel costs for coal on a $/ton basis were 6.70% higher than forecasted. Fuel cost for gas on a $/MCF basis was 23.48% higher than forecasted. The higher average per

KWH fuel cost is attributed to higher than projected fuel costs. This information is from Schedule A-3 of the Monthly Fuel Filing for the month of December, 2005.

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

A. Excluding Plant Scherer Unit 3, Gulf purchased 2,686,488 tons of coal or 50% of its total coal purchased on the spot market. Schedule 1 of my exhibit consists of a list of contract and spot coal purchases for the period.

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

A. The total actual cost of coal purchased was $281,750,159 (sum of lines 17 & 30 period to date on the December 2005, Schedule A-5) compared to the projected cost of $268,277,899 or 5.02% above projected. The higher cost was due to a higher per unit cost ($/ton) of coal purchases than projected for the period. The higher per unit cost of coal is attributed to higher than anticipated coal prices for spot coal purchases.

Q How did the total projected cost of coal burned compared to the actual cost?

A. The total cost of coal burned was $273,891,971 (the sum of lines 21 and 34 period to date on the December 2005, Schedule A-5). This is 6.92% higher than our projection of $260,026,321. On a fuel cost per MMBTU basis, the actual cost of coal plus boiler lighter fuel was $2.04 per MMBTU which is 6.25% greater than the projected cost of $1.92 per MMBTU.

Q. How did the total projected cost of natural gas burned compare to the actual cost?

A. The total cost of natural gas burned for generation was $156,367,744 (line 47 period to date on the December 2005, Schedule A-5). This is 4.30% below our projection of $163,386,306. The ~~increase~~ decrease can be attributed to lower than forecasted generation on gas fired units. On a natural gas cost per unit basis, the actual burn cost was $10.22 per MMBTU which is 17.61% higher than the projected burn cost of $8.69 per MMBTU.

Q. For the period in question, what volume of natural gas was actually hedged using a fixed price contract or instrument?

A. Gulf Power hedged 9,270,000 MMBTU of natural gas in 2005 using fixed price financial swaps.

Q. What types of hedging instruments were used by Gulf Power Company and what type and volume of fuel was hedged by each type of instrument?

A. Natural gas was hedged using financial swaps that fixed the price of gas to a certain price. These swaps settled against either a NYMEX Last Day price or Gas Daily price. The entire amount (9,270,000 MMBTU) of gas hedged was hedged using these financial instruments as reflected on Schedule 2 of my exhibit.

Q. What was the actual total cost (e.g., fees, commissions, option premiums, futures gains and losses, swap settlements) associated with each type of hedging instrument?

A. Schedule 2 of my exhibit consists of a table of all natural gas hedge transactions and associated costs. No fees, commissions, or option premiums were paid. Gulf's 2005 hedging program resulted in a net financial gain of $22,528,337 (settlement gains less support costs from lines 2 and 3 of Schedule A-1 December period-to-date).

Q. Did fuel procurement activity during the period in question follow Gulf Power's Risk Management Plan for Fuel Procurement filed with the Florida Public Service Commission on April 1, 2005?

A. Yes, Gulf Power's fuel strategy in 2005 complied with the Risk Management Plan, and the actual results achieved compared favorably with the projected results in the plan. Supply of all fuel types and associated transportation to Gulf's generating plants are secured through a combination of long term contracts and spot purchase orders as specified in the plan. The result was that Gulf's generating plants had an adequate supply of fuel available at all times to meet the electric generation demands of its customers. Fuel cost volatility was mitigated by compliance with the Risk Management Plan. In 2005, Gulf's average cost of fuel consumed was $2.88 per MMBTU. This was 5.11% higher than the original projection of $2.74 per MMBTU. However, the actual cost of fuel was reduced to $2.73 per MMBTU when gas hedging and other fuel cost credits are considered. Gulf was able to hold per unit fuel costs to very reasonable levels for its customers during a period of volatile market fuel prices by following its Fuel Risk Management Plan.

Q. Were there any other significant developments in Gulf's fuel procurement program during the period?

A. No.

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

A. Yes, Gulf's coal supply program is based on a mixture of long term contracts and spot purchases at market prices. Coal suppliers are selected using procedures that assure reliable coal supply, consistent quality, and competitive delivered pricing. The terms and conditions of coal supply agreements have been administered appropriately. Natural gas is purchased using agreements that tie price to published market index schedules and is transported using a combination of firm and interruptible gas transportation agreements. Natural gas storage is utilized to assure that supply is available during times when gas supply is otherwise curtailed or unavailable. Gulf's fuel oil purchases were made from qualified vendors using an open bid process to assure competitive pricing and reliable supply.

Q. During the period January 2005 through December 2005, how did Gulf's actual net purchased power capacity cost compare with the net projected cost?

A. The actual net capacity cost for the January 2005 through December 2005 recovery period, shown on line 5 of Schedule CCA-2, was $23,700,121. Gulf's projected net purchased power capacity cost for the same period was $24,009,955, as indicated on Line 4 of Schedule CCE-1 filed September 9, 2004. The difference between the actual net capacity cost and the projected net capacity cost for the recovery period is $309,834, or a decrease of 1.3%.

Q. Please explain the reason for the decrease in Gulf's capacity cost.

A. The capacity cost decrease for the 2005 recovery period is due to Gulf's lower IIC reserve sharing cost of $23,667,221 that is shown on Line 36 of Schedule CCA-4 in Witness Davis' testimony exhibit and higher actual transmission revenues. Gulf's actual IIC reserve sharing cost was $198,504 less than the $23,865,725 projected amount due to a greater decrease in owned capacity of other SES operating companies as compared to Gulf's owned capacity. This caused other SES operating companies to purchase a greater share of SES reserves and Gulf's IIC reserve sharing capacity cost was reduced. Also, Gulf's transmission revenues associated with energy sales were $100,008 above the projected amount for this period. Together , these increased transmission revenues and Gulf's lower IIC reserve sharing cost resulted in Gulf's overall lower capacity cost for the January 2005 through December 2005 cost recovery period.

Q. Was Gulf's actual 2005 IIC capacity cost prudently incurred and properly allocated to Gulf?

A. Yes. Gulf's capacity costs were incurred in accordance with the reserve sharing provisions of the IIC, a Federal Energy Regulatory Commission approved contract in which Gulf has been a participant for many years. Gulf's participation in the integrated SES that is governed by the IIC has produced substantial benefits for Gulf's territorial customers and has been recognized as being prudent by the Florida Public Service Commission in previous proceedings and reviews.

Per contractual agreement, Gulf and the other SES operating companies are obligated to provide for the continued operation of its electric facilities in the most economical manner that achieves the highest possible service reliability. The coordinated planning of future SES generation resource additions that produce adequate reserve margins for the benefit of all SES operating companies' customers facilitates this "continued operation" in the most economical manner.

Furthermore, the IIC provides for mechanisms to facilitate the equitable sharing of the costs associated with the operation of facilities that exist for the mutual benefit of all the operating companies. In 2005, Gulf's reserve sharing cost represents the equitable sharing of the costs that the SES operating companies incurred to ensure that adequate generation reserve levels are available to provide reliable electric service to territorial customers. This cost has been properly allocated to Gulf per the terms of the IIC.

Q. Mr. Ball, does this complete your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
H. R. Ball
Docket No. 060001-EI
Date of Filing: August 8, 2006

Q. Please state your name and business address.
A. My name is H. R. Ball. My business address is One Energy Place, Pensacola, Florida 32520-0335. I am the Fuel Manager for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.
A. I graduated from the University of Southern Mississippi in Hattiesburg, Mississippi in 1978 with a Bachelor of Science Degree in Chemistry and graduated from the University of Southern Mississippi in Long Beach, Mississippi in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power's (MPC) Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Fuel Department as a Fuel Business Analyst. I was promoted in 1987 to Supervisor of Chemistry and Regulatory Compliance at Plant Daniel. I was promoted to Supervisor of Coal Logistics with Southern Company Fuel Services in Birmingham, Alabama in 1998. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the Southern

Electric System. I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. I manage the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's Intercompany Interchange Contract (IIC).

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

A. The purpose of my testimony is to compare Gulf Power Company's original projected fuel and net power transaction expense and purchased power capacity costs with current estimated/actual costs for the period January, 2006 through December, 2006 and to summarize any noteworthy developments at Gulf in these areas. The current estimated/actual costs consist of actual expenses for the period January, 2006 through June, 2006 and newly projected fuel and net power transaction costs for July, 2006 through December, 2006. Projected capacity costs for July through December remain as originally filed. It is also my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel and net power transaction expenses and purchased power capacity costs.

Q. During the period January, 2006 through December, 2006 how will Gulf Power Company's recoverable total fuel and net power transactions cost compare with the original cost projection?

A. Gulf's currently projected recoverable total fuel and net power transactions cost for the period is $363,343,100 which is $16,090,874 or 4.63% above the original projected amount of $347,252,226. The resulting average fuel cost is projected to be 2.9298 cents per KWH or 5.17% above the original projected amount of 2.7859 cents per KWH. The higher total fuel expense and average per unit fuel cost is attributed to higher than projected coal prices for the period which are reflected in the fuel cost of generation. Gulf also is projecting that a greater portion of its energy needs will come from higher cost purchased power and less from lower cost system net generation. This current projection of fuel and net purchased power transaction cost is captured in the exhibit to Witness Martin's testimony, Schedule E-1 B-1, Line 20.

Q. During the period January, 2006 through December, 2006 how will Gulf Power Company's recoverable fuel cost of system net generation compare with the original projection of fuel cost?

A. Gulf's currently projected recoverable fuel cost of system net generation for the period is $487,758,630 which is 35,305,084 or 6.75% below the original projected amount of $523,063,714. Total net system generation is expected to be 16,465,574 MWH compared to the original projected generation of 17,810,860 MWH or 7.55% below projections. The resulting average fuel cost is expected to be 2.9623 cents per KWH or 0.87% above the original projected amount of 2.9368 cents per KWH. This current projection of fuel cost of system net generation is captured in the exhibit to Witness Martin's testimony, Schedule E-1 B-1, Line 1.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost of system net generation and the current projection?

A. The lower total fuel expense is due to lower than projected generation for the period. The higher average per unit fuel cost is attributed to higher than projected delivered coal prices for the period.

Q How did the total projected fuel cost of system net generation compare to the actual cost for the first six months of 2006?

A. The total fuel cost of system net generation was $231,486,616 which is $7,408,830 or 3.10% lower than the projection of $238,895,446. On a fuel cost per KWH basis, the actual cost was 2.9506 cents per KWH, which is 2.93% higher than the projection of 2.8666 cents per KWH. This higher cost of system generation on a cent per KWH basis is due to fuel cost in $/MMBTU being 1.73% higher than projected and heat rate (BTU/KWH) of the generating units operating being 1.47% higher than projected. This information is found on Schedule A-1, Period to Date and Schedule A-3 of the June, 2006 Monthly Fuel Filing.

Q. How did the total projected cost of coal burned compare to the actual cost for the first six months of 2006?

A. The total cost of coal burned (including boiler lighter) was $175,197,137 which is $22,269,196 or 14.56% greater than our projection of $152,927,941. On a fuel cost per KWH basis, the actual cost was 2.498 cents per KWH which is 18.33% greater than the projected cost of 2.111 cents per KWH. The higher than projected cost of coal burned and cost of coal fired generation is due to coal prices being 17.65% higher than projected on a $/MMBTU basis. This information is found on Schedule A-3 of the June, 2006 Monthly Fuel Filing.

Q. How did the total projected cost of natural gas burned compare to the actual cost during the first six months of 2006?

A. The total cost of natural gas burned for generation was $56,227,702 which is $29,739,803 or 34.59% lower than our projection of $85,967,505. On a cost per unit basis, the actual cost was 6.77 cents per KWH which is 14.30% lower than the projected cost of 7.90 cents per KWH. The total cost of natural gas burned for generation is lower than projected due to lower than projected net generation from gas fired units and lower gas prices. The cost per KWH for gas fired generation is lower than projected due to lower natural gas prices. Natural gas prices were 15.38% lower than projected on a $/MMBTU basis. This information is found on Schedule A-3 of the June, 2006 Monthly Fuel Filing.

Q. For the period in question, what volume of natural gas was actually hedged using a fixed price contract or instrument?

A. Gulf Power hedged 3,600,000 MMBTU of natural gas for the period January, 2006 through June, 2006 using fixed price financial swaps.

Q. What types of hedging instruments were used by Gulf Power Company and what type and volume of fuel was hedged by each type of instrument?

A. Natural gas was hedged using financial swaps that fixed the price of gas to a certain price. These swaps settled against either a NYMEX Last Day price or Gas Daily price. The entire amount (3,600,000 MMBTU) of gas hedged was hedged using these financial instruments.

Q. What was the actual total cost (e.g., fees, commission, option premiums, futures gains and losses, swap settlements) associated with each type of hedging instrument?

A. No fees, commission, or option premiums were paid. Gulf's gas hedging program has resulted in a net financial loss of $7,521,292 for the period January through June, 2006 (hedging settlement excluding support costs).

Q. Are Gulf Power's actual and projected operation and maintenance expenses for its financial hedging programs to mitigate fuel and purchased power price volatility reasonable for cost recovery purposes?

A. Yes, the O&M costs associated with managing the fuel hedging programs are a small percentage of the total benefit received from these programs. As an example, the actual recoverable O&M cost of managing the gas hedging program for the last twelve month period (July, 2005 through June, 2006) was $80,552 while the total financial gain credited to fuel expense from the gas hedging program for this period was $13,905,732.

Q. During the period January, 2006 through December, 2006 how will Gulf Power Company's recoverable fuel cost of power sold compare with the original cost projection?

A. Gulf's currently projected recoverable fuel cost of power sold for the period is ($166,396,834) or 17.39% below the original projected amount of $(201,426,000). Total megawatt hours of power sales is expected to be 5,110,002 MWH compared to the original projection of 5,878,653 MWH or 13.08% below projections. The resulting average fuel cost of power sold is expected to be 3.2563 cents per KWH or 4.96% below the original projected amount of 3.4264 cents per KWH. This current projection of fuel cost of power sold is captured in the exhibit to Witness Martin's testimony, Schedule E-1 B-1, Line 18.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost of power sold and the current projection?

A. The lower total credit to fuel expense from power sales is attributed to lower replacement fuel costs than originally projected. Lower market prices for natural gas during the period reduced the fuel reimbursement rate ($/MWH) for power sales. Also, there is a decrease in the number of MWH being sold due to the less favorable economic position of Gulf's generating resources in Southern Company's power pool dispatch.

Q. How did the total projected fuel cost of power sold compare to the actual cost for the first six months of 2006?

A. The total fuel cost of power sold was ($81,213,834) which is $4,687,166 or 5.46% less than our projection of ($85,901,000). On a fuel cost per KWH basis, the actual cost was 3.0931 cents per KWH which is 5.11% below the projected cost of 3.2596 cents per KWH. This information is found on Schedule A-1, Period to Date of the June, 2006 Monthly Fuel Filing.

Q. During the period January, 2006 through December, 2006 how will Gulf Power Company's recoverable fuel cost of purchased power compare with the original cost projection?

A. Gulf's currently projected recoverable fuel cost of purchased power for the period is $32,355,700 or 37.33% above the original projected amount of $23,561,000. Total megawatt hours of purchased power is expected to be 970,606 MWH compared to the original projection of 464,921 MWH or 108.77% above projections. The resulting average fuel cost of purchased power is expected to be 3.3336 cents per KWH or 34.22% below the original projected amount of 5.0677 cents per KWH. This current projection of fuel cost of purchased power is captured in the exhibit to Witness Martin's testimony, Schedule E-1 B-1, Line 12.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost of purchased power and the current projection?

A. The higher total fuel cost of purchased power is attributed to Gulf purchasing a greater amount of MWH to supplement its own generation to meet load demands. However, replacement fuel costs are lower than projected as a result of lower natural gas market prices for the period.

These lower fuel prices have decreased the fuel reimbursement rate for purchased power.

Q. How did the total projected fuel cost of purchased power compare to the actual cost for the first six months of 2006?

A. The total fuel cost of purchased power was $18,564,700 which is $6,724,700 or 56.80% greater than our projection of $11,840,000. On a fuel cost per KWH basis, the actual cost was 2.7001 cents per KWH which is 37.48% lower than the projected cost of 4.3187 cents per KWH. The higher than anticipated purchased power expense is due to actual KWH purchases being 150.8% above the projected amount during the first six months of the year. This information is found on Schedule A-1, Period to Date of the June, 2006 Monthly Fuel Filing.

Q. Were there any other significant developments in Gulf's fuel procurement program during the period?

A. No.

Q. Were Gulf Power's actions through June 30, 2006 to mitigate fuel and purchased power price volatility through implementation of its financial and/or physical hedging programs prudent?

A. Yes, Gulf's physical and financial fuel hedging programs have resulted in more stable fuel prices. Over the long term, Gulf anticipates lower fuel costs than would have otherwise occurred if these programs had not been utilized.

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

A. Yes, Gulf's coal supply program is based on a mixture of long term contracts and spot purchases at market prices. Coal suppliers are selected using procedures that assure reliable coal supply, consistent quality, and competitive delivered pricing. The terms and conditions of coal supply agreements have been administered appropriately. Natural gas is purchased using agreements that tie price to published market index schedules and is transported using a combination of firm and interruptible gas transportation agreements. Natural gas storage is utilized to assure that supply is available during times when gas supply is curtailed or unavailable. Gulf's fuel oil purchases were made from qualified vendors using an open bid process to assure competitive pricing and reliable supply. Gulf makes sales of power when available and gets reimbursed at the marginal cost of replacement fuel. This fuel reimbursement is credited back to the fuel cost recovery account so that lower cost fuel purchases made on behalf of Gulf's customers remain to the benefit of those customers. Gulf purchases power when necessary to meet customer load requirements and when the cost of purchased power is expected to be less than the cost of system generation. The fuel cost of purchased power is the lowest cost available in the market at the time of purchase to meet Gulf's load requirements.

Q. During the period January 2006 through December 2006, what is Gulf's projection of actual / estimated net purchased power capacity transactions and how does it compare with the company's original projection of net capacity transactions?

A. As shown on Line 3 of Schedule CCE-1b in the exhibit to Witness Martin's testimony, Gulf's total current net capacity payment projection for the January 2006 through December 2006 recovery period is $29,403,149. Gulf's original projection for the period was $29,458,820 and is shown on Line 3 of Schedule CCE-1 filed in September, 2005. The difference between these projections is $55,671, or less than 1% lower than the original projection of net capacity payments and represents the difference between actual capacity payments year to date June 2006 and the original projection for this period.

Q. Mr. Ball, does this complete your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
H. R. Ball
Docket No. 060001-EI
Date of Filing: September 1, 2006

Q. Please state your name and business address.

A. My name is H. R. Ball. My business address is One Energy Place, Pensacola, Florida 32520-0335. I am the Fuel Manager for Gulf Power Company.

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

A. I graduated from the University of Southern Mississippi in Hattiesburg, Mississippi in 1978 with a Bachelor of Science Degree in Chemistry and graduated from the University of Southern Mississippi in Long Beach, Mississippi in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power's (MPC) Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Fuel Department as a Fuel Business Analyst. I was promoted in 1987 to Supervisor of Chemistry and Regulatory Compliance at Plant Daniel. In 1988, I assumed the role of Supervisor of Coal Logistics with Southern Company Fuel Services in Birmingham, Alabama. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the Southern

Electric System. I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. My responsibilities include the management of the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's Intercompany Interchange Contract (IIC).

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

A. The purpose of my testimony is to support Gulf Power Company's projection of fuel expenses, net power transaction expense, and purchased power capacity costs for the period January 1, 2007 through December 31, 2007. It is also my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel and net power transaction expenses and purchased power capacity costs.

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

A. Yes, I have prepared an exhibit that compares actual and projected fuel cost of net generation for the past ten years. The purpose of this exhibit is to indicate the accuracy of Gulf's short term fuel expense projections.

Counsel: We ask that Mr. Ball's Exhibit, consisting of one schedule, be marked as Exhibit No. _____ (HRB-1).

Q. Has Gulf Power Company made any significant changes to its methods for projecting fuel expenses, net power transaction expense, and purchased power capacity costs for this period?

A. No. Gulf has been consistent in how it projects annual fuel expenses, net power transactions, and capacity costs.

Q. What is Gulf's projected recoverable total fuel and net power transactions cost for the January, 2007 – December, 2007 recovery period?

A. Gulf's projected total fuel and net power transaction cost for the period is $422,437,201. This projected amount is captured in the exhibit to Witness Martin's testimony, Schedule E-1, Line 21.

Q. How does the total projected fuel and net power transactions cost for the 2007 period compare to the projected fuel cost for the same period in 2006?

A. The total updated cost of fuel and net power transactions for 2006, reflected on revised Schedule E-1B of Witness Martin's testimony, is projected to be $372,802,084. The cost for 2007 is an increase of $49,635,117 or 13.31% over 2006. On a fuel cost per KWH basis, the 2006 projected cost is 2.9909 cents per KWH and the 2007 projected fuel cost is 3.3241 cents per KWH. This represents an increase of 0.3332 cents per KWH or 11.14%.

Q. What is Gulf's projected recoverable fuel cost of net generation for the 2007 period?

A. The projected total cost of fuel to meet system net generation needs in 2007 is $584,363,414. The projection of fuel cost of system net generation for 2007 is captured in the exhibit to Witness Martin's testimony, Schedule E-1, Line 1.

Q. How does the total projected fuel cost of net generation for the 2007 period compare to the projected fuel cost for the same period in 2006?

A. The total updated cost of fuel to meet 2006 system net generation needs, reflected on revised Schedule E-1B of Witness Martin's testimony, is projected to be $485,972,965. The projected total cost of fuel to meet system net generation needs in 2007 represents an increase of $98,390,449 or 20.25%. Total system net generation in 2007 is projected to be 17,529,530 MWH which is 1,169,257 MWH or 7.15% higher than is currently projected for 2006. On a fuel cost per KWH basis, the 2006 projected cost is 2.9704 cents per KWH and the 2007 projected fuel cost is 3.3336 cents per KWH. This is an increase of 0.3632 cents per KWH or 12.23%. This higher projected total fuel expense and average per unit fuel cost reflects a continued trend of increases in the forecasted price of coal and natural gas to fuel Gulf's generating units.

Q. Does the 2007 projection of fuel cost of net generation reflect any major changes in Gulf's fuel procurement program for this period?

A. Yes. Gulf was contracted to receive 1.9 million tons of coal under an existing coal supply agreement with a particular coal vendor. Gulf also had an associated agreement for the supply of 0.6 million tons of coal under a market price based purchase order. The vendor is claiming *force majeure* and is no longer shipping the contracted amount of coal. Gulf contends that the vendor is in default of its obligations and is pursuing a claim for damages through the courts on behalf of the ratepayers. Gulf does not expect any coal shipments under these agreements in 2007. In order to replace this coal supply, Gulf has purchased 1.5 million tons of coal under an agreement with Interocean Coal Sales, LDC, 0.8 million tons of coal under an agreement with Glencore, LTD, and 1.0 million tons of coal under an agreement with American Coal Co. for delivery in 2007 to Plants Crist and Smith at market price. These replacement coal purchases are at higher prices than the base contract price for the 1.9 million ton shipment obligation of the vendor Gulf contends is in default. As in the past, Gulf's remaining coal requirements, if any, will be purchased in the market through the Request for Proposal (RFP) process that has been used for many years by Southern Company Services - Fuel Services as agent for Gulf. Coal will be delivered under existing coal transportation contracts. Natural gas requirements will be purchased from various suppliers using firm quantity agreements with market pricing for base needs and on the daily spot market when necessary. Natural gas transportation will be secured using a combination of firm and spot transportation agreements.

Q. What fuel price hedging programs will be utilized by Gulf to protect the customer from fuel price spikes?

A. Natural gas prices will be hedged financially using instruments that conform to Gulf's established guidelines for hedging activity. Coal supply and transportation prices will be hedged physically using term agreements with either fixed pricing or term pricing with escalation terms tied to various published market price indexes.

Q. Has Gulf adequately mitigated the price risk of natural gas and purchased power for 2005 through 2007?

A. Gulf had adequate gas hedges in place for 2005 to mitigate price risk and the net result was a reduction in recoverable fuel cost of $22,528,337 (Schedule A1, December 2005 Period to Date, lines 2 & 3). Gulf currently has gas and purchased power hedges in place for 2006 and 2007 and continues to look for opportunities to enter into financial hedges that we believe will be of benefit to the customer.

Q. Should recent changes in the market price for natural gas impact the percentage of Gulf's natural gas requirements that Gulf plans to hedge?

A. Gulf has a disciplined process in place to evaluate the benefits of gas hedging transactions prior to entering into financial hedges that considers both market price and anticipated burn. The focus of this process is to mitigate the price volatility and risk of natural gas purchases for the customer and not to attempt to speculate in the natural gas market. Gulf's current strategy is to have gas hedges in place that do not exceed the anticipated gas burn at its Smith Unit 3 combined cycle plant. Gas burn requirements change as the market price of natural gas changes due to the economic dispatch process utilized by the Southern System generation pool in accordance with the Intercompany Interchange Contract. Typically, as gas prices increase, anticipated gas burn decreases and the percentage of gas requirements that are currently hedged financially increases. Gulf will continue to evaluate the performance of this hedging strategy and will make adjustments within the guidelines of the currently approved hedging program when needed.

Q. What actions does Gulf take to procure natural gas and natural gas transportation for its units at competitive prices for both long term and short term deliveries?

A. Gulf procures natural gas using both long and short term agreements for supply at market based prices. Gulf secures gas transportation for non-peaking units using long term agreements for firm transportation capacity and for peaking units using interruptible transportation, released seasonal firm transportation, or delivered natural gas agreements. Details of Gulf's natural gas procurement strategy are included in the "Risk Management Plan for Fuel Procurement" on file in this docket.

Q. What is Gulf's projected recoverable fuel cost of power sold for the 2007 period?

A. Gulf's projected recoverable fuel cost of power sold is ($197,895,521). This projected amount is captured in the exhibit to Witness Martin's testimony, Schedule E-1, Line 19.

Q. How does the total projected recoverable fuel cost of power sold for the 2007 period compare to the projected recoverable fuel cost of power sold for the same period in 2006?

A. The total projected recoverable fuel cost of power sold, reflected on revised Schedule E-1B of Witness Martin's testimony, is projected to be ($158,431,673). The projected recoverable fuel cost of power sold in 2007 represents an increased credit of ($39,463,848) or 24.91%. Total power sales in 2007 are projected to be 5,509,506 MWH. This is 498,993 MWH or 9.96% higher than is currently projected for 2006. On a fuel cost per KWH basis, the 2006 projected cost is 3.1620 cents per KWH and the 2007 projected fuel cost is 3.5919 cents per KWH. This is an increase of 0.4299 cents per KWH or 13.60%. This higher total credit to fuel expense from power sales is attributed to higher replacement fuel costs as a result of the forecasted higher market prices for coal and natural gas increasing the fuel reimbursement rate ($/MWH) for power sales.

Q. What is Gulf's projected purchased power recoverable cost for energy purchased for the 2007 period?

A. Gulf's projected recoverable cost for energy purchases is $31,564,000. This projected amount is captured in the exhibit to Witness Martin's testimony, Schedule E-1, Line 13.

Q. How does the total projected purchased power cost for the 2007 period compare to the projected purchased power cost for the same period in 2006?

A. The total updated cost of purchased power to meet 2006 system needs, reflected on revised Schedule E-1B1 of Witness Martin's testimony, is projected to be $32,910,297. The projected cost of purchased power to meet system needs in 2007 represents a decrease of $1,346,297 or 4.09%. Total purchased power in 2007 is projected to be 575,829 MWH which is 468,206 MWH or 44.85% lower than is currently projected for 2006. On a fuel cost per KWH basis, the 2006 projected cost is 3.1522 cents per KWH and the 2007 projected fuel cost is 5.4815 cents per KWH. This is an increase of 2.3293 cents per KWH or 73.89%. This higher projected purchased power average per unit cost reflects a continued trend of increases in replacement fuel costs as a result of the forecasted increases in the market price of coal and natural gas.

Q. What is Gulf's projected recoverable capacity cost for the 2007 period?

A. The total recoverable capacity cost for the period is $32,623,193. This amount is captured in Witness Martin's testimony on Line 3 of Schedule CCE-1. Schedule CCE-4 of Witness Martin's testimony lists the long term power contracts that are included for capacity cost recovery, their associated capacity amount in megawatts, and the resulting capacity dollar amounts. Also included on Schedule CCE-4 is a total of the revenues produced by several market based service agreements between the Southern Electric System operating companies and entities outside the system that are included in Gulf's 2007 projection. The total capacity cost shown on Schedule CCE-4 is included on Line 1 of Schedule CCE-1.

Q. What are the other projected revenues that Gulf has included in its capacity cost recovery clause for the period?

A. Gulf has included an estimate of transmission revenues in the amount of $275,000 in its capacity cost recovery projection. This amount is captured in Witness Martin's testimony on Line 2 of Schedule CCE-1.

Q. How does the total projected net capacity cost for the 2007 period compare to the projected net capacity cost for the same period in 2006?

A. Gulf's 2007 Projected Jurisdictional Capacity Payments (Schedule CCE-1, line 5) are projected to be $31,529,897 or 9.51% higher than the current estimate of $28,790,826 for 2006 captured in Witness Martin's testimony on Line 5 of Schedule CCE-1b. This increase is a result of Gulf's increased need for capacity reserves under the provisions of the Intercompany Interchange Contract. Gulf projects an increase in customer load responsibility for the 2007 period over the prior year while its owned capacity remains relatively unchanged. Therefore, this will require the purchase of more system capacity reserves in order to provide the level of reserve margin needed to reliably serve Gulf's customer load requirements.

Q. Mr. Ball, does this complete your testimony?

A. Yes, it does.

MR. BADDERS: Thank you. This witness is available for cross-examination.

CHAIRMAN EDGAR: Thank you. Questions on cross?

MS. CHRISTENSEN: Yes.

CROSS-EXAMINATION

BY MS. CHRISTENSEN:

Q. Good afternoon, Mr. Ball. I have a few questions about Gulf's gas storage. Would you agree that Gulf obtained its natural gas storage for Plant Crist approximately September 1st, 1997?

A. Yes, I agree with that.

Q. And would you also agree that the carrying costs applicable to any fuel kept in storage should be recovered through base rates, not through the fuel clause?

A. That's correct. Natural gas storage costs or carrying costs were included in base rates in our last rate proceeding.

Q. Okay. And your last rate proceeding had a test year of May 31st, 2003, and that would have been in Docket 010949E; is that correct?

A. That's correct.

Q. Okay. And is it correct to say that your inventory balance of natural gas storage was included in your working capital calculation in your last rate case?

A. That's correct.

Q. And that was for the projected test year, which ended May 31st, 2003; correct?

A. Correct.

MS. CHRISTENSEN: I have no further questions.

CHAIRMAN EDGAR: Mr. McWhirter.

MR. McWHIRTER: Yes, ma'am.

CROSS-EXAMINATION

BY MR. McWHIRTER:

Q. Mr. Ball, you were deposed on October 23rd, and you were asked if you had not hedged in 2006, your fuel costs would be lower, but you didn't specify how much lower they would have been for this year. Can you give us -- can you tell us what your hedging losses will be in 2006?

A. Our current estimate of hedging losses in 2006 amount to $17.4 million.

Q. Your total fuel costs are $454.7 million for 2007?

A. Yes.

Q. Have you projected whether you're going to have gains or losses in 2007?

A. Based on the current market price of gas, we have projected that we are going to pay to the bank approximately $2 million in 2007 for the settlement of our financial hedges.

Q. You are a subsidiary of the Southern Company, and Southern Company is deeply involved in the futures market, as I understand it. Is that correct?

A. Well, I guess, yes, I would agree with that to some degree. Yes, specifically in natural gas hedging, which I'm familiar with, Southern Company -- all of the operating companies within Southern Company do financially hedge natural gas purchases; that's correct.

Q. Do you deal with and pay commissions to the Southern Company for hedging transactions?

A. No. Gulf Power does not pay any commissions to Southern Company for hedging gas transaction.

Q. In your opinion, would it be appropriate to pay commissions on hedging to affiliated companies?

A. It's -- I guess since we don't pay any commission and we don't have a program that involves commissions, we don't anticipate ever having that situation come up.

Q. You indicated that you had long-term coal contracts, coal purchase contracts. Do you consider those long-term contracts to be hedges, and do you include them in your hedging program?

A. We consider long-term contracts that are for a specific quantity of fuel at specific prices to be physical hedges of fuel prices; that's correct. And I guess in a way, that is a part of our fuel procurement strategy, and it is a part of our filing that we make with the Commission that details our procurement strategy, yes.

Q. And how long have you been engaged in long-term purchases and your coal supply contracts?

A. Southern Company as a whole has been involved in the long-term coal procurement process for many years. I would hesitate to say how far back, but certainly longer than I've been associated with Southern Company.

Q. So although those are classified as physical hedges currently, they've been in -- that operation was in existence long before the Commission's order approving hedging programs in 2002; is that correct?

A. That is correct. But I would state that Southern Company, and particularly Gulf Power Company, is not a significant and has not been a significant utilizer of natural gas for fuel. We are primarily a coal-fired utility, and Gulf Power is and in the past was much more of a coal-fired utility.

Q. When you engage in hedging transactions, what percentage are financial hedges as opposed to physical hedges for gas?

A. For gas, we are 100 percent financially hedged, at least all of our hedging is financially hedged. We do not enter into physical price hedges on our gas agreements.

Q. Your gas storage gives you additional reliability. In your opinion, do you obtain additional reliability for your gas supply through financial hedging?

A. There's no connection between gas storage and financial hedging. We employ gas storage primarily for reliability of supply and for operational reasons, to balance gas flows in and out of the pipelines.

Q. Did you hear Mr. Yupp's testimony? Were you in the room when he talked about hedging?

A. Yes, I was here.

Q. Do you agree with his concept that it is not the purpose of hedging to save fuel costs or to lower fuel costs or to speculate, but rather only to avoid volatility?

A. Gulf Power certainly is involved in the gas hedging process in an attempt to reduce volatility of fuel prices. Also, primarily, it's to protect the customers against large increases in fuel prices.

As far as the speculative nature of the

program, we have certain percentages that we will hedge up to to prevent us from becoming more of a speculative program, so we would never hedge more than 100 percent of our forecasted burn in any case.

Q. That's good.

A. Doing more than you're -- hedging more than you burn would certainly put you into a speculative position.

Q. Do you have limits on your hedging now that is not confidential?

A. We don't consider our hedging limits confidential. We have a specific strategy that we employ. We update that strategy each month. Typically our strategy is that we will hedge between 40 and 60 percent of our forecasted gas burn for the next year, and we hedge up to 42 months in advance.

Q. As you get closer to the burn date, do you hedge a larger percentage and then a smaller percentage as you're further away? Is that the way the program works?

A. No, not necessarily. Our hedge program is typically built around watching the market and making strategic decisions about when to hedge and when not to hedge. We don't set time limits on when we need to hedge. We don't try to hedge more as we approach the burn date.

Actually, what we're looking for is -- we're looking at the marketplace, and if we see that there's a dip in gas prices that provide an opportunity to hedge, we'll take that opportunity and do so at that time.

So in some cases, we will have our gas hedges in place several years before the actual gas burn occurs. In other cases, we may see an opportunity to hedge prices in a few months before the gas burn occurs, and if we think that that is an advantageous time to hedge prices, we'll enter the market and do so.

Q. Does your 2007 fuel cost recovery application include any O&M costs that relate to your hedging program, O&M as opposed to commissions and --

A. Yes, we do.

Q. And what is that amount of money?

A. I believe for the '07 forecast, it's approximately $98,000.

Q. The stipulation we entered into back in October -- or August of 2002 that was approved by the Commission in October limited the time period with which you could recover these costs to end at December 31, 2006. Were you aware of that?

MR. BADDERS: I would like to make an objection. He's reading from an order that the witness does not have in front of him. If he would like to make that available to the witness, I think that would be more appropriate.

CHAIRMAN EDGAR: Mr. McWhirter?

MR. McWHIRTER: I will do that, yes. All I have to do is find it.

BY MR. McWHIRTER:

Q. This is my solitary copy of Commission Order 021484 that I hand you to refresh your recollection. The operative paragraph is number 4 in the stipulation that I've yellow marked. Would you read that into the record?

A. May I read the entire paragraph, sir?

Q. Well, the yellow marked part.

A. Well, there's -- okay. I'll read that, but if you don't mind, I will read a little bit further to clarify this.

Q. Please do.

A. Thank you.

Q. Read whatever makes you comfortable to accurately portray what the stipulation says.

A. Thank you, sir. "Each investor-owned eletric utility may recover through the fuel and purchased power cost recovery clause prudently incurred incremental operating and maintenance expenses incurred for the purpose of initiating and/or maintaining a new or expanded nonspeculative financial and/or physical hedging program designed to mitigate fuel and purchased power price volatility for its retail customers each year until December 31, 2006, or the time of the utility's next rate proceeding, whichever comes first."

Q. All right. Did you have a rate proceeding in which the Commission approved incremental hedging as a fuel cost recovery as --

A. It's my understanding --

Q. -- opposed to base rates?

A. I'm sorry. It's my understanding that Gulf's rate proceeding occurred prior to the hedging order, so our next rate proceeding will be at a later date.

Q. Now, in fairness to you, Gulf did not sign that stipulation, and you'll see from the order that Gulf came along later. And I'm not sure I understand the circumstances of that. Do you know the basis upon which you recover your O&M costs through the fuel clause for 2007?

A. It's my understanding that we have the opportunity to recover our O&M costs up until the point that we have our next rate proceeding.

Q. Is that what you think that order says?

A. That's my interpretation, yes, sir.

Q. All right, sir. Thank you very much for that.
How do you determine internally when a hedging program is, quote, successful?

A. The overall objective of the hedging program, of course, is to save the customer money. We should not involve ourselves in any hedging program that is not to the benefit of the customer. So over the long term -- that's not just looking at one year or one month, but over a long period of time, the customer should see tangible benefits from a hedging program.

Now, we believe that the hedging program is a benefit, because over the time period that we've been involved in the hedging program, we have shown tangible benefits in dollars and cents to our customers. This program is out there to protect the customer against large increases in gas prices.

Who knows what the future may hold? But certainly if you look at past history, you will see that we've had many occasions where gas prices have increased dramatically, and there's certainly no assurance that that will not happen in the future. The gas hedging program is out there to protect the customers against those occurrences. If we determine that the gas hedging program does not accomplish that feat, then certainly the gas hedging program should not be continued.

Q. The gas hedging programming entails commissions and other fees. What fees do you pay for the privilege of engaging in hedging?

A. Gulf Power Company does not pay any commissions or fees associated with its gas hedging program.

Q. Do you deal over the counter, or do you deal with a commodity exchange?

A. We deal strictly with financial institutions that are creditworthy based on analyses that are made by our risk management group. Out hedges are primarily and for the most part financial swaps.

Q. Do you pay option premiums?

A. No, we do not.

Q. What do you mean by a financial swap?

A. A financial swap is where you take a position on a firm quantity of gas at a firm price, and then at the settlement date of that agreement, you settle either against a last-day NYMEX price, Henry Hub basis, or you can swap that for a gas daily price and settle those agreements each day as you -- in this case, in our case, we consider -- as we're burning the gas, we may elect to swap this month-end price to a gas daily settlement price and settle as we burn the gas.

Q. And when you deal with a financial institution, you don't pay any fee or premium to the institution other than specified price for the commodity you're purchasing?

A. In the transactions that we're involved in, that is true.

Q. Can you name some of your counterparties, or is that privileged information?

A. No, I wouldn't consider it privileged information, but organizations like the Bank of America, Mitsui Corporation, to name a few. If you would like a more extensive list, I can get that for you.

MR. McWHIRTER: That's all right. I have no further questions and tender the witness.

CHAIRMAN EDGAR: Thank you. Does any other party have questions on cross for this witness?

MR. BUTLER: Madam Chairman, I have a couple of questions, if I may.

CROSS-EXAMINATION

BY MR. BUTLER:

Q. Good afternoon, Mr. Ball. My name is John Butler with Florida Power & Light Company. I just have a couple of questions for you.

There was a reference early in the examination of you this afternoon to MFRs that were prepared for a test year that ended in -- well, I think it ended May

31, 2003, is that right, your most recent rate proceeding?

A. That is correct.

Q. So it was a one-year period ending May 31, 2003?

A. That's correct.

Q. Okay. And to state the obvious, therefore, it began in May of 2002; correct?

A. That is correct.

Q. Okay. Do you know when the MFRs were prepared or that set of MFRs were prepared for the test year running from May 2002 to May 2003?

A. No, I do not.

Q. But it would have been sometime before the May 2002 point; correct?

A. I would assume so. I was not in this role at that time.

Q. Okay. In any event, a date before May 2002 would have been before the Commission had entered its hedging order approving the hedging resolution; is that correct?

A. That's correct.

MR. BUTLER: Thank you. That's all that I have.

CHAIRMAN EDGAR: Any other party with

questions on cross?

Seeing none, questions from staff?

MS. BENNETT: Staff has no questions. Commissioners.

CHAIRMAN EDGAR: Mr. Badders.

MR. BADDERS: No redirect. And we would like to move Exhibits 23 and 24.

CHAIRMAN EDGAR: The exhibits will be moved into the record.

(Gulf Power Company Exhibits Number 23 and 24 were admitted into evidence.)

CHAIRMAN EDGAR: And the witness may be excused.

MR. BADDERS: The next two witnesses I believe may be subject to being stipulated. We can take them one at a time if you prefer.

CHAIRMAN EDGAR: Ms. Bennett?

MS. BENNETT: I believe that Ms. Martin, all of the issues for Gulf have been stipulated, and if that is the case and no party objects, then we can stipulate the testimony and exhibits into the record.

MS. CHRISTENSEN: No objection.

CHAIRMAN EDGAR: Seeing no other objection, okay. Then the prefiled testimony of Ms. Martin will be entered into the record as though read.

MR. BADDERS: And Exhibits 25 through 27.

CHAIRMAN EDGAR: And Exhibits 25 through 27.

(Gulf Power Company Exhibits Number 25, 26, and 27 were admitted into evidence.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Rhonda J. Martin
Docket No. 060001-EI
Date of Filing: August 8, 2006

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

A. My name is Rhonda Martin. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Rates and Regulatory Matters at Gulf Power Company.

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

A. I graduated from the University of West Florida in Pensacola, Florida in 1994 with a Bachelor of Arts Degree in Accounting. I am also a licensed Certified Public Accountant and a member of the Florida Institute of Certified Public Accountants. I joined Gulf Power in 1994 as an Accountant. Prior to assuming my current position, I have held various positions of increasing responsibility with Gulf as an accountant in the Accounting Services, Financial Reporting, and Corporate Accounting Departments and as Supervisor of Financial Planning. In April 2006, I joined the Rates and Regulatory Matters area.

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

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

Counsel: We ask that Ms. Martin's Exhibit consisting of fourteen schedules be marked as Exhibit No. _____ (RJM-2).

Q. Are you familiar with the Fuel and Purchased Power (Energy) estimated true-up calculations for the period of January 2006 through December 2006 and the Purchased Power Capacity Cost estimated true-up calculations for the period of January 2006 through December 2006 set forth in your exhibit?
A. Yes, these documents were prepared under my supervision.

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

Q. How were the estimated true-ups for the current period calculated for both fuel and purchased power capacity?
A. In each case, the estimated true-up calculations include six months of actual data and six months of estimated data.

Q. Ms. Martin, what has Gulf calculated as the fuel cost recovery true-up to be applied in the period January 2007 through December 2007?
A. The fuel cost recovery true-up for this period is an increase of .3331¢/kwh.

As shown on Schedule E-1A, this includes an estimated under-recovery for the January through December 2006 period of $18,242,487, plus a final under-recovery for the January through December 2005 period of $20,174,117 (see Schedule 1 of Exhibit TAD-1 in this docket filed on March 1, 2006). The resulting total under-recovery of $38,416,604 will be included for recovery during 2007.

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

A. Schedules CCE-1a, CCE-1b and CCE-4 of my exhibit relate to the Purchased Power Capacity Cost true-up calculation to be applied in the January 2007 through December 2007 period.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2007 through December 2007?

A. The true-up for this period is a decrease of .0012¢/kwh as shown on Schedule CCE-1a. This includes an estimated over-recovery of $24,639 for January 2006 through December 2006. It also includes a final over-recovery of $112,632 for the period of January 2005 through December 2005 (see Schedule CCA-1 of Exhibit TAD-1 in this docket filed March 1, 2006). The resulting total over-recovery of $137,271 will be refunded to customers during 2007.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Rhonda J. Martin
Docket No. 060001-EI
Date of Filing: September 1, 2006

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

A. My name is Rhonda Martin. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Rates and Regulatory Matters at Gulf Power Company.

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

A. I graduated from the University of West Florida in Pensacola, Florida in 1994 with a Bachelor of Arts Degree in Accounting. I am also a licensed Certified Public Accountant and a member of the Florida Institute of Certified Public Accountants. I joined Gulf Power in 1994 as an Accountant. Prior to assuming my current position, I have held various positions of increasing responsibility with Gulf as an accountant in the Accounting Services, Financial Reporting, and Corporate Accounting Departments and as Supervisor of Financial Planning. In April 2006, I joined the Rates and Regulatory Matters area.

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

Q. Have you previously filed testimony before this Commission in this on-going docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the calculation of Gulf Power's fuel cost recovery factors for the period January 2007 through December 2007. I will also discuss the calculation of the purchased power capacity cost recovery factors for the period January 2007 through December 2007.

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

A. Yes. My exhibit consists of 15 schedules, each of which was prepared under my direction, supervision, or review.

Counsel: We ask that Ms. Martin's Exhibit consisting of 15 schedules, be marked as Exhibit No. _____(RJM-3).

Q. Ms. Martin, what is the levelized projected fuel factor for the period January 2007 through December 2007?

A. Gulf has proposed a levelized fuel factor of 3.939¢/kwh. This factor is based on projected fuel and purchased power energy expenses for January 2007 through December 2007 and projected kwh sales for the same period, and includes the true-up and GPIF amounts. This levelized fuel factor has not been adjusted for line losses.

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

A. The projected levelized fuel factor for 2007 is .863 ¢/kwh more or 28 percent higher than the levelized fuel factor for 2006 upon which current fuel factors are based.

Q. Please explain the calculation of the true-up amount included in the levelized fuel factor for the period January 2007 through December 2007.

A. As shown on Schedule E-1A of my exhibit, the true-up amount of $46,679,464 to be collected during 2007 includes an estimated under-recovery for the January through December 2006 period of $26,505,347, plus a final under-recovery for the January through December 2005 period of $20,174,117. The estimated under-recovery for the January through December 2006 period has been revised to include 7 months of actual data and 5 months of estimated data as reflected on my revised Schedule E-1B.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of January 2005 through December 2005?

A. The GPIF result is shown on Line 33 of Schedule E-1 as a decrease of .0073¢/kwh, thereby penalizing Gulf $842,874.

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

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

Q. Ms. Martin, how were the line loss multipliers used on Schedule E-1E calculated?

A. The line loss multipliers were calculated in accordance with procedures approved in prior filings and were based on Gulf's latest mwh Load Flow Allocators.

Q. Ms. Martin, what fuel factor does Gulf propose for its largest group of customers (Group A), those on Rate Schedules RS, GS, GSD, and OSIII?

A. Gulf proposes a standard fuel factor, adjusted for line losses, of 3.960¢/kwh for Group A. Fuel factors for Groups A, B, C, and D are shown on Schedule E-1E. These factors have all been adjusted for line losses.

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

A. The time-of-use fuel factors were calculated based on projected loads and system lambdas for the period January 2007 through December 2007. These factors included the GPIF and true-up, and were adjusted for line losses. These time-of-use fuel factors are also shown on Schedule E-1E.

Q. How does the proposed fuel factor for Rate Schedule RS compare with the factor applicable to December 2006 and how would the change affect the cost of 1,000 kwh on Gulf's residential rate RS?

A. The current fuel factor for Rate Schedule RS applicable through December 2006 is 3.092¢/kwh compared with the proposed factor of 3.960¢/kwh. For a residential customer who uses 1,000 kwh in January 2007, the fuel portion of the bill would increase from $30.92 to $39.60.

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

A. Yes. A tabulation of these costs is set forth in Schedule E-11 of my exhibit. These costs represent the estimated averages for the period from January 2007 through December 2008.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2007 gains on non-separated wholesale energy sales eligible for a shareholder incentive?

A. In accordance with Order No. PSC-00-1744-AAA-EI, a benchmark level of $3,092,606 has been calculated for 2007. The actual gains for 2004, 2005, and the estimated gains for 2006 on all non-separated sales have been averaged to determine the minimum projected threshold for 2007 that must be achieved before shareholders may receive any incentive. As demonstrated on Schedule E-6, page 2 of 2, Gulf's projection reflects a credit to customers of 100 percent of the gains on non-separated sales for 2007 for the months January through October. In November, the estimated benchmark of $3,092,606 is expected to be met. Therefore, based on Order No. PSC-00-1744-PAA-EI, issued September 26, 2000, Gulf has calculated the gains above the threshold for November and December and applied the 80%/20% split between ratepayers and shareholders, respectively.

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

A. Schedule CCE-1, including CCE-1a and CCE-1b, Schedule CCE-2, and Schedule CCE-4 of my exhibit relate to the calculation of the PPCC recovery factors for the period January 2007 through December 2007.

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

A. Schedule CCE-1 shows the calculation of the amount of capacity payments to be recovered through the PPCC Recovery Clause. Mr. Ball has provided me with Gulf's projected purchased power capacity transactions. Gulf's total projected net capacity expense which includes a credit for transmission revenue for the period January 2007 through December 2007 is $32,623,193. The jurisdictional amount is $31,529,897. This amount is added to the total true-up amount to determine the total purchased power capacity transactions that would be recovered in the period.

Q. Has there been any change that would affect the capacity clause estimated true-up for 2006 filed by Gulf on August 8, 2006?

A. Yes. The estimated true-up for 2006 now includes actual information through July.

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

A. As required by Commission Order No. 25773 in Docket No. 910794-EQ, the revenue requirements have been allocated using the cost of service methodology used in Gulf's last rate case and approved by the Commission in Order No. PSC-02-0787-FOF-EI issued June 10, 2002, in Docket No. 010949-EI. For purposes of the PPCC Recovery Clause, Gulf has allocated the net purchased power capacity costs to rate class with 12/13th on demand and 1/13th on energy. This allocation is consistent with the treatment accorded to production plant in the cost of service study used in Gulf's last rate case.

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

A. The allocation factors used in the PPCC Recovery Clause have been calculated using the 2003 load data filed with the Commission in accordance with FPSC Rule 25-6.0437. The calculations of the allocation factors are shown in columns A through I on Page 1 of Schedule CCE-2.

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

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

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

A. The purchased power capacity costs recovered through the clause for a residential customer who uses 1,000 kwh will be $3.11.

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

A. The fuel and capacity factors will be effective beginning with Cycle 1 billings in January 2007 and continuing through the last billing cycle of December 2007.

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

A. Yes.

MR. BADDERS: The next witness is Witness Noack. I believe the same is also true with regard to her projections and target filing testimony, which would include both Exhibits 27 and 28.

CHAIRMAN EDGAR: Is there any objection to entering the prefiled testimony of Witness Noack into the record?

MS. CHRISTENSEN: No objection.

MR. McWHIRTER: No objection.

CHAIRMAN EDGAR: Then the prefiled testimony of Ms. Noack and her -- excuse me, of Witness Noack and Exhibits 27 and 28 will be entered into the record.

MS. BENNETT: Can I clarify just a moment, Madam Chair?

CHAIRMAN EDGAR: You may, Ms. Bennett.

MS. BENNETT: First, Ms. Noack will appear later on the dead band issue, so we will be entering just the testimony for April and --

MR. BADDERS: That is correct. We would enter just the April and September testimony. The August testimony would still be outstanding.

CHAIRMAN EDGAR: Okay. For clarification, the April and September prefiled testimony is entered into the record, and the August testimony we will take up later in this proceeding.

MR. BADDERS: Right. And I do believe I misspoke on the exhibits. I believe for Witness Martin it's 25 through 27, and for Noack, it's 28 and 29.

CHAIRMAN EDGAR: So noted.

(Gulf Power Company Exhibits Number 28 and 29 were admitted into evidence.)

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony and Exhibit of
L. S. Noack
Docket No. 060001-EI
Date of Filing April 3, 2006

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

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

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Environmental Engineering from the University of Florida in 1995 and received my Master of Business Administration degree from the University of West Florida in 2000. I joined Gulf Power in 1995 as an Environmental Engineer and served in that role with increasing levels of responsibility for over six years. Major responsibilities included coordination of federal and state air-related compliance testing for all Gulf Power generating units, management of the Continuous Emission Monitoring (CEM) System program at each of the Company's generating facilities, and coordination of

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

Q. Are there any issues related to the GPIF targets for this period that were filed with the Commission on September 9, 2004, in Docket No. 040001-EI that may affect the validity of those targets for this period?

A. Yes. Plant Daniel Units 1 and 2, which had been burning a high-Btu bituminous coal for several years, switched to a blend of approximately 60% high-Btu bituminous coal and 40% low-Btu sub-bituminous coal in March of 2004. This change in fuel mix was due to economic conditions and results in lower costs to customers than if the units continued burning the high-Btu coal only. However, this change in fuel also results in an increase in the heat rates of these units above the targets set for this period. This increase is not an indication of a change in unit efficiency but is more a reflection of the change in heat content and properties of the new fuel mix being burned.

Because the heat rate targets for this period were set according to the GPIF Implementation Manual, which required the targets to be set based on the historical high-Btu coal burn for Daniel Units 1 and 2, the heat rate targets for this period are only valid for these units when burning high-Btu coal. Consequently, there is no reasonable way to determine what portion of the actual unit heat rates are due to unit performance and what portion is due to the lower-Btu fuel mix. The GPIF process was not established to reward or penalize units for fuel switching; therefore, the heat rate targets set for this period for Daniel Units 1 and 2 are not applicable during the months when the units burned the low-Btu fuel mix.

Q. Please describe how this change in fuel mix is being addressed in this filing.

A. In accordance with past Commission Orders, including Commission Orders PSC-04-1276-FOF-EI and PSC-05-1252-FOF-EI, Plant Daniel Units 1 and 2 are excluded from the GPIF heat rate calculations for the months when the low-Btu fuel mix was burned. This was accomplished by setting the units' Adjusted Actual Heat Rates equal to their respective Target Heat Rates indicated on lines 1 and 5 of Pages 16 and 17 of Schedule 3 for each month beginning with January through December 2005. This results in producing neither a reward nor a penalty for heat rate for these two units for these months when the units were burning the low-Btu fuel mix.

It should be noted that the Btu/lb independent variable that was stipulated and approved in Commission Order PSC-99-2512-FOF-EI was added to the target heat rate equations for Daniel Units 1 and 2 beginning with the 2006 GPIF Target Filing that was approved in Commission Order PSC-05-1252-FOF-EI. This process will account for the change in fuel mix for these units in the next Results Filing to be filed in Spring of 2007.

Q. Is there any other information that has been supplied to the Commission pertaining to this GPIF period that requires amendment?

A. Yes. Some corrections have been made to the actual unit performance data, which was submitted monthly to the Commission during this time period. These corrections are based on discoveries made during the final data review to ensure the accuracy of the information reported in this filing. The actual unit performance data tables on Pages 16 through 31 of Schedule 5 of Exhibit_(LSN-1) incorporate these changes. The data contained in these tables is the data upon which the GPIF calculations were made.

Q. Would you now review the Company's equivalent availability results for the period?

A. Actual equivalent availability and adjusted actual equivalent availability figures for each of the Company's GPIF units are shown on Page 15 of Schedule 5. Pages 3 through 10 of Schedule 2 contain the calculations for the adjusted actual equivalent availabilities.

A calculation of GPIF availability points based on these availabilities and the targets established by Commission Order PSC-04-1276-FOF-EI is on Page 11 of Schedule 2. The results are: Crist 4, -10.00 points; Crist 5, -10.00 points; Crist 6, +10.00 points; Crist 7, -10.00 points; Smith 1, +10.00 points; Smith 2, +10.00 points; Daniel 1, -10.00 points; and Daniel 2, -6.47 points.

Q. What were the heat rate results for the period?

A. The detailed calculations of the actual average net operating heat rates for the Company's GPIF units are on Pages 2 through 9 of Schedule 3.

As was done for the prior GPIF periods, and as indicated on Pages 10 through 17 of Schedule 3, the target equations were used to adjust actual results to the target bases. These equations, submitted in September 2004, are shown on Page 20 of Schedule 3.

As calculated on Page 21 of Schedule 3, the adjusted actual average net operating heat rates correspond to the following GPIF unit heat rate points: -6.87 for Crist 4, -4.40 for Crist 5, -4.60 for Crist 6, -8.09 for Crist 7, 0.00 for Smith 1, -5.84 for Smith 2, 0.00 for Daniel 1, and 0.00 for Daniel 2.

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

A. Using the unit equivalent availability and heat rate points previously mentioned, along with the appropriate weighting factors, the number of Company points achieved is -3.59, as indicated on Page 2 of Schedule 4. This calculated to a penalty in the amount of $842,874.

Q. Would you please summarize your testimony?

A. Yes. In view of the adjusted actual equivalent availabilities, as shown on Page 11 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on Page 21 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a penalty in the amount of $842,874 as provided for by the GPIF plan.

Q. Does this conclude your testimony?
A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission

Direct Testimony of

L. S. Noack

Docket No. 060001-EI

Date of Filing: September 1, 2006

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

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

Q. Please describe your educational and business background.

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

Power Company. In this position, I am responsible for preparing all GPIF filings as well as other generating plant reliability and heat rate performance reporting.

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

A. The purpose of my testimony is to present GPIF targets for Gulf Power Company for the period of January 1, 2007 through December 31, 2007.

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

A. Yes. I have prepared one exhibit consisting of three schedules.

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes, it was.

Counsel: We ask that Ms. Noack's exhibit be marked for identification as Exhibit_(LSN-2).

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

A. We propose that Crist Units 4, 5, 6, and 7, Smith Units 1 and 2, and Daniel Units 1 and 2, continue to be the Company's GPIF units. The projected net generation from these units, which represent all of Gulf's qualifying base and intermediate load units for GPIF, is approximately 86.39% of Gulf's projected net generation for 2007.

Q. What are the target heat rates Gulf proposes to use in the GPIF for these units for the performance period January 1, 2007 through December 31, 2007?

A. I would like to refer you to Page 45 of Schedule 1 of my Exhibit_(LSN-2) where these targets are listed.

Q. How were these proposed target heat rates determined?

A. They were determined according to the GPIF Implementation Manual procedures for Gulf. For Daniel Units 1 and 2, the Btu/lb independent variable that was stipulated and approved in Commission Order PSC-99-2512-FOF-EI and referenced in the 2005 GPIF Target Filing, Docket No. 040001-EI, was added to the regression.

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

A. Page 2 of Schedule 1 of Exhibit_(LSN-2) shows the target average net operating heat rate equations for the proposed GPIF units, and Pages 4 through 41 of Schedule 1 contain the weekly historical data used for the statistical development of these equations. Pages 42 through 44 of Schedule 1 present the calculations that provide the unit target heat rates from the target equations. For Daniel Units 1 and 2, the estimates of the monthly Btu/lb for 2007 used to determine the heat rate targets for these units are included on Page 44 of Schedule 1.

Q. Were the maximum and minimum attainable heat rates for each proposed GPIF unit, indicated on Page 45 of Schedule 1 of Exhibit_(LSN-2), calculated according to the appropriate GPIF Implementation Manual procedures?

A. Yes.

Q. What are the proposed target, maximum, and minimum equivalent availabilities for Gulf's units?

A. The target, maximum, and minimum equivalent availabilities are listed on Page 4 of Schedule 2 of Exhibit_(LSN-2).

Q. How were the target equivalent availabilities determined?

A. The target equivalent availabilities were determined according to the standard GPIF Implementation Manual procedures for Gulf and are presented on Page 2 of Schedule 2 of Exhibit_(LSN-2).

Q. How were the maximum and minimum attainable equivalent availabilities determined for each unit?

A. The maximum and minimum attainable equivalent availabilities, which are presented along with their respective target availabilities on Page 4 of Schedule 2 of Exhibit_(LSN-2), were determined per GPIF Implementation Manual procedures for Gulf.

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

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

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

A. Yes. Gulf asks that the Commission accept:

1. Crist Units 4, 5, 6 and 7, Smith Units 1 and 2, and Daniel Units 1 and 2 for inclusion under the GPIF for the period of January 1, 2007 through December 31, 2007.

2. The target, maximum attainable, and minimum attainable average net operating heat rates, as proposed by the Company and as shown on Page 45 of Schedule 1 and also on Page 5 of Schedule 3 of Exhibit_(LSN-2).

3. The target, maximum attainable, and minimum attainable equivalent availabilities, as proposed by the Company and as shown on Page 4 of Schedule 2 and also on Page 5 of Schedule 3 of Exhibit_(LSN-2).

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

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

MS. HELTON: Madam Chairman, this is --

CHAIRMAN EDGAR: Ms. Helton, yes.

MS. HELTON: Just for purposes of clarification of the record -- and I apologize. This is probably something I should have checked out before mentioning it, but do we need to mention on the record that Ms. Martin is adopting the prefiled testimony of Terry A. Davis, or is that already made clear enough?

MR. BADDERS: I believe we made that clear at the prehearing, and I believe it appears in the prehearing order, but at the Commission's pleasure, we can do that.

MR. HORTON: I just think stating it on the record is probably good enough.

CHAIRMAN EDGAR: Okay. Then once again, for the record, Witness Martin has also adopted the prefiled testimony and exhibits of Witness Davis.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Terry A. Davis
Docket No. 060001-EI
Fuel and Purchased Power Capacity Cost Recovery
Date of Filing: March 1, 2006

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

A. My name is Terry Davis. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Treasury and Regulatory Matters at Gulf Power Company.

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

A. I graduated in 1979 from Mississippi College in Clinton, Mississippi with a Bachelor of Science Degree in Business Administration and a major in Accounting. Prior to joining Gulf Power, I was an accountant for Geophysical Field Surveys, a seismic survey firm in Jackson, Mississippi. In that capacity, my responsibilities included accounts receivable, accounts payable, sales, use, and fuel tax returns, and various other accounting activities. In 1986, I joined Gulf Power as an Associate Accountant in the Plant Accounting Department. Since then, I have held various positions of increasing responsibility with Gulf Power in Accounts Payable, Financial Reporting, and Cost Accounting. In 1993, I joined the Rates and Regulatory Matters area, where I have participated with increasing responsibility in activities related to the cost recovery clauses, the rate case, budgeting, and other regulatory functions. In 2003, I was promoted to my current position.

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

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

A. Yes, I have.

Counsel: We ask that Ms. Davis' Exhibit consisting of five schedules be marked as Exhibit No. _____ (TAD-1).

Q. Are you familiar with the Fuel and Purchased Power (Energy) true-up calculations for the period of January 2005 through December 2005 and the Purchased Power Capacity Cost true-up calculations for the period of

January 2005 through December 2005 set forth in your exhibit?

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

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

A. Yes, I have.

Q. What is the amount to be refunded or collected through the fuel cost recovery factors in the period January 2007 through December 2007?

A. A net amount to be collected of $20,174,117 was calculated as shown on Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $20,174,117 was calculated by taking the difference in the estimated January 2005 through December 2005 under-recovery of $30,102,348 and the actual under-recovery of $50,276,465, which is the sum of the Period-to-Date amounts on lines 7 and 8 shown on Schedule A-2, page 2, of the monthly filing for December 2005. The estimated true-up amount for this period was approved in Order No. PSC-05-1252-FOF-EI dated December 23, 2005. Additional details supporting the approved estimated true-up amount are included on revised Schedule E1-A filed September 16, 2005.

Q. Ms. Davis has the estimated benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for 2006?

A. Yes, it has.

Q. What is the actual threshold for 2006?

A. Based on actual data for 2003, 2004, and now 2005, the threshold is calculated to be $3,546,453.

Q. The Commission approved Gulf's hedging program in October 2002. What incremental hedging support costs related to administering Gulf's approved hedging program is Gulf seeking to recover for 2005?

A. Gulf has included $43,640 as shown on the December 2005 Period-to-Date Schedule A-1 for incremental hedging support costs related to administering the approved hedging program during the 2005 recovery period.

Q. Is Gulf seeking to recover any gains or losses from hedging settlements in the 2005 recovery period?

A. Yes. On the December 2005 Fuel Schedule A-1, Period to Date, Gulf has recorded a net gain of $22,571,977 related to hedging activities in 2005. Mr. Ball will address the details of those hedging activities in his testimony.

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

A. Schedules CCA-1, CCA-2, CCA-3 and CCA-4 of my exhibit relate to the Purchased Power Capacity Cost Recovery true-up calculation for the period January 2005 through December 2005.

Q. What is the amount to be refunded or collected in the period January 2007 through December 2007?

A. An amount to be refunded of $112,632 was calculated as shown in Schedule CCA-1, of my exhibit.

Q. How was this amount calculated?

A. The $112,632 was calculated by taking the difference in the estimated January 2005 through December 2005 over-recovery of $913,842 and the actual over-recovery of $1,026,474, which is the sum of lines 11 and 12 under the total column of Schedule CCA-2. The estimated true-up amount for this period was approved in Order No. PSC-05-1252-FOF-EI dated December 23, 2005. Additional details supporting the approved estimated true-up amount are included on Schedule CCE-1A filed September 16, 2005.

Q. Please describe Schedules CCA-2 and CCA-3 of your exhibit.
A. Schedule CCA-2 shows the calculation of the actual over-recovery of purchased power capacity costs for the period January 2005 through December 2005. Schedule CCA-3 of my exhibit is the calculation of the interest provision on the over-recovery for the period January 2005 through December 2005. This is the same method of calculating interest that is used in the Fuel and Purchased Power (Energy) Cost Recovery Clause and the Environmental Cost Recovery Clause.

Q. Please describe Schedule CCA-4 of your exhibit.
A. Schedule CCA-4 provides additional details related to Lines 1 and 2 of Scheduled CCA-2. This information is provided as a result of Staff's request.

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

MR. BADDERS: Thank you. I believe that concludes the Gulf witnesses for this section.

CHAIRMAN EDGAR: That is my understanding. And it looks like that's a good time for us to break, so we will do that here in a few moments.

Are there any questions, comments, concerns that we should address before we go on break to resume again in the morning?

Okay. Seeing none, then we are on break until 9:30 tomorrow morning, and we will begin with Witness Portuondo.

(Proceedings adjourned at 5:08 p.m.)

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 188 through 405 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 7th day of November, 2006.

MARY ALLEN NEEL, RPR, FPR
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