BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of: DOCKET NO. 090001-EI

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

(Pages 1 through 226)

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN MATTHEW M. CARTER, II
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER NANCY ARGENZIANO
COMMISSIONER NATHAN A. SKOP
COMMISSIONER DAVID E. KLEMENT

DATE: Monday, November 2, 2009

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

REPORTED BY: LINDA BOLES, RPR, CRR
Official FPSC Reporter
(850) 413-6734

APPEARANCES

R. WADE LITCHFIELD and JOHN T. BUTLER, ESQUIRES, 700 Universe Boulevard, Juno Beach, Florida 33408, appearing on behalf of Florida Power & Light Company.

NORMAN H. HORTON, JR., ESQUIRE, Messer, Caparello & Self, P.A., Post Office Box 15579, Tallahassee, Florida 32317, appearing on behalf of Florida Public Utilities Company.

JEFFREY A. STONE, RUSSELL A. BADDERS and STEVEN R. GRIFFIN, ESQUIRES, Beggs & Lane, Post Office Box 12950, Pensacola, Florida 32591, appearing on behalf of Gulf Power Company.

JOHN T. BURNETT, ESQUIRE, Progress Energy Service Company, LLC, 100 Central Avenue, St. Petersburg, Florida 33701-3323, appearing on behalf of Progress Energy Florida, Inc.

JAMES D. BEASLEY and LEE L. WILLIS, ESQUIRES, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company.

APPEARANCES (Continued):

PATRICIA A. CHRISTENSEN and CHARLIE BECK, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

ALLAN L. JUNGELS, CAPTAIN, 139 Barnes Drive, Suite 1, Tyndall Air Force Base, Florida 32403-5319, appearing on behalf of the Federal Executive Agencies.

JOHN W. McWHIRTER, JR., ESQUIRE, McWhirter, Reeves & Davidson, P.A., Post Office Box 3350, Tampa, Florida 33601-3350, appearing on behalf of the Florida Industrial Power Users Group.

ROBERT SCHEFFEL WRIGHT, ESQUIRE, Young van Assenderp, P.A., 225 South Adams Street, Suite 200, Tallahassee, Florida 32301, appearing on behalf of the Florida Retail Federation.

CECILIA BRADLEY, ESQUIRE, Office of the Attorney General, The Capitol - PL01, Tallahassee, Florida 32399-1050, appearing on behalf of the Office of the Attorney General.

APPEARANCES (Continued):

JAMES W. BREW, ESQUIRE, Brickfield, Burchette, Ritts & Stone, P.C., 1025 Thomas Jefferson Street, NW Eighth Floor, West Tower, Washington, DC 20007, appearing on behalf of White Springs Agricultural Chemicals, Inc., d/b/a PCS Phosphate - White Springs.

LISA C. BENNETT, ERIK SAYLER, ANNA WILLIAMS and KEINO YOUNG, ESQUIRES, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

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I N D E X

WITNESSES

(REPORTER'S NOTE: Comments made by the City of Marianna City Manager, Mr. Dean, are contained in the transcript for Docket 090003-GU for ease of the record.

EXHIBITS

NUMBER:	ID.	ADMTD.
1 Comprehensive Exhibit List	26	26
2 through 61 (Detailed description can be found in Comprehensive Exhibit List)	26	
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CERTIFICATE OF REPORTER

P R O C E E D I N G S

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CHAIRMAN CARTER: Staff, you are recognized now for the 01 docket.

MS. BENNETT: Good morning, Commissioners. We have several stipulations in this docket also. Before we get to the stipulations, I do want to note that Issue 2C with, in relation to Florida Power & Light was spun out by the Prehearing Officer because of changes in circumstances that will be heard probably early in 2010.

But with that, I'd like to go ahead and talk to you about the stipulations that are in this docket. The Commissioners and parties have been provided with copies of the additional stipulations. Most of them appear in your Prehearing Order on Pages 30 through 43. But I would also suggest that you mark the additional stipulations dated October 30th as Exhibit 133. And Ms. Walsh is handing a copy to the court reporter. She has additional copies if anyone didn't bring theirs. We'll enter that into the record when we enter the composite, staff's composite and the Comprehensive Exhibit List into the record.

CHAIRMAN CARTER: Okay.

MS. BENNETT: And I would suggest that the Commission at this point, unless the parties have any questions or concerns about the stipulations, could actually enter, or could actually vote on the stipulations. The first set of stipulations is found in the Prehearing Order on Pages 30 through 43.

CHAIRMAN CARTER: Okay. Are there any questions by any of the parties before we move forward?

Commissioner Skop, you're recognized.

COMMISSIONER SKOP: Thank you, Mr. Chairman.

Just a quick clarification on, on Issue 2C, Ms. Bennett. That is, Issue 2C pertains to the FPL February 2008 outage; is that correct?

MS. BENNETT: That's correct.

COMMISSIONER SKOP: Okay. I just wanted to state what that was, and my rationale for spinning that out was there was a preliminary agreement between OPC and FPL that would address that issue in 2011. And given the recent FERC settlement, I thought it was important in terms of reaching some sort of disposition as to that issue sooner rather than later, and so I've asked staff to identify some early hearing dates that we can take that issue up, should it be necessary.

I do have a question as to Issue 10, which is stipulated as to FPL. And I don't know if technical staff is available, but this is overrecovery for the fuel adjustment true-up of approximately 600, I mean, excuse me, approximately $365 million. And we had had some discussion, I think, before, I know there's some prior Commission precedent, but with respect to that amount of overrecovery, that will, is expected to be refunded to customers from January 2010 to December; is that correct?

MS. BENNETT: That is correct.

COMMISSIONER SKOP: Okay. And does staff have any, I guess, idea what the, what that refund amount would be per customer, assuming, you know, 4.5 million plus customers?

MS. BENNETT: I'm being told we have not calculated it. We could provide that in a few minutes, I think.

COMMISSIONER SKOP: Okay. Subject to check, would staff agree that that would be anywhere from about $66 to $80 per customer?

MS. BENNETT: Subject to check.

COMMISSIONER SKOP: Okay.

MS. BENNETT: Are you saying $66 to $80 per month per customer --

COMMISSIONER SKOP: No.

MS. BENNETT: -- or overall?

COMMISSIONER SKOP: That would be in its entirety. It would work out to probably $6, nearly $6 a month on a 12-month period.

(Pause.)

MS. BENNETT: We're still in the rough estimate between 5 and 6, with the estimate being closer to $6 a month.

COMMISSIONER SKOP: Okay. And I guess, Commissioners, the point I was trying to make and I'm struggling with is typically for overrecoveries they're refunded across the 12 months in the next year, but in this particular case there is a substantial overrecovery. Part of this overrecovery is basically I think in part being used in terms of how rates will go down next year for FPL's customers, amongst other things. I don't really want to get into that aspect of it.

But what I am looking at is given the amount of overrecovery and past Commission precedent, whether it might be more appropriate to refund that amount sooner rather than over a 12-month period.

Again, you know, there's some pros and cons to that. The pros are obviously you put money back in the consumers' pocket as quickly as possible. The cons are you might see some rate fluctuation through midyear.

Historically there was an order in 2001 where they had refunded an overrecovery for the last three months of that year of approximately $138 million. This is about two and a half times greater. And, again, I just wanted to briefly, in light of the stipulation, discuss whether it might be more appropriate to issue that amount over a near-term 3-month credit rather than spread it over 12.

CHAIRMAN CARTER: Commissioner Edgar.

COMMISSIONER EDGAR: Mr. Chairman, I would ask that we hear from OPC on that suggestion.

CHAIRMAN CARTER: Good morning, Mr. Beck.

MR. BECK: Good morning, Mr. Chairman. Certainly if the reverse were true, if there were an underrecovery, we would be against an immediate surcharge on customers.

I think I'd like to take a moment and speak with the other Intervenors and the Public Counsel, if that would be agreeable to the Commission.

COMMISSIONER EDGAR: I'd also like to hear from the company at whatever is the appropriate time.

CHAIRMAN CARTER: Okay. Let's do this. Let's do this. Let's do this. Let me back up for a moment. Before we get into that issue, which is Issue 10, we probably want to give everyone an opportunity to talk about that. Let's do this. Let's move forward on the things that we can kind of clarify so then we'll be --

I'll get us to a point to where we can break, Commissioners. Then we have a clean break, we take a break, all of the parties can talk about the issue before we come back on that. Because it may -- I mean, there's pros and cons on how to do it, but we certainly want to have all of the parties that are, have a vested interest to be able to discuss it and maybe come back to us with a unified voice, if possible.

Commissioner Skop.

COMMISSIONER SKOP: Thank you, Mr. Chair. And the only other question I have before we approve the remaining stipulations would be just a brief explanation as to Issue 21, which is the GPIF, generating performance incentive factors, as to what led to, to those incentive amounts. Again, that's based on utilities having excellence in their generation, and I think a brief overview of that would be helpful.

MS. BENNETT: I believe that you'll find that beginning on Page 35 of the Prehearing Order, the generic generating performance incentive factors. And I'm going to ask Mr. Matlock to speak to that, I believe.

MR. MATLOCK: These, these rewards and penalties are, those are just the results of the last year's performance with, with regard to heat rate and availability. It's last year's performance in relation to the targets that were set in the, in the fuel hearing year before last. That's --

COMMISSIONER SKOP: Okay. I guess what I was looking for was in terms, in comparison to last year. I think that the, the operational performance of the generating utilities has somewhat improved with one, with one exception in terms of their incentive awards for this year on a year-to-year basis.

MR. MATLOCK: One exception what?

COMMISSIONER SKOP: Well, I guess obviously FPL captured an award of about $11.5 million. So it's met its generation targets and ranges for outages and heat rate. Gulf earned a reward this year, Progress did not, and TECO actually earned a reward this year; is that correct?

MR. MATLOCK: Yes, sir.

COMMISSIONER SKOP: Okay. All right. Thank you.

MR. MATLOCK: Yes, sir. Yes, sir. They were all, all rewards except for the one penalty this year.

COMMISSIONER SKOP: All right. Thank you.

CHAIRMAN CARTER: Thank you.

Commissioners, before dealing with the preliminary, the stipulations, let's do this. Now Issue

10, let's pull that one out, staff. Was that the right one?

MS. BENNETT: Issue 10 I think only for Florida Power & Light, and that's on Page 38. But I think you could probably vote on Issue 10 for, for Progress and TECO.

CHAIRMAN CARTER: Let me ask the parties because I -- Mr. Beck, on this Issue 10, that was the one we were talking about earlier and that we're going to give you an opportunity to revisit on. And staff has brought to my attention that it's probably more appropriate that we just take the one out that pertains to FPL. Is that your understanding?

MR. BECK: Yes.

CHAIRMAN CARTER: With the parties, is that right?

MR. BREW: Yes, sir.

MR. BURNETT: Yes, sir.

CHAIRMAN CARTER: So let's, let's do that, Commissioners. We'll take out item 10, Issue 10 as it relates to FPL. And that way when we get to the break, all of the parties can look over that and come back to that.

Are there any other within this context, Ms. Bennett, from Pages 30 through 43 on that that we need to take out before --

MS. BENNETT: My understanding is that the only purpose of Issue 10 being taken out to discuss is to discuss the length of the recovery time, because otherwise it is a fallout issue. It's the big number that 9 and 8 and 7 relate to. But I think we're just talking about how soon and how quickly to recover that. And if that's the case, then it's just Issue 10 that needs to come out.

CHAIRMAN CARTER: Commissioner Skop, is that your understanding?

COMMISSIONER SKOP: Yes, Mr. Chair. I think you accurately framed it, that it's just Issue 10 as it pertains to the timing of any refund as it pertains to FPL for Issue 10.

CHAIRMAN CARTER: Okay. Okay. Commissioners, before we go forward, anything further?

Staff, recommendation on the --

MS. BENNETT: Staff recommends that the stipulations found on Pages 30 through 43, except for Issue 10 as it relates to Florida Power & Light, be approved.

CHAIRMAN CARTER: Okay. Commissioners?

COMMISSIONER EDGAR: So moved.

COMMISSIONER SKOP: Second.

CHAIRMAN CARTER: Okay, Commissioners, just so we're all on the same page, the stipulations are listed on Pages 30 through 43 of the Prehearing Order. We've taken out Issue 10 as it pertains to FPL only. And so with that, I guess that would, we could take the rest of them in order. Is that right, Ms. Bennett?

MS. BENNETT: We do have one other set of stipulations.

CHAIRMAN CARTER: We're not there yet.

MS. BENNETT: Right. But, yes.

CHAIRMAN CARTER: We're not there yet. Okay. Let's -- first things first. Okay? You know, just, just one, one thing at a time.

Okay. Now, Ms. Bennett, is that correct, Pages 30 through 43?

MS. BENNETT: Yes. Pages --

CHAIRMAN CARTER: With the exception of Issue 10 as it relates to FPL only.

MS. BENNETT: Page 30 through -- let me confirm.

CHAIRMAN CARTER: Through 43, that was what, that's what my notes say.

COMMISSIONER EDGAR: I believe that's correct, Mr. Chairman.

MS. BENNETT: Yes. 30 through 43.

COMMISSIONER EDGAR: That's what my motion encompassed.

CHAIRMAN CARTER: Okay. Then that's the motion that's before us.

Okay. Commissioners, it's been moved and properly seconded. Any further discussion? Any debate? Hearing none, all in favor, let it be known by the sign of aye.

(Affirmative vote.)

All those opposed, like sign.

Show it done.

Ms. Bennett.

MS. BENNETT: The next set of stipulations is found in the handout entitled Docket 090001, Proposed Stipulations, October 30th, 2009, and has been marked as Exhibit 133.

(Exhibit 133 marked for identification.)

CHAIRMAN CARTER: Exhibit 133, Commissioners. Do all the parties -- all the parties have this as well; is that correct?

Okay. Okay. Ms. Bennett, you're recognized.

MS. BENNETT: Staff would, would recommend that the Commission approve the stipulations found on Exhibit 133 at this time.

CHAIRMAN CARTER: Are there any objections from any of the parties? Hearing none, a motion. Commissioner Edgar.

COMMISSIONER EDGAR: Just a question, if I may, Mr. Chairman.

CHAIRMAN CARTER: You're recognized for a question.

COMMISSIONER EDGAR: Thank you. Just to, to make sure I'm clear to staff for Issue 23A, this incorporates the decisions that this Commission recently made in the nuclear cost recovery docket?

MS. BENNETT: Yes, it does.

COMMISSIONER EDGAR: Okay. With that, Mr. Chairman, then I would make a motion at this time that we adopt the proposed stipulations as stated on newly marked Exhibit Number 133.

CHAIRMAN CARTER: Commissioner Skop.

COMMISSIONER SKOP: Thank you. Before I second the motion, just a point of clarification to staff. To Commissioner Edgar's prior question as to the nuclear cost recovery, both of those submittals have been updated by both Progress and FPL and reflected in these numbers; is that correct?

MS. BENNETT: Yes, they have, both for FPL and Progress.

COMMISSIONER SKOP: Okay. And then as to

Issue 33 with the capacity cost recovery factors or any of the other issues in the second group of stipulations under, marked as Exhibit Number 133, will Issue 10 for FPL have any fallout on these remaining stipulations?

MS. BENNETT: No, they won't.

COMMISSIONER SKOP: Okay. Thank you. I would second Commissioner Edgar's motion.

CHAIRMAN CARTER: Okay. It's been moved and properly seconded. Commissioners, any further questions? Any debate? It's been moved and properly seconded. All in favor, let it be known by the sign of aye.

(Affirmative vote.)

All those opposed, like sign.

Show it done.

Staff, you're recognized.

MS. BENNETT: At this time I'd like to note that Gulf is withdrawing Issue 4C, and as such would want to change its positions in Issues 12, 13 and 15. I think Gulf is prepared to address those at this time.

CHAIRMAN CARTER: You're recognized.

MR. BADDERS: Thank you. Good morning. Russell Badders.

Yes. On Friday afternoon we filed a notice withdrawing Issue 4C, which also resulted in our refiling revised testimony, which I have passed out to all the parties and the Commissioners.

In addition to that, there will be changes to Issues 12, 13 and 15, which I can pass out for the record.

CHAIRMAN CARTER: Okay. Staff, your recommendation on proceeding on this?

MS. BENNETT: We recommend that you accept the changed positions. I think that Gulf is handing them out, and that will be the subject of your, of your vote decisions later based upon the testimony.

CHAIRMAN CARTER: Okay. All right then. So all we need to do now is just accept it. We don't need to vote on it or anything like that, we'd just accept it and go forward. Is that the plan?

MS. BENNETT: I think you probably should go ahead and vote on these because it is a change in position.

CHAIRMAN CARTER: Okay. Let's give an opportunity for all the parties to have that. Mr. Badders, did you talk to the other, your compadres on both sides of the bench there?

MR. BADDERS: Yeah. Actually I don't know that these would become stipulated issues. These are the fallout issues.

MS. BENNETT: No, they won't be stipulated issues.

MR. BADDERS: So -- right. So I don't think they're ripe for a decision.

CHAIRMAN CARTER: Okay. Then we'll deal with them as we go further, as we trog through the mud, I mean as we go through the weeds.

MS. BENNETT: And I'm sorry if I confused you. It was not my intention that you would vote to approve these issues, but just to allow Gulf to change its positions in the prehearing statements so that they reflect these new numbers.

CHAIRMAN CARTER: Show it done.

MR. BADDERS: Thank you.

CHAIRMAN CARTER: Okay. Any further preliminary matters, staff?

MS. BENNETT: Yes. In relation to the withdrawal of the Perdido landfill project from Gulf's testimony, when we get to the staff's composite exhibit and when we get to the exhibits there will be some changes in the Comprehensive Exhibit List and in the testimony. I believe that Gulf will hand out new testimony removing those issues. But we can address that as we get to it. I just want to give you a heads-up that that's coming.

My next statement is I believe that FIPUG also wanted to change its position on Issue 15.

CHAIRMAN CARTER: Mr. McWhirter, on Issue 15.

MR. McWHIRTER: Mr. Chairman, I took no position on Issue 15 because it's a fallout position. And if FIPUG is successful in the position it suggests in 8, 9 and 10, the numbers here will change. And I wanted to make it clear that no, I took, we took no position because it's fallout, and I didn't want to go through the calculations to get the results for each class. But we do think it is a fallout position, as has already been stated. And I believe that if you rule in our favor on the other issues, that will change the numbers that are in 15 today.

CHAIRMAN CARTER: Okay. So we just move further, staff; is that cool?

MS. BENNETT: That's correct.

CHAIRMAN CARTER: Okay. Good deal.

MS. BENNETT: One -- oh, I'm sorry.

CHAIRMAN CARTER: You may proceed.

MS. BENNETT: Am I jumping the gun?

We want to note that the, that most of the witnesses have been excused. And it's, generally we take them up in order. But because there are so many witnesses that have been excused, we suggest that perhaps at the beginning of the proceeding once you've opened the record that we go ahead and admit all of the testimony and exhibits of the excused witnesses in, and then you would have just FPU's witnesses and Gulf's witnesses remaining to hear testimony.

CHAIRMAN CARTER: Okay. And unlike we normally do, we normally take them in order, why don't we do it in bulk, en masse as we, right after the opening statements or just before the opening statements. We can just do it at that point in time and then go directly to opening statements. What do you think?

MS. BENNETT: I think right before opening statements, it might shorten your opening statements.

CHAIRMAN CARTER: Excellent. Excellent. I'm all in favor of shortening opening statements.

MS. BENNETT: I will note that staff has a Comprehensive Exhibit List and also staff's composite exhibits, which consist of 2 through 61. There are no objections other than I will make some changes when we get to it to remove those issues related to 4C. After opening statements we'll ask that the Comprehensive Exhibit List and staff's exhibits be moved into the record.

CHAIRMAN CARTER: Okay. Okay. We'll do it at that time then.

MS. BENNETT: There is a motion, outstanding motion from the Attorney General's Office to be excused from the Prehearing Conference. Staff recommends that that be granted at this time.

CHAIRMAN CARTER: Show it done.

MS. BENNETT: There are a number of outstanding motions and petitions regarding confidentiality that will be addressed by the Prehearing Officer after the fuel hearing.

CHAIRMAN CARTER: Okay.

MS. BENNETT: And I don't believe we will be discussing any confidential matters in this hearing, but if we have any, we do need to remember to take precautions that anything that's highlighted in yellow not be discussed openly. That's our general procedure.

CHAIRMAN CARTER: Okay. That's fine with me.

MS. BENNETT: And I have no other preliminary matters.

CHAIRMAN CARTER: Okay. Then on opening statements, five minutes per party. Let's do this before we go there. Are there any preliminary matters from any of the parties? Mr. Burnett.

MR. BURNETT: Mr. Chair, if appropriate, I believe that after the exhibits and testimony come in, at your pleasure I could be dismissed from the proceeding, if you were to be so kind.

CHAIRMAN CARTER: Okay. We'll do that. Not a problem.

MR. BURNETT: Thank you, sir.

CHAIRMAN CARTER: Mr. Beasley.

MR. BEASLEY: We would make a similar request. Thank you.

CHAIRMAN CARTER: Okay. All right. No reasonable offer will be refused.

(Laughter.)

Okay. Staff, are there -- before I go back to staff, any other preliminary matters from any of the parties?

Staff?

MS. BENNETT: I would suggest that -- Mr. Butler was asking was I going move the testimony of the excused witnesses. I would suggest that each party move the testimony and exhibits of their excused witnesses rather than staff.

CHAIRMAN CARTER: Do you want to do that now?

MS. BENNETT: But right now, right now I'd like to move the Comprehensive Exhibit List.

CHAIRMAN CARTER: Let's do this for all the parties, let's do this, we'll take staff's Comprehensive

Exhibit List first. Then all of the witnesses and their exhibits that have been excused, we'll do that now in order. We'll have each one of the party members -- party members, that sounds like part of the old Russia -- we'll have each party's representative make that motion to introduce their witnesses and their exhibits.

Staff, you're recognized for the Comprehensive Exhibit List.

MS. BENNETT: I would move the Comprehensive Exhibit List, which would be Exhibit Number 1, into the record.

CHAIRMAN CARTER: Okay. Without objection, show it done.

(Exhibit 1 marked for identification and admitted into the record.)

MS. BENNETT: I'd also move staff's exhibits 2 through 61, with the exception that for Exhibit 32 we're only moving Items 43 through 47 in. We're not going to move Exhibits 33 through 36 into the record.

CHAIRMAN CARTER: Are there any objections? Without objection, show it done.

(Exhibits 2 through 61 marked for identification.)

(Exhibits 2 through 32 and 37 through 61 admitted into the record.)

Staff?

MS. BENNETT: And I think you could turn to the parties now to move their excused witnesses and exhibits into the record.

CHAIRMAN CARTER: Okay. I'll go from left to right, my left. Mr. Butler, you're recognized.

MR. BUTLER: Thank you, Mr. Chairman. FPL would ask that the prefiled direct testimony of its witnesses G. Yupp, T. J. Keith, J. A. Stall and R. R. Kennedy be inserted into the record as though read.

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

MR. BUTLER: We note that the exhibits for those witnesses are identified as 62 through 67 (sic.) on staff's exhibit list, and I would move the admission into the record of those exhibits at this time.

CHAIRMAN CARTER: Are there any objections? Without objection, show it done.

MR. BUTLER: Thank you.

CHAIRMAN CARTER: Thank you.

REPORTER'S NOTE: Exhibits 62 through 77 were identified and admitted for ease of the record.

(Exhibits 62 through 77 marked for identification and admitted into the record.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 090001-EI

APRIL 3, 2009

Q. Please state your name and address.

A. My name is Gerard J. Yupp. 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 Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Have you previously testified in the predecessors to this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present data on FPL's hedging activities, by month, for calendar year 2008. This data is required per Item 5 of the Resolution of Issues in Docket 011605-EI approved by the Commission per Order No. PSC-02-1484-FOF-EI, which states:

"5. Each investor-owned utility shall provide, as part of its final true-up filing in the fuel and purchased power cost recovery docket, the following information: (1) the volumes of each fuel the utility actually hedged using a fixed price contract or instrument; (2) the types of hedging instruments the utility used, and the volume and type of fuel associated with each type of instrument; (3) the average period of each hedge; and (4) the actual total cost (e.g. fees, commissions, options premiums, futures gains and losses, swaps settlements) associated with using each type of hedging instrument."

The requirement for this data was further clarified in Section III of the Hedging Order Clarification Guidelines that were approved by the Commission per Order No. PSC-08-0667-PAA-EI issued on October 8, 2008.

Q. Are you sponsoring an Exhibit for this proceeding?

A. Yes. I am sponsoring Exhibit GJY-1 -- 2008 Hedging Activity Final True-Up Report.

Q. Please describe FPL's hedging objectives.

A. Consistent with the guiding principles described in Section IV of the Hedging Order Clarification Guidelines, the primary objective of FPL's hedging program is to reduce the impact of fuel price volatility in the fuel adjustment charges paid by FPL's customers. FPL does not execute speculative hedging strategies aimed at "out guessing" the market in the hopes of potentially returning savings to FPL's customers. FPL has implemented a well-disciplined, well-defined, and well-controlled hedging program that is executed in compliance with FPL's risk management policies and procedures.

Q. Please summarize FPL's 2008 hedging activities.

A. FPL hedged its fuel portfolio for 2008 utilizing fixed price transactions. A fixed price transaction allows a buyer to lock in the price of a commodity for a set volume over a set period of time.

Natural gas and fuel oil markets were extremely volatile during 2008. Fuel prices began the year at somewhat moderate levels and within six months climbed to unprecedented highs only to return to moderate levels by the end of the year. Actual monthly settlement prices for natural gas on the NYMEX ranged from $7.17 per MMBtu in January to a high of $13.11 per MMBtu in July, down to a low of $6.47 per MMBtu in November, and finally $6.89 per MMBtu in December. United States Gulf Coast (USGC) heavy fuel oil and New York Harbor (NYH) heavy fuel oil prices were approximately $73 per barrel in January 2008. By July, prices had climbed to approximately $113 per barrel and by year-end had dropped approximately $77 per barrel to $36 per barrel. Overall, FPL's hedging activities helped to reduce the impact of this extreme volatility on customer's fuel charges and resulted in total gains of $368.26 million.

On a cumulative basis, from inception through 2008, FPL's expanded hedging program has resulted in net losses of approximately $16.5 million. While the cumulative impact of FPL's hedging program will vary and, at times, may show either net savings or net losses, FPL expects that the cumulative, long-term impact of its hedging program will not result in significant savings or losses to FPL's customers.

Q. Does your Exhibit GJY-1 provide the detail on FPL's 2008 hedging activities required by Item 5 of the Resolution of Issues?

A. Yes.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 090001-EI

AUGUST 20, 2009

Q. Please state your name and address.

A. My name is Gerard J. Yupp. 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 Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain FPL's projections for (1) the dispatch costs of heavy fuel oil, light fuel oil, coal and natural gas; (2) the availability of natural gas to FPL; (3) generating unit heat rates and availabilities; and (4) the quantities and costs of wholesale (off-system) power and purchased power transactions. Lastly, I review FPL's 2009 hedging program and its 2010 Risk Management Plan.

Q. Have you prepared or caused to be prepared under your supervision, direction and control any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

- GJY-3: Appendix I
- Schedules E2 through E9 of Appendix II

FUEL PRICE FORECAST

Q. What forecast methodologies has FPL used for the 2010 recovery period?

A. For natural gas commodity prices, the forecast methodology relies upon the NYMEX Natural Gas Futures contract prices (forward curve). For light and heavy fuel oil prices, FPL utilizes Over-The-Counter (OTC) forward market prices. Projections for the price of coal are based on actual coal purchases and price forecasts developed by J.D. Energy. Forecasts for the availability of natural gas are developed internally at FPL and are based on contractual commitments and market experience. The forward curves for both natural gas and fuel oil represent expected future prices at a given point in time and are consistent with the prices at which FPL can transact its hedging program. The basic assumption made with respect to using the forward curves is that all available data that could impact the price of natural gas and fuel oil in the future is incorporated into the curves at all times. The methodology allows FPL to execute hedges consistent with its forecasting method and to optimize the dispatch of its units in changing market conditions. FPL utilized forward curve prices from the close of business on August 10, 2009 for its 2010 projection filing.

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the January through December 2010 period?

A. The key factors that could affect FPL's price for heavy oil are (1) worldwide demand for crude oil and petroleum products (including domestic heavy fuel oil); (2) non-OPEC crude oil supply; (3) the extent to which OPEC adheres to their quotas and reacts to fluctuating demand for OPEC crude oil; (4) the political and civil tensions in the major producing areas of the world like the Middle East and West Africa; (5) the availability of refining capacity; (6) the price relationship between heavy fuel oil and crude oil; (7) the price relationship between heavy oil and natural gas; (8) the supply and demand for heavy oil in the domestic market; (9) the terms of FPL's supply and fuel transportation contracts; and (10) domestic and global inventory.

While global demand for oil continues to be weak and inventories remain high, crude oil prices have steadily risen over the past several months, reflecting market expectations for economic recovery and an increase in the demand for oil. Therefore, the extent of economic growth will be a major driver for the price of crude oil and petroleum products in 2010. Currently, global consumption is expected to increase slightly in 2010 in response to positive economic growth, however sufficient OPEC production capacity is expected to be available to meet this projected increase in demand and help moderate the price of oil. A greater-than-expected economic recovery resulting in higher-than-expected oil demand will put upward pressure on price. Conversely, a weaker-than-expected global economic recovery will put downward pressure on the price of oil.

Q. Please provide FPL's projection for the dispatch cost of heavy fuel oil for the January through December 2010 period.

A. FPL's projection for the system average dispatch cost of heavy fuel oil, by month, is provided on page 3 of Appendix I.

Q. What are the key factors that could affect the price of light fuel oil?

A. The key factors are similar to those described above for heavy fuel oil.

Q. Please provide FPL's projection for the dispatch cost of light fuel oil for the January through December 2010 period.

A. FPL's projection for the system average dispatch cost of light oil, by month, is provided on page 3 of Appendix I.

Q. What is the basis for FPL's projections of the dispatch cost of coal for St. Johns' River Power Park (SJRPP) and Plant Scherer?

A. FPL's projected dispatch costs for both plants are based on FPL's price projection for spot coal, delivered to the plants.

Q. Please provide FPL's projection for the dispatch cost of SJRPP and Plant Scherer for the January through December 2010 period.

A. FPL's projection for the system average dispatch cost of coal for this period, by plant and by month, is shown on page 3 of Appendix I.

Q. What are the factors that can affect FPL's natural gas prices during the January through December 2010 period?

A. In general, the key physical factors are (1) North American natural gas demand and domestic production; (2) LNG and Canadian natural gas imports; (3) heavy fuel oil and light fuel oil prices; and (4) the terms of FPL's natural gas supply and transportation contracts.

Similar to oil, the major driver for natural gas prices during 2010 revolves around economic recovery and an associated increase in demand. Future prices reflect this expectation of economic recovery. Natural gas prices fell dramatically in 2009 as demand dropped, particularly in the industrial sector, while domestic production remained unchanged. Although the number of working natural gas rigs is down almost 60% since August 2008, domestic production from unconventional sources continues to create ample supply. Natural gas storage is projected to reach record levels by the end of the 2009 injection season. Natural gas consumption in 2010 is projected to remain relatively flat compared to 2009; however domestic production is projected to decline. Higher projected prices in 2010 compared to current levels reflect this "balancing" of supply and demand.

Q. What are the factors that FPL expects to affect the availability of natural gas to FPL during the January through December 2010 period?

A. The key factors are (1) the capacity of the Florida Gas Transmission (FGT) pipeline into Florida; (2) the capacity of the Gulfstream Natural Gas System (Gulfstream) pipeline into Florida; (3) the portion of FGT and Gulfstream capacity that is contractually committed to FPL on a firm basis each month; and (4) the natural gas demand in the State of Florida.

The current capacity of FGT into the State of Florida is approximately 2,030,000 million BTU per day and the current capacity of Gulfstream is about 1,100,000 million BTU per day. For 2010, FPL has firm natural gas transportation capacity on FGT ranging from 750,000 to 874,000 million BTU per day, depending on the month, and 695,000 million BTU per day of firm natural gas transportation on Gulfstream. Additionally, FPL has 500,000 million BTU per day of firm transport on the Southeast Supply Header (SESH) pipeline. The firm transport on the SESH pipeline does not increase transportation capacity into the state, but FPL's firm transportation rights on this pipeline provide FPL access to 500,000 million BTU per day of on-shore natural gas supply, which helps diversify FPL's natural gas portfolio and enhance the reliability of fuel supply. FPL projects that during the January through December 2010 period between 100,000 and 280,000 million BTU per day of non-firm natural gas transportation capacity (varying by month) will be available into the state. FPL projects that it could acquire some of this capacity, if economic, to supplement FPL's firm allocation on FGT and Gulfstream. This projection is based on the current capability and availability of the two interconnections between Gulfstream and FGT pipeline systems, as well as FPL's projected Florida natural gas supply/demand balance.

Q. Please provide FPL's projections for the dispatch cost and availability of natural gas for the January through December 2010 period.

A. FPL's projections of the system average dispatch cost and availability of natural gas, by transport type, by pipeline and by month, are provided on page 3 of Appendix I.

<u>PLANT HEAT RATES, OUTAGE FACTORS, PLANNED OUTAGES, AND CHANGES IN GENERATING CAPACITY</u>

Q. Please describe how FPL developed the projected Average Net Heat Rates shown on Schedule E4 of Appendix II.

A. The projected Average Net Heat Rates were calculated by the POWRSYM model. The current heat rate equations and efficiency factors for FPL's generating units, which present heat rate as a function of unit power level, were used as inputs to POWRSYM for this calculation. The heat rate equations and efficiency factors are updated as appropriate based on historical unit performance and projected changes due to plant upgrades, fuel grade changes, and/or from the results of performance tests.

Q. Are you providing the outage factors projected for the period January through December 2010?

A. Yes. This data is shown on page 4 of Appendix I.

Q. How were the outage factors for this period developed?

A. The unplanned outage factors were developed using the actual historical full and partial outage event data for each of the units. The historical unplanned outage factor of each generating unit was adjusted, as necessary, to eliminate non-recurring events and recognize the effect of planned outages to arrive at the projected factor for the period January through December 2010.

Q. **Please describe the significant planned outages for the January through December 2010 period.**

A. Planned outages at FPL's nuclear units are the most significant in relation to fuel cost recovery. St. Lucie Unit 1 is scheduled to be out of service from April 5, 2010 until May 20, 2010 or 45 days during the period. Turkey Point Unit 3 is scheduled to be out of service from September 27, 2010 until November 1, 2010 or 35 days during the period. St. Lucie Unit 2 is scheduled to be out of service from November 8, 2010 until January 11, 2011 or 54 days during the projected period (64 days total).

Q. **Please list any changes to FPL's fossil generation capacity projected to take place during the January through December 2010 period.**

A. FPL does not project to have any changes to its fossil generation capacity during 2010.

WHOLESALE (OFF-SYSTEM) POWER AND PURCHASED POWER TRANSACTIONS

Q. **Are you providing the projected wholesale (off-system) power and purchased power transactions forecasted for January through December 2010?**

A. Yes. This data is shown on Schedules E6, E7, E8, and E9 of Appendix II of this filing.

Q. In what types of wholesale (off-system) power transactions does FPL engage?

A. FPL purchases power from the wholesale market when it can displace higher cost generation with lower cost power from the market. FPL will also sell excess power into the market when its cost of generation is lower than the market. Purchasing and selling power in the wholesale market allows FPL to lower fuel costs for its customers because savings on purchases and gains on sales are credited to the customer through the Fuel Cost Recovery Clause. Power purchases and sales are executed under specific tariffs that allow FPL to transact with a given entity. Although FPL primarily transacts on a short-term basis (hourly and daily transactions), FPL continuously searches for all opportunities to lower fuel costs through purchasing and selling wholesale power, regardless of the duration of the transaction. Additionally, FPL has become a member of the Florida Cost-Based Broker System (FCBBS) and will begin transacting on the FCBBS when it becomes operational in early October 2009. The FCBBS will match hourly cost-based bids and offers to maximize savings for all participants. Currently, the FCBBS is comprised of 11 members, including FPL. FPL can also purchase and sell power during emergency conditions under several types of Emergency Interchange agreements that are in place with other utilities within Florida.

Q. Please describe the method used to forecast wholesale (off-system) power purchases and sales.

A. The quantity of wholesale (off-system) power purchases and sales are projected based upon estimated generation costs, generation availability, expected market conditions and historical data.

Q. What are the forecasted amounts and costs of wholesale (off-system) power sales?

A. FPL has projected 1,288,000 MWh of wholesale (off-system) power sales for the period of January through December 2010. The projected fuel cost related to these sales is $52,746,120. The projected transaction revenue from these sales is $70,194,000. The projected gain for these sales is $14,959,057.

Q. In what document are the fuel costs for wholesale (off-system) power sales transactions reported?

A. Schedule E6 of Appendix II provides the total MWh of energy, total dollars for fuel adjustment, total cost and total gain for wholesale (off-system) power sales.

Q. What are the forecasted amounts and costs of wholesale (off-system) power purchases for the January to December 2010 period?

A. The costs of these purchases are shown on Schedule E9 of Appendix II. For the period, FPL projects it will purchase a total of 838,590 MWh at a cost of $38,832,738. If FPL generated this energy, FPL estimates that it would cost $52,054,017. Therefore, these purchases are projected to result in savings of $13,221,279.

Q. Does FPL have additional agreements for the purchase of electric power and energy that are included in your projections?

A. Yes. FPL purchases coal-by-wire electrical energy under the 1988 Unit Power Sales Agreement (UPS) with the Southern Companies. This agreement, in its current form, will expire on May 31, 2010. A new UPS agreement that was approved by the Commission in 2004 will go into effect beginning on June 1, 2010. It is comprised of 790 MW of gas-fired, combined cycle generation (Franklin Unit 1-190 MW and Harris Unit 1-600 MW) and 165 MW of coal generation (Scherer Unit 3). The new UPS agreement has a term that runs through December 31, 2015. FPL also has contracts to purchase and sell nuclear energy under the St. Lucie Plant Nuclear Reliability Exchange Agreements with Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA). Additionally, FPL purchases energy from JEA's portion of the SJRPP Units.

Capacity that FPL purchases through short-term agreements will be lower in 2010 compared with 2009, as three of FPL's short-term capacity agreements expire in 2009. FPL's agreements with Constellation Energy Commodities Group, Inc. expired on April 30,

2009. FPL's agreements with Reliant Energy Services and JP Morgan Ventures Energy Corp. will expire on December 31, 2009. The capacity associated with these agreements totaled approximately 785 MW. FPL's remaining short-term capacity agreement for 2010 is with Southern Power Company (Oleander) for the output of one combustion turbine totaling 155 MW. The Southern Power Company (Oleander) agreement expires on May 31, 2012.

Lastly, FPL purchases energy and capacity from Qualifying Facilities under existing tariffs and contracts.

Q. Please provide the projected energy costs to be recovered through the Fuel Cost Recovery Clause for the power purchases referred to above during the January through December 2010 period.

A. Under the current UPS agreement, FPL's capacity entitlement during the period from January through May 2010 is 932 MW. Based upon the alternate and supplemental energy provisions of UPS, an availability factor of 100% is applied to these capacity entitlements to project energy purchases. The projected UPS energy (unit) cost for this period, used as an input to POWRSYM, is based on data provided by the Southern Companies. UPS energy purchases under the current agreement are projected to be

3,318,655 MWh for January through May 2010 at an energy cost of $89,966,000. Under the new UPS agreement, FPL projects to purchase a total of 2,748,144 MWh from June through December 2010 at a projected energy cost of $99,759,000. The total UPS energy projections (existing and new) are presented on Schedule E7 of Appendix II.

Energy purchases from the JEA-owned portion of SJRPP are projected to be 3,110,177 MWh for the period at an energy cost of $97,198,000. FPL's cost for energy purchases under the St. Lucie Plant Reliability Exchange Agreements is a function of the operation of St. Lucie Unit 2 and the fuel costs to the owners. For the period, FPL projects purchases of 389,031 MWh at a cost of $2,015,028. These projections are shown on Schedule E7 of Appendix II.

FPL projects to dispatch 28,530 MWh from its short-term capacity agreement with Southern Power Company (Oleander) at a cost of $2,348,452. These projections are shown on Schedule E7 of Appendix II.

In addition, as shown on Schedule E8 of Appendix II, FPL projects that purchases from Qualifying Facilities for the period will provide 4,852,014 MWh at a cost of $182,019,000.

Q. What are the forecasted amounts and cost of energy being sold under the St. Lucie Plant Reliability Exchange Agreement?

A. FPL projects the sale of 471,599 MWh of energy at a cost of $3,409,622. These projections are shown on Schedule E6 of Appendix II.

Q. How does FPL develop the projected energy costs related to purchases from Qualifying Facilities?

A. For those contracts that entitle FPL to purchase "as-available" energy, FPL used its fuel price forecasts as inputs to the POWRSYM model to project FPL's avoided energy cost that is used to set the price of these energy purchases each month. For those contracts that enable FPL to purchase firm capacity and energy, the applicable Unit Energy Cost mechanisms prescribed in the contracts are used to project monthly energy costs.

<u>HEDGING/ RISK MANAGEMENT PLAN</u>

Q. Please describe FPL's hedging objectives.

A. The primary objective of FPL's hedging program has been, and remains, the reduction of fuel price volatility. Reducing fuel price volatility helps deliver greater price certainty to FPL's customers. FPL does not engage in speculative hedging strategies aimed at "out guessing" the market.

Q. Has FPL filed a comprehensive risk management plan for 2010, consistent with the Hedging Order Clarification Guidelines as required by Order PSC- 08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its 2010 Risk Management Plan as part of its annual Fuel Cost Recovery and Capacity Cost Recovery Estimated/Actual True/Up filing on August 4, 2009.

Q. Please provide an overview of FPL's 2010 Risk Management Plan.

A. FPL's 2010 Risk Management Plan remains consistent with FPL's overall objectives that I previously described. It addresses Items 1-9 and 13-15 of Exhibit TFB-4, which is required per the Proposed Resolution of Issues approved in Order No. PSC-02-1484-FOF-EI dated October 30, 2002. FPL's 2010 Risk Management Plan specifically addresses the parameters within which FPL intends to place hedges in 2010 for its projected fuel requirements in 2011. FPL plans to hedge the percentages of its 2011 projected natural gas and heavy oil requirements over the time periods in 2010 that are described in the plan.

Q. Has FPL filed a Hedging Activity Supplemental Report for 2009, consistent with the Hedging Order Clarification Guidelines, as required by Order PSC- 08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its Hedging Activity Supplemental Report for 2009 (January through July) on August 17, 2009.

Q. Have FPL's 2009 hedging strategies been successful in achieving its hedging objectives?

A. Yes. FPL's hedging strategies have been successful in reducing fuel price volatility and delivering greater price certainty to its customers. Additionally, FPL's customers have been able to benefit from the extreme decrease in natural gas and heavy oil prices from the unhedged portion of FPL's portfolio. As described previously in this testimony, the economic downturn has substantially impacted the price of natural gas and heavy oil during 2009. At the time FPL was placing its hedges for its 2010 projected natural gas and heavy oil requirements, market conditions were significantly different than exist today. For example, at the end of July 2008 (within FPL's hedging window for 2009 hedges), the average monthly NYMEX forward price for the January through July 2009 time period was approximately $9.70 per MMBtu. The actual average NYMEX monthly settlement price for this same time period was $4.16 per MMBtu or $5.54 per MMBtu lower. Likewise, for the same January through July 2009 time period, monthly forward heavy oil prices at the end of July 2008 averaged approximately $105 per barrel. Actual monthly prices during this time period averaged $47.43 per barrel or almost $58 per barrel lower. As described in the Hedging Order Clarification Guidelines, hedging in this type of market conditions results in significant lost opportunities for savings in the fuel costs paid by customers; however, this lost opportunity is a reasonable trade-off for reducing customers' exposure to fuel price increases when market conditions change in the other direction.

Q. Does FPL's projection filing include incremental operating and maintenance expenses with respect to maintaining an expanded, non-speculative financial and/or physical hedging program for the January through December 2010 period?

A. Yes. FPL projects to incur incremental expenses of $715,000. The projected expenses are comprised of salaries and employee-related expenses for the three personnel who were added to support FPL's enhanced hedging program, incremental annual license fees for FPL's volume forecasting software and incremental expenses associated with credit costs necessary to support FPL's hedging program. However, as described in the testimony of FPL witness Terry J. Keith, FPL is proposing to recover these incremental hedging costs through base rates.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 090001-EI

MARCH 9, 2009

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

A. My name is Terry J. Keith and my business address is 9250 West Flagler Street, Miami, Florida, 33174. I am employed by Florida Power & Light Company (FPL or the Company) as Director, Cost Recovery Clauses in the Regulatory Affairs Department.

Q. Please state your education and business experience.

A. I graduated from North Carolina Agricultural & Technical State University with a Bachelor's degree in Accounting in 1977. I subsequently earned a Master of Business Administration degree from the University of Wisconsin in 1982. Prior to joining FPL in 2006, I held various accounting positions at Phillips Petroleum Company and later Centel Corporation. At FPL, I held positions of increasing responsibility in the Accounting Department, including various supervision assignments relating to accounting research, financial reporting, development and application of overhead rates, and property accounting. I spent ten years in the Regulatory Affairs Department as Principal Regulatory Coordinator and later as Regulatory Issues Manager primarily responsible for managing and coordinating regulatory accounting and finance dockets. In 2008, I assumed my current position as Director, Cost Recovery Clauses, where I am responsible for providing direction as to the appropriateness of cost recovery through a cost recovery clause and the overall preparation and filing of all cost recovery clause documents including testimony and discovery.

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

A. The purpose of my testimony is to present the schedules necessary to support the actual Fuel Cost Recovery (FCR) Clause and Capacity Cost Recovery (CCR) Clause Net True-Up amounts for the period January 2008 through December 2008. The Net True-Up for the FCR is an under-recovery, including interest, of $79,321,012. The Net True-Up for the CCR is an under-recovery, including interest, of $14,920,089. FPL is requesting Commission approval to include the FCR true-up under-recovery of $79,321,012 in the calculation of the FCR factor for the period January 2010 through December 2010. FPL is also requesting Commission approval to include the CCR true-up under-recovery of $14,920,089 in the calculation of the CCR factor for the period January 2010 through December 2010.

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

A. Yes, I have. It consists of two appendices. Appendix I contains the FCR related schedules and Appendix II contains the CCR related schedules. In addition, FCR Schedules A-1 through A-12 for the January 2008 through December 2008 period have been filed monthly with the Commission and served on all parties of record in this docket. Those schedules are incorporated herein by reference.

Q. What is the source of the data that you will present in this proceeding?

A. Unless otherwise indicated, the data are taken from the books and records of FPL. The books and records are kept in the regular course of the Company's business in accordance with generally accepted accounting principles and practices, and with the applicable provisions of the Uniform System of Accounts as prescribed by the Commission.

FUEL COST RECOVERY CLAUSE (FCR)

Q. Please explain the calculation of the Net True-up Amount.

A. Appendix I, page 3, entitled "Summary of Net True-Up," shows the calculation of the Net True-Up for the period January 2008 through December 2008, an under-recovery of $79,321,012.

The Summary of the Net True-up amount shown on Appendix I, page 3 shows the actual End-of-Period True-Up under-recovery for the period January 2008 through December 2008 of $255,605,390 on line 1. The Estimated/Actual True-Up under-recovery for the same period of $176,284,378 is shown on line

2. Line 1 less line 2 results in the Net Final True-Up for the period January 2008 through December 2008 shown on line 3, an under-recovery of $79,321,012.

The calculation of the true-up amount for the period follows the procedures established by this Commission set forth on Commission Schedule A-2 "Calculation of True-Up and Interest Provision."

Q. Have you provided a schedule showing the calculation of the actual true-up by month?

A. Yes. Appendix I, pages 4 and 5, entitled "Calculation of Actual True-up Amount," show the calculation of the FCR actual true-up by month for January 2008 through December 2008.

Q. Have you provided a schedule showing the variances between actuals and estimated/actuals for 2008?

A. Yes. Appendix I, page 6 provides a comparison of jurisdictional revenues and costs on a dollar per MWh basis. Appendix I, page 7 compares the Actual End of Period Net True-up under-recovery of $255,605,390 to the Estimated/Actual End of Period Net True-up under-recovery of $176,284,377 resulting in a variance of $79,321,012.

Q. Please describe the variance analysis on Page 6 of Appendix I.

A. Appendix I, page 6 provides a comparison of Jurisdictional Total Revenues and Jurisdictional Total Fuel Costs and Net Power Transactions on a dollar per MWh basis. The $79,321,012 variance is due primarily to an increase in the fuel cost per MWh ($59.12/MWh vs. $58.49/MWh) that results in a positive variance of $64,402,834 and a decrease in fuel revenues per MWh ($58.77/MWh vs. $58.91/MWh) that results in a negative variance of $14,829,009. The impact of the MWh variance due to consumption was virtually offset between cost per MWh and revenues per MWh, netting to a decrease of $713,405. Finally, the variance reflects a decrease of $624,236 in interest primarily due to lower than expected commercial paper rates.

Q. What was the variance in Adjusted Total Fuel Costs and Net Power Transactions?

A. The variance in Adjusted Total Fuel Costs and Net Power Transactions was $35,361,301. As shown on Appendix I, page 7, this $35.4 million decrease in Adjusted Total Fuel Costs and Net Power Transactions is due primarily to a $31.6 million (0.6%) decrease in the Fuel Cost of System Net Generation, a $9.1 million (14.3%) decrease in the Energy Cost of Economy Purchases and a $3.2 million (1.0%) decrease in Fuel Cost of Purchased Power. These amounts are partially offset by a $6.3 million (3.3%) increase in Energy Payments to Qualifying Facilities and a $1.1 million (1.8%) decrease in the Fuel Cost of Power Sold.

As shown on the December 2008 A3 Schedule, the $31.6 million (0.6%)

decrease in the Fuel Cost of System Net Generation is primarily due to a $39.8 million (0.8%) lower than projected natural gas cost, partially offset by a $8.9 million (1.5%) greater than projected heavy oil cost. The natural gas price averaged $10.24 per MMBtu, $0.05 per MMBtu (0.5%) higher than projected, but 6,236,773 fewer MMBtus (1.3%) of natural gas were used during the period than projected. Of the $39.8 million natural gas variance, $63.6 million is due to lower natural gas consumption partially offset by $23.8 million due to higher prices. Heavy oil averaged $10.30 per MMBtu, $0.31 per MMBtu (3.1%) higher than projected, but 951,657 less MMBtus (1.6%) of heavy oil were used during the period than projected. Of the $8.9 million heavy oil variance, $18.4 million is due to higher heavy oil prices partially offset by $9.5 million due to lower heavy oil consumption.

The $9,146,631 decrease in the Energy Cost of Economy Purchases is primarily due to lower than projected economy purchases (246,824 MWh less than projected). This consumption variance accounts for $17,598,140, which is partially offset by the cost variance of $8,451,509.

The $3.2 million (1.0%) decrease in Fuel Cost of Purchased Power is primarily due to lower than projected energy deliveries due to higher than projected energy rates for the Southern Company UPS contract and lower than projected utilization of FPL's short-term purchased power agreements. This

$3.2 million decrease reflects a $6.3 million reduction due to lower consumption partially offset by an increase of $3.1 million due to higher cost.

The $6.3 million (3.3%) increase in Energy Payments to Qualifying Facilities is primarily due to an increase in energy purchases from Cedar Bay and ICL. This $6.3 million variance reflects $8.9 million due to higher consumption partially offset by a reduction of $2.6 million due to lower cost.

The $1.1 million (1.8%) variance in the Fuel Cost of Power Sold is primarily due to lower than projected fuel costs for economy sales. Power sold was actually higher than projected (13,943 MWh); however the fuel cost of this power was approximately $.96/MWh less than projected. Of this $1.1 million variance, $1,595,811 due to lower cost and $504,396 is due to higher consumption.

Q. What was the variance in retail (jurisdictional) Fuel Cost Recovery revenues?

A. As shown on Appendix I, page 7, line C3, actual jurisdictional Fuel Cost Recovery revenues, net of revenue taxes, were $115.3 million (1.9%) lower than the estimated/actual projection reflecting lower than projected jurisdictional sales of 1,706,024,857 kWh (1.6%).

Q. Pursuant to Commission Order No. PSC-08-0824-FOF-EI, FPL's 2008 gains on non-separated wholesale energy sales are to be measured against

a three-year average Shareholder Incentive Benchmark of $19,668,561. Did FPL exceed this benchmark?

A. No.

Q. What is the appropriate final Shareholder Incentive Benchmark level for calendar year 2009 for gains on non-separated wholesale energy sales eligible for a shareholder incentive as set forth by Order No. PSC-00-1744-PAA-EI in Docket No. 991779-EI?

A. For the year 2009, the three year average Shareholder Incentive Benchmark consists of actual gains for 2006, 2007 and 2008 (see below) resulting in a three year average threshold of $18,328,381.

2006	$19,438,254
2007	$18,545,406
2008	$17,001,482

Gains on sales in 2009 are to be measured against the three-year average Shareholder Incentive Benchmark of $18,328,381.

CAPACITY COST RECOVERY CLAUSE (CCR)

Q. Please explain the calculation of the Net True-up Amount.

A. Appendix II, page 3, entitled "Summary of Net True-Up" shows the calculation of the Net True-Up for the period January 2008 through December

2008, an under-recovery of $14,920,089, which FPL is requesting to be included in the calculation of the CCR factors for the January 2010 through December 2010 period.

The actual End-of-Period under-recovery for the period January 2008 through December 2008 of $41,752,805 (shown on line 1) less the estimated/actual End-of-Period under-recovery for the same period of $26,832,716 that was approved by the Commission in Order No. PSC-08-0824-FOF-EI (shown on line 2), results in the Net True-Up under-recovery for the period January 2008 through December 2008 (shown on line 3) of $14,920,089.

Q. Have you provided a schedule showing the calculation of the actual true-up by month?

A. Yes. Appendix II, pages 4 and 5, entitled "Calculation of Actual True-up Amount," shows the calculation of the CCR End-of-Period true-up for the period January 2008 through December 2008 by month.

Q. Is this true-up calculation consistent with the true-up methodology used for the fuel cost recovery clause?

A. Yes, it is. The calculation of the true-up amount follows the procedures established by this Commission set forth on Commission Schedule A-2 "Calculation of True-Up and Interest Provision" for the Fuel Cost Recovery Clause.

Q. Have you provided a schedule showing the variances between actuals and

estimated/actuals?

A. Yes. Appendix II, page 6, entitled "Calculation of Final True-up Variances," shows the actual capacity charges and applicable revenues compared to the estimated/actuals for the period January 2008 through December 2008.

Q. What was the variance in net capacity charges?

A. Appendix II, page 6, Line 13 provides the variance in Jurisdictional Capacity Charges, which is a decrease of $2,257,177 or 0.4%. This $2,257,177 variance was primarily due to a $6,389,418 (21.5%) decrease in Incremental Power Plant Security Costs, partially offset by a $2,398,601 (0.7%) increase in Payments to Cogenerators, a $703,762 (21.2%) decrease in Transmission Revenues from Capacity Sales and a $511,794 (7.7%) increase in Transmission of Electricity by Others.

The $6,389,418 (21.5%) decrease in Incremental Power Plant Security Costs is primarily due to: (1) Hiring requirements related to NRC Part 26 that were originally budgeted to begin in January 2008 were ultimately not required until the end of 2008; (2) project activities related to anticipated Part 73 rule requirements were deferred to 2009 due to the fact that no NRC orders were issued in 2008; and (3) lower than budgeted Wackenhut officer costs.

The $2,398,601 (0.7%) increase in Payments to Cogenerators is due to higher than estimated capacity payments to ICL, BN and BS of $3.3 million, $0.3

million and $0.1 million, respectively, from August to December 2008, partially offset by lower than estimated capacity payments to Cedar Bay of $1.3 million for the same period.

The $703,762 (21.2%) decrease in Transmission Revenues from Capacity Sales is due to lower than projected economy power sales. From August through December, FPL sold 231,122 MWh less of economy power than projected. This resulted in lower than projected Transmission Revenues from Capacity Sales.

The $511,794 (7.7%) increase in Transmission of Electricity by Others is due to the fact that the transmission provider that FPL utilizes for its Indian River PPA raised its firm transmission rate beginning in February 2008.

Q. What was the variance in Capacity Cost Recovery revenues?

A. As shown on page 6, line 16, actual Capacity Cost Recovery Revenues (Net of Revenue Taxes), were $17,101,376 (3.3%) lower than the estimated/actual projection. This $17,101,376 decrease in revenues, less the $2,257,177 decrease in costs, plus interest of $75,891 (page 6, line 18), results in the final under-recovery of $14,920,089.

Q. Have you provided Schedule A12 showing the actual monthly capacity payments by contract?

A. Yes. Schedule A12 consists of two pages that are included in Appendix II as pages 7 and 8. Page 7, shows the actual capacity payments for Qualifying Facilities, the Southern Company UPS contract and the St John River Power Park (SJRPP) contract. Page 8 provides the Short Term Capacity payments for the period January 2008 through December 2008.

Q. **Does this conclude your testimony?**

A. Yes, it does.

ERRATA SHEET

Direct testimony of Terry J. Keith. Fuel Cost Recovery Final True-up for the period January 2008 through December 2008, filed on March 9, 2009 in Docket No. 090001-EI.

PAGE/LINE	CHANGE OR CORRECTION
1/16	Strike "2006". Replace with "1986".

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 090001-EI

August 4, 2009

Q. Please state your name and address.

A. My name is Terry J. Keith and my business address is 9250 West Flagler Street, Miami, Florida 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as Director, Cost Recovery Clauses in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the calculation of the Estimated/Actual True-up amounts for the Fuel Cost Recovery (FCR) Clause and the Capacity Cost Recovery (CCR) Clause for the period January 2009 through December 2009.

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

A. Yes, I have. It consists of various schedules included in Appendices I and II. Appendix I contains the FCR related schedules and Appendix

II contains the CCR related schedules.

The FCR Schedules contained in Appendix I include Schedules E3 through E9 that provide revised estimates for the period July 2009 through December 2009. FCR Schedules A1 through A9 provide actual data for the period January 2009 through June 2009. They are filed monthly with the Commission, are served on all parties and are incorporated herein by reference.

The CCR Schedules contained in Appendix II provide the calculation of estimated/actual variances and the estimated/actual true-up amount for the period January through December 2009.

Q. **What is the source of the actual data that you will present by way of testimony or exhibits in this proceeding?**

A. Unless otherwise indicated, the actual data is taken from the books and records of FPL. The books and records are kept in the regular course of our business in accordance with generally accepted accounting principles and practices, as well as the provisions of the Uniform System of Accounts as prescribed by this Commission.

Q. **Please describe what data FPL has used as a comparison when calculating the FCR and CCR true-ups that are presented in your testimony.**

A. The FCR true-up calculation compares estimated/actual data consisting of actuals for January through June 2009, and revised estimates for July through December 2009, with the original projections filed on November 17, 2008. The CCR true-up calculation compares estimated/actual data consisting of actuals for January through June 2009, and revised estimates for July through December 2009 with the original estimates for January through December 2009 filed on September 2, 2008.

Q. Please explain the calculation of the interest provision that is applicable to the FCR and CCR true-ups.

A. The calculation of the interest provision follows the same methodology used in calculating the interest provision for the other cost recovery clauses, as previously approved by this Commission. The interest provision is the result of multiplying the monthly average true-up amount times the monthly average interest rate. The average interest rate for the months reflecting actual data is developed using the 30 day commercial paper rates as published in the Wall Street Journal on the first business day of the current and subsequent months. The average interest rate for the projected months is the actual rate as of the first business day in July 2009.

FUEL COST RECOVERY CLAUSE

Q. Please explain the calculation of the FCR End of Period Net True-up and Estimated/Actual True-up amounts you are requesting this Commission to approve.

A. Appendix I, pages 2 and 3, show the calculation of the FCR End of Period Net True-up and Estimated/Actual True-up amounts. The end of period net true-up amount to be carried forward to the 2010 fuel factor is an over-recovery of $335,111,088 (Appendix I, Page 3, Column 13, Line C11). This $335,111,088 over-recovery includes the 2008 Final True-up under-recovery of $79,321,012 (Appendix I, Page 3, Column 13, Line C9b), filed with the Commission on March 9, 2009, and the Estimated/Actual True-up over-recovery, including interest, of $414,432,100 (Appendix I, Page 3, Column 13, Lines C7 plus C8) for the period January 2009 through December 2009.

Q. Were these calculations made in accordance with the procedures previously approved in predecessors to this Docket?

A. Yes, they were.

Q. Have you provided a schedule showing the calculation of the estimated/actual true-up by month?

A. Yes. Appendix I, pages 2 and 3, entitled "Calculation of True-Up Amount," show the calculation of the FCR estimated/actual true-up by month for January 2009 through December 2009.

Q. Have you provided a schedule showing the variances between estimated/actuals and original projections for 2009?

A. Yes. Appendix I, page 4 provides a comparison of jurisdictional revenues and costs on a dollar per MWh basis. Appendix I, page 5 provides a variance calculation that compares the Estimated/Actual data to the original projections filing for the January through December 2009 period.

Q. Please describe the variance analysis on page 4 of Appendix I.

A. Appendix I, page 4 provides a comparison of Jurisdictional Total Revenues and Jurisdictional Total Fuel Costs and Net Power Transactions on a dollar per MWh basis. The $335,111,088 variance is primarily due to a decrease in the fuel cost per MWh of $51.14/MWh vs. $55.40/MWh that results in a variance of ($431,392,069) and a decrease in fuel revenues per MWh of $57.02/MWh vs. $57.12/MWh that results in a variance of ($9,456,400), for a total variance due to cost of $421,935,669. The impact of the variance due to consumption was mostly offset between cost per MWh and revenues per MWh, netting to a variance due to consumption of ($8,275,548). The variance analysis also reflects a decrease of $65,563 in interest primarily due to lower than expected commercial paper rates. When the 2008 final true-up under-recovery amount of $79,321,012 and the adjustment of $706,415 associated with Order No. PSC-09-0024-FOF-EI (difference between the approved refund amount and actual refund amount applied to customer billings) are included in the calculation, the total amount of the variance results in the $335,111,088.

Q. Please summarize the variance schedule provided as page 5 of Appendix I.

A. FPL's original projections filed on November 17, 2008 projected

Jurisdictional Total Fuel and Net Power Transactions to be $5.872 billion through December 2009 (See Appendix I, Page 5, Column 2, line C6). The estimated/actual Jurisdictional Total Fuel Cost and Net Power Transactions are now projected to be $ 5.173 billion for that period (Actual data for January through June 2009 and revised estimates for July through December 2009) (See Appendix I, Page 5, Column 1, Line C6). Therefore, Jurisdictional Total Fuel Cost and Net Power Transactions are $698.9 million or 11.9% lower than the original projections filing (See Appendix I, Page 5, Column 3, line C6). Jurisdictional Fuel Revenues for 2009 are $284.5 million lower than the original projection filing (Appendix I, Page 5, Column 3, Line C3).

Q. **Please explain the variances in Jurisdictional Total Fuel Costs and Net Power Transactions.**

A. As shown on Appendix I, Page 5 Line C6, the variance in Jurisdictional Total Fuel Costs and Net Power Transactions of $698.9 million is a 11.9% decrease from original projections. The primary reasons for this variance are lower than projected Fuel Cost of System Net Generation ($629.1 million), lower than projected Fuel Cost of Purchased Power ($49.3 million), lower than projected Energy Payments to Qualifying Facilities ($46.4 million) and lower than projected Energy Cost of Economy Purchases ($15.9 million), partially offset by lower than projected Fuel Cost of Power Sold ($33.9 million) and lower than projected Gains from Off-System Sales

($4.9 million).

The $629.1 million or 11.7 % decrease in the Fuel Cost of System Net Generation is primarily due to lower than projected residual oil and natural gas costs. Residual oil is currently projected to be $279.9 million (39.85%) lower than the original projection. The unit cost of residual oil in the estimated/actual period is $10.95 per MMBTU, which is 18.43% higher than the $9.24 per MMBTU included in the original projections. Consumption of residual oil decreased by 49.2% from original projections. Natural gas costs are currently projected to be $328.7 million (7.53%) lower than the original projections. The unit cost of natural gas in the estimated/actual is $8.55 per MMBTU, which is 15.51% lower than the $10.12 per MMBTU included in the original projections. Consumption of natural gas increased by 9.4% compared to the original projections. Projections for Generation by Fuel Type for the period July 2009 through December 2009 are included in Appendix I, Schedule E3.

The $49.3 million, or 14.3% decrease in Fuel Cost of Purchased Power is primarily due to lower than projected costs for energy purchases from UPS and SJRPP. The Southern Company energy rate for UPS was $2.42/MWh less than projected and UPS energy deliveries were 822,797 MWh less than anticipated. The SJRPP energy rate was $2.03/MWh less than projected and SJRPP energy deliveries were 215,357 MWh less than anticipated.

The $46.4 million, or 21.7% decrease in Energy Payments to Qualifying Facilities is primarily due to $11.10/MWh lower than projected energy rate for Cedar Bay and 709,435 MWh less than projected energy purchases from ICL.

The $15.9 million, or 28.2% decrease in the Energy Cost of Economy Purchases is primarily due to lower than projected economy purchases. While FPL now expects that the average cost of its economy purchases will be higher than originally projected ($54.61/MWh versus original projections of $48.63/MWh), the major cause for the variance is that FPL currently projects to purchase approximately 419,000 MWh less of economy power than the original projections.

The $33.9 million, or 45.9% decrease in the Fuel Cost of Power Sold is primarily due to lower than projected fuel costs for economy sales and lower than projected economy sales. FPL currently projects that its average fuel cost attributable to economy sales will be $34.91/MWh as compared to an original estimate of $49.57/MWh. Additionally, FPL currently estimates that it will sell approximately 375,000 MWh less of economy power than originally projected. Of the total fuel cost variance, approximately 60% is due to lower than projected fuel costs and approximately 40% is due to lower than projected sales.

The $4.9 million or 27.4% decrease in Gains from Off-System Sales is primarily due to lower than projected economy sales. While FPL currently projects that its average margin on economy sales will be slightly lower than originally projected (approximately $0.34/MWh lower), the major cause for the variance is that FPL currently projects to sell approximately 375,000 MWh less in economy sales than its original projections.

Q. What is the appropriate estimated benchmark level for calendar year 2010 for gains on non-separated wholesale energy sales eligible for a shareholder incentive as set forth by Order No. PSC-00-1744-PAA-EI, in Docket No. 991779-EI?

A. For the forecast year 2010, the three-year average threshold consists of actual gains for 2007, 2008, and January through June 2009, and estimates for July through December 2009. Gains on sales in 2010 are to be measured against this three-year average threshold, after it has been adjusted with the true-up filing (scheduled to be filed in March 2010) to include all actual data for the year 2009.

2007	$18,545,406
2008	$17,001,482
2009	$12,935,661
Average threshold	$16,160,850

CAPACITY COST RECOVERY CLAUSE

Q. **Please explain the calculation of the CCR Estimated/Actual True-up amount you are requesting this Commission to approve.**

A. Appendix II, Pages 2 and 3 show the calculation of the CCR Estimated/Actual True-up amount. The calculation of the Estimated/Actual True-up for the period January 2009 through December 2009 is an under-recovery of $ 57,534,451 including interest (Appendix II, Page 3, Column 13, Lines 16 plus 17).

Q. **Is this true-up calculation made in accordance with the procedures previously approved in predecessors to this Docket?**

A. Yes, it is.

Q. **Have you provided a schedule showing the variances between the Estimated/Actuals and the Original Projections?**

A. Yes. Appendix II, Page 4, shows the Estimated/Actual capacity charges and applicable revenues (January through June 2009 reflects actual data and the data for July through December 2009 is based on updated estimates) compared to the original projections for the January 2009 through December 2009 period, filed September 2, 2008.

Q. **Please explain the variances related to capacity charges.**

A. As shown in Appendix II, Page 4, Column 3, Line 13, the variance related to capacity charges is a $ 21.9 million, or 2.8% increase. The primary reasons for this variance are a $2.8 million increase in Capacity Payments to Non-cogenerators, a $9.1 million increase in Payments to Cogenerators, an $11.8 million increase in Incremental Plant Security Costs and a $1.2 million increase in Transmission Revenues from Capacity Sales, partially offset by a $1.9 million decrease in Short Term Capacity Payments and a $0.7 million decrease in Transmission of Electricity by Others.

The increase in Payments to Non-cogenerators is primarily due to higher than estimated capacity payments to Southern Company of $2.9 million for the UPS contract due to an approximate increase of 2% in Southern Company's production cost over original projections.

The increase in Payments to Cogenerators is primarily due to higher than estimated capacity payments to ICL of approximately $8.9 million. ICL's performance in 2009 to date has exceeded projections.

The increase in Incremental Plant Security costs is primarily attributable to expenses associated with NRC compliance requirements. The NRC recently updated the Enhanced Adversary Characteristics (EAC) of the Design Basis Threat (DBT). These enhancements are now being utilized during the triennial Force on Force (FOF) inspections performed at the nuclear stations. Turkey Point required extensive engineering support and significant modifications to the station security defensive positions in preparation for the triennial FOF drill that will occur in August, 2009. Additionally, on March 27, 2009 the NRC issued a new rule under Part 73.54 of the Code of Federal Regulations that involves the protection of station digital computer, communication systems and networks, which imposes significant requirements for monitoring, hardening and responding to cyber intrusions. FPL is required to provide a plan to the NRC by November 23, 2009 that outlines when full implementation will be completed. On March 27, 2009, the NRC issued a new rule under Part 73.55 of the Code of Federal Regulations that involves the need for significant modifications to various areas of the site. The new rule directs licensees to have an on-site physical protection system and security organization that provides the level of protection required for nuclear power reactors against radiological sabotage. FPL is required to complete full implementation by March 31, 2010. Moreover, the increase in incremental Plant Security costs reflects an earlier implementation date than originally anticipated.

The decrease in Transmission Revenues from Capacity Sales is primarily due to lower than projected economy sales (approximately 375,000 MWh lower than originally projected), which resulted in lower than projected transmission revenues.

The decrease in Short Term Capacity Payments is due to lower than projected contract capacity of FPL's short term PPA agreements, resulting in lower than projected capacity payments.

The decrease in the Transmission of Electricity by Others is due to FPL not exercising its rollover rights to extend its long-term firm transmission service through Jacksonville Electric Authority (JEA).

In addition to the cost variances, Appendix II, Page 4, Column 3, Line 14 shows that Capacity Cost Recovery Revenues, Net of Revenue Taxes, are $35.5 million lower than originally projected. The $21.9 million higher costs (Appendix II, Column 3, Line 13) plus the $35.5 million reduction in revenues (Appendix II, Column 3, Line 16), including interest, results in an estimated/actual 2009 true-up amount of $57.5 million under-recovery (Appendix II, Page 4, Column 3, Lines 17 plus 18). This under-recovery of $57.5 million including interest, plus the final 2008 under-recovery of $14.9 million filed on March 9, 2009 and the deferred true-up for the Turkey Point 5 GBRA refund amount of $0.17 million results in an under-recovery of $72.6 million to be carried forward to the 2010 capacity factor.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 090001-EI

August 20, 2009

Q. Please state your name and address.

A. My name is Terry J. Keith and my business address is 9250 West Flagler Street, Miami, Florida 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as Director, Cost Recovery Clauses in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. My testimony addresses the following subjects:

- I present for Commission review and approval the Fuel Cost Recovery (FCR) factors for the period January 2010 through December 2010.
- I present for Commission review and approval a revised 2009 FCR estimated/actual true-up amount, which has been updated to include July 2009 actual data and which

is incorporated into the calculation of the 2010 FCR Factors.

- I present for Commission review and approval the Capacity Cost Recovery (CCR) factors for the period January 2010 through December 2010.
- I present for Commission review and approval a revised 2009 CCR estimated/actual true-up amount, which has been updated to include July 2009 actual data and which is incorporated into the calculation of the 2010 CCR Factors.
- I present for Commission review and approval FPL's projected incremental security costs for 2010, to be recovered through the CCR Clause.
- I present FPL's Nuclear Power Plant Cost Recovery costs to be recovered through the CCR Clause in 2010.
- Finally, I provide on pages 70-72 of Appendix II FPL's proposed COG tariff sheets, which reflect 2010 projections of avoided energy costs for purchases from small power producers and cogenerators and an updated ten year projection of FPL's annual generation mix and fuel prices.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits in this proceeding?

A. Yes, I have. They are as follows:

- TJK-5 -- Schedules E1, E1-A, E1-B, E1-C, E1-D, E1-E, E2, E10, H1, and pages 12-14 and 70-72 included in Appendix II
- TJK-6 -- the entire Appendix III

Appendix II contains the FCR related schedules and Appendix III contains the CCR related schedules.

FUEL COST RECOVERY CLAUSE

Q. What is the proposed levelized fuel cost recovery (FCR) factor?

A. 3.813¢ per kWh. Schedule El, Page 3 of Appendix II shows the calculation of this twelve-month levelized FCR factor. Schedule E2, Pages 15 and 16 of Appendix II shows the monthly fuel factors for January 2010 through December 2010 and also the twelve-month levelized FCR factor for the period.

Q. Has the Company developed levelized FCR factors for its Time of Use rates?

A. Yes. Schedule E1-D, Page 8 of Appendix II, provides a twelve-month levelized FCR factor of 4.305¢ per kWh on-peak and 3.590¢ per kWh off-peak for our Time of Use rate schedules. The time of use rates for the Seasonal Demand Time of Use Rider (SDTR) are 4.395¢ (on-peak) and 3.628¢ (off-peak) and are provided on Schedule E-1D, Page 9 of Appendix II. The SDTR was implemented pursuant to the Stipulation and Settlement Agreement approved in Docket No. 050045-EI, which incorporates a different on-peak period during the months of June through September.

FCR factors by rate group for the period January through December 2010 are presented on Schedule E1-E, Page 10 of Appendix II. FCR factors by rate group for the SDTR are provided on Schedule E-1E, Page 11 of Appendix II.

Q. **Were these calculations made in accordance with the procedures approved in predecessors to this Docket?**

A. Yes.

Q. **Has FPL revised its 2009 FCR Estimated/Actual True-up amount that was filed on August 4, 2009 to reflect July actual data?**

A. Yes. The 2009 FCR estimated/actual true-up amount has been revised to an over-recovery of $444,164,222 reflecting July 2009 actual data, plus interest. The calculation of the revised 2009 FCR estimated/actual true-up amount is shown on revised schedule E1-B, on Pages 5-6 of Appendix II. This $444,164,222 over-recovery is to be included in the FCR factor for the January 2010 through December 2010 period.

Q. What adjustments are included in the calculation of the levelized FCR factor shown on Schedule E1, Page 3 of Appendix II?

A. As shown on line 28 of Schedule E1, Page 3 of Appendix II, the total net true-up to be included in the 2010 factors is a revised over-recovery of $364,843,209. This amount divided by the projected retail sales of 101,028,632 MWh for January 2010 through December 2010 results in a decrease of 0.3611¢ per kWh before applicable revenue taxes. The Generating Performance Incentive Factor (GPIF) Testimony of FPL Witness Roxane Kennedy, filed on April 3, 2009, calculated a reward of $11,464,340 for the period ending December 2008, which is being applied to the January 2010 through December 2010 period. This $11,464,340 reward divided by the projected retail sales of 101,028,632 MWh during the projected period results in an increase of .0113¢ per kWh, as shown on line 32 of Schedule E1, Page 3 of Appendix II.

Q. Is FPL proposing any adjustments in its base rate proceeding (Docket No. 080677-EI) that impact the FCR calculation?

A. Yes. In the testimonies of Kim Ousdahl and Marlene Santos filed in Docket No. 080677-EI, FPL discusses several adjustments to move items between base rates and clause recovery. One adjustment impacting the FCR is to recover bad debt expense associated with clause revenues through the related cost recovery clause instead of base rates. Additionally, FPL is proposing to transfer to base rates its recovery of incremental hedging costs that are currently being recovered through the FCR. Finally, FPL is proposing to dissolve FPL Fuels, Inc., the financing company for FPL's fuel lease, which will remove from the fuel clause the lease payments for nuclear fuel that are currently paid to FPL Fuels, Inc., with the carrying costs for the nuclear fuel instead being recovered in base rates.

Q. Has FPL included these proposed adjustments in the calculation of its 2010 FCR factors?

A. No, however FPL has quantified the impact of each adjustment on the FCR and will revise its FCR factors to be consistent with the Commission's decisions in Docket No. 080677-EI.

If approved, the adjustment for the projected bad debt expense of $14.1 million associated with FCR revenues results in an increase of $0.14 on the FCR portion of the 2010 Residential 1,000 kWh bill.

If approved, the adjustment for incremental hedging projections of $715,000 results in a reduction of $0.01 to the FCR portion of the

2010 Residential 1,000 kWh bill.

If approved, the adjustment for an estimated $8.9 million associated with carrying costs on nuclear fuel results in a reduction of $0.09 to the FCR portion of the 2010 Residential 1,000 kWh bill.

Therefore, if all three adjustments are approved, the proposed FCR charge for 2010 of $34.96, shown on Schedule E-10, page 68 of Appendix II, would increase $0.04 to $35.00.

CAPACITY COST RECOVERY CLAUSE

Q. Has FPL revised its 2009 CCR Estimated/Actual True-up amount that was filed on August 4, 2009 to reflect July actual data?

A. Yes. The 2009 CCR estimated/actual true-up amount has been revised to an under-recovery of $55,988,146 reflecting July 2009 actual data plus interest. The calculation of the revised 2009 CCR estimated/actual true-up amount is shown on Pages 4a-4b of Appendix III. This $55,988,146 under-recovery is to be included for recovery in the CCR factor for the January 2010 through December 2010 period.

Q. Have you prepared a summary of the requested capacity

payments for the projected period of January 2010 through December 2010?

A. Yes. Page 3 of Appendix III provides this summary. Total Recoverable Capacity Payments are $576,888,639 (line 18) and include payments of $299,568,081 to non-cogenerators (line1), Short-term Capacity Payments of $8,184,000 (line 2), payments of $157,009,305 to cogenerators (line 3), $2,156,916 relating to the St. John's River Power Park (SJRPP) Energy Suspension Accrual (line 4) and $45,592,794 in Incremental Power Plant Security Costs (line 6). These amounts are partially offset by $5,914,897 of Return Requirements on SJRPP Suspension Payments (line 5) and by Transmission Revenues from Capacity Sales of $2,488,823 (line 8). The resulting amount is then decreased by $56,945,592 of jurisdictional capacity related payments included in base rates (line 12) and increased by the net under-recovery for 2008 and 2009 of $70,908,235 (line 13), the Nuclear Power Plant Cost Recovery Clause amount of $62,792,990 (line 14) and an adjustment of $168,809 related to the true-up of the Turkey Point Unit 5 Generating Base Rate Adjustment (GBRA) for the period May 2007 through December 2008 (line 15).

Q. What does line 14 - Nuclear Power Plant Cost Recovery (NPPCR) represent?

A. FPL has included the $62,792,990 contained in Exhibit WP-1 in FPL's May 1, 2009 testimony for the NPPCR in the calculation of its CCR Factors. Per Order No. PSC-07-0240-FOF-EI, issued on March 20, 2007, the Commission adopted the Rule to implement Section 366.93, Florida Statutes, which was enacted by the Florida Legislature in 2006. The stated purpose of the Statute is to promote utility investment in nuclear power plants, and it directed the Commission to establish alternative mechanisms for cost recovery and step-wise, periodic prudence determinations with respect to costs incurred to build nuclear power plants. The Rule provides the mechanism to determine recoverable costs and provides for annual recovery of those costs through the CCR.

Q. Has FPL included an adjustment associated with its Generating Base Rate Adjustment (GBRA) for Turkey Point Unit 5?

A. Yes. FPL has included an adjustment of $168,809, including interest, (Appendix III, page 3, line 15) for the true-up of Turkey Point Unit 5 costs for the period May 1, 2007 through December 31, 2008 in the calculation of its CCR Factors. The $168,809 represents the difference between the $9,307,126 approved estimated credit for the period May 1, 2007 through December 31, 2008 associated with the Turkey Point Unit 5 GBRA factor reduction, which is being refunded to customers through the 2009

CCR factors, and the actual credit amount, including interest, of $9,138,317 for the same period.

Q. Is FPL proposing any adjustments in its base rate proceeding that impact the CCR?

A. Yes. As I stated earlier, FPL is proposing several adjustments to move items between base rates and clause recovery. One adjustment impacting the CCR is to recover bad debt expense associated with clause revenues through the related cost recovery clause instead of base rates. Additionally, FPL is proposing to transfer capacity charges associated with SJRPP that are currently being recovered in base rates so that they would be recovered instead through the CCR.

Q. Has FPL included these proposed adjustments in the calculation of its 2010 CCR factors?

A. No, however FPL has quantified the impact of each adjustment on the CCR and will revise its CCR factors to be consistent with the Commission's decisions in Docket No. 080677-EI.

If approved, the adjustment for projected bad debt expense of $1.8 million associated with CCR revenues results in an increase of $0.02 on the CCR portion of the 2010 Residential 1,000 kWh bill.

If approved, the adjustment of $56.9 million associated with SJRPP capacity charges results in an increase of $0.61 on the CCR portion of the 2010 Residential 1,000 kWh bill.

Therefore, if both of these adjustments are approved, the proposed CCR charge for 2010 of $6.21, shown on Schedule E-10, page 68 of Appendix II, would increase $0.63 to $6.84.

Q. **Have you prepared a calculation of the allocation factors for demand and energy?**

A. Yes. Page 5 of Appendix III provides this calculation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate class contributes to total kWh sales, as adjusted for losses.

Q. **Have you prepared a calculation of the proposed CCR factors by rate class?**

A. Yes. Page 6 of Appendix III presents this calculation.

Q. **What effective date is the Company requesting for the new FCR and CCR factors?**

A. FPL is requesting that the FCR and CCR factors become effective with customer bills for January 2010 (cycle day 1) through December 2010 (cycle day 21). This will provide for 12 months of billing on the FCR and CCR factors for all our customers.

Q. What will be the charge for a Residential customer using 1,000 kWh effective January 2010?

A. Schedule E-10 (Appendix II, Page 68) presents a preliminary Residential 1,000 kWh bill for January through December 2010 of $100.41. This preliminary bill includes the proposed Fuel Cost Recovery charge of $34.96 and the proposed Capacity Cost Recovery charge of $6.21, as presented in my testimony. Since FPL's proposed 2010 Environmental and Conservation charges are not yet available and neither the 2010 base rate charges nor the 2010 Storm charge have been approved, FPL's preliminary 2010 Residential 1,000 kWh bill amount of $100.41 is based on Exhibit RBD-2, which was updated August 20, 2009 in Docket No. 080677-EI and also incorporates FPL's proposed Fuel and Capacity Charges for 2010.

Q. Does this conclude your testimony?

A. Yes, it does.

ERRATA SHEET

Direct testimony of Terry J. Keith. Fuel Cost Recovery Projections for the period January 2010 through December 2010, filed on August 20, 2009 in Docket No. 090001-EI.

PAGE/LINE	CHANGE OR CORRECTION
6/13-23	Strike text on lines 13 through 23. Replace with "No, however FPL will reflect the results of the Commission's decisions in Docket No. 080677-EI in its 2010 Estimated/Actual True-up filed in August, 2010".
7/1-10	Strike text on lines 1 through 10
10/15-22	Strike text on lines 15 through 22. Replace with "No, however FPL will reflect the results of the Commission's decisions in Docket No. 080677-EI in its 2010 Estimated/Actual True-up filed in August, 2010".
11/1-7	Strike text on lines 1 through 7

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 090001-EI

October 22, 2009

Q. Please state your name and address.

A. My name is Terry J. Keith and my business address is 9250 West Flagler Street, Miami, Florida 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as Director, Cost Recovery Clauses in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval revised Capacity Cost Recovery (CCR) cost projections for the period January 2010 through December 2010 that reflect the Nuclear Power Plant Cost Recovery (NPPCR) amount approved by the Commission on October 16, 2009.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits in this

proceeding?

A. Yes, I have. TJK-7 provides the revised CCR schedules for the period January 2010 through December 2010.

Q. What is the NPPCR amount that the Commission approved for recovery through the CCR during the January 2010 through December 2010 period?

A. At the October 16, 2009 agenda conference the Commission authorized FPL to recover $62,676,366 through the CCR during the January 2010 through December 2010 period.

Q. Is this the same amount that FPL included in the 2010 CCR factors at the time of FPL's August 20, 2009 projection filing?

A. No. In its August 20, 2009 filing in this docket, FPL included $62,792,990 for the NPPCR in the calculation of its 2010 CCR factors, which was the amount that FPL had originally requested in its May 1, 2009 filing in Docket No. 090009-EI. At the October 16, 2009 agenda conference, the Commission reduced the Company's requested AFUDC recovery amount by $116,624, which reduces the overall recovery amount from $62,792,990 to $62,676,366.

Q. Does this revision change the CCR factors filed on August 20, 2009?

A. No. Due to the minor change in the approved NPPCR amount, the CCR factors based on this revised amount do not change from those filed in my testimony on August 20, 2009.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF J.A. STALL

DOCKET NO. 090001-EI

August 20, 2009

Q. Please state your name and address.

A. My name is J.A. (Art) Stall. 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 FPL Group, Inc. as President, FPL Group Nuclear.

Q. Please describe your duties and responsibilities in that position.

A. I am responsible for the overall strategic direction for all of FPL's nuclear assets, consisting of four nuclear units in Florida – two at Turkey Point Nuclear Plant near Florida City, Florida, (1,386 MW) and two at St. Lucie Nuclear Plant, near Jensen Beach, Florida (1,677 MW). I also hold this same responsibility for the other FPL Group nuclear plants – one unit at Seabrook Station in Seabrook, New Hampshire (1,294 MW), one unit at Duane Arnold Energy

Center in Palo, Iowa (600 MW), and two units at Point Beach Nuclear Plant in Two Rivers, Wisconsin (1,036 MW).

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 and the costs of disposal of spent nuclear fuel. I am also updating the status of certain litigation that affects FPL's nuclear fuel costs; plant security costs and new NRC security initiatives; and outage events. 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 2010 through December 2010.

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 2010 through December 2010.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2010 through December 2010.

A. FPL projects the nuclear units will produce 256,579,560 MMBtu of energy at a cost of $0.6265 per MMBtu, excluding spent fuel disposal costs, for the period January 2010 through December 2010. Projections by nuclear unit and by month are in Appendix II, on Schedule E-4, starting on page 22 of the Appendix II.

Spent Nuclear Fuel Disposal Costs

Q. Please provide FPL's projections for spent nuclear fuel disposal costs for the period January 2010 through December 2010 and explain the basis for FPL's projections.

A. FPL's projections for spent nuclear fuel disposal costs of approximately $21.4 million are provided in Appendix II, on Schedule E-2, starting on page 16 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 0.9319 mills per net kWh generated, including transmission and distribution line losses.

Litigation Status Update

Q. Has FPL's dispute with the U.S. Government regarding disposal of spent nuclear fuel from FPL's nuclear plants been resolved?

A. Yes. FPL has been in a longstanding dispute under FPL's contract with the DOE for final disposal of spent nuclear fuel (SNF). In 1998, FPL sued the Government for damages for failure to begin disposal of SNF from FPL's nuclear power plants. On March 31, 2009, FPL entered into a settlement agreement with the U.S. Government that resolves FPL's SNF damages claims against the Government. Under the settlement agreement, FPL received a cash payment of $77.1 million from the Government, representing damages incurred related to the Government's SNF default through December 31, 2007. The settlement agreement also formalizes an annual claims process that will enable FPL to submit and receive payment from the Government for annual SNF expenditures related to the Government's default. This process will enable FPL to recover its expenses relating to the long-term storage of SNF at FPL's nuclear power plants without the need for and uncertainty of additional litigation.

Q. How will customers benefit from the DOE SNF settlement?

A. The SNF settlement represents reimbursement for incremental costs incurred by FPL because DOE failed to meet its obligations in a timely manner. As these incremental costs were incurred by FPL they were charged either to base O&M or capitalized, resulting in an increase in capital structure and lowering the base ROE realized. The SNF settlement was subsequently recorded as a reduction to plant, CWIP, and O&M and reversal of previously incurred depreciation expense. Customers will receive the benefits associated with the SNF settlement through base rates, which the Commission is currently reviewing in Docket No. 080677-EI.

Nuclear Plant Security Costs

Q. What is FPL's projection of incremental security costs at FPL's nuclear power plants for the period January 2010 through December 2010?

A. FPL presently projects that it will incur $44.2 million in incremental nuclear power plant security costs in 2010.

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 rule under Part 26, which limits the number of hours security personnel may work; additional personnel training; additional regulatory initiatives for fires, aircraft threat strategy; and protection of spent fuel pools and containments. It also includes impacts of implementing NRC's rule under Part 73 including Cyber Security.

Q. Has the NRC issued any revisions to the security-related Orders that affect FPL's projection?

A. Yes. On March 31, 2008 the NRC issued a new rule under Part 26 of the Code of Federal Regulations dealing with worker fatigue.

The new rule mandates more restrictive work hour limits, including a specific requirement for "days off" for the security officers at the St. Lucie and Turkey Point sites. Full implementation is required by October 1, 2009. The Part 26 rulemaking impact costs for 2010 are estimated to be $5.2 million for the St. Lucie and Turkey Point nuclear sites.

In addition, on March 27, 2009, the NRC issued a new rule under Part 73.55 of the Code of Federal Regulations that involves the need for significant modifications to various areas of the site. The new rule directs licensees to have an on-site physical protection system and security organization that provides the level of protection required for nuclear power reactors against radiological sabotage. Some examples include redundant features for Central Alarm Station (CAS) and Secondary Alarm Station (SAS), enhanced weaponry, Owner Controlled Area (OCA) detection, and enhancements to assessment and interdiction. Full implementation is required by March 31, 2010. The Part 73 rulemaking costs for 2010 are estimated to be $5.0 million for the St. Lucie and Turkey Point nuclear sites.

On March 27, 2009 the NRC issued a new rule under Part 73.54 of the Code of Federal Regulations that involves the protection of station digital computer, communications systems and networks which would impose significant requirements for monitoring, hardening and responding to cyber intrusions. FPL is required to provide a plan to the NRC by November 23, 2009 that outlines when full implementation will be completed. The Cyber Security rulemaking costs for 2010 are estimated to be $7.5 million for the St. Lucie and Turkey Point nuclear sites.

Finally, in February 2009, the NRC updated the Enhanced Adversary Characteristics (EAC) of the Design Basis Threat (DBT). These enhancements are now being utilized during the triennial Force on Force (FoF) inspections performed at the nuclear stations. The DBT is the measure that all nuclear stations are designed to defend against. Some examples of changes are: enhanced intrusion detection, adversary delay barriers, and installing additional vehicle barriers. Some of these EAC/DBT enhancements required Turkey Point to provide extensive engineering support and make significant modifications to the station security defensive positions in preparation for the triennial FoF inspection that occurred in August, 2009.

FoF inspections are scheduled on a repeating three year cycle. Consequently, St. Lucie and Turkey Point will receive third round FoF inspections in the 2011-2013 cycle and FPL may require additional modifications to ensure successful regulatory inspection conclusions. Adversary Characteristics are constantly being reviewed by the NRC due to the potential change in adversary capabilities. Consequently, future enhancements of nuclear facilities may be required.

<u>**2009 Outage Events**</u>

Turkey Point

Q. Has FPL experienced any unplanned outages at its Turkey Point plant in 2009?

A. Yes. In April 2009, when FPL was preparing to return Unit 3 to service from a planned refueling outage, FPL found that control rod D-6 did not move in response to a control command to move.

Q. What caused the control rod malfunction?

A. On April 3, 2009 during lowering of the Reactor Vessel Closure Head (RVCH) a rod control cluster assembly (RCCA) drive shaft was noted to have contacted the edge of the guide funnel that helps position it for insertion into the RVCH. The shaft was visually inspected and did not appear to have been damaged by the contact. FPL continued with lowering the RCVH, and the shaft inserted smoothly without apparent any interference. However, the drive shaft had an undetected bow in the top portion of the shaft. The bow created a tight fit inside the CRDM such that the CRDM motor could not develop enough force to move the control rod during testing once the RVCH had been reinstalled.

Q. How many days was the Turkey Point Unit 3 refueling outage extended due to issues with control rod drive mechanism?

A. Unit 3 refueling outage was extended approximately 15 days for issues associated with the CRDM. Additional issues unrelated to the CRDM arose during start up from the refueling outage and were addressed before Turkey Point Unit 3 was returned to service.

Q. What corrective actions has FPL initiated to avoid this problem in the future?

A. FPL replaced the CRDM, extension shaft, and associated rod control cluster assembly (RCCA). Although no damage to the RCCA was found, the assembly was replaced as a precautionary measure. Additionally, fuel assemblies in proximity to the affected area were inspected and no damage was found. Also, FPL has made a number of procedure and process changes to enhance

FPL's ability to detect and evaluate potential damage from contact with the RVCH.

St. Lucie

Q. Has FPL experienced any unplanned outages at its St. Lucie plant in 2009?

A. Yes. In April 2009, Unit 2 shut down due to sea grass intrusion in the intake debris filter system.

Q. How many days was the St. Lucie Unit 2 outage due to sea grass intrusion?

A. The outage was approximately 2 days in order to perform cleaning of the sea grass from the debris filter system.

Q. Has FPL experienced any other unplanned outages at its St. Lucie plant in 2009?

A. Yes. In June 2009, when Unit 2 was shut down for a refueling outage, FPL determined the #7 and #8 generator bearings were degraded. FPL evaluated the options to refurbish the bearings or replace them. As a prudent measure, FPL replaced the affected generator bearings. During the process of restoring the 2A low pressure safety injection (LPSI) pump to service, the pump failed to start. The LPSI pump was overhauled and tested satisfactorily.

Q. How many days was the St. Lucie Unit 2 outage due to these issues?

A. The Unit 2 refueling outage was extended approximately 12 days.

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

A. FPL replaced the #7 and #8 main generator bearings and the 2A LPSI pump was overhauled.

Q. Has FPL experienced any other unplanned outages at its St. Lucie plant in 2009?

A. Yes. In June 2009, following the return of Unit 2 to service from a planned refueling outage, the main generator experienced vibration levels above expected values and the unit start up was interrupted to investigate. FPL corrected the vibration of the turbine by addition of a balance weight.

Q. How many days was the St. Lucie Unit 2 outage due to this issue?

A. The Unit 2 outage was approximately 1 day.

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

A. FPL plans to undertake a detailed inspection of the generator components during the next scheduled outage.

Q. Has FPL experienced any other unplanned outages at its St. Lucie plant in 2009?

A. Yes. In July, 2009, St. Lucie Unit 2 was shut down to investigate an increasing trend in Reactor Coolant System leakage. The cause of the increase was determined to be a cracked weld in a seal injection line in the 2B2 reactor coolant pump. The cause of the weld cracking was determined to be low stress high cycle fatigue which is caused by vibration.

Q. How many days was the St. Lucie Unit 2 outage due to these issues?

A. The outage duration was approximately 15 days. Following normal unit restart and return to service, a delay in reaching full power operation to repair the 2A Turbine Cooling Water pump (TCW) resulted in a 62% power hold for 120 hours to allow repairs.

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

A. Inspections and tests were conducted on all of the seal injection lines and associated welds on each of the unit's four reactor coolant pumps. No problems were detected. As a preventative measure, certain lines were either capped or replaced on each of the pumps to prevent recurrence.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF ROXANE R. KENNEDY

DOCKET NO. 090001-EI

APRIL 3, 2009

Q. Please state your name and business address.

A. My name is Roxane R. Kennedy, 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 Director of Production Assurance and Business Services in the Power Generation Division of FPL.

Q. Would you please describe your educational background and business experience?

A. I received a Bachelor's degree in Chemical Engineering from the University of Florida in 1985. I am a Registered Professional Engineer in Florida and have held my license for over thirteen years. Since 1985, I have been employed with various affiliates of FPL Group. Between 1985 and 2008 I have held a variety of staff, technical, maintenance, and operating positions at several FPL and NextEra Energy sites. In March 2009, I assumed my current position.

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-08-0030-FOF-EI issued January, 2008, for the period January through December 2008, 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 is identified as Exhibit RRK-1 and shows the reward/penalty calculations prescribed by the GPIF Manual. Page 1 of Exhibit RRK-1 is an index to the contents of the exhibit.

Q. What is the incentive amount you have calculated for the period January through December, 2008?

A. I have calculated a GPIF incentive reward of $11,464,340.

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

A. The steps involved in making this calculation are provided in Exhibit RRK-1. Page 2 provides the GPIF Reward/Penalty Table (Actual), which shows an overall GPIF performance point value of +3.73 corresponding to a GPIF reward of $11,464,340. 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. Are there any changes to the targets approved through Commission Order No. PSC-08-0030-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, 2008 period.

A. The primary reason that FPL will receive a reward for the period was that St. Lucie Units 1 and 2, Turkey Point Units 3 and 4, Scherer Unit 4 and Ft. Myers Unit 2 adjusted availabilities were each better than target, and Martin Unit 2 actual heat rate was better than target.

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

A. St. Lucie Unit 1 operated at an adjusted actual EAF of 87.0%, compared to its target of 82.4%. This results in a +10.0 point reward, which corresponds to a GPIF reward of $2,887,234. St. Lucie Unit 2 operated at an adjusted actual EAF of 94.8%, compared to its target of 93.6%. This results in a +4.0 point reward, which corresponds to a GPIF reward of $1,111,845. Turkey Point Unit 3 operated at an adjusted actual EAF of 97.8% compared to its target of 90.9%. This results in a +10.0 point reward, which corresponds to a GPIF reward of $2,714,963. Turkey Point Unit 4 operated at an adjusted actual EAF of 85.5% compared to its target of 81.7%. This results in a +10.0 point reward, which corresponds to a GPIF reward of $2,455,018.

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

A. St. Lucie Unit 1 operated with an adjusted actual ANOHR of 10,830 Btu/kWh compared to its target of 10,881 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 10,846 Btu/kWh compared to its target of 11,052 Btu/kWh. This ANOHR results in a GPIF reward of $868,590.

Turkey Point Unit 3 operated with an adjusted actual ANOHR of 11,129 Btu/kWh compared to its target of 11,125 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 11,049 Btu/kWh compared to its target of 11,070 Btu/kWh. This ANOHR is within the ± 75 Btu/kWh deadband around the projected target; therefore, there is no GPIF reward or penalty.

In total, the nuclear units' heat rate performance results in a GPIF reward of $868,590.

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

A. $10,037,651.

Q. Please summarize the performance of FPL's fossil units.

A. Regarding EAF performance, five (5) of the nine (9) fossil generating units performed better than their availability targets, while the remaining four (4) units performed worse than their targets. The combined fossil units' availability performance results in a GPIF reward of $3,037,901.

Regarding ANOHR, five (5) out of the nine (9) fossil units operated with an ANOHR that was above the ± 75 Btu/kWh deadband resulting in a penalty, while two (2) out of the nine (9) fossil units operated with an ANOHR that was below the ± 75 Btu/kWh deadband resulting in a reward. The remaining two (2) units operated with ANOHRs that were within the ± 75 Btu/kWh deadband, and receive no incentive reward or penalty. The combined fossil units' heat rate performance results in a GPIF penalty of $1,611,211.

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

A. $1,426,689.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF ROXANE R. KENNEDY

DOCKET NO. 090001-EI

SEPTEMBER 1, 2009

Q. Please state your name and business address.

A. My name is Roxane Kennedy 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 Vice President of Production Assurance and Business Services in the Power Generation Division of FPL.

Q. Have you previously testified 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, 2010, 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 is identified as Exhibit RRK-2. The first page of this exhibit is an index to the contents of the exhibit. All other pages are numbered according to the GPIF Manual as approved by the Commission.

Q. Please summarize the 2010 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, 2010, FPL projects a weighted system equivalent planned outage factor of 8.3% and a weighted system equivalent unplanned outage factor of 6.9%, which yield a weighted system equivalent availability target of 84.8%. 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 8,274 Btu/kWh for the period January through December, 2010. As discussed later in my 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 RRK-2, pages 6 and 7, contain the information summarizing the targets and ranges for EAF and ANOHR for the 10 generating units which FPL proposes to be considered as GPIF units for the period of January through December, 2010. 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 POWRSYM 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 10 units which FPL proposes to use for the period of January through December 2010 represent the top 83.5% of the total forecasted system net generation for this period excluding three units: Turkey Point Unit 5 and West County Units 1&2. These three units are new units for 2007 and 2009 respectively and were excluded from the GPIF calculation because there is insufficient historical data to include them. Therefore, consistent with the GPIF Manual, the above mentioned units will be excluded from the GPIF calculations until FPL has 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 CARTER: Mr. Beasley.

MR. BEASLEY: Mr. Chairman, we would ask on behalf of Tampa Electric that the testimony prefiled for witnesses Carlos Aldazabal, Brian S. Buckley, Benjamin F. Smith and Joann T. Wehle be inserted into the record as though.

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

MR. BEASLEY: I would move the admission of their exhibits that are identified in the Composite Exhibit List as Exhibits 124 through 132.

CHAIRMAN CARTER: On the Comprehensive Exhibit List?

MR. BEASLEY: That's on the, the Comprehensive Exhibit List.

CHAIRMAN CARTER: 130 --

MR. BEASLEY: 124 through 132.

CHAIRMAN CARTER: 124 through 132. Are there any objections? Without objection, show it done.

MR. BEASLEY: Thank you.

(Exhibits 124 through 132 marked for identification and admitted into the record.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 090001-EI
FILED: 03/09/2009

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

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

A. My name is Carlos Aldazabal. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Regulatory Affairs in the Regulatory Affairs Department.

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

A. I received a Bachelor of Science Degree in Accounting in 1991, and received a Masters of Accountancy from the University of South Florida in Tampa in 1995. I am a CPA in the State of Florida and have accumulated 14 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, and budgeting and analysis. In April 1999, I joined Tampa Electric as Supervisor, Regulatory

Accounting. In January 2004, I was promoted to Manager, Regulatory Affairs. My present responsibilities include managing cost recovery for fuel and purchased power, interchange sales, and capacity payments.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for the Commission's review and approval, the final true-up amounts for the period January 2008 through December 2008 for both the Fuel and Purchased Power Cost Recovery Clause ("fuel clause") and the Capacity Cost Recovery Clause ("capacity clause"). I also present the wholesale incentive benchmark for January 2009 through December 2009 as well as the actual incremental operation and maintenance ("O&M") security alert and North American Electric Reliability Council ("NERC") cyber security expenses for the period January 2008 through December 2008.

Q. What is the source of the data which you will present by way of testimony or exhibit in this process?

A. Unless otherwise indicated, the actual data is taken from the books and records of Tampa Electric. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices and provisions of the Uniform System of Accounts as prescribed by the Florida Public Service Commission ("Commission").

Q. Have you prepared an exhibit in this proceeding?

A. Yes. Exhibit No.___ (CA-1), consisting of four documents which are described in my testimony, was prepared under my direction and supervision.

Capacity Cost Recovery Clause

Q. What is the final true-up amount for the Capacity Cost Recovery Clause for the period January 2008 through December 2008?

A. The final true-up amount for the capacity clause for the period January 2008 through December 2008 is an under-recovery of $8,525,166.

Q. Please describe Document No. 1 of your exhibit.

A. Document No. 1, page 1 of 5, entitled "Tampa Electric Company Capacity Cost Recovery Clause Calculation of

Final True-up Variances for the Period January 2008 Through December 2008", provides the calculation for the final under-recovery of $8,525,166. The actual capacity cost under-recovery, including interest was $28,354,108 for the period January 2008 through December 2008 as identified in Document No. 1, pages 1 and 2 of 5. This amount, less the $19,828,942 actual/estimated under-recovery approved in Order No. PSC-08-0824-FOF-EI issued December 22, 2008 in Docket No. 080001-EI, results in a final under-recovery for the period of $8,525,166 as identified in Document No. 1, page 4 of 5. This under-recovery amount will be applied in the calculation of the capacity cost recovery factors for the period January 2010 through December 2010.

Q. What is the estimated effect of this $8,525,166 under-recovery for the January 2008 through December 2008 period on residential bills during January 2010 through December 2010?

A. The $8,525,166 under-recovery will increase a 1,000 kWh residential bill by approximately $0.53.

Incremental Security Alert Expenses

Q. What were Tampa Electric's actual 2008 incremental O&M

security alert and NERC cyber security expenses as a result of the events of September 11, 2001?

A. As shown in Document No. 1, Page 2 of 5, line 4, Tampa Electric incurred $2,202,569 for incremental O&M security and NERC cyber security expenses for measures taken by the company to protect its generating facilities for the period January 2008 through December 2008.

Q. How did the actual incremental O&M security and NERC cyber security costs compare to the costs included in the 2008 Actual/Estimated capacity filing?

A. Actual incremental O&M security and NERC cyber security costs were $77,190 lower than projected in the 2008 Actual/Estimated capacity filing. The variance is driven by lower than projected expenses to install card key controls and control room wall modifications to meet NERC cyber-security standards.

Q. Is Tampa Electric's methodology used to calculate incremental security costs consistent with the one described in Order No. PSC-03-1461-FOF-EI, issued December 22, 2003?

A. Yes. To calculate incremental security costs, Tampa Electric compared its actual total O&M security guard expenses to baseline expenses or pre-9/11 annual security expenses. Incremental expenses to comply with new NERC cyber security requirements due to the events of September 11, 2001 were also identified. All incremental security costs were separately identified, and any savings gained through the implementation of any security related projects were credited pursuant to the method described in Order No. PSC-03-1461-FOF-EI, issued December 22, 2003.

Fuel and Purchased Power Cost Recovery Clause

Q. What is the final true-up amount for the Fuel and Purchased Power Cost Recovery Clause for the period January 2008 through December 2008?

A. The final fuel clause true-up for the period January 2008 through December 2008 is an over-recovery of $35,402,527. The actual fuel cost under-recovery, including interest, was $97,480,411 for the period January 2008 through December 2008. This $97,480,411 amount, less the $132,882,938 actual/estimated under-recovery amount approved in Order No. PSC-08-0824-FOF-EI, issued December 22, 2008 in Docket No. 080001-EI results in a net over-recovery amount for the period of $35,402,527.

Q. What is the estimated effect of the $35,402,527 over-recovery for the January 2008 through December 2008 period on residential bills during January 2010 through December 2010?

A. The $35,402,527 over-recovery would decrease a 1,000 kWh residential bill by approximately $1.77.

Q. Please describe Document No. 2 of your exhibit.

A. Document No. 2 is entitled "Tampa Electric Company Final Fuel and Purchased Power Over/(Under) Recovery for the Period January 2008 Through December 2008". It shows the calculation of the final fuel over-recovery of $35,402,527.

Line 1 shows the total company fuel costs of $1,132,380,262 for the period January 2008 through December 2008. The jurisdictional amount of total fuel costs, which includes the Commission ordered waterborne coal transportation expense disallowance, is $1,090,489,169, as shown on line 2. This amount is compared to the jurisdictional fuel revenues applicable to the period on line 3 to obtain the actual under-recovered fuel costs for the period, shown on line 4. The resulting $74,787,816 under-recovered fuel costs for the period, combined with the interest, true-up collected and the prior period true-up shown on lines 5, 6 and 7, respectively, constitute the actual under-recovery of $97,480,411 shown on line 8. The $97,480,411 actual under-recovery amount less the $132,882,938 actual/estimated under-recovery amount shown on line 9, results in a final $35,402,527 over-recovery amount for the period January 2008 through December 2008 as shown on line 10.

Q. Please describe Document No. 3 of your exhibit.

A. Document No. 3 entitled "Tampa Electric Company Calculation of True-up Amount Actual vs. Original Estimates for the Period January 2008 Through December 2008", shows the calculation of the actual under-recovery as compared to the estimate for the same period.

Q. What was the total fuel and net power transaction cost variance for the period January 2008 through December

2008?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost variance is $8,822,912 more than what was originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2008 through December 2008?

A. As shown on line C3 of Document No. 3, the company collected $74,599,977 or 6.8 percent less jurisdictional fuel revenues than originally estimated.

Q. Please describe Document No. 4 of your exhibit.

A. Document No. 4 contains a twelve-month summary detailing the transactions for each of Commission Schedules A6, A7, A8, A9 and A12 for the period January 2008 through December 2008.

Wholesale Incentive Benchmark

Q. What is Tampa Electric's wholesale incentive benchmark for 2009, as derived in accordance with Order No. PSC-01-2371-FOF-EI, Docket No. 010283-EI?

A. The company's 2009 benchmark is $1,077,446, which is the three-year average of $757,156, $799,040, and $1,676,141 actual gains on non-separated wholesale sales, excluding emergency sales, for 2006, 2007 and 2008, respectively.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 090001-EI
FILED: 8/4/2009

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

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

A. My name is Carlos Aldazabal. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Regulatory Affairs in the Regulatory Affairs Department.

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

A. I received a Bachelor of Science Degree in Accounting in 1991, and a Masters of Accountancy in 1995 from the University of South Florida in Tampa. I am a CPA in the State of Florida and have over 14 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, budgeting and analysis, and cost recovery clause management. In April 1999, I joined Tampa Electric as Supervisor, Regulatory Accounting. In January 2004, I was promoted to Manager, Regulatory Affairs. My present responsibilities include managing cost recovery for fuel and purchased power, interchange sales, and capacity payments.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2009 through December 2009 fuel and purchased power and capacity true-up amounts to be recovered in the January 2010 through December 2010 projection period. My testimony addresses the recovery of fuel and purchased power costs as well as capacity costs for the year 2009, based on six months of actual data and six months of estimated data. This information will be used in the determination of the 2010 fuel and purchased power costs and capacity cost recovery factors.

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

A. Yes. I have prepared Exhibit No. _____ (CA-2), which contains two documents. Document No. 1 is comprised of Schedules E1-B, E-2, E-3, E-5, E-6, E-7, E-8, and E-9, which provide the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2009 through December 2009. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period of January 2009 through December 2009. These documents are furnished as support for the projected true-up amount for this period.

Fuel and Purchased Power Cost Recovery Factors

Q. What has Tampa Electric calculated as the estimated net true-up amount for the current period to be applied in the January 2010 through December 2010 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount applicable for the period January 2010 through December 2010 is an over-recovery of $45,016,697.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2010 through December 2010 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2010 is normally the sum of the final true-up amount for the period January 2008 through December 2008 and the actual/estimated true-up amount for the period January 2009 through December 2009. However, in Order No. PSC-09-0254-PCO-EI, issued April 27, 2009 the Commission required the final fuel and purchased power cost recovery true-up amount for 2008 to be refunded as part of Tampa Electric's mid-course correction effective May 7, 2009. Therefore, the net true-up amount to be recovered in the 2010 fuel and purchased power cost recovery factors is the actual/estimated true-up amount for the period January 2009 through December 2009.

Q. What did Tampa Electric calculate as the final fuel and purchased power cost recovery true-up amount for 2008?

A. The final true-up was an over-recovery of $35,402,527. The actual fuel cost under-recovery, including interest was $97,480,411 for the period January 2008 through December 2008. The $97,480,411 amount, less the actual/estimated under-recovery amount of $132,882,938 approved in Order No. PSC-08-0824-FOF-EI, issued December 22, 2008 in Docket No. 080001-EI resulted in a net over-recovery amount for the period of $35,402,527. As previously stated, Tampa Electric included the $35,402,527 final true-up amount in its 2009 mid-course correction factors effective May 7, 2009.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2009 through December 2009?

A. The actual/estimated fuel and purchased power cost recovery true-up is an over-recovery amount of $45,016,697 for the January 2009 through December 2009 period. The detailed calculation supporting the actual/estimated current period true-up is shown in Exhibit No. ____ (CA-2), Document No. 1 on Schedule E1-B.

Capacity Cost Recovery Clause

Q. Please describe the changes to the 2009 capacity cost recovery factors related to Tampa Electric's new rate design approved in Docket No. 080317-EI.

A. As a result of Tampa Electric's base rate case the Commission approved the consolidation of the company's General Service - Demand ("GSD") and General Service - Large Demand ("GSLD") rate customers into one new GSD rate class. Additionally, the allocation of production demand costs according to the 12 Coincident Peak ("CP") and 1/13th Average Demand ("AD") methodology, where 1/13th or approximately eight percent of the demand costs is allocated on an energy basis, was modified to 12 CP and

25 percent AD to better reflect cost causation. The new methodology approved by the Commission in Order No. PSC-09-0283-FOD-EI issued April 30, 2009, in Docket No. 080317-EI and effective for meter readings on or after May 7, 2009 ensures that the prices customers pay for electric service bear a reasonable relationship to the costs of providing that service.

Q. Are there any other approved modifications that impact the capacity cost recovery factors?

A. Yes. The Commission also approved the recovery of capacity costs through a factor applied to billed kW demand for demand-measured customers because that recovery method would be consistent with the recovery of production plant that otherwise would have been built. Therefore, effective May 7, 2009 Tampa Electric commenced recovery of capacity costs from demand-measured customer classes on a dollar per kW basis rather than an energy basis.

Q. What has Tampa Electric calculated as the estimated net true-up amount to be applied in the January 2010 through December 2010 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2010 through December 2010 is an under-recovery of $28,618,100 as shown in Exhibit No. ____ (CA-2), Document No. 2, page 2 of 5.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2010 through December 2010 capacity cost recovery factors?

A. The net true-up amount to be recovered in the 2010 capacity cost recovery factors is the sum of the final true-up amount for 2008 and the actual/estimated true-up amount for January 2009 through December 2009.

Q. What did Tampa Electric calculate as the final capacity cost recovery true-up amount for 2008?

A. The final 2008 true-up is an under-recovery of $8,525,166. The actual capacity cost under-recovery including interest was $28,354,108 for the period January 2008 through December 2008. The $28,354,108 amount, less the actual/estimated under-recovery amount of $19,828,942 approved in Order No. PSC-08-0824-FOF-EI issued December 22, 2008 in Docket No. 080001-EI results in a net under-recovery amount for the period of $8,525,166 as identified in Exhibit No. ____ (CA-2), Document No. 2, page 1 of 5.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2009 through December 2009?

A. The actual/estimated true-up amount is an under-recovery of $20,092,934 as shown on Exhibit No. ____ (CA-2), Document No. 2, page 1 of 5.

Q. Are 2009 incremental security O&M costs included for cost recovery through the capacity clause?

A. Pursuant to Commission Order No. PSC-02-1761-FOF-EI issued December 13, 2002, in Docket No. 020001-EI, Tampa Electric agreed to move incremental O&M expenses associated with security costs into base rates at the company's next traditional rate case. Accordingly, Tampa Electric included incremental security O&M costs in the company's approved base rates implemented May 7, 2009 and did not include those costs for recovery through the capacity clause.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 090001-EI
FILED: 09/01/2009

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

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

A. My name is Carlos Aldazabal. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Regulatory Affairs in the Regulatory Affairs Department.

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

A. I received a Bachelor of Science Degree in Accounting in 1991, and received a Masters of Accountancy in 1995 from the University of South Florida in Tampa. I am a CPA in the State of Florida and have accumulated 14 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, budgeting and analysis, and cost recovery clause management. In April 1999, I joined Tampa Electric as Supervisor, Regulatory Accounting. In January 2004, I was promoted to Manager, Regulatory Affairs. My present responsibilities include managing cost recovery for fuel and purchased power, interchange sales, and capacity payments.

Q. Have you previously testified before this Commission?

A. Yes. I have submitted written testimony in the annual fuel docket since 2004, and I testified before this Florida Public Service Commission ("FPSC" or "Commission") in Docket Nos. 060001-EI and 080001-EI regarding the appropriateness and prudence of Tampa Electric's recoverable fuel and purchased power costs as well as capacity costs.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, the proposed annual levelized fuel and purchased power cost recovery factors including an inverted or two-tiered residential fuel charge to encourage energy efficiency and conservation and the projected wholesale incentive benchmark for January 2010 through December 2010. I will also describe significant events that affect the factors and provide an overview of the composite effect from the various cost recovery factors for 2010.

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

A. Yes. Exhibit No. ____ (CA-3), consisting of three documents, was prepared under my direction and supervision. Document No. 1, consisting of four pages, is furnished as support for the projected capacity cost recovery factors utilizing the Commission approved allocation methodology from Order No. PSC-09-0283-FOF-EI issued April 30, 2009, in Docket No. 080317-EI based on 12 Coincident Peak ("CP") and 25 percent Average Demand ("AD"). Document No. 2, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, is comprised of Schedules E1 through E10 for January 2010 through December 2010 as well as Schedule H1 for January through December, 2007 through 2010. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate and a levelized fuel rate, which demonstrates that the tiered rate is revenue neutral.

Capacity Cost Recovery

Q. Are you requesting Commission approval of the projected capacity cost recovery factors for the company's various rate schedules?

A. Yes. The capacity cost recovery factors, prepared under my direction and supervision, are provided in Exhibit No. ____ (CA-3), Document No. 1, page 3 of 4. The capacity factors reflect the company's approved rate design modifications approved as part of Order No. PSC-09-0283-FOF-EI in Docket No. 080317-EI, issued April 30, 2009.

Q. Please describe the changes to the 2010 capacity cost recovery factors related to Tampa Electric's approved rate design approved in Order No. PSC-09-0283-FOF-EI.

A. As a result of Tampa Electric's base rate case, the Commission approved the consolidation of the company's General Service - Demand ("GSD") and General Service - Large Demand ("GSLD") rate customers into one new GSD rate class. Additionally, the allocation of production demand costs was modified to the 12 CP and 25 percent AD to better reflect cost causation. The Commission also approved the recovery of capacity costs through a factor applied to billed kW demand for demand-measured customers because that recovery method would be consistent with the recovery of production plant that otherwise would have been built.

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

A. Tampa Electric is requesting recovery of capacity payments for power purchased for retail customers excluding optional provision purchases for interruptible customers through the capacity cost recovery factors.

Q. Is Tampa Electric requesting recovery through the capacity clause for "post-9/11" incremental security costs?

A. No, the company is not requesting recovery of 2010 incremental security expenses as a result of the events of September 11, 2001 through the capacity cost recovery clause. Pursuant to Commission Order No. PSC-02-1761-FOF-EI issued December 13, 2002, in Docket No. 020001-EI, Tampa Electric agreed to move incremental O&M expenses associated with security costs into base rates at the company's next traditional rate case. Accordingly, Tampa Electric included incremental security O&M costs in the company's approved base rates implemented May 7, 2009 and did not include those costs for recovery through the capacity clause.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2010 through December 2010.

A.

Rate Class and **Metering Voltage**	**Capacity Cost** **Cents per kWh**	**Recovery Factor** **Cents per kW**
RS Secondary	0.539	
GS and TS Secondary	0.526	
GSD, SBF Standard		
Secondary		1.74
Primary		1.72
Transmission		1.71
IS, IST, SBI		
Primary		1.55
Transmission		1.54
GSD Optional		
Secondary	0.419	
Primary	0.414	
LS1 Secondary	0.158	

These factors are shown in Exhibit No. ____ (CA-3), Document No. 1, page 3 of 4.

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.539 cents per kWh compare to the factor for May 2009 through December 2009?

A. The proposed capacity cost recovery factor is 0.005 cents per kWh (or $0.05 per 1,000 kWh) higher than the average capacity cost recovery factor of 0.467 cents per kWh for the May 2009 through December 2009 period.

Fuel and Purchased Power Cost Recovery Factor

Q. What is the appropriate amount of the levelized fuel and purchased power cost recovery factor for the year 2010?

A. The appropriate amount for the 2010 period is 4.517 cents per kWh before any application of time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. ____ (CA-3), Document No. 2, shows the appropriate value for the total fuel and purchased power cost recovery factor for each metering voltage level as projected for the period January 2010 through December 2010.

Q. Please describe the information provided on Schedule E1-C.

A. The Generating Performance Incentive Factor ("GPIF") and true-up factors are provided on Schedule E1-C. Tampa Electric has calculated a GPIF reward of $1,239,009, which is included in the calculation of the total fuel and purchased power cost recovery factors. Additionally, E1-C indicates the net true-up amount for the January 2009 through December 2009 period. The net true-up amount for this period is an over-recovery of $45,016,697.

Q. Please describe the information provided on Schedule E1-D.

A. Schedule E1-D presents Tampa Electric's on-peak and off-peak fuel adjustment factors for January 2010 through December 2010. The schedule also presents Tampa Electric's levelized fuel cost factors at each metering voltage level.

Q. Please describe the information provided on Schedule E1-E.

A. Schedule E1-E presents the standard, tiered, on-peak and off-peak fuel adjustment factors at each metering voltage to be applied to customer bills.

Q. Please describe the information provided in Document No. 3.

A. Exhibit No. ____ (CA-3), Document No. 3 demonstrates that the tiered rate structure is designed to be revenue neutral so that the company will recover the same fuel costs as it would under the traditional levelized fuel approach.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2010 through December 2010.

A.

Metering Voltage Level	**Fuel Charge Factor (cents per kWh)**	
Secondary	4.517	
Tier I (Up to 1,000 kWh)	4.167	
Tier II (Over 1,000 kWh)	5.167	
Distribution Primary	4.472	
Transmission	4.427	
Lighting Service	4.383	
Distribution Secondary	5.407	(on-peak)
	4.173	(off-peak)
Distribution Primary	5.353	(on-peak)
	4.131	(off-peak)

Transmission 5.299 (on-peak)
4.090 (off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 4.167 cents per kWh compare to the levelized fuel adjustment factor for the May 2009 through December 2009 period?

A. The proposed fuel charge factor is 0.632 cents per kWh (or $6.32 per 1,000 kWh) lower than the average fuel charge factor of 4.799 cents per kWh for the May 2009 through December 2009 period.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2010 fuel and purchased power and capacity cost recovery projections?

A. Yes. There are three significant events. These are 1) the significant changes in natural gas prices and hedge results; 2) the company's wholesale purchases; and 3) the commencement of coal deliveries by rail at Big Bend Station.

Q. Please describe the first event that affects the company's projection filing.

A. With the addition of Bayside Station in 2004 and more recently the combustion turbines ("CT's") at Polk, Bayside and Big Bend Station, Tampa Electric has increased its reliance on natural gas as a fuel source. In the fall of 2008 the prolonged economic downturn resulted in a dramatic decline in fuel commodity prices, particularly natural gas, which has resulted in a significant decrease in fuel and purchased power costs. In order to minimize fuel price volatility and comply with the company's Commission approved Risk Management Plan, financial hedges were entered into for natural gas in 2009 and 2010 which have partially mitigated some of that benefit. Witness J. T. Wehle's direct testimony describes the decrease in natural gas costs and associated hedge results in more detail.

Q. Please describe the second event.

A. Tampa Electric continued several cost-effective purchase agreements with Hardee Power Partners, RRI Energy Services, Pasco Cogen, Calpine Energy Services, L.P., and qualifying facilities. The purchases improve supply reliability for retail ratepayers in 2009 and 2010 at reasonable and prudent costs. The direct testimony of Tampa Electric witness Benjamin F. Smith, II describes the purchases and demonstrates that the costs associated with the purchased power agreements are prudent and appropriate for recovery through the fuel and purchased power and capacity cost recovery clauses.

Q. Please describe the third event.

A. During June through August of 2008, Tampa Electric signed new fuel transportation agreements that took effect beginning January 1, 2009. Under the new contracts, the company will have the ability to ship solid fuels by rail in addition to existing waterborne capabilities beginning January 1, 2010. As described in greater detail in the direct testimony of witness J. T. Wehle in January of 2009 the company issued a request for rail car proposal to determine the most cost-effective option for the movement of coal from Illinois Basin and Northern Appalachian coal supply regions to Big Bend Station. After an evaluation of all proposals a five year lease agreement has been agreed upon and is expected to be signed in the third quarter of 2009. Tampa Electric has separately identified and included those transportation related costs for recovery in accordance with Commission

Order 14546. The Commission has subsequently allowed the inclusion of investments in rail cars in Order 18136, in docket 870001-EI and also in Order PSC-95-1089-FOF-EI, in Docket No. 950001.

Q. Are the anticipated CSX refunds or credits included in the fuel filing?

A. Yes. In accordance with Tampa Electric's rate case order PSC-09-0283-FOF-EI issued April 30, 2009, the projected refunds from CSX to mitigate the costs associated with building the rail facility are to be entirely credited back to customers through a reduction in coal transportation costs.

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric's projected wholesale incentive benchmark for 2010?

A. The company's projected 2010 benchmark is $1,846,336, which is the three-year average of $799,040, $1,676,141 and $3,063,829 in gains on the company's non-separated wholesale sales, excluding emergency sales, for 2007, 2008 and 2009 (estimated/actual), respectively.

Q. Does Tampa Electric expect gains in 2010 from non-separated wholesale sales to exceed its 2010 wholesale incentive benchmark?

A. Yes. Tampa Electric anticipates that sales will exceed the projected benchmark by $254,803 of which 80 percent or $203,842 will flow back to customers.

Cost Recovery Factors

Q. What is the composite effect of Tampa Electric's proposed changes in its capacity, fuel and purchased power, environmental and energy conservation cost recovery factors on a 1,000 kWh residential customer's bill?

A. The composite effect on a residential bill for 1,000 kWh is a decrease of $1.46 beginning January 2010. These charges are shown in Exhibit No. ____ (CA-3), Document No. 2, on Schedule E10.

Q. When should the new rates go into effect?

A. The new rates should go into effect concurrent with meter reads for the first billing cycle for January 2010.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

A. My name is Brian S. Buckley. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Operations & Performance Planning.

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

A. I received a Bachelor of Science degree in Mechanical Engineering in 1997 from the Georgia Institute of Technology and a Master of Business Administration from the University of South Florida in 2003. I began my career with Tampa Electric in 1999 as an Engineer in Plant Technical Services. I have held a number of different engineering positions at Tampa Electric's power generating stations including Operations Engineer at Gannon Station, Instrumentation and Controls Engineer at Big Bend Station, and Senior Engineer in Operations Planning. In August 2008, I was promoted to Manager, Operations & Performance Planning, where I am currently responsible for unit commitment, unit performance analysis and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Tampa Electric's actual performance results from unit equivalent availability and station heat rate used to determine the Generating Performance Incentive Factor ("GPIF") for the period January 2008 through December 2008. I will also compare these results to the targets established prior to the beginning of the period.

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

A. Yes, I prepared Exhibit No. _____ (BSB-1), consisting of two documents. Document No. 1, entitled "Tampa Electric Company, Generating Performance Incentive Factor, January 2008 - December 2008 True-up" is consistent with the GPIF Implementation Manual previously approved by the Commission. Document No. 2 provides the company's Actual Unit Performance Data for the 2008 period.

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

A. Four of the company's coal-fired units, one integrated gasification combined cycle unit and two natural gas combined cycle unit are included. These are Big Bend Units 1 through 4, Polk Unit 1 and Bayside Units 1 and 2, respectively.

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during the January 2008 through December 2008 period?

A. Yes, I have. This is shown on Document No. 1, page 4 of 32. Based upon 1.888 Generating Performance Incentive Points ("GPIP"), the result is a reward amount of $1,239,009 for the period.

Q. Please proceed with your review of the actual results for the January 2008 through December 2008 period.

A. On Document No. 1, page 3 of 32, the actual average common equity for the period is shown on line 14 as $1,673,419,462. This produces the maximum penalty or reward amount of $6,561,022 as shown on line 21.

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

A. Yes. Operating data for each of the units is filed monthly with the Commission on the Actual Unit Performance Data form. Additionally, outage information is reported to the Commission on a monthly basis. A summary of this data for the 12 months provides the basis for the GPIF.

Q. Are the actual equivalent availability results shown on Document No. 1, page 6 of 32, column 2, directly applicable to the GPIF table?

A. No. Adjustments to actual equivalent availability may be required as noted in section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown on Document No. 1, page 6 of 32, column 4. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the Commission's Staff. The adjustments for each unit are as follows:

Big Bend Unit No. 1

On this unit, 336.0 planned outage hours were originally scheduled for 2008. Actual outage activities required 430.9 planned outage hours. Consequently, the actual equivalent availability of 75.7 percent is adjusted to 76.6 percent as shown on Document No. 1, page 7 of 32.

Big Bend Unit No. 2

On this unit, 768.0 planned outage hours were originally scheduled for 2008. Actual outage activities required 897.0 planned outage hours. Consequently, the actual equivalent availability of 71.0 percent is adjusted to 72.2 percent as shown on Document No. 1, page 8 of 32.

Big Bend Unit No. 3

On this unit, 2,328.0 planned outage hours were originally scheduled for 2008. Actual outage activities required 2,846.7 planned outage hours. Consequently, the actual equivalent availability of 44.5 percent is adjusted to 48.4 percent as shown on Document No. 1, page 9 of 32.

Big Bend Unit No. 4

On this unit, 336.0 planned outage hours were originally scheduled for 2008. Actual outage activities required 512.1 planned outage hours. Consequently, the actual equivalent availability of 72.8 percent is adjusted to 74.4 percent as shown on Document No. 1, page 10 of 32.

Polk Unit No. 1

On this unit, 691.8 planned outage hours were originally scheduled for 2008. Actual outage activities required 267.8 planned outage hours. Consequently, the actual equivalent availability of 83.2 percent is adjusted to 79.0 percent, as shown on Document No. 1, page 11 of 32.

Bayside Unit No. 1

On this unit, 336.0 planned outage hours were originally scheduled for 2008. Actual outage activities required 207.7 planned outage hours. Consequently, the actual equivalent availability of 94.9 percent is adjusted to 93.5 percent, as shown on Document No. 1, page 12 of 32.

Bayside Unit No. 2

On this unit, 1,344.0 planned outage hours were originally scheduled for 2008. Actual outage activities required 1,277.2 planned outage hours. Consequently, the actual equivalent availability of 83.6 percent is adjusted to 82.8 percent, as shown on Document No. 1, page 13 of 32.

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

A. The final adjusted equivalent availabilities for each unit are shown on Document No. 1, page 6 of 32, column 4. This number is entered into the respective GPIP table for each particular unit, shown on pages 7 of 32 through 13 of 32. Page 4 of 32 summarizes the weighted equivalent availability points to be awarded or penalized.

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

A. The actual heat rate and adjusted actual heat rate for Tampa Electric's seven GPIF units are shown on Document No. 1, page 6 of 32. The adjustment was developed based on the guidelines of section 4.3.16 of the GPIF Manual. This procedure is further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the FPSC Staff. The final adjusted actual heat rates are also shown on page 5 of 32, column 9. The heat rate value is entered into the respective GPIP table for the particular unit, shown on pages 14 of 32 through 20 of 32. Page 4 of 32 summarizes the weighted heat rate points to be awarded or penalized.

Q. What is the overall GPIP for Tampa Electric for the January 2008 through December 2008 period?

A. This is shown on Document No. 1, page 2 of 32. Essentially, the weighting factors shown on page 4 of 32, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 32, column 4, are substituted within the equation found on page 32 of 32. The resulting value, 1.888, is then entered into the GPIF table on page 2 of 32. Using linear interpolation, the reward amount is $1,239,009.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 090001-EI
FILED: 9/1/2009

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

A. My name is Brian S. Buckley. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Operations and Performance Planning.

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

A. I received a Bachelor of Science degree in Mechanical Engineering in 1997 from the Georgia Institute of Technology and a Master of Business Administration from the University of South Florida in 2003. I began my career with Tampa Electric in 1999 as an Engineer in Plant Technical Services. I have held a number of different engineering positions at Tampa Electric's power generating stations including Operations Engineer at Gannon Station, Instrumentation and Controls Engineer at Big Bend Station, Senior Engineer in Asset Management and Supervisor of Performance Planning and Analysis. In October 2008, I was promoted to Manager, Operations and Performance Planning, where I am currently responsible for unit commitment and reporting of generation statistics.

Q. What is the purpose of your testimony?

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

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

A. Yes, Exhibit No. ____ (BSB-2), consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2010 period.

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

A. Four of the company's coal-fired units, one integrated gasification combined cycle unit and two natural gas combined cycle units are included. These are Big Bend Units 1 through 4, Polk Unit 1 and Bayside Units 1 and 2.

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

A. Yes, the documents are consistent with the GPIF Implementation Manual previously approved by the Commission. To account for the concerns presented in the testimony of Commission Staff witness Sidney W. Matlock during the 2005 fuel hearing, Tampa Electric removes outliers from the calculation of the GPIF targets. Section 3.3 of the GPIF Implementation Manual allows for removal of outliers, and the methodology was approved by the Commission in Order No. PSC-06-1057-FOF-EI issued in Docket No. 060001-EI on December 22, 2006.

Q. Did Tampa Electric identify any outages as outliers?

A. Yes. One outage from Big Bend Unit 2, one outage from Big Bend Unit 3 and one outage from Big Bend Unit 4 were identified as outlying outages; therefore, the associated forced outage hours were removed from the study.

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

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2010 period. A range of potential improvements and degradations were determined for each of these metrics.

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

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

To give an example for the 2010 period, the projected

EUOF for Big Bend Unit 3 is 14.5 percent, and the POF is 8.5 percent. Therefore, the target EAF for Big Bend Unit 3 equals 77.0 percent or:

$$100\% - (14.5\% + 8.5\%) = 77.0\%$$

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

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

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

$$EAF_{MAX} = 1 - [0.8 \ (EUOF_T) + 0.95 \ (POF_T)]$$

The factors included in the above equations are the same factors that determine the target equivalent availability. To determine the maximum incentive points, a 20 percent reduction in EUOF and Equivalent Maintenance Outage Factor ("EMOF"), plus a five percent reduction in the POF are necessary. Continuing with the Big Bend Unit 3 example:

$$EAF_{MAX} = 1 - [0.8 \ (14.5\%) + 0.95 \ (8.5\%)] = 80.3\%$$

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

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

A. The potential for unit availability degradation is significantly greater than the potential for unit availability improvement. This concept was discussed extensively during the development of the incentive. To incorporate this biased effect into the unit availability tables, Tampa Electric uses a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is calculated using the following formula:

$$EAF_{MIN} = 1 - [1.40 \ (EUOF_T) + 1.10 \ (POF_T)]$$

Again, continuing with the Big Bend Unit 3 example,

$$EAF_{MIN} = 1 - [1.40 \ (14.5\%) + 1.10 \ (8.5\%)] = 70.3\%$$

The equivalent availability maximum and minimum for the other six units are computed in a similar manner.

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

A. The company's planned outages for January through December 2010 are shown on page 21 of Document No. 1. Two GPIF units have a major outage of 28 days or greater in 2010; therefore, two Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 2 is scheduled for a planned outage from February 13, 2010 to February 28, 2010. There are 384 planned outage hours scheduled for the 2010 period, and a total of 8,760 hours during this 12-month period. Consequently, the POF for Big Bend Unit 2 is 4.4 percent or:

$$\frac{384}{8{,}760} \times 100\% = 4.4\%$$

The factor for each unit is shown on pages 5 and 14 through 20 of Document No. 1. Big Bend Unit 1 has a POF of 26.8 percent. Big Bend Unit 2 has a POF of 4.4 percent. Big Bend Unit 3 has a POF of 8.5 percent. Big Bend Unit 4 has a POF of 15.3 percent. Polk Unit 1 has a POF of 3.8 percent. Bayside Unit 1 has a POF of 3.8 percent, and Bayside Unit 2 has a POF of 3.8 percent.

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

A. For each unit the most current 12-month ending value, June 2009, was used as a basis for the projection. All projected factors are based upon historical unit performance unless adjusted for outlying forced outages. These target factors are additive and result in a EUOF of 14.5 percent for Big Bend Unit 3. The EUOF for Big Bend Unit 3 is verified by the data shown on page 16, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

$$EUOF = \frac{(EFOH + EMOH)}{PH} \times 100\%$$

Or

$$EUOF = \frac{(1,007 + 266)}{8,760} \times 100\% = 14.5\%$$

Relative to Big Bend Unit 3, the EUOF of 14.5 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 1

The projected EUOF for this unit is 18.7 percent. The unit will have a planned outage in 2010, and the POF is 26.8 percent. Therefore, the target equivalent availability for this unit is 54.4 percent.

Big Bend Unit 2

The projected EUOF for this unit is 28.1 percent. The unit will have a planned outage in 2010, and the POF is 4.4 percent. Therefore, the target equivalent availability for this unit is 67.6 percent.

Big Bend Unit 3

The projected EUOF for this unit is 14.5 percent. The unit will have a planned outage in 2010, and the POF is 8.5 percent. Therefore, the target equivalent availability for this unit is 77.0 percent.

Big Bend Unit 4

The projected EUOF for this unit is 15.4 percent. The unit will have a planned outage in 2010, and the POF is 15.3 percent. Therefore, the target equivalent availability for this unit is 69.2 percent.

Polk Unit 1

The projected EUOF for this unit is 11.3 percent. The unit will have a planned outage in 2010, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 84.9 percent.

Bayside Unit 1

The projected EUOF for this unit is 0.6 percent. The unit will have a planned outage in 2010, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 95.6 percent.

Bayside Unit 2

The projected EUOF for this unit is 0.5 percent. The unit will have a planned outage in 2010, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 95.6 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 67.5 percent is shown on Page 5 of Document No. 1. This target is comparable to the 2007 and 2008 January through December actual performance.

Q. Why are Forced and Maintenance Outage Factors adjusted for planned outage hours?

A. The adjustment makes the factors more accurate and comparable. A unit in a planned outage stage or reserve shutdown stage will not incur a forced or maintenance outage. To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent

Unplanned Outage Factor for Big Bend Unit 3 on page 16 of Document No. 1. Except for the months of March and October, the Equivalent Unplanned Outage Rate and the EUOF are equal. This is because no planned outages are scheduled during these months. During the months of March and October, the Equivalent Unplanned Outage Rate exceeds the EUOF due to scheduled planned outages. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

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

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

$$EFOF + EMOF + POF + EAF = 100\%$$

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

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

A. Yes. Target heat rates and ranges of potential operation have been developed as required and have been adjusted to reflect the aforementioned agreed upon GPIF methodology.

Q. How were these targets determined?

A. Net heat rate data for the three most recent July through June annual periods formed the basis of the target development. The historical data and the target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or equipment modifications having material effect on heat rate can be taken into consideration.

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

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate versus net output factor curves have been developed for each unit. This information is shown on pages 31 through 37 of Document No. 1.

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

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

Q. Please summarize your heat rate projection (Btu/Net·kWh) and the range about each target to allow for potential improvement or degradation for the 2010 period.

A. The heat rate target for Big Bend Unit 1 is 10,785 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±360 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,481 Btu/Net kWh with a range of ±305 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,627 Btu/Net kWh, with a range of ±262 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,661 Btu/Net kWh with a range of ±431 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,375 Btu/Net kWh with a range of ±727 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,250 Btu/Net kWh with a range of ±125 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,409 Btu/Net kWh with a range of ±83 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within the range for each target. This is shown on page 4, and pages 7 through 13 of Document No. 1.

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

A. Yes.

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

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown on pages 7 through 13. The baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $936,879,400 is shown on page 6, column 2. Multiple production cost simulations were performed to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6, column 4 of Document No. 1.

After all of the individual savings are calculated, column 4 totals $33,641,218 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing individual savings by the total. For Big Bend Unit 3, the weighting factor for equivalent availability is 5.6 percent as shown in the right-hand column on page 6. Pages 7 through 13 of Document No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, on Big Bend Unit 3, page 9, if the unit operates at 80.3 percent equivalent availability, fuel savings would equal $1,872,300, and 10 equivalent availability points would be awarded.

The GPIF Reward/Penalty table on page 2 is a summary of the tables on pages 7 through 13. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, or $33,641,218. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January through December 2010 is $1,949,226,994. This produces the maximum allowed jurisdictional incentive of $7,726,902 shown on line 21.

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

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

Q. Please summarize your testimony.

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

$$\begin{aligned} GPIP: = (\ & 0.1106\ EAP_{BB1} + 0.1496\ EAP_{BB2} \\ & + 0.0557\ EAP_{BB3} + 0.0999\ EAP_{BB4} \\ & + 0.0349\ EAP_{PK1} + 0.0017\ EAP_{BAY1} \\ & + 0.0036\ EAP_{BAY2} + 0.0558\ HRP_{BB1} \\ & + 0.0598\ HRP_{BB2} + 0.0542\ HRP_{BB3} \\ & + 0.0910\ HRP_{BB4} + 0.1079\ HRP_{PK1} \\ & + 0.1117\ HRP_{BAY1} + 0.0636\ HRP_{BAY2}) \end{aligned}$$

Where:

GPIP = Generating Performance Incentive Points.

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

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

TAMPA ELECTRIC COMPANY
DOCKET NO. 090001-EI
FILED: 09/01/2009

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH, II

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

A. My name is Benjamin F. Smith, II. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the Fuel Services and Systems group within the Fuels Management Department.

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

A. I received a Bachelor of Science degree in Electric Engineering in 1991 from the University of South Florida in Tampa, Florida and am a registered Professional Engineer within the State of Florida. I joined Tampa Electric in 1990 as a cooperative education student. During my years with the company, I have worked in the areas of transmission engineering, distribution engineering, resource planning, retail marketing, and wholesale power marketing. I am currently the Manager of Strategic Fuels and Power Services in the Fuel Services and Systems group. My responsibilities are to evaluate short-term and long-term purchase and sale opportunities within the wholesale power market, assist in wholesale contract structure and help evaluate the processes used to value wholesale power opportunities. In this capacity, I interact with wholesale power market participants such as utilities, municipalities, electric cooperatives, power marketers and other wholesale generators.

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

A. Yes. I have submitted written testimony in the annual fuel docket since 2003, and I testified before this Commission in Docket Nos. 030001-EI, 040001-EI, and 080001-EI regarding the appropriateness and prudence of Tampa Electric's wholesale purchases and sales.

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

A. The purpose of my testimony is to provide a description of Tampa Electric's purchased power agreements that the company has entered into and for which it is seeking cost recovery through the Fuel and Purchased Power Cost Recovery Clause ("fuel clause") and the Capacity Cost Recovery Clause. I also describe Tampa Electric's purchased power strategy for mitigating price and supply-side risk, while providing customers with a reliable supply of economically priced purchased power.

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

A. Tampa Electric evaluates potential purchased power needs and sale opportunities by analyzing the expected available amounts of generation and the power required to meet the projected demand and energy of its customers. Purchases are made to achieve reserve margin requirements, to meet customers' demand and energy needs, to supplement generation during unit outages and for economical purposes. When there is a purchased power need, the company aggressively polls the marketplace for wholesale capacity or energy, searching for reliable supplies at the best possible price from creditworthy counterparties.

Conversely, when there is a sales opportunity, the company offers profitable wholesale capacity or energy products to creditworthy counterparties. The company has wholesale power purchase and sale transaction enabling agreements with numerous counterparties. This process helps to ensure that the company's wholesale purchase and sale activities are conducted in a reasonable and prudent manner.

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

A. Yes, it has. Tampa Electric has fully complied with, and continues to fully comply with, the Commission's March 11, 1997 Order, No. PSC-97-0262-FOF-EI, issued in Docket No. 970001-EI, which governs the treatment of separated and non-separated wholesale sales. The company's wholesale purchase and sale activities and transactions are also reviewed and audited on a recurring basis by the Commission.

In addition, Tampa Electric actively manages its wholesale purchases and sales with the goal of capitalizing on opportunities to reduce customer costs.

The company monitors its contractual rights with purchased power suppliers as well as with entities to which wholesale power is sold to detect and prevent any breach of the company's contractual rights. Also, Tampa Electric continually strives to improve its knowledge of wholesale power markets and the available opportunities within the marketplace. The company uses this knowledge to minimize the costs of purchased power and to maximize the savings the company provides retail customers by making wholesale sales when excess power is available on Tampa Electric's system and market conditions allow.

Q. Please describe Tampa Electric's 2009 wholesale energy purchases.

A. Tampa Electric assessed the wholesale power market and entered into short-term and long-term purchases based on price and availability of supply. Approximately 10 percent of the expected energy needs for 2009 will be met using purchased power. This purchased power energy includes economy purchases and existing firm purchased power agreements with Hardee Power Partners, qualifying facilities, Calpine, RRI Energy Services (formally known as Reliant), Pasco Cogen, and Progress Energy Florida. With the exception of the Progress Energy Florida purchase, the testimony in previous years describe each existing firm purchase power agreement, which were subsequently approved by the Commission as being cost-effective for Tampa Electric customers.

The Progress Energy Florida purchase is for 100 MW that began September 2008 and continues through September 2009. This purchase is not an extension or amendment of the Progress Energy Florida agreements previously approved by the Commission, but it does have the same structure. Like the previously approved agreements, it is a firm purchase with the energy priced at system average fuel. Since this agreement had not been signed at the time Tampa Electric prepared its 2009 fuel projection for submission, it was not described in that filing. However, the Company included it in its 2009 Ten Year Site Plan ("TYSP") and provided information concerning this purchase in its responses to the TYSP Commission Staff Supplemental Data Request filed April 1, 2009. This purchase provides an estimated $786,000 savings to customers.

All of these purchases provide supply reliability and help reduce fuel price volatility.

and Bayside Units 1 and 2.

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2010 period?

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

Q. Does this conclude your testimony?

A. Yes.

Q. Has Tampa Electric entered into any other wholesale energy purchases?

A. Yes. Tampa Electric has two petitions for approval before the Commission for consideration, and each involves renewable energy. One is a 25 MW purchase from Energy 5.0, filed March 9, 2009, and the other is the extension of an existing 19 MW purchase from the City of Tampa, filed March 23, 2009. Both agreements, although signed, contain a provision requiring Commission approval as a condition precedent. Thus, Tampa Electric may terminate either agreement, without penalty, if the Commission determines they are not cost-effective.

For 2010, the company expects to meet approximately seven percent of its customers' energy needs through purchased power, which includes economy purchases and the existing firm purchased power agreements with Hardee Power Partners, qualifying facilities, Calpine, RRI Energy Services, and Pasco Cogen. All of these purchases provide supply reliability and help reduce price volatility.

Lastly, Tampa Electric will continue to evaluate economic combinations of forward and spot market energy purchases during its spring and fall generation maintenance periods and peak periods. This purchasing strategy provides a reasonable and diversified approach to serving customers.

Q. Does Tampa Electric plan to enter into any other new purchased power agreements during its upcoming Big Bend Unit 1 Selective Catalytic Reduction ("SCR") installation outage?

A. Currently, the company has no plans to make a purchase for the upcoming SCR installation outage on Big Bend Unit 1, which is scheduled to occur November 28, 2009 through April 8, 2010. However, the company continually monitors and engages the marketplace for power purchase opportunities and will evaluate the economics of potential forward purchases during the Big Bend Unit 1 outage to reduce the overall cost to customers.

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

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

Q. Does Tampa Electric's risk management strategy for power transactions adequately mitigate price risk for purchased power for 2009?

A. Yes, Tampa Electric expects its physical wholesale purchases to continue to reduce its customers' purchased power price risk. For example, the 170 MW Calpine purchase and the 158 MW purchase from Reliant in 2009 are reliable, cost-based call options on peaking power. These purchases serve as both a physical hedge and reliable source of economical power in 2009. The availability of these purchases is high, and their price structures provide some protection from rising market prices, which are largely influenced by supply and the volatility of natural gas prices.

Mitigating price risk is a dynamic process, and Tampa Electric continually evaluates its options in light of changing circumstances and new opportunities. Tampa Electric also strives to maintain an optimum level and mix of short- and long-term capacity and energy purchases to augment the company's own generation for the year 2009 and beyond.

Q. How does Tampa Electric mitigate the risk of disruptions to its purchased power supplies during major weather related events such a hurricane?

A. During hurricane season, Tampa Electric continues to utilize a purchased power risk management strategy to minimize potential power supply disruptions during major weather related events. The strategy includes monitoring storm activity; evaluating the impact of the storm on the wholesale power market; purchasing power on the forward market for reliability and economics; evaluating transmission availability and the geographic location of electric resources; reviewing the seller's fuel sources and dual fuel capabilities; and focusing on fuel-diversified purchases. Notably, both the RRI Energy Services and Pasco Cogen purchases are dual fuel resources, having both natural gas and oil capability, which enhances supply reliability during a potential hurricane-related disruption in natural gas supply. Absent the threat of a hurricane, and for all other months of the year, the company continues its strategy of evaluating economic combinations of short- and long-term purchase opportunities identified in the marketplace.

Q. Please describe Tampa Electric's wholesale energy sales for 2009 and 2010.

A. Tampa Electric entered into various non-firm, non-separated wholesale sales in 2009, and the company anticipates making additional non-separated sales during the balance of 2009 and in 2010. In accordance with Order No. PSC-01-2371-FOF-EI, issued on December 7, 2001 in Docket No. 010283-EI, all gains from non-separated sales are to be returned to customers through the fuel clause, up to the three-year rolling average threshold. For all gains above the three-year rolling average threshold, customers receive 80 percent and the company retains the remaining 20 percent. In 2009, the three-year rolling average threshold is $1,077,446, and the projected gains above this threshold are $1,986,383. In 2010, the projected three-year rolling average threshold is $1,846,336, and the projected gains above this threshold are $254,803.

Q. Please summarize your testimony.

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

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 090001-EI
FILED: 04/03/2009

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOANN T. WEHLE

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

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

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

A. I received a Bachelor's of Business Administration Degree in Accounting in 1985 from St. Mary's College, South Bend, Indiana. I am a CPA in the State of Florida and worked in several accounting positions prior to joining Tampa Electric. I began my career with Tampa Electric in 1990 as an auditor in the Audit Services Department. I became Senior Contracts Administrator, Fuels in 1995. In 1999, I was promoted to Director, Audit Services and subsequently rejoined the Fuels Department as Director in April 2001. I became Director, Wholesale Marketing and Fuels in August 2002. I am responsible for managing Tampa Electric's wholesale energy marketing and fuel-related activities.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present, for the Florida Public Service Commission's ("FPSC" or "Commission") review, information regarding the 2008 results of Tampa Electric's risk management activities, as required by the terms of the stipulation entered into by the parties to Docket No. 011605-EI and approved by the Commission in Order No. PSC-02-1484-FOF-EI.

Q. What is the source of the data you present in your testimony in this proceeding?

A. Unless otherwise indicated, the source of the data is the books and records of Tampa Electric. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by this Commission.

Q. What were the results of Tampa Electric's risk management activities in 2008?

A. As outlined in Tampa Electric's annual Risk Management Plan, most recently filed on September 2, 2008 in Docket No. 080001-EI, the company follows a non-speculative risk management strategy to reduce fuel price volatility while maintaining a reliable supply of fuel. In an effort to limit exposure to market price fluctuations of natural gas, Tampa Electric established a hedging program. Over time, the program has been enhanced as Tampa Electric's gas needs have evolved and grown. All enhancements have been reviewed and approved by the company's Risk Authorization Committee.

On April 3, 2009, Tampa Electric filed its annual risk management report, which describes the outcomes of its 2008 risk management activities. The report indicates that Tampa Electric's 2008 hedging activities resulted in a net gain of approximately $18.1 million. Tampa Electric followed the plan objective of reducing price volatility while maintaining a reliable fuel supply. For 2008, the net gain is a combination of large gains during the summer offset by losses during the mild winter at the beginning of 2008 and losses due to low prices during the economic downturn at the end of 2008. The gains during the summer were the result of a dramatic rise in the price of all energy commodities, including natural gas. The losses at the beginning of 2008 were driven primarily by the mild winter of 2007/2008 that allowed natural gas prices to decrease. The losses at the end of 2008 were due to the severe and abrupt economic downturn that reduced demand for natural gas; as a result, the price of natural gas dropped dramatically during the third and fourth quarters of 2008. Although there was considerable price volatility in the natural gas market during 2008, Tampa Electric mitigated price volatility through the financial hedges.

Q. Does Tampa Electric implement physical hedges for natural gas?

A. Yes, Tampa Electric maintains contracts for gas supplies from various regions and on different pipelines to enhance its physical gas supply reliability. During 2007, Tampa Electric contracted for access to natural gas supplies via the Southeast Supply Header and Gulf South, adding approximately 65,000 MMBtu per day of inland supply to increase supply reliability during Gulf storms. While contracted in 2007, the access became effective in the summer of 2008.

Q. Does Tampa Electric use a hedging information system?

A. Yes, Tampa Electric continues to use Sungard's Nucleus Risk Management System ("Nucleus"). Nucleus supports sound hedging practices with its contract management, separation of duties, credit tracking, transaction limits, deal confirmation, and business report generation functions. The Nucleus system records all financial natural gas hedging transactions, and the system calculates risk management reports. Nucleus is also used for contract, credit management and risk exposure analysis.

Q. What were the results of the company's incremental hedging activities in 2008?

A. Tampa Electric's incremental natural gas hedging activities protected customers from price volatility for [redacted] percent of the natural gas used in the company's generating stations. The net result of natural gas hedging activity in 2008 was a gain of approximately $18.1 million, when the instrument prices were compared to market prices on settled positions.

Q. Did the company use financial hedges for other commodities in 2008?

A. No, Tampa Electric did not use financial hedges for other commodities primarily because of its fuel mix.

Tampa Electric's generation is comprised mostly of coal and natural gas. Though the price of coal has increased, it is relatively stable compared to the prices of oil and natural gas. In addition, financial hedging instruments for the primary coal Tampa Electric burns, high sulfur Illinois Basin coal, do not exist.

Tampa Electric consumes a small amount of oil. However, its low and erratic usage pattern makes price hedging of oil consumption impractical; therefore, the company did not use financial hedges for oil.

The company did not use financial hedges for wholesale energy transactions because a liquid, published market does not exist in Florida.

Q. Did Tampa Electric use physical hedges for other commodities?

A. Yes, Tampa Electric used physical hedges in managing its coal supply reliability. The company enters into a portfolio of differing term contracts with various suppliers to obtain the types of coal used on its system. Additionally, Tampa Electric fills its oil tanks prior to entering hurricane season to reduce exposure to supply or price issues that may arise during hurricane season.

Q. What is the basis for your request to recover the commodity and transaction costs described above?

A. Commission Order No. PSC-02-1484-FOF-EI, in Docket No. 011605-EI states:

> "Each investor-owned electric utility shall be authorized to charge/credit to the fuel and purchased power cost recovery clause its non-speculative, prudently-incurred commodity costs and gains and losses associated with financial and/or physical hedging transactions for natural gas, residual oil, and purchased power contracts tied to the price of natural gas."

Therefore, Tampa Electric's request for recovery is in accordance with the aforementioned order.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 090001-EI
FILED: 09/01/2009

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOANN T. WEHLE

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

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

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

A. I received a Bachelor of Business Administration Degree in Accounting in 1985 from St. Mary's College in Notre Dame, Indiana. I am a CPA in the State of Florida and worked in several accounting positions prior to joining Tampa Electric. I began my career with Tampa Electric in 1990 as an auditor in the Audit Services Department. I became Senior Contracts Administrator, Fuels in 1995. In 1999, I was promoted to Director, Audit Services and subsequently rejoined the Fuels Department as Director in April 2001. I became Director, Wholesale Marketing and Fuels in August 2002. I am responsible for managing Tampa Electric's wholesale energy marketing and fuel-related activities.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to discuss Tampa Electric's fuel mix, fuel price forecasts, potential impacts to fuel prices, and the company's fuel procurement strategies. I will address steps Tampa Electric takes to manage fuel supply reliability and price volatility and describe projected hedging activities. I also sponsor Tampa Electric's 2010 risk management plan submitted on August 4, 2009 in this docket.

Q. Have you previously testified before this Commission?

A. Yes. I have testified or filed testimony before this Commission in several dockets, including Docket No. 011605-EI, 031033-EI and 080317-EI as well as the annual fuel and purchased power cost recovery dockets from 2001 through 2008. My testimony in these dockets described the appropriateness and prudence of Tampa Electric's fuel procurement activities, fuel supply risk management, fuel price volatility hedging activities, and fuel transportation costs.

2010 Fuel Mix and Procurement Strategies

Q. What fuels will Tampa Electric's generating stations use in 2010?

A. In 2010, Tampa Electric expects its fuel mix to be comparable to 2009. In 2010, natural gas-fired and coal-fired generation is expected to be 49 percent and 50 percent of total generation, respectively. Generation from No. 2 oil and No. 6 oil is less than one percent of the total expected generation.

Q. Have Tampa Electric's generation facilities, and subsequent fuel requirements, changed recently?

A. Yes. Tampa Electric recently retired three oil-fired combustion turbines at Big Bend Station. In 2009, Tampa Electric added five 60 MW aero derivative combustion turbines to its generation portfolio. Four are natural gas fired units located at Bayside Power Station. The fifth unit located at Big Bend Station has dual fuel capability that can burn either natural gas or No. 2

oil. These units provide black start capability, improve the reliability of the system and provide economical dispatch alternatives.

Q. How does Tampa Electric's natural gas procurement and transportation strategy achieve competitive natural gas purchase prices for long and short term deliveries?

A. Tampa Electric uses a portfolio approach to natural gas procurement. The company's portfolio consists of a blend of pre-arranged base load, intermediate and swing supply complemented with daily spot purchases. The contracts have various time lengths to help secure needed supply at competitive prices and maintain the ability to take advantage of favorable natural gas price movements. Tampa Electric purchases its physical natural gas supply from many approved counterparties, enhancing liquidity and diversification of its natural gas supply portfolio. The natural gas prices are based on monthly and daily price indices, further increasing portfolio pricing diversification.

Tampa Electric has improved the reliability of the physical delivery of natural gas to its power plants by diversifying its pipeline transportation assets, including receipt points, and utilizing pipeline and storage tools to enhance access to natural gas supply during hurricanes or other events that constrain supply. On a daily basis, Tampa Electric strives to obtain reliable supplies of natural gas at favorable prices in order to mitigate costs to its customers. Additionally, Tampa Electric's risk management activities improve the company's natural gas procurement activities by reducing natural gas price volatility.

Q. Please describe Tampa Electric's diversified natural gas transportation arrangements.

A. Tampa Electric receives natural gas via the Florida Gas Transmission ("FGT") pipeline and Gulfstream Natural Gas System, LLC ("Gulfstream"). The ability to deliver natural gas directly from two pipelines enhances the fuel delivery reliability of the Bayside Power Station, the largest natural gas units on Tampa Electric's system. Natural gas can also be delivered to Big Bend Station directly from Gulfstream to support the new aero derivative combustion turbine.

Q. What actions does Tampa Electric take to enhance the reliability of its natural gas supply?

A. Tampa Electric has maintained natural gas storage capacity with Bay Gas Storage near Mobile, Alabama since 2005. Currently the company reserves 850,000 mmBtu of storage capacity, which enhances access to natural gas in the case of severe weather or other events that disrupt supply. Tampa Electric's storage capacity at Bay Gas Storage will increase to 1,250,000 mmBtu when the fourth cavern is completed in fall 2010.

In addition to storage, Tampa Electric maintains diversified natural gas supply receipt points in FGT Zones 1, 2 and 3. Diverse receipt points reduce the company's vulnerability to hurricane impacts in FGT Zone 3 and provide access to lower priced gas supply. Tampa Electric also participated in the Southeast Supply Header ("SESH") project. SESH connects the receipt points of FGT and other Mobile Bay area pipelines with natural gas supply in the mid-continent. Mid-continent natural gas production has grown and continues to increase through non-conventional shale gas and the Rockies Express. Thus, SESH gives Tampa Electric access to secure on-shore gas supply for a small portion of its portfolio. This is beneficial because mid-continent gas supply is typically priced lower than gas supply around Mobile Bay. Commitment to larger quantities would require firm pipeline capacity resulting in an additional fixed cost component.

Q. What is Tampa Electric's coal procurement strategy?

A. Tampa Electric's two coal-fired plants are Big Bend Station and Polk Station. Big Bend Station is a fully scrubbed plant whose design fuel is high-sulfur Illinois Basin coal. Polk Station is an integrated gasification combined cycle plant currently burning a mix of petroleum coke and low sulfur coal. The plants have varying operational and environmental restrictions and require fuel with custom quality characteristics such as ash, fusion temperature and sulfur, heat and chlorine content. Since coal is not a homogenous product, fuel selection is based on these unique characteristics, along with price, availability, and creditworthiness of the supplier.

Tampa Electric maintains a portfolio of bilateral contracts varying in term lengths of long, intermediate, and short for coal supply. Tampa Electric monitors the market to obtain the most favorable prices from sources that meet the needs of the generating stations. The use of daily and weekly publications, independent research analyses from industry experts, discussions with suppliers, and coal solicitations aid the company in monitoring the coal market and shaping the company's coal procurement strategy to reflect current market conditions. This allows for stable supply sources while providing flexibility to take advantage of favorable spot market opportunities. The company's efforts to obtain the most favorable coal prices directly benefit its customers.

Q. Has Tampa Electric entered into coal and natural gas supply transactions for 2010 delivery?

A. Yes, Tampa Electric has contracted its 2010 expected coal needs through bilateral agreements with coal suppliers to mitigate price volatility and ensure reliability of supply. Additionally, the majority of the company's 2010 expected natural gas requirements are already under contract.

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

A. Yes. Tampa Electric diligently manages its mix of long, intermediate, and short term purchases of fuel in a manner designed to reduce overall fuel costs while maintaining electric service reliability. The company's fuel activities and transactions are reviewed and audited on a recurring basis by the Commission. In addition, the company monitors its rights under contracts with fuel suppliers to detect and prevent any breach of those rights. Tampa Electric continually strives to improve its knowledge of fuel markets and to take advantage of opportunities to minimize the costs of fuel.

Coal Transportation Costs

Q. Are there any changes to Tampa Electric's coal transportation portfolio in 2010?

A. Yes. Tampa Electric is nearing completion of a rail delivery and unloading facility at Big Bend Station. Delivery of coal through this facility is expected to commence in December of 2009. In 2010, Tampa Electric expects to receive nearly 2 million tons of high quality coal for use at Big Bend Station through this rail facility.

Q. What benefits exist from rail transportation of coal for

Tampa Electric and its customers?

A. Bimodal solid fuel transportation to Big Bend Station affords the company and its customers 1) access to more potential coal suppliers providing a more competitive, overall delivered cost, 2) the flexibility to switch to either water or rail in the event of a transportation breakdown or interruption on the other mode, and 3) competition for solid fuel transportation contracts for future periods.

Q. Did the Commission agree that there are customer benefits associated with bi-modal waterborne and rail deliveries?

A. Yes, it did. In the 080001 Docket, the Commission determined that the company complied with all requirements of Order No. PSC-04-0999-FOF-EI in procuring its fuel transportation contracts, which required a fair and open competitive procurement process to ensure the lowest possible delivered costs through the use of a bimodal fuel delivery system.

Q. In order to begin taking rail delivery of solid fuels at Big Bend Station, what infrastructure is required?

A. The company has constructed extensive rail unloading facilities. The facilities must be built and tested in 2009 to begin taking delivery by January 1, 2010. The facilities include a double loop track, a large unloading pit, and several thousand feet of conveyors. These facilities will benefit customers over the five-year term of the rail contract and will continue to benefit customers in subsequent years through dual delivery capability and access to additional coal supplies.

Q. Are there any additional rail related costs required for the delivery of coal?

A. Yes. In conjunction with the construction of rail unloading facilities at Big Bend Station, the company conducted a bid solicitation for railcars in late January 2009. The objective was to solicit competitive bids and enter into either an agreement for approximately 440 aluminum, rapid-discharge railcars for the movement of solid fuel from the Illinois Basin and Northern Appalachian coal supply regions to Big Bend Station.

Tampa Electric sent the solicitation to 18 different railcar companies and received responses from seven and five railcar leasing companies and railcar builders, respectively. The evaluation was primarily based upon the following components: railcar rate, delivery location, and capacity. It was determined that leasing the railcars was the best option because of the high cost to purchase railcars, lack of experience owning or maintaining railcars, and uncertainty surrounding carbon legislation.

Projected 2010 Fuel Prices

Q. How does Tampa Electric project fuel prices?

A. Tampa Electric reviews fuel price forecasts from sources widely used in the industry, including Wood Mackenzie (who acquired the former Hill & Associates), the Energy Information Administration, the New York Mercantile Exchange ("NYMEX") and other energy market information sources. Futures prices for energy commodities as traded on the NYMEX, form the basis of the natural gas, No. 6 oil and No. 2 oil market commodity price forecasts. The commodity price projections are then adjusted to incorporate expected transportation costs and location differences.

Coal prices and coal transportation prices are projected using contracted pricing and information from industry-recognized consultants and published indexes and are specific to the particular quality and mined location of coal utilized by Tampa Electric's Big Bend Station and Polk Unit 1. Final as-burned prices are derived using expected commodity prices and associated transportation costs.

Q. How do the 2010 projected fuel prices compare to the fuel prices projected for 2009?

A. The entire industry, including Tampa Electric, has experienced lower than expected fuel prices in 2009. The global recession, financial crises, and credit constraints coupled with plentiful natural gas and coal supply caused 2009 prices to plummet from a high in the summer of 2008. Projected fuel prices for 2010 are expected to increase slightly in 2010 as the economy and financial crises is projected to improve.

Q. What are the market drivers of the expected 2010 price of natural gas?

A. The major market drivers for the expected 2010 pricing of natural gas are the protracted economic downturn, which has resulted in a decline in demand for natural gas from commercial and industrial consumers, and, the additional supply of natural gas from new wells and improved extraction methods. The current market forecasts are projecting a slight recovery of natural gas pricing in the first quarter of 2010.

Q. What are the market drivers of the change in the price of coal?

A. Coal prices dropped dramatically as the global economy deteriorated. Additionally, low natural gas prices have caused higher cost coal-fired generation to be displaced by lower cost natural gas combined cycle units. The reduced demand for coal has caused inventories to increase throughout the nation. While some mines have cut back on production to counterbalance the inventory increases, prices are projected to stay down until the stock piles decline.

Q. Did Tampa Electric consider the impact of higher than expected or lower than expected fuel prices?

A. Yes. Tampa Electric prepared a scenario in which the forecasted fuel prices were 30 percent higher for both natural gas and No. 2 oil. Similarly, Tampa Electric prepared a scenario in which the forecasted fuel prices were 30 percent lower for both natural gas and No. 2 oil.

Risk Management Activities

Q. Please describe Tampa Electric's risk management activities.

A. Tampa Electric complies with its risk management plan as approved by the company's Risk Authorizing Committee. Tampa Electric's plan is described in detail in the Risk Management plan filed August 4, 2009 in this docket.

Q. Has Tampa Electric used financial hedging in an effort to help mitigate the price volatility of its 2009 and 2010 natural gas requirements?

A. Yes. Tampa Electric hedged a significant portion of its 2009 natural gas supply needs and a portion of its expected 2010 natural gas supply needs. Tampa Electric will continue to take advantage of available natural gas hedging opportunities in an effort to benefit its customers, while complying with the company's approved Risk Management Plan. The current market position for natural gas hedges was provided in the Risk Management Plan submitted on August 4, 2009.

Q. Are the company's strategies adequate for mitigating price risk for Tampa Electric's 2009 and 2010 natural gas purchases?

A. Yes, the company's strategies are adequate for mitigating price risk for Tampa Electric's natural gas purchases. Tampa Electric's strategies balance the desire for reduced price volatility and reasonable cost with the uncertainty of natural gas volumes. These strategies are described in detail in Tampa Electric's Risk Management Plan filed August 4, 2009.

Q. How does Tampa Electric determine the volume of natural gas it plans to hedge?

A. Tampa Electric projects the quantity or volume of natural gas expected to be consumed in its power plants. The volume hedged is driven primarily by the projected total gas levels by month and the time until that natural gas is needed. Based on those two parameters, the amount hedged is maintained within a range authorized by the company's Risk Authorizing Committee.

The market price of natural gas does not affect the percentage of natural gas requirements that the company hedges since the objective is price volatility reduction, not price speculation.

Q. Were Tampa Electric's efforts through July 31, 2009 to mitigate price volatility through its non-speculative hedging program prudent?

A. Yes. Tampa Electric has executed hedges according to the risk management plan filed with this Commission, which was approved by the company's Risk Authorizing Committee. On April 3, 2009, the company filed its 2008 hedging results as part of the final true-up process. Additionally, Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, requires the utilities to file a Hedging Information Report showing the results of hedging activities from January through July of the current year. The Hedging Information Report facilitates prudence reviews through July 31 of the current year and allows for the Commission's prudence determination at the annual fuel hearing. Tampa Electric filed its Hedging Information Report showing the results of its prudent hedging activities from January through July 2009 in this docket on August 14, 2009.

Q. Does Tampa Electric expect its hedging program to provide fuel savings?

A. No. The primary objective of the company's hedging program is to reduce fuel price volatility as approved by the Commission. Tampa Electric employs a well-disciplined hedging program. This discipline requires consistent hedging based on expected needs and avoidance of speculative hedging strategies aimed at out-guessing the market. This discipline insures hedges will be in place should prices spike and also means hedges are in place when prices decline. Using this disciplined approach means that much of the volatility and uncertainty in natural gas prices are removed from the fuel cost used to generate electricity for our customers.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 090001-EI
FILED: 10/12/09

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED SUPPLEMENTAL DIRECT TESTIMONY

OF

JOANN T. WEHLE

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

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

Q. Are you the same Joann T. Wehle who submitted prepared direct testimony on September 1, 2009 in this proceeding?

A. Yes, I am.

Q. What is the purpose of your supplemental direct testimony testimony?

A. The purpose of my supplemental direct testimony is to address the *single* audit finding contained in the audit report filed by the audit staff of the Florida Public Service Commission ("FPSC") in Tampa Electric's 2009 Hedging Activities audit for the period August 1, 2008 through July 31, 2009. The audit report was issued September 23, 2009 subsequent to my direct testimony filing on September 1, 2009.

Q. Do you agree with the audit findings by the Commission audit?

A. Yes, I do.

Q. Please elaborate on the company's explanations to the Commission's audit staff as to why the company hedged outside of its Risk Management Plan percentage limits.

A. Tampa Electric agrees with the Commission audit finding showing that for four months during the period August 2008 through July 2009 the quantity of natural gas hedged compared to the actual natural gas consumption was at a percentage level outside the prescribed levels in the Risk Management Plan. However, the percentage hedged for all four months in question are within the guidelines when compared to the projected natural gas consumption. Therefore, Tampa Electric's hedging activities were consistent with its Risk Management Plan.

For the four months in question, changes in load, outages, and generation caused the actual natural gas consumption to vary relative to the projection. These are events beyond the control of the company and, thus, do not imply a violation of its Risk Management Plan.

Q. Has the Commission evaluated the effect of actual natural gas consumption on actual versus targeted hedging percentages?

A. Yes, the Commission completed a comprehensive review of the Fuel Procurement Hedging Practices of Florida's Investor-Owned Electric Utilities and issued its final report in June 2008, in which the staff recognized that hedges may exceed the percentage targets when actual fuel burns are significantly lower than the fuel projections. In addition, audit staff believed that the yearly averages of fuel hedged against forecast and actual burn demonstrate that the company provides enough flexibility within its strategy to allow for fluctuations in its fuel consumption. Thus, due to the normal fluctuation in actual monthly consumption, any comparison of hedge percentages compared to actual consumption volumes should be made over an extended time period. For the twelve-month period included in the audit, Tampa Electric hedged approximately 74 percent of its actual natural gas consumption, which is within its prescribed Risk Management Plan guidelines.

Q. Do you believe Tampa Electric has complied with its Risk Management Plan?

A. Yes, I do. Tampa Electric has abided by its Commission approved Risk Management Plan and has executed its hedging program in a manner that is non-speculative and consistent with the overall objective of minimizing fuel price volatility. Furthermore, Tampa Electric has also executed its Risk Management Plan according to sound separation of duty principles.

Q. Please summarize your supplemental direct testimony.

A. Tampa Electric concurs with the findings in the Commission staff audit dated September 23, 2009. Tampa Electric performed its hedging duties consistent with the projected levels of natural gas consumption and therefore complied with its Commission approved Risk Management Plan. Tampa Electric believes that variances caused by actual consumption being different than projected consumption are to be expected and that the Commission has previously recognized this can occur and does not imply any failure to comply with the Risk Management Plan.

Q. Does this conclude your testimony?

A. Yes, it does.

(Transcript continues in sequence with Volume 2.)

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

I, LINDA BOLES, RPR, CRR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

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

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

DATED THIS 5th day of November, 2009.

Linda Boles
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