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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 130009-EI

NUCLEAR COST RECOVERY CLAUSE.
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VOLUME 1

Pages 1 through 241

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING:
CHAIRMAN RONALD A. BRISÉ
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER ART GRAHAM
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

DATE: Monday, August 5, 2013

TIME: Commenced at 9:30 a.m.
Concluded at 11:01 a.m.

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

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

APPEARANCES:

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JOHN T. BURNETT, ESQUIRE, Duke Energy Florida, Inc., Post Office Box 14042, Saint Petersburg, Florida 33733; JAMES MICHAEL WALLS and BLAISE N. GAMBA, ESQUIRES, Carlton Fields, P.A., Post Office Box 3239, Tampa, Florida 33601-3239, appearing on behalf of Duke Energy Florida, Inc.

ROBERT SCHEFFEL WRIGHT and JOHN T. LAVIA, III, ESQUIRES, Gardner Bist Wiener Law Firm, 1300 Thomaswood Drive, Tallahassee, Florida 32308, appearing on behalf of the Florida Retail Federation.

JAMES W. BREW and F. ALVIN TAYLOR, ESQUIRES, PCS Phosphate - White Springs, c/o Brickfield Law Firm, 1025 Thomas Jefferson Street, NW, Eighth Floor, West Tower, Washington, DC 20007, appearing on behalf of PCS Phosphate - White Springs.

GEORGE CAVROS, ESQUIRE, Southern Alliance for Clean Energy, 120 East Oakland Park Boulevard, Suite 105, Fort Lauderdale, Florida 33334, appearing on behalf of Southern Alliance for Clean Energy.

APPEARANCES (Continued):

JON C. MOYLE, JR., ESQUIRE, c/o Moyle Law Firm, 118 North Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

J.R. KELLY, PUBLIC COUNSEL, CHARLES REHWINKEL, JOSEPH McGLOTHLIN, and ERIK SAYLER, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32393-1400, appearing on behalf of the Citizens of the State of Florida.

KEINO YOUNG and MICHAEL LAWSON, ESQUIRES, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

CURT KISER, General Counsel, and MARY ANNE HELTON, Deputy General Counsel, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisors to the Florida Public Service Commission.

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
1	Comprehensive Exhibit List	60	60
2 through 111	(As identified on Comprehensive Exhibit List)	61	
84 through 111			61

P R O C E E D I N G S

CHAIRMAN BRISÉ: Good morning. We're going to go ahead and convene or call to order this Nuclear Cost Recovery Clause hearing, Docket Number 130009-EI. And I'm going to ask Mr. Lawson to read the notice.

MR. LAWSON: Thank you. By notice issued June 17th, 2013, this time and place was set for this hearing in Docket Number 130009-EI, the Nuclear Cost Recovery Clause. The purpose of this hearing is for the Commission to take action on Florida Power & Light Company's and Duke Energy Florida, Inc.'s petitions in this proceeding.

CHAIRMAN BRISÉ: Thank you very much. At this time we will take appearances.

MR. ANDERSON: Good morning, Chairman Brisé and Commissioners. I'd like to enter the appearances, please, of myself, Bryan Anderson, my colleagues Ken Rubin and Jessica Cano on behalf of Florida Power & Light.

CHAIRMAN BRISÉ: Thank you.

MS. GAMBA: Blaise Gamba with Carlton Fields for Duke Energy Florida. Good morning.

CHAIRMAN BRISÉ: Good morning.

MR. WALLS: Mike Walls with Carlton Fields on behalf of Duke Energy Florida.

MR. BURNETT: John Burnett, Duke Energy Florida.

MR. WRIGHT: Schef Wright and J. LaVia on behalf of the Florida Retail Federation. Thank you.

MR. REHWINKEL: Charles Rehwinkel, Joe McGlothlin, and Erik Sayler, and J. R. Kelly for the Office of Public Counsel.

CHAIRMAN BRISÉ: Thank you.

MR. CAVROS: George Cavros on behalf of Southern Alliance for Clean Energy.

CHAIRMAN BRISÉ: Thank you.

MR. BREW: Good morning. James Brew and Alvin Taylor from Brickfield, Burchette, Ritts & Stone for White Springs Agricultural Chemicals. Thank you.

CHAIRMAN BRISÉ: Thank you.

MR. MOYLE: Jon Moyle with the Moyle Law Firm appearing on behalf of the Florida Industrial Power Users Group, FIPUG.

CHAIRMAN BRISÉ: Thank you.

MR. LAWSON: Oh, yes. Mike Lawson and Keino Young on behalf of Commission staff.

MS. HELTON: Mary Anne Helton, advisor to the Commission. Also here today is Curt Kiser, the

General Counsel.

CHAIRMAN BRISÉ: Thank you very much.

Is there anyone else that we're missing in terms of appearances that needs to put in an appearance at this time? Okay. If not, thank you.

Moving on to -- staff, are there any preliminary matters?

MR. LAWSON: Yes, Commissioner, we have several.

First, Duke Energy Florida has filed a motion to defer the entirety of its case until next year's NCRC docket, pending the Commission's review of a global joint settlement that would, if approved, resolve the issues in this docket.

At this time staff has not received any objections to the motion to defer, and all parties to the proposed global settlement support this motion. If it is the will of the Commission, it would be appropriate for the Commissioners to take up DEF's motion at this time.

CHAIRMAN BRISÉ: Thank you very much. I think we will go ahead and take up the motion. We want to hear Duke make a presentation on the motion at this time.

MR. BURNETT: Thank you, Mr. Chairman.

Commissioner, Mr. Lawson correctly stated that the motion is to defer all issues in this case pending the, the Commission's consideration of the, of the settlement agreement.

A couple of points we wanted to make clear is, number one, this motion to defer in no way impacts or limits the Commission's ability to ask questions in the limited proceeding. And part and parcel of the settlement includes issues with the Levy project and the CR3 extended power uprate. So this motion to defer does no harm to the Commission's ability to take information, ask questions on that at the time.

Second, there is also a legal issue in this proceeding about the amount of AFUDC to be applied to cost. And the legal issue would have been for Duke Energy Florida whether the 13.1 percent AFUDC rate at the time of the need proceeding applied or the, the post Senate Bill 1472 rate of 10.46 applied. Because the, under the proposed settlement the Levy project is now under subsection 6 of the statute, the lowest AFUDC rate of 10.29 percent applies, and that will be the AFUDC rate that Duke Energy will be applying to the Levy project now, like we're doing with the CR3 uprate.

So we're making that retroactive to July 1st of this year. So that obviates our need to be involved in the dispute over, if there is a dispute left, on which AFUDC rate applies to a non-subsection 6 proceeding.

And then finally, as Mr. Lawson correctly noted, all the parties to the settlement do not oppose. And I also understand that SACE, who is a non-party to the settlement, also does not oppose the motion being granted.

CHAIRMAN BRISÉ: Okay. Thank you. At this time I want to confirm the parties support or oppose or have no position.

MR. WRIGHT: Mr. Chairman, the Florida Retail Federation supports the motion to defer. Thank you.

CHAIRMAN BRISÉ: Okay.

MR. REHWINKEL: Public Counsel supports the motion to defer.

CHAIRMAN BRISÉ: Thank you.

MR. CAVROS: Commissioners, I feel compelled to put our position in, in context. We do not oppose the motion or the associated settlement agreement that provides the recovery of cost to wind down the project. But we have appeared before this

Commission since 2008 challenging cost recovery for nuclear projects because we believed that they were speculative and that lower cost, lower risk options were available to meet the demand for electricity.

By all accounts this project has been a financial fiasco. Duke Energy/Progress Energy customers paid a whole lot of money for a whole lot of nothing. We believe that that was facilitated by a law that allows a utility to shift all the financial risk of building a nuclear reactor from the company's shareholders to the company's customers, and, quite frankly, Commissioners, also by you by approving certain costs for recovery for a project that was increasingly speculative.

But that said, we do approve -- do not -- we do not oppose the motion, the associated settlement agreement, or any prudently incurred costs to wind down the plant. Thank you.

CHAIRMAN BRISÉ: Thank you.

MR. BREW: Mr. Chairman, White Springs supports the motion to defer.

CHAIRMAN BRISÉ: Thank you.

MR. MOYLE: FIPUG also supports the motion to defer and the description that counsel for Duke provided with respect to the AFUDC treatment.

CHAIRMAN BRISÉ: Thank you. Are there any other signatories or those who agree to the motion to defer or oppose it that we haven't heard from? Okay. Seeing none, thank you.

At this time we're going to open the floor to questions from Commissioners.

Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman. Just a couple, I believe, very brief questions so that I am sure that I am clear kind of on where we are procedurally, and potentially next steps from our potential decisions this morning.

First question, and I'm not sure if I should pose this to our staff or to Mr. Burnett, so let me just put it out there.

Mr. Burnett, in your comments just a moment ago you mentioned specifically what I believe is numbered Issue 1 as listed in the Prehearing Order addressing the legal issue of the appropriate AFDC that would apply, recognizing the change in law just a little while ago, earlier this year. Is that issue or the potential resolution of that issue as you described from 13.1 AFUDC previously to 10.29, is that an issue that is encompassed in the proposed stipulation and settlement agreement?

MR. BURNETT: No, ma'am, it is not. But on Friday we circulated to staff and all the parties just a written change in position here from us to note in writing with the Commission that we have voluntarily applied the lower AFUDC rate retroactive to July. So it's just an action that Duke independently took outside of the settlement, but to ensure that we had no, if you will, dog left in the fight as to the Issue 1.

COMMISSIONER EDGAR: Okay. Thank you.

And then, if I may, to our staff again, just procedurally, recognizing that, is that an issue? And, if so, when that would come before this Commission for a vote of approval or further discussion or other.

MR. LAWSON: I believe what we'll need to do is now that we have that on record, when we address the next issue, which involves Florida Power & Light and we have their take on resolve it, once we have the joint positions before us, we'll be in a position to, for the Commissioners to take the appropriate action.

COMMISSIONER EDGAR: Are you saying later this morning?

MR. LAWSON: Yes.

COMMISSIONER EDGAR: Okay. All right. Thank you.

And then -- Mr. Chairman?

CHAIRMAN BRISÉ: Sure.

COMMISSIONER EDGAR: My next question is a little more global, but applying just to the Duke portion of this proceeding. If, and I realize that we have further discussion and further matters to address here this morning, but just for thinking it through, if the motion to defer were to be granted this morning by this Commission, accepting that that is in the public interest as the circumstances are at this time, then what would be the next steps procedurally and the approximate timeline for that settlement to come before us for further discussion and action?

MR. YOUNG: Next steps would be staff will, the Commission will issue a procedural order detailing how they're going to handle the settlement agreement. And then we would move to Special Agenda hearing, however the Commission decides to, what procedural -- in terms of the procedure. So we're looking possibly October-ish time frame, late September, October-ish time frame.

COMMISSIONER EDGAR: And I was going to say may I presume, let me just ask, those dates would be set in coordination through our legal office, the Chairman's office, and all parties, as is normal practice?

MR. YOUNG: Yes, ma'am.

COMMISSIONER EDGAR: And that would then be the time to potentially take testimony and further, have further discussion and analysis of specific terms in the proposed agreement?

MR. YOUNG: Yes, ma'am.

COMMISSIONER EDGAR: Okay. I think that's it for now, Mr. Chairman.

CHAIRMAN BRISÉ: Sure. Thank you.

Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman.

I'd like to discuss what's before us today, which is this motion to defer Duke's portion of the, this year's NCRC proceeding. And I have a couple of concerns and I would like some clarification from staff or one of the parties on it.

And one of the main concerns that I have, and it's something that was touched on by, by Duke Energy, is the compliance with Senate Bill 1472.

And not only do we have the change in the AFUDC rate that's in the plain language of that statute clearly states what, how that's to be determined, but there's also a limitation as to what the companies can recover, and solely costs associated with obtaining certification or license from the NRC and not any construction activities without coming before us first.

So one of the things that I want to do before we vote on this motion to defer is make sure that if we do so, that we're still in compliance with those two aspects of the statute. And you've discussed the AFUDC, AFUDC rate, and I understand you've given verbal clarification, but the motion as filed just states that we're to approve Duke's petition as filed. And Duke's petition as filed, could you please explain what that includes? Because it's my understanding it's the higher AFUDC rate; is that correct?

MR. BURNETT: That's correct, sir. But I believe, as staff noted, that I understand that later this morning there will be an opportunity for Duke to take positions on each one of the Issues 1, 2, and 3. I've stated number 1. And then with respect to number 2 and 3, by moving Levy retroactive to July 1st of 2013 into subsection 6 of the statute, we will now similarly not be implicated by Senate Bill 1472 at all because those, those costs by, by the application of where we were with the 2012 settlement, we won't have any costs at issue within those buckets. So we will not have any, any standing actually to participate in those.

COMMISSIONER BALBIS: Okay. And focusing again on, on allowing Duke to recover the amounts as filed, it's my understanding that it will result in an increase in what Duke is currently recovering; is that correct?

MR. BURNETT: Yes, sir.

COMMISSIONER BALBIS: Okay. And one of the concerns that I have, and maybe this is a question for legal staff, that the recovery amount that Duke is currently collecting is based upon a 2012 settlement agreement, which clearly states that $3.45 per 1,000 kilowatt hours, and yet by approving this, we're allowing that to increase. And wouldn't that be in violation of the 2012 settlement agreement -- and I guess I should look to staff on that -- and can we do that?

MR. LAUX: In the current petition that is filed by Duke for the Levy portion of it the recovery that they are requesting is consistent with that earlier settlement agreement.

COMMISSIONER BALBIS: Okay.

MR. LAUX: So it would be $3.45. The change or the increase that you're talking about has to do more with the recovery of costs that are associated with the CR3 uprate.

COMMISSIONER BALBIS: So we would, by approving the petition as filed, we would increase the amount that Duke is recovering in total; correct?

MR. LAUX: Compared to the factor that is currently in place, the rate, our calculation, the rate would go up by 89 cents per 1,000 kWh. And that's all -- the change in that rate or the total would be completely consistent with the change in the costs that they're asking for recovery of the CR3 uprate, not the Levy project.

COMMISSIONER BALBIS: Okay. But the end result is 89 cents per 1,000 kilowatt hours?

MR. LAUX: That is correct, Commissioner.

MR. BURNETT: Commissioner Balbis, if I may add to that. So with respect to CR3, it would be likened to the normal process that the Commission does in the NCRC. So you effectively, by granting the motion to defer, would be saying for cost recovery purposes those costs are reasonable but subject to refund with interest should the Commission not approve the settlement agreement, and then have those costs in consideration elsewhere. So those, those -- again, the customer is protected by having those subject to refund with interest. And this is not unlike the same process you use every year of finding costs reasonable for cost recovery but no determination on prudence yet.

COMMISSIONER BALBIS: Okay. Then I'll just move on to the -- perhaps we'll get back to that -- but I want to move on to the other concern that I have is that one of your witnesses that you have brought forward and we were prepared to hear testimony from is dealing specifically with the long-term feasibility of the Levy nuclear projects. And if we're going to move forward with a future proceeding, as Commissioner Edgar discussed, my concern is that this is the only opportunity to discuss the long-term feasibility of the projects for the conditions as it exists today. And in a future proceeding perhaps that testimony may change or, or -- I don't know.

But the point is, is that I would like the opportunity to discuss the long-term feasibility because one of the main components of the proposed settlement agreement is the cancellation of the EPC contract. And a discussion as to whether or not that's a public interest depends on the long-term feasibility, along with other factors. So I would like to have the opportunity to question your Witness Fallon on long-term feasibility. I don't know what process we could have to do that.

But that's really a listing of the concerns that I have on the proposed deferral. So I'd like to open it up to other Commissioners while maybe staff thinks of some different ideas.

MR. BURNETT: Commissioner, may I address your question?

COMMISSIONER BALBIS: Sure.

MR. BURNETT: With respect to feasibility, by, by signing the settlement agreement, Duke Energy Florida has acknowledged that the Levy project is no longer feasible. And we are in subsection 6 of the statute now, which states that Duke Energy Florida will elect not to complete the construction of the Levy project.

So much like the CR3 uprate, when we announced the retirement of CR3, that project also moved under subsection 6. And as you will recall, we filed no feasibility analysis with that project this year.

Now to your, to your next point, you will be able in a limited proceeding to question a Duke Energy witness as to -- and to explore just what you noted, as whether the inclusion of Levy under subsection 6 in the settlement is in the public interest, and whether looking at the settlement in the whole the settlement is fair, just, and reasonable. So you would have that opportunity, sir, at that time if you desired it.

COMMISSIONER BALBIS: Mr. Chairman --

CHAIRMAN BRISÉ: Sure.

COMMISSIONER BALBIS: -- with your indulgence.

I'm concerned with one of the statements that you just made in that because Duke has decided to cancel the EPC contract, that the project is no longer feasible. And this brings me to where I want to focus, which is this proceeding, and that is the testimony that was filed by your witness indicates that it is feasible.

MR. BURNETT: Yes, sir. And that testimony filed in May is no longer valid testimony.

So in effect that testimony is stale.

COMMISSIONER BALBIS: I think I need to think about that for a little bit.

MR. BURNETT: If it helps, Commissioner, similar to the same situation we were in with the CR3 uprate at the time. We, we had testimony that had previously suggested that the CR3 uprate, had the unit been repaired, would have been feasible. But with the retirement of the unit an intervening circumstance came into play which made the feasibility determination and the analysis in general moot. We're in the same process, the same position now with Levy.

CHAIRMAN BRISÉ: Commissioner Brown.

COMMISSIONER BROWN: Thank you.

I have a couple of questions. First, I just want to make a comment, general comment. I'm a proponent and believer in our process, in the NCRC process. It's an annual and ongoing docket that all the parties and staff works on routinely throughout the year. Obviously a wrench has been thrown in the process by having the settlement filed five days before the hearing. I'm sure there's been extensive and ongoing negotiations, but here we are where the process is somewhat messed -- again, a wrench has been thrown in that.

Typically in a normal judicial proceeding we would take up the settlement or stipulation prior to the hearing occurring. But what we're being asked today is to allow recovery today for a hearing that will occur tomorrow. And I understand that the settlement agreement may obviate the need to have the NCRC hearing for this year; I get that.

But my question, I guess, and I'm going to ask Office of Public Counsel, since they represent the customers' interests across the state, how is collection today which actually increases the customers' bills in the public interest prior to a full evidentiary hearing on the NCRC docket or even exploring an in-depth analysis of the comprehensive amended settlement agreement?

MR. REHWINKEL: Commissioner Brown, Charles Rehwinkel with the Public Counsel's Office.

First, with respect to the Levy project, the amount for recovery in this year is the same as last year and per the stipulation that was approved last year. So we don't look at the amount relative to the Levy project as having, as being really affected by the question that you asked. The, for one thing, the motion to defer would, if granted, would preserve your opportunity to have whatever you can do today at the same time next year if the settlement agreement is not approved.

With respect to Crystal River 3 uprate there was a litigated position that was taken by -- there was a litigation position taken by the parties prior to the settlement being entered into. We, through a complex series of discussions and negotiations that dealt with both the delamination docket and the CR3 docket and certain assets, we came to a resolution that resolves our concerns about the costs that were at issue there. So the amount that is for recovery for the CR3 component is the amount that the company proposed based on the statutory formula for taking all of the costs and recovering them over a seven-year period. So there's a formulaic approach that's in the statute that is the amount of money that's there. So it results in an increase from last year just because of the way the math works based on how the statutory formula applies.

Prior to reaching the settlement we did not take a position in opposition to the costs, nor did we offer expert witness testimony this year for the first time because we had reached a level of satisfaction that while agreeing with a lot of what Mr. Cavros said about the, the amount of money that was spent with no gain, we agree that based on the statutory formula that this is what would be the result of NCRC recovery for the CR3 component. So if you put the two together, there is a net increase, but they're driven by two things: The stipulation last year for the LNP piece, and the statutory formula for the Crystal River piece this year.

And, of course, with respect to Crystal River, again, if the stipulation is not approved and we're back sitting here next year, you will have not lost one iota of authority to look at costs, and I don't think there would be any, any loss of available resources or information between now and next year.

So we felt like we're protected, but by our stipulation the NCRC amounts would be the same under the stipulation as what our litigation position would have been had we been in hearing, if that makes sense.

COMMISSIONER BROWN: Okay. So even before the settlement agreement was filed the Office of Public Counsel was taking no position about the prudency of the recovery of this year's NCRC.

MR. REHWINKEL: We did not have a basis to contest them based on all the information that we had and everything that we had litigated with them up until this point.

Our position on recoverability of the uprate costs to the CR3 plant were largely driven by the fact that we settled the case with some significant refunds and other monetary benefits over the long-term that did not impose a, a liability one way or the other.

So these costs were under a specific statute, the NCRC statute, that gives them recovery for costs that are approved by the Commission. And we believe that the costs that, that are in that $265 million, the remaining costs that will be recovered over the next six years, we believe there's no basis to claim those, to make a claim against those costs on behalf of the customers based on the rulings of the Commission and the statute to date.

COMMISSIONER BROWN: Thank you, Mr. Rehwinkel.

I guess what I really want to get at -- I'm not opposed to the motion to defer. I think administratively it makes sense. I'm focused on the recovery today. I know that the parties want to, by entering into the amended settlement agreement, the parties intend to stop the bleeding. However, I think increasing the cost here is, is not effectuating that.

And I -- my focus here is really on recovery today. What's the harm if we just defer, as we've done in the past with this utility, we defer recovery along with the hearing after we've had a full consideration of the settlement agreement and/or the NCRC proceeding for next year?

MR. REHWINKEL: Well, I believe that in the past the deferral did also -- was accompanied by implementation of the requested rates. So I don't think this would be different than what has been done in the past.

My big concern with not allowing recovery at the, at the $2.17 level, that's the NC -- that's the CR3 EPU recovery charge, is that we, we have entered into agreement that encompasses that rate, and there was, you know, easily a dozen major other issues that went into the whole thing. So going in and not allowing a provision of the settlement agreement puts me in a difficult position because

I've entered into an agreement on behalf of the customers for that level of recovery. And I, and I feel comfortable with that because that is the same position we would have taken in this hearing were it to occur on the NCRC CR3 piece. So --

COMMISSIONER BROWN: I understand.

MR. REHWINKEL: -- I would be very reluctant do that because I would feel like we would start to unwind a very complicated settlement agreement if that was to happen. And I'm not advocating higher rates. It's just this is the way the math turns out based on the statutory formula we follow.

COMMISSIONER BROWN: And it's a component of the global overall amended.

MR. REHWINKEL: That's right.

COMMISSIONER BROWN: And I completely understand that. But, you know, as a regulator we're in a different seat here in evaluating what is in fact in the public interest.

And last question for you before I just finish up with some additional comments and questions. I just want to be sure that the Office of Public Counsel obviously has been negotiating the amended settlement for months. I mean, it's a hefty settlement and encompasses a lot of different areas. I just want to make sure that the Office of Public Counsel is prepared to go through with this year's NCRC hearing if we were to deny the motion to defer.

MR. REHWINKEL: That's a good question. Well, I can say this, is that with respect to -- we, we had not -- we have focused -- we went up the 11th hour in working on this. And from the, from the minute we got additional time we put that to, to use and we worked around the clock on this thing for weeks. So our efforts were focused on getting this resolution and not preparing for this hearing. I can, I can say that honestly. But we can -- we would -- we'd be able to do what we had to do.

I, I would also caution that not putting in the requested rates, I think I would be concerned about the basis for doing anything other than what's the filed and supported rates by the company. But that's, that's an issue, I guess, for, for others to deal with.

COMMISSIONER BROWN: Thank you, Mr. Rehwinkel.

Just a follow-up question for Duke regarding the -- not to get into the substance of the two thousand -- of the settlement agreement and the proposed amendment to the settlement agreement, but I know that the 2012 settlement agreement addresses the NEIL, that all the NEIL insurance proceeds will first be applied to offset the fuel factors. And I know the amended settlement, I looked at it, and I looked -- it addresses the negotiated NEIL proceeds.

And the question really is how does Duke believe this portion regarding offsetting the fuel factors from the NEIL insurance proceeds, how will it be addressed in this year's NCRC proceeding if we ultimately do not approve the amended settlement agreement and, thereby, we also allow Duke's motion to defer? So we allow recovery today and we approve your motion to defer, but then we ultimately do not find in favor of the amended settlement agreement. How are we going to treat that, that issue?

MR. BURNETT: Yes, Commissioner. My understanding of the facts that you laid out is that there would not be an impact because the allocation of the NEIL proceeds are covered by the previous approved and in effect now 2012 settlement agreement. So the allocation of those funds ultimately making it back to the customers in the manner that you described consistent with the 2012 agreement will take place, notwithstanding any decisions at all you make here.

COMMISSIONER BROWN: Okay. So it will be offset then -- if we allow recovery, it will be offset from that 89 cents a month factor that goes into effect?

MR. BURNETT: Yes, ma'am. In totality the NEIL proceeds would be a credit to the recovery.

COMMISSIONER BROWN: Thank you.

MR. BURNETT: Yes, ma'am.

COMMISSIONER BROWN: One question just for staff. Thank you.

Staff, didn't we -- have we previously allowed deferral of Duke/Progress recovery along with the hearing? I think it occurred in the fuel docket last year, the year before. And if you could explain it a little bit.

MR. LAUX: Commissioner, there -- during the time that Duke was considering whether to repair or retire the Crystal River 3 plant there were a number of issues dealing with the uprate that was deferred from one year to the next year.

I believe most -- whenever we did a deferral, for those costs that were being looked at as to being prudent, the Commission did make a decision on those costs. So it's, it's sort of a mixed bag because in any one period you're looking at a, a true-up period, an actual period, and a projected period. And most of the time the deferrals dealt with the projected period, and there would -- there were not costs associated being recovered in, in that period when the deferral was made.

When that period came up to be a true-up period, there were collections of those costs, if memory serves me correct.

COMMISSIONER BROWN: Thank you.

CHAIRMAN BRISÉ: Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman.

I have a couple of questions for Rehwinkel. And you made a few comments that I'd like you to clarify. And I noticed that the Office of Public Counsel did not provide a single witness for Duke's case. And you indicated, and I'm not sure what your answer was, is if we denied this motion to defer, whether or not the Office of Public Counsel would be prepared to try this case. And, you know, it's not a case. So could you please explain that? Because I hope that there wasn't an assumption by the Office of Public Counsel that we were going to approve this deferral, and if we do not, you're not prepared to try this.

MR. REHWINKEL: I appreciate the opportunity to clarify.

My, my position and my response to Commissioner Brown was intended this way. We did not provide a witness in opposition to what Duke requested with respect to the CR3 uprate because in the pre-testimony phase Dr. Jacobs and his staff looked at the costs, looked at the submission by Duke, and determined that the expenditures for the CR3 uprate project from the time of the last NCRC hearing through the time of their testimony were consistent with what we expected to see, which would be minimal costs, cost curtailment, as well as --

COMMISSIONER BALBIS: Mr. Rehwinkel, that sounds a lot like testimony, and there is no testimony that you sponsored or a witness sponsored to that effect.

MR. REHWINKEL: But my point --

COMMISSIONER BALBIS: And, but back to the question, if we deny the deferral, would OPC be prepared to adequately try this case?

MR. REHWINKEL: I was just explaining that we did not feel the need to provide testimony because we were satisfied that they had done what we expected them to do. So we had no basis to contest it.

Our ability to conduct the hearing would be -- we would be able to manage what we needed to do. We did not have any testimony in opposition. If we were to cross-examine, it would be reactive to what would be happening at the, at the hearing or testimony that we would hear or questions that were offered by others. So the answer to your question is, yes, we are prepared to go forward and we would, we would be able to represent the customers adequately.

COMMISSIONER BALBIS: Okay. And I'm just having a hard time with the 89 cent increase. And I agree with a lot of the points Commissioner Brown had brought up, and I would feel much more comfortable if we left everything the same, deferred all of the decisions, the hearing, et cetera, until the settlement agreement that's out there is resolved and acted upon. Customers are not harmed. I know there's discussion, well, it's subject to refund. But customers move and it's not the most perfect situation. But if we kept everything status quo, there's no increase to customer bills, we deal with the settlement agreement and then move forward accordingly, I would be much more comfortable. So why didn't the Office of Public Counsel go that route and why did you feel that the 89 cents was appropriate and warranted?

MR. REHWINKEL: Okay. My answer to Commissioner Brown is the same one I would give you, which is that we negotiated a comprehensive set of issues and resolutions that had bill impacts, that had financial impacts that we evaluated globally. The $2.17 rate that is, that is what is in the settlement agreement, as well as Duke's petition in the NCRC docket, are based on the statutory formula for taking, collecting all the costs and then amortizing them over a seven-year period.

So not having any basis to disagree with that or to disagree with the $265 million that made up that pot, we did not have any reason to depart from that rate. And our agreement with that rate was, was also influenced by other considerations that led to the global settlement agreement that we entered into.

So from the position we started with even before we began negotiating to today there was not going to be a lot of difference between the rate that was filed. Because we knew that in February CR3 had been, uprate had been canceled because the plant was retired. So what we were left with was this pot of dollars and how it was dealt with based on the statute, and that statutory framework for cancellation was not touched by Senate Bill 1472. So we had no basis for departing from that.

So I don't really look at the 89 cents as an increase based on additional spend or anything like that. It is because they, they have gone now into a cancellation mode for that, that entire project. That's the reason why we really didn't have any discomfort with that. We feel like whether we went to the hearing or we went with the settlement agreement, the same result would attach. That was our assessment that we made when we entered into this agreement.

COMMISSIONER BALBIS: And I'm sure you mean that you would have the same position, not the same result, because we would be the ones determining that result.

MR. REHWINKEL: Absolutely. But when we, when we sit down to negotiate, we do have to sort of try to decide where things are going to come out.

And we were able to look at the status of the, of the hearing. There was no testimony in opposition to the $2.17 charge. There was no -- we certainly understood it's the Commission's final decision and I wasn't meaning to say that we, we were sure that you would come out that way. We just thought that, that based on the statutory formula, the testimony that was in the record, and the level of opposition, that there would not be a great departure from that, from that dollar figure. But that was just a handicap that we would make as we were negotiating.

COMMISSIONER BALBIS: Okay. I'm still not comfortable raising customer rates without considering one shred of evidence in the record. But I want to follow up with Mr. Burnett.

If we were to deny the motion to defer, and obviously I would assume you're prepared to move forward with the case, you indicated that that information from Witness Fallon is stale. Would you be filing revised testimony to that effect?

MR. BURNETT: Yes, sir. But that presents another problem that I feel compelled to alert the Commission about. If the Commission denied the motion to defer and asked the parties to proceed with the NCRC hearing, that action would invoke a provision of the filed settlement agreement that allows the parties to withdraw from the settlement agreement if the agreement was not granted in its entirety. So a threshold issue would have to be the parties would have to confer, I would have to confer with my management to see if we still would go forward with the settlement. That is something I feel compelled to bring to the Commission's decision [sic].

Now to your question, yes, we would go forward with the NCRC. But as to Levy, the question of the ultimate factor is, is set by the 2012 settlement agreement. But as to feasibility, that basically becomes a nonissue. But there would have to be at some point feasibility testimony filed or testimony new filed saying that we are no longer in construction mode and we are under subsection 6.

And another point, just to add, to follow up on, with your EPU, with respect to those costs, if we proceeded, I would be asking for a stipulation because no party nor staff has presented any evidence to oppose those costs. So we would be in the position of saying, since our testimony is unopposed, I would ask the Commission for a stipulation at that time and see if you would approve it.

So ultimately the 89 cents in, just speaking logically by testimony on the record, would, unless the Commission had a problem with it, would be approved.

And one, one question that you had mentioned earlier about how can the customer be harmed if you don't approve the 89 cents, well, that is part and parcel to the settlement agreement. So ultimately if you proceeded with the NCRC, which I would not suggest the Commission do, and no testimony was presented against the 89 cents, it would remain in place. If you approved the settlement agreement in the forthcoming proceeding, that amount would have to be added back in from the customers with interest from the customers. So there is a bill shock and a lag that the customers would have to pay if you did approve the settlement agreement later.

COMMISSIONER BALBIS: I think we're in an awkward procedural position because it seems to me that the settlement agreement needs to be considered first because everything is dependent on that. And it sounds like the Office of Public Counsel has agreed to the motion to defer, and I'm not, I don't want to put words into your mouth, but because of this overall global settlement. So I don't know if a better option may to be defer this entire proceeding in Duke's case until we consider the settlement agreement.

CHAIRMAN BRISÉ: It sounds to me that that's what we're attempting to do.

COMMISSIONER BALBIS: The different -- without raising customer bills. That is the difference in that if we just defer everything, keep everything status quo, customers are not harmed, then we move forward with that. In this case we're raising rates without a bit of evidence into the record.

CHAIRMAN BRISÉ: Commissioner Graham and then Commissioner Brown.

COMMISSIONER GRAHAM: Thank you, Mr. Chairman.

I, first of all, want to thank the parties for coming together with the, with the settlement. I'm sure you can tell from the past three years of working with me up here that I'm a huge proponent of, of a lot of these settlements coming forward. I like it when everybody comes to the table and works this thing, works it out. I like it even more when everybody comes to the table and works it out.

That being said, I do understand when these things are going on, as Mr. Rehwinkel said earlier, there's give and take across the board and it's kind of hard to kind of sit back and, and pick and choose and say you don't like this piece because you find out that two or three other people voted for it because of that one piece. So you just, you can't start pulling this apart.

So I'm supportive of the deferral as stated initially, and I look forward to getting into the settlement itself and better understanding some of the deals you had to, you guys had to come up with to, to allow us to get to this point. So, Mr. Chairman, when it gets to the point, I'll be ready to make that motion.

MR. BREW: Mr. Chairman.

CHAIRMAN BRISÉ: Yes, Mr. Brew.

MR. BREW: Thank you. If I could just chime in on the questions that I've heard, not speaking for anybody else but for White Springs. In the -- and I appreciate entirely the Commission not wanting to get ahead of itself with respect to making the decision on the NCRC factor before taking up the settlement.

That being said, I just wanted to emphasize that with respect to the Duke NCRC, the proposed factor, as Mr. Rehwinkel mentioned, for Levy, the $3.45, isn't changed. That decision was made in the settlement last year. And there's nothing about the new pending settlement that changes that, so there's absolutely no reason not to address that.

With respect to Crystal River 3, I'd like to reiterate what Mr. Rehwinkel said, which was that from a PCS perspective we were not prepared to challenge the 265 million for CR3 in this docket. And so to the extent, if we had not reached a settlement on the global issues, which is the 100437 docket primarily, we still would have been stipulating to the 265 million.

And what the settlement proposes with respect to recovery is a business as usual mode, which is to apply the statutory amortization period to the dollars that were proposed. So if -- to the extent that you're trying to figure out sort of can you decide the NCRC without getting into the settlement, I believe the motion to defer gives you that flexibility. And so to the extent that you are concerned about there being a litigated issue left on the table that you -- we're not asking you to presume that. And so I think the motion to defer actually puts things in a logical sequence where if you, once you've acted on the settlement, you still have the ability to, to adjust the factor based on the motion to defer. Thank you.

CHAIRMAN BRISÉ: Commissioner Brown.

COMMISSIONER BROWN: Thank you.

I think it's, I think it is clear from discussion here that the motion to defer is necessary given the change in circumstances and factors here, feasibility, all of that. Again, you know, my, my point is does it make -- is it in the public interest? Does it make sense to collect today for a hearing that's going to occur tomorrow?

And my question for you, Mr. Burnett, is really -- I mean, obviously the company enjoys the benefit and the guarantee of collecting that set factor today for consideration that we're going to have later. But would the company be willing to defer those costs until we actually have a fully vetted administrative hearing or, and/or review the settlement agreement?

MR. BURNETT: No, ma'am. And if I may explain why.

COMMISSIONER BROWN: Sure.

MR. BURNETT: Again, procedurally as we find ourselves today hypothetically saying if the settlement never existed with respect to the CR3 uprate, the Commission itself would have to find that notwithstanding the lack of any evidence to the contrary or any evidence challenging the prudence of those costs from staff or anyone else. And I would note that that has been on the record for a while, has been fully vetted by discovery, staff has taken discovery on that, the parties have looked at it. So it's not like we're starting with a blank slate with those costs.

I would anticipate that unless the Commission independently found and voted that those costs nonetheless are imprudent, we would end up with 89 cents in any event. So that's, that's the first issue.

The second one is Mr. Rehwinkel is right, is that the interplay between this and the settlement and the assumptions made in the settlement are intertwined, and that would put at some degree a complication with the relatively amount -- the amount of time between now and, and I anticipate from what I heard earlier, the hearing is not going to be long. But, nonetheless, that 89 cents would still be carried in the scenario you proposed by the customers, and if the ultimate settlement was approved, would have to be refunded back to the company with interest from the customers. So that's not an ideal situation. So for both of those reasons the company would not.

COMMISSIONER BROWN: Okay. Thank you.

MR. BURNETT: Yes.

COMMISSIONER BROWN: Mr. Chairman, could -- before we take up a motion to consider this, could we possibly take a five-minute recess?

CHAIRMAN BRISÉ: Sure. I think there's still some questions, so when we get there.

I have a question for staff. I just want to verify that the $265 million in question or the 89 cents is not a contested issue in the -- if we were going through the normal course of the NCRC.

MR. LAUX: That is correct.

CHAIRMAN BRISÉ: Okay. And so, therefore, if the Commission were to make a decision to deviate from that, we would have to rely upon information that we would have to sort of come up from ourselves, in essence.

MR. LAUX: I would assume that you would be, your decision would be based on information that would come from a hearing. Since all the parties, from what I understand, with maybe the exception of SACE, support the positions of Progress, or Duke, excuse me, they would come from the decisions -- or questions that the Commission would actually ask the witnesses.

The majority of those costs are based on activities that the Commission has already reviewed and found to be prudent and/or reasonable. So this now -- for the CR3 they're in the process of recovering those costs that came from activities that the Commission has already reviewed. I'm not 100 percent sure -- there would be some activity that the Commission hasn't quite looked at yet, but it would be a very, very small amount of the total amount that's being asked for recovery at this point.

CHAIRMAN BRISÉ: So, in essence, if we went ahead and said that we're not going to allow recovery of those 89 cents per customer or the 265 million, we would be reversing course on decisions that we have made already?

MR. LAUX: Philosophically, yes. It depends on what costs you would identify that wouldn't be able to be recovered going forward. There isn't a particular activity that falls right into the 89 cents.

Part of the -- one of the things that's very difficult to, to realize while you're going through, each year we kind of go back to a zero sum game. It isn't a continuation of costs. I don't remember if it was the attorney for Duke or Mr. Rehwinkel that said they didn't identify any changes in cost from the activities that they took, that they took issue with. And that's what we look at is the activities each year and then the costs that are able to be recovered from that.

So the activities that you were looking at last year that came up with a certain cost level are different than the activities that you're looking at this year. By adding up the cost between those two, the difference is 89 cents. But that doesn't mean that there has, there has been a change in activities that the Commission would not find to be reasonable or prudent.

CHAIRMAN BRISÉ: Sure. Mr. Young, it seemed like you wanted to say something.

MR. YOUNG: I think Mr. Laux summed it up pretty well.

CHAIRMAN BRISÉ: Okay. Thank you.

Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman. And I appreciate the opportunity to have a little more discussion and question and then maybe a short break to let it sink in, since I'm still trying to get rid of the cobwebs for early Monday morning. But very briefly a comment and then a question.

The -- I also would like to take this opportunity, and I may again later as well, to commend all of the parties for continuing to work towards a settlement. I have made statements from this bench over past years that there were some cases that came before us that to me appeared to be potentially settleable by all of the parties. I don't know that this is one that initially appeared that way, but I commend the parties for continuing to work together. And I recognize that that does require work on parallel tracks at times to both get ready for hearing and to continue to negotiate and try to reach some sort of compromise consensus, give and take. So congratulations on working on those parallel tracks and bringing together an agreement that does encompass many, many issues and addresses a number of dockets.

And as we have said, it is also our responsibility to look at that very closely and make sure that we understand the interplay between all of the different pieces, and I'm glad to have potentially the opportunity to continue to do that.

This issue as to approving a piece of an overall rate within an overall rate structure, Mr. Rehwinkel has, has spoken to that, as has Mr. Burnett and others. But I would like to also hear from our other consumer advocate representative. And, Mr. Wright, I don't know that you have talked on that point, but I would like to ask you to chime in as to the questions that have been posed in the discussion.

MR. WRIGHT: If you could help me out as to which ones in particular you're looking for comment on. The 89 cents?

COMMISSIONER EDGAR: Yes. Specifically the 89 cents/approximately 265 million and the interplay of that piece with the currently in existence settlement agreement, the items that have been approved similar to that. The costs, excuse me, not items, the costs that have been approved up to this point.

MR. WRIGHT: Agreeing on the recovery period as a component of the settlement was something that was negotiated. We talked about different means of recovering the dollars, and at the end of the day all parties agreed that what we wound up calling the business as usual recovery period, given the retired status of CR3 starting at 2.17 and tapering down through normal amortization under regulatory ratemaking was the consensus best way to go. It is an integral part of the settlement and we support the settlement, and, accordingly, we support the motion to defer.

I think Mr. Laux -- and I confess to you, I haven't gone back and looked at every single component of the $265 million. But I think Mr. Laux hit it on the head that all or virtually all of the CR3 uprate costs to be recovered pursuant to subsection 6 of the nuclear cost recovery statute have already been approved as being reasonable and prudent. So they're there in any event. I think you'd be in -- I think the Commission would be in a difficult position to attempt to disallow any of them, particularly with no contrary evidence in the record in this case, plus, plus the fact that you probably approved, like I said, I think all or nearly all of them already. So what you're really left with is -- unfortunately, you know, we're not wild about rate increases at all. But, you know, what you're left with unfortunately is, is an 89 cent increase in the component -- in the NCRC due to the change in the recovery to becoming under subsection 6 of already approved costs. It's, it's -- it just is what it is.

COMMISSIONER EDGAR: And I wanted, I wanted you to address that point. Thank you.

MR. WRIGHT: Thank you.

CHAIRMAN BRISÉ: Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman.

I just have a quick question on procedure before we take a break, and it's going to focus on the 265 million. If everyone has stated that the 89 cents or $265 million is what would fall out, why aren't we faced with a stipulation to all of that testimony, get it into the record so that we have evidence in the record to justify raising customer bills?

MR. BURNETT: Commissioner, my understanding is that is what we will do later. We would move that testimony into the record at the appropriate time and that would be on the record, as you suggest, sir.

COMMISSIONER BALBIS: If we --

MR. BURNETT: If you grant the motion to defer, that will nonetheless be moved into the record and be part of the evidence in this docket.

COMMISSIONER BALBIS: So why not just have that proposed stipulation in front of us, we close the proceeding out this year, and we have evidence in the record, we can justify increasing customer bills, and everything is a heck of a lot cleaner, rather than this motion to defer?

MR. BURNETT: You, you could do that. But I would recommend that what you're doing now is simply saying that based on the evidence that we will move in the record, as you typically do in the NCRC, those costs, as Mr. Wright said, largely have already been determined as reasonable and prudent. But you would still be reserving your right to say nonetheless I will look at the global settlement agreement and consider that as an element later. So I don't think you have to do that or have to have an independent stipulation and you get to the same place.

COMMISSIONER BALBIS: Okay. And then a question for Mr. Rehwinkel.

If the proposed global settlement is not approved, will OPC change its position on the $265 million, which warranted a deferral until after that fact?

MR. REHWINKEL: That's a difficult question, Commissioner, because at this point I'm bound by the stipulation that we've entered into that we support this level of recovery.

Certainly if we get into a position where the stipulation is for whatever reason at whatever time not agreed to and we're back before the Commission in the NCRC proceeding, whether it's later this year or just next year's cycle, I cannot speak for the office as far as what position we would take based on what evidence we would, we would see between now and then.

But I would agree with Mr. Wright's statement that we looked at the $265 million. We did not see a reason to take issue with it then, I mean, then in deciding whether to file testimony or not or in our prehearing position statements. Were that to change based on new information or something we don't know now I can't speak for. But generally speaking, we wouldn't be in a different position, all things being equal, if that answers your question.

COMMISSIONER BALBIS: Well, I was hoping you would say that you wouldn't change your position because then it would make it a lot easier. But I guess I'll pose the same question to you as I did Mr. Burnett. Why didn't you pursue a proposed stipulation so that we could handle it? Because I don't have questions for any of the witnesses other than the feasibility analysis, I don't know about other Commissioners, but it could be a lot easier to handle it that way.

MR. REHWINKEL: Well, I was -- I apologize. I was under the assumption that as a part of this deferral process -- I had spoken to staff counsel last week and they kind of layed out the logic of how things would flow today. And it would be the motion to defer, and if it was granted, there would be administrative details. And I was assuming that one of the administrative details would be is that the testimony would be entered into the record. Because the company was, is asking you to approve the 2.17. And if the testimony goes in and it's stipulated into the record, it would be the foundation upon which the 2.17 should be granted.

And we, we agree with that approach. I just assumed that's how it would go. And to my thinking, that was the same as stipulated testimony, is it would go in but there would be an affirmative deferral such that when you got here next year, if something came up or you -- you'd have full rights to go back and revisit the whole thing as if it was occurring here in '13 instead of in '14.

COMMISSIONER BALBIS: And I believe we always have that in the true-up period for the next year. But, Mr. Chairman, it might be break time.

CHAIRMAN BRISÉ: Just to clarify, Mr. Rehwinkel, what you laid out is exactly what we have laid out in our process here.

So are there any further questions, Commissioners, before we take a pause so that we can go in to meet with our staff and so forth so we can think about this for a second? Okay. Seeing that there are no questions, we will be generous and we will take a ten-minute break, and we will be back at 10:45.

(Recess taken.)

We're going to go ahead and reconvene at this time.

So we've gone through questions and I

think we're now in the time for decision. And so I see a few lights that have come on, and so we'll go with Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman. I just have two very quick questions. I think the break was helpful to kind of focus everybody in.

And I just want to focus on really the only issue I have, and a question for Mr. Rehwinkel. As the representative of the ratepayers, do you believe that the additional $265 million that customers will pay because of this deferral is appropriate and in the best interest of the ratepayers?

MR. REHWINKEL: Commissioner, I believe that given the circumstances of the retirement and the cancellation of the project and the statutory framework that the current year's revenue requirement that it reflects in a $2.17 rate is the, is the appropriate amount, given the Commission's decision and the statutory framework.

We don't have an opinion about the propriety of the $265 million. What you're approving this year is, is the revenue requirement for the amortization under the cancellation. So this year's amortization and the revenue requirement is what it is and we have no basis to contest it, and I say that on behalf of the customers.

COMMISSIONER BALBIS: Okay. So that would be a yes?

MR. REHWINKEL: In effect, yes, sir.

COMMISSIONER BALBIS: Okay. Thank you.

And just a quick question for staff. I understand that in the script there's an outline on moving things into the record, because that's my other concern is not having any evidence in the record to justify this increase. If we vote on the deferral and it's approved, can we still enter that information into the record?

MS. HELTON: Yes, sir.

COMMISSIONER BALBIS: Okay. Thank you. That's all I have.

CHAIRMAN BRISÉ: Commissioner Brown.

COMMISSIONER BROWN: Thank you, Mr. Chairman.

And I want to thank the parties all here and staff for clarifying some points. It really highlighted some facts that I wasn't really sure of. I think it's clear now that with the deferral, without the deferral, the rate impact is going to be essentially the same. So at this stage it's also clear that there's no evidence in the record supporting a finding of imprudence or unreasonableness. And, you know, I really rely on the consumer advocates here. They're all here supporting this motion and the deferral, and so I would be willing to support the motion.

CHAIRMAN BRISÉ: Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

Two brief points. The first is it's my understanding that the 265 million is cost recovery under the statute and the information that has been filed and is available to our staff. It is not 265 million that is additional because of the deferral, which is, I think, kind of what I heard, but maybe I misheard.

Secondly, as has been stated, I think, by others up here, and I certainly would repeat it as well, the process of reviewing cost recovery amounts under the statute and under our rule and under our hearing process is something that I stand by, and I recognize has never been successfully appealed. I think it is something that has been recognized as being appropriate under the rule, under the statute, under court opinions, and has recognized due process and public interest.

So with that, Mr. Chairman, maybe -- I think it's kind of six in one, half a dozen in the other, but because we do often, very often in the nuclear cost recovery proceedings under the statute enter prefiled and/or stipulated testimony, that maybe to alleviate some of the questions that I've heard here it might be that we just sort of flip it around and go ahead and, if, if we are all amenable, take up entering the prefiled testimony and exhibit, related exhibits, et cetera, as procedural matters. And after we have done all that, maybe then we are in the posture to take up the motion, the agreed by all parties upon and requested motion to defer for consideration.

COMMISSIONER BALBIS: Can I second that motion?

COMMISSIONER EDGAR: And that is therefore now in the form of a motion.

CHAIRMAN BRISÉ: All right. Let's make sure that we have no legal issues with that.

MS. HELTON: Not any that I can think of, Mr. Chairman.

CHAIRMAN BRISÉ: Perfect. Thank you.

So then we have a motion on the floor to move in, move into the record all of the exhibits associated with Duke Energy's prefiled testimony and all that stuff, the Comprehensive Exhibit List. So we have that motion, and I think that would be Exhibit 1. And so we'll ask staff to go ahead and, and set that up for us.

MR. YOUNG: Mr. Chairman. Before we get there, if we can have the Comprehensive Exhibit List be identified first and marked as Exhibit Number 1.

CHAIRMAN BRISÉ: Exhibit 1.

MR. YOUNG: And entered into the record. And then we can move to page number 10 on the Comprehensive Exhibit List starting with Exhibit Number 89 -- I mean 86 through 111.

CHAIRMAN BRISÉ: Is it 84 through 101?

MR. YOUNG: Yes. 84. I'm sorry. 84 through 101 -- 111 I have.

CHAIRMAN BRISÉ: Okay. 111. Yes, that includes staff's. Thank you.

Okay. So then we are moving into the record the Comprehensive Exhibit List.

MR. YOUNG: Yes.

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

(Exhibits 2 through 111, as listed on the Comprehensive Exhibit List, marked for identification.)

CHAIRMAN BRISÉ: Okay. And then we are also moving into the record Exhibits 84 through 111.

MR. YOUNG: Yes.

CHAIRMAN BRISÉ: Okay. Are there any objections? Okay. Seeing none, Exhibit 1 and Exhibit 84 through 111 have been entered into the record.

(Exhibits 84 through 111 admitted into the record.)

Okay. Thank you. All right. So I think now we are in proper posture for a motion or a discussion.

MR. LAWSON: We have the prefiled testimony next.

COMMISSIONER EDGAR: Prefiled testimony.

CHAIRMAN BRISÉ: Prefiled testimony. Thank you.

COMMISSIONER EDGAR: Mr. Chairman, I would, if I may, I would ask the parties sponsoring the witnesses that had prefiled testimony if they are in a posture to request that those prefiled testimonies be entered into the record.

CHAIRMAN BRISÉ: Sure.

MS. GAMBA: Certainly. At this time Duke Energy would ask that the prefiled testimony dated March 1, 2013, and May 1, 2013, of Thomas G. Foster, Garry D. Miller and Christopher M. Fallon be entered into the record as though read. And I believe Mr. Burnett has a clarification on that as well.

CHAIRMAN BRISÉ: Okay.

MR. BURNETT: Yes, sir. Thank you. The only clarification, I would note that the prior statement I made about Mr. Fallon's feasibility testimony, those sections of his testimony that speak to those have been superseded and are now stale, so with that caveat.

And then a second qualification important to my colleagues, that by entering this Duke is not asking -- doing any violence to their right that if the, if the settlement agreement is not approved, they retain all their rights to challenge prudence later on. So this is in no way taking that right away. I just wanted to make that clear. I had said it earlier. Thank you, sir.

CHAIRMAN BRISÉ: Thank you. So at this time we will move Witness Foster, Miller, and Fallon's testimony into the record, seeing no objections.

IN RE: NUCLEAR COST RECOVERY CLAUSE
BY PROGRESS ENERGY FLORIDA, INC.
FPSC DOCKET NO. 130009-EI
DIRECT TESTIMONY OF THOMAS G. FOSTER

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Thomas G. Foster. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

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

A. I am employed by Progress Energy Service Company, LLC as Manager, Retail Riders and Rate Cases.

Q. What are your responsibilities in that position?

A. I am responsible for regulatory planning and cost recovery for Progress Energy Florida, Inc. ("PEF"). These responsibilities include: regulatory financial reports; and analysis of state, federal, and local regulations and their impact on PEF. In this capacity, I am also responsible for the Levy Nuclear Project ("LNP") and the Crystal River Unit 3 ("CR3") Extended Power Uprate ("EPU") Project ("CR3 Uprate") Cost Recovery True-up, Actual/Estimated, Projection and True-up to Original filings, made as part of this docket, in accordance with Rule 25-6.0423, Florida Administrative Code (F.A.C.).

Q. Please describe your educational background and professional experience.

A. I joined Progress Energy on October 31, 2005 as a Senior Financial analyst in the Regulatory group. In that capacity I supported the preparation of testimony and exhibits associated with various Dockets. In late 2008, I was promoted to Supervisor Regulatory Planning. In 2012, following the merger with Duke Energy, I was promoted to my current position. Prior to working at Progress I was the Supervisor in the Fixed Asset group at Eckerd Drug. In this role I was responsible for ensuring proper accounting for all fixed assets as well as various other accounting responsibilities. I have 6 years of experience related to the operation and maintenance of power plants obtained while serving in the United States Navy as a Nuclear operator. I received a Bachelors of Science degree in Nuclear Engineering Technology from Thomas Edison State College. I received a Masters of Business Administration with a focus on finance from the University of South Florida and I am a Certified Public Accountant in the State of Florida.

Q. Have you previously filed testimony before this Commission in connection with PEF's Nuclear Cost Recovery?

A. Yes.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Florida Public Service Commission ("FPSC" or the "Commission") review and approval, the actual costs associated with PEF's LNP and CR3 Uprate activities for the period January 2012 through

December 2012. Pursuant to Rule 25-6.0423, F.A.C., PEF is presenting testimony and exhibits for the Commission's determination of prudence for actual expenditures and associated carrying costs.

Q. Are you sponsoring any exhibits in support of your testimony on 2012 LNP and CR3 Uprate costs?

A. Yes. I am sponsoring sections of the following exhibits, which were prepared under my supervision:

2012 Costs:

- Exhibit No. __ (TGF-1), consisting of Schedules T-1 through T-7B of the NFRs and Appendices A through D, which reflect PEF's retail revenue requirements for the LNP from January 2012 through December 2012; however, I will only be sponsoring Schedules T-1 through T-6 and Appendices A through C. Christopher Fallon will be co-sponsoring portions of Schedules T-4, T-4A, T-6 and sponsoring Schedules T-6A through T-7B and Appendix D.
- Exhibit No. ___ (TGF-2), consisting of Schedules T-1 through T-7B of the NFRs and Appendices A through D, which reflect PEF's retail revenue requirements for the CR3 Uprate Project from January 2012 through December 2012; however, I will only be sponsoring Schedules T-1 through T-6 and Appendices A through C. Jon Franke will be co-sponsoring Schedules T-4, T-4A, T-6, and sponsoring Schedules T-6A through T-7B and Appendix D.

These exhibits are true and accurate.

Q. What are Schedules T-1 through T-7B and the Appendices?

A.
- Schedule T-1 reflects the actual true-up of total retail revenue requirements for the period.
- Schedule T-2 reflects the calculation of the site selection, preconstruction, and construction costs for the period.
- Schedule T-3A reflects the calculation of actual deferred tax carrying costs for the period.
- Schedule T-3B reflects the calculation of the actual construction period interest for the period.
- Schedule T-4 reflects Capacity Cost Recovery Clause ("CCRC") recoverable Operations and Maintenance ("O&M") expenditures for the period.
- Schedule T-4A reflects CCRC recoverable O&M expenditure variance explanations for the period.
- Schedule T-6 reflects actual monthly capital expenditures for site selection, preconstruction, and construction costs for the period.
- Schedule T-6A reflects descriptions of the major tasks.
- Schedule T-6B reflects capital expenditure variance explanations.
- Schedule T-7 reflects contracts executed in excess of $1.0 million.
- Schedule T-7A reflects details pertaining to the contracts executed in excess of $1.0 million.
- Schedule T-7B reflects contracts executed in excess of $250,000, yet less than $1.0 million.
- Appendix A reflects support for beginning balances.

- Appendix B (Levy) reflects individual components of Site Selection, Preconstruction, and the PSC approved deferral.
- Appendix B (CR3 Uprate) reflects various Uprate in-service project revenue requirements.
- Appendix C reflects a schedule of 2006 to 2012 revenue requirements.
- Appendix D reflects a schedule of 2006 to 2012 actual capital expenditures.

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

A. The actual data is taken from the books and records of PEF. The books and records are kept in the regular course of our business in accordance with generally accepted accounting principles and practices, provisions of the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission ("FERC"), and any accounting rules and orders established by this Commission.

Q. What is the final true-up amount for the LNP for which PEF is requesting recovery for the period January 2012 through December 2012?

A. PEF is requesting approval of a total under-recovery amount of $3,644,953 for the calendar period ending December 2012. This amount, which can be seen on Line 9 of Schedule T-1 of Exhibit No. ___ (TGF-1), represents the site selection, preconstruction, carrying costs on preconstruction cost balance, carrying costs on construction cost balance, CCRC recoverable O&M, and deferred tax asset carrying cost associated with the LNP, and was calculated in accordance with Rule 25-6.0423, F.A.C.

Q. What is the final true-up amount for the CR3 Uprate project for which PEF is requesting recovery for the period January 2012 through December 2012?

A. PEF is requesting approval of a total under-recovery amount of $2,596,849 for the calendar period of January 2012 through December 2012. This amount, which can be seen on Line 9 of Schedule T-1 of Exhibit No. ___ (TGF-2), represents the carrying costs on construction cost balance, CCRC recoverable O&M, and deferred tax asset carrying cost associated with the CR3 Uprate, as well as the revenue requirements associated with the various in service projects, and was calculated in accordance with Rule 25-6.0423, F.A.C..

Q. What is the carrying cost rate used in Schedules T-2.1, T-2.2, and T-2.3?

A. The carrying cost rate used on Schedules T-2.1, T-2.2, and T-2.3 is 8.848 percent. On a pre-tax basis, the rate is 13.13 percent. This rate represents the approved rate as of June 12, 2007, and is the appropriate rate to use consistent with Rule 25-6.0423(5)(b), F.A.C. The rate was approved by the Commission in Order No. PSC-05-0945-S-EI in Docket No. 050078-EI. The annual rate was adjusted to a monthly rate consistent with the Allowance for Funds Used During Construction ("AFUDC") rule, Rule 25-6.0141, Item (3), F.A.C.

III. CAPITAL COSTS INCURRED IN 2012 FOR THE LEVY NUCLEAR PROJECT.

Q. What are the total costs PEF incurred for the LNP during the period January 2012 through December 2012?

A. Total preconstruction capital expenditures, excluding carrying costs, were [redacted], as shown on Schedule T-6.2, Line 8 and 21. Total construction capital expenditures, excluding carrying costs, were [redacted], as shown on Schedule T-6.3, Line 10 and 25.

Q. How did actual Preconstruction Generation capital expenditures for January 2012 through December 2012 compare with PEF's actual/estimated costs for 2012?

A. Schedule T-6B.2, Line 6 shows that total preconstruction Generation project costs were [redacted], or [redacted] lower than estimated. By cost category, major cost variances between PEF's projected and actual 2012 preconstruction LNP Generation project costs are as follows:

License Application: Capital expenditures for License Application activities were [redacted] or [redacted] higher than estimated. As explained in the testimony of Christopher Fallon, this variance is primarily attributable to higher than originally estimated Nuclear Regulatory Commission ("NRC") review fees and outside legal counsel fees associated with the LNP Combined Operating License Application ("COLA") activities and regulatory reviews.

Engineering & Design: Capital expenditures for Engineering & Design activities were [redacted] or [redacted] lower than estimated. As explained in the testimony of Christopher Fallon, this variance is primarily attributable to lower than estimated internal labor and expenses and deferral of conditions of certification work scope into future years.

Q. Did the Company incur Preconstruction Transmission capital expenditures for January 2012 through December 2012?

A. No. As shown on Schedule T-6B.2, Line 11 the total preconstruction Transmission project costs were $0 in 2012. No costs were projected in the prior-year Actual/Estimated filing, so there is no true-up to report.

Q. How did actual Construction Generation capital expenditures for January 2012 through December 2012 compare with PEF's actual/estimated costs for 2012?

A. Schedule T-6B.3, Line 8 shows that total construction Generation project costs were [redacted], or [redacted] higher than estimated. By cost category, major cost variances between PEF's actual/estimated and actual 2012 construction LNP Generation project costs are as follows:

Power Block Engineering: Capital expenditures for Power Block Engineering activities were [redacted] or [redacted] higher than estimated. As explained in the testimony of Christopher Fallon, this variance is attributable to the accrual of costs for partially completed LLE milestones, which were included as 2013 costs in the prior-year projection, but were actually incurred in 2012 based on the percentage of LLE milestones completed during the year.

Q. How did actual Construction Transmission capital expenditures for January 2012 through December 2012 compare with PEF's actual/estimated costs for 2012?

A. Schedule T-6B.3, Line 15 shows that total construction Transmission project costs were [redacted] or [redacted] lower than estimated. Consequently, there were no major (more than $1.0 million) variances between the actual/estimated costs and the actual costs incurred for 2012.

Q. What was the source of the separation factors used in Schedule T-6?

A. The jurisdictional separation factors are calculated based on the 2012 sales forecast, using the Retail Jurisdictional Cost of Service methodology that was approved in Order No. PSC-10-0131-FOF-EI in PEF's base rate proceeding in Docket No. 090079-EI.

IV. O&M COSTS INCURRED IN 2012 FOR THE LEVY NUCLEAR PROJECT.

Q. How did actual O&M expenditures for January 2012 through December 2012 compare with PEF's actual/estimated costs for 2012?

A. Schedule T-4A, Line 15 shows that total O&M costs were $1.1 million or $61,768 higher than estimated. There were no major variances with respect to O&M costs.

V. CAPITAL COSTS INCURRED IN 2012 FOR CR3 UPRATE PROJECT.

Q. What are the total Construction costs incurred for the CR3 Uprate project for the period January 2012 through December 2012?

A. Schedule T-6.3, Line 12 shows that total Construction capital expenditures gross of joint owner billing and excluding carrying costs were $44.3 million.

Q. How did actual capital expenditures for January 2012 through December 2012 compare to PEF's actual/estimated costs for 2012?

A. Schedule T-6B.3, Line 8 shows that total project costs were $44.3 million or $7.2 million lower than estimated. By cost category, major cost variances between PEF's actual/estimated and actual 2012 Construction costs are as follows:

Power Block Engineering & Procurement: Capital expenditures for Power Block Engineering & Procurement activities were $38.1 million or $7.3 million lower than estimated. As explained in the testimony of Jon Franke, this variance is primarily attributed to deferral of contract payments, control and reduction of engineering work scope, and lower warehouse inventory expenses than projected as a result of deferring EPU work and costs beyond 2012.

Q. Has PEF billed the CR3 joint owners for their portion of the costs relative to the CR3 Uprate and identified them in this filing?

A. Yes. Construction expenditures shown on Schedule T-6.3, Line 12 are gross of Joint Owner Billings, but construction expenditures have been adjusted as reflected on Schedule T-6.3, Line 15 to reflect billings to Joint Owners related to CR3 Uprate expenditures. Due to this, no carrying cost associated with the Joint Owner portion of the Uprate are included on Schedule T-2.3. Total Joint Owner billings were $3.6 million for 2012.

Q. What was the source of the separation factors used in Schedule T-6?

A. The jurisdictional separation factors are calculated based on the 2012 sales forecast, using the Retail Jurisdictional Cost of Service methodology that was approved in Order No. PSC-10-0131-FOF-EI in PEF's base rate proceeding in Docket No. 090079-EI.

VI. O&M COSTS INCURRED IN 2012 FOR THE CR3 UPRATE PROJECT.

Q. How did actual O&M expenditures for January 2012 through December 2012 compare with PEF's actual/estimated costs for 2012?

A. Schedule T-4A, Line 15 shows that total O&M costs were $0.5 million or $65,356 higher than estimated. There were no major variances with respect to O&M costs.

VII. 2012 PROJECT ACCOUNTING AND COST CONTROL OVERSIGHT.

Q. Have the project accounting and cost oversight controls PEF used for the LNP and CR3 Uprate projects in 2012 substantially changed from the controls used prior to 2012?

A. No, they have not. The project accounting and cost oversight controls that PEF utilizes to ensure the proper accounting treatment for the LNP and CR3 Uprate project in 2012 have not substantively changed since 2009. In addition, these controls have been reviewed in annual financial audits by Commission Staff and were found to be reasonable and prudent by the Commission in Docket Nos. 090009-EI, 100009-EI, 110009-EI, and 120009-EI.

Q. Can you describe how the merger between Duke Energy and Progress Energy impacted the project accounting and cost oversight controls?

A. Yes, I can. During the first six months of 2012, prior to the July 2012 merger between Duke Energy and Progress Energy, the project accounting and cost oversight controls were exactly the same as those previously reviewed. This included continued project governance under the Major Projects - Integrated Project Plan ("IPP") Approval and Authorization policy for capital project initial authorization.

Following the merger, the IPP procedure was superseded by the Duke Energy Approval of Business Transaction ("ABT") process, which is a similar Duke Energy senior management project oversight process. This governance procedure change in the end of 2012 however did not affect PEF's 2012 accounting and cost oversight controls for the LNP and CR3 Uprate projects. More specifically, PEF's day-to-day project accounting and cost oversight controls remained the same.

Q. Can you please describe the project accounting and cost oversight controls process PEF has utilized for the LNP and CR3 Uprate Project.?

A. Yes. Starting at the initial approval stage, PEF continues to determine whether projects are capital based on the Company's Capitalization Policy and then projects are documented in PowerPlant.

The justifications and other supporting documentation are reviewed and approved by the Financial Services Manager, or delegate, based on input received from the Financial Services or Project Management Analyst to ensure that the project is properly classified as capital, eligibility for AFUDC is correct, and that disposals/retirements are identified. Supporting documentation is maintained within Financial Services or with the Project Management Analyst. Financial Services personnel, and selected other personnel (including project management analysts), access this documentation to set-up new projects in Oracle or make changes to existing project estimates in PowerPlant. The Oracle and PowerPlant system administrators review the transfer and termination information provided by Human Resources each pay period and take appropriate action regarding access to the systems as outlined in the Critical Financial Application Access Review Process Policy.

An analyst in Property Accounting must review and approve each project set up before it can receive charges. All future status changes are made directly in PowerPlant by a Property Accounting analyst based on information received by the Financial Services Analyst or the Project Management Analyst.

Finally, to ensure that all new projects have been reviewed each month, Financial Services Management reviews a report of all projects set up during the month prior to month-end close for any project that was not approved by them in the system at set up.

The next part of the Company's project controls is project monitoring. First, there are monthly reviews of project charges by responsible operations managers and Financial Services Management for the organization. Specifically, these managers review various monthly cost and variance analysis reports for the capital budget. Variances from total budget or projections are reviewed, discrepancies are identified, and corrections made as needed. Journal entries to projects are prepared by an employee with the assigned security and are approved in accordance with the Journal Entry Policy. Accruals are made in accordance with Progress Energy policy.

The Company uses Cost Management Reports produced from accounting systems to complete these monthly reviews. Financial Services may produce various levels of reports driven by various levels of management, but all reporting is tied back to the Cost Management Reports, which are tied back to Legal Entity Financial Statements.

Finally, the Property Accounting unit performs a quarterly review of sample project transactions to ensure charges are properly classified as capital. Financial Services is responsible for answering questions and making necessary corrections as they arise to ensure compliance. These accounting and cost oversight processes continued to be utilized in 2012 for the CR3 Uprate and LNP.

Q. Are there any other accounting and costs oversight controls that pertain to the LNP and the CR3 Uprate Project?

A. Yes, the Company also has Disbursement Services Controls and Regulatory Accounting Controls.

Q. Can you please describe the Company's Disbursement Services Controls?

A. Yes. First, a requisition is created in the Passport Contracts module for the purchase of services. The requisition is reviewed by the appropriate Contract Specialist in Corporate Services, or field personnel in the various Business Units, to ensure sufficient data has been provided to process the contract requisition. The Contract Specialist prepares the appropriate contract document from pre-approved contract templates in accordance with the requirements stated on the contract requisition.

The contract requisition then goes through the bidding or finalization process. Once the contract is ready to be executed, it is approved online by the appropriate levels of the approval matrix pursuant to the Approval Level Policy and a contract is created.

Contract invoices are received by the Account Payable Department. The invoices are validated by the project manager and Payment Authorizations approving payment of the contract invoices are entered and approved in the Contracts module of the Passport system.

Q. Can you please describe the Company's Regulatory Accounting Controls?

A. Yes. The journal entries for deferral calculations, along with the summary sheets and the related support, are reviewed in detail and approved by the Manager of Regulatory & Property Accounting, per the Progress Energy Journal Entry policy. The detail review and approval by the Manager of Regulatory & Property Accounting ensure that recoverable expenses are identified, accurate, processed, and accounted for in the appropriate accounting period. In addition, transactions are reviewed to ensure that they qualify for recovery through the Nuclear Cost Recovery

Rule and are properly categorized as O&M, Site selection, Preconstruction, or Construction expenditures.

Analysis is performed monthly to compare actuals to projected (budgeted) expenses and revenues for reasonableness. If any errors are identified, they are corrected in the following month.

For balance sheet accounts established with Regulatory & Property Accounting as the responsible party, a Regulatory Accounting member will reconcile the account on a monthly or quarterly basis. This reconciliation will be reviewed by the Lead Business Financial Analyst or Manager of Regulatory & Property Accounting to ensure that the balance in the account is properly stated and supported and that the reconciliations are performed regularly and exceptions are resolved on a timely basis.

The review and approval will ensure that regulatory assets or liabilities are recorded in the financial statements at the appropriate amounts and in the appropriate accounting period.

Q. How does the Company verify that the accounting and costs oversight controls you identified are effective?

A. The Company's assessment of the effectiveness of our controls is based on the framework established by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). This framework involves both internal and external audits of PEF accounting and cost oversight controls.

With respect to internal audits, all tests of controls were conducted by the Audit Services Department, and conclusions on the results were reviewed and approved by both the Steering Committee and Compliance Team chairpersons. Based on these internal audits, PEF's management has determined that PEF maintained effective internal control over financial reporting and identified no material weaknesses within the required Sarbanes Oxley controls during 2012. With respect to external audits, Deloitte and Touche, PEF's external auditors, determined that the Company maintained effective internal control over financial reporting during 2012.

Q. Are the Company's project accounting and cost oversight controls reasonable and prudent?

A. Yes, they are. PEF's project accounting and cost oversight controls are consistent with best practices for capital project cost oversight and accounting controls in the industry and have been and continue to be vetted by internal and external auditors. We believe, therefore, that the accounting and cost oversight controls continue to be reasonable and prudent.

Q. Does this conclude your testimony?

A. Yes, it does.

IN RE: NUCLEAR COST RECOVERY CLAUSE

BY DUKE ENERGY FLORIDA, INC.

FPSC DOCKET NO. 130009-EI

DIRECT TESTIMONY OF THOMAS G. FOSTER IN SUPPORT OF LEVY ESTIMATED/ACTUAL, PROJECTION, TRUE-UP TO ORIGINAL COSTS AND CR3 UPRATE COSTS

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Thomas G. Foster. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

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

A. I am employed by Duke Energy Service Company, LLC as Manager, Retail Riders and Rate Cases.

Q. What are your responsibilities in that position?

A. I am responsible for regulatory planning and cost recovery for Duke Energy Florida, Inc. ("DEF" or the "Company"). These responsibilities include: regulatory financial reports; and analysis of state, federal, and local regulations and their impact on DEF. In this capacity, I am also responsible for the Levy Nuclear Project ("LNP") and the Crystal River Unit 3 ("CR3") Extended Power Uprate ("EPU") Project ("CR3 Uprate") Cost Recovery True-up, Actual/Estimated, Projection and True-up to

Original filings, made as part of this docket, in accordance with Rule 25-6.0423, Florida Administrative Code (F.A.C.).

Q. Please describe your educational background and professional experience.

A. I joined Progress Energy on October 31, 2005 as a Senior Financial Analyst in the Regulatory group. In that capacity I supported the preparation of testimony and exhibits associated with various Dockets. In late 2008, I was promoted to Supervisor Regulatory Planning. In 2012, following the merger with Duke Energy, I was promoted to my current position. Prior to working at Progress I was the Supervisor in the Fixed Asset group at Eckerd Drug. In this role I was responsible for ensuring proper accounting for all fixed assets as well as various other accounting responsibilities. I have 6 years of experience related to the operation and maintenance of power plants obtained while serving in the United States Navy as a nuclear operator. I received a Bachelors of Science degree in Nuclear Engineering Technology from Thomas Edison State College. I received a Masters of Business Administration with a focus on finance from the University of South Florida and I am a Certified Public Accountant in the State of Florida.

II. PURPOSE OF TESTIMONY.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Florida Public Service Commission ("FPSC" or the "Commission") review and approval, DEF's estimated/actual costs associated with the LNP activities for the period January 2013 through December 2013, projected costs for the period January 2014 through December 2014, and the total estimated revenue requirements for 2014 for purposes of setting 2014 rates in the Capacity Cost Recovery Clause ("CCRC"). I will also present DEF's costs associated with the CR3 Uprate project consistent with Rule 25-6.0423(6), which includes actual costs to date and expected costs to close-out the project in 2013 and 2014 for purposes of setting 2014 rates.

Q. Are you sponsoring any exhibits in support of your testimony?

A. Yes. I am sponsoring sections of the following exhibits, which were prepared under my supervision:

- Exhibit No. ___ (TGF-3), consists of Schedules AE-1 through AE-7B of the Nuclear Filing Requirements ("NFRs"), which reflect DEF's retail revenue requirements for the LNP from January 2013 through December 2013. I am sponsoring Schedules AE-1 through AE-6.3, and Appendices A through E. Mr. Christopher Fallon will be co-sponsoring portions of Schedules AE-4, AE-4A, and AE-6 and sponsoring Schedules AE-6A through AE-7B.
- Exhibit No. ___ (TGF-4), consists of Schedules P-1 through P-8 of the NFRs, which reflect DEF's retail revenue requirements for the LNP from January 2014 through December 2014. I am sponsoring Schedules P-1 through P-6.3, P-8, and Appendices A through E. Mr.

Fallon will be co-sponsoring portions of Schedules P-4, P-6 and sponsoring Schedules P-6A through P-7B.

- Exhibit No. ___ (TGF-5), consists of Schedules TOR-1 through TOR-7, which reflect the total project estimated costs for the LNP. I am sponsoring Schedules TOR-1 through TOR-3 and co-sponsoring portions of Schedules TOR-4 and TOR-6. Mr. Fallon will be co-sponsoring Schedules TOR-4 and TOR-6 and sponsoring Schedules TOR-6A and TOR-7.
- Exhibit No.___(TGF-6), consists of the actual and expected costs associated with the CR3 Uprate project for 2013 and 2014, as a result of the cancellation of the project in February 2013, and pursuant to Rule 25-6.0423(6), F.A.C. These schedules, Schedule 2013 Detail and Schedule 2014 Detail for the CR3 Uprate project, contain the same calculations provided in the NFR Schedules prior to project cancellation in a more concise manner. DEF expects to file these schedules for the CR3 Uprate project to provide information for the recoverable costs under Rule 25-6.0423(6), F.A.C. Mr. Garry Miller will be co-sponsoring portions of Schedule 2013 Detail Lines 1 (a – f) and Schedule 2014 Detail Lines 1 (a - f).
- Exhibit No.___(TGF-7), consists of Schedules AE-1 through AE-7B of the NFRs, which reflect DEF's retail revenue requirements for the CR3 Uprate project from January 2013 through December 2013. I am sponsoring Schedules AE-1 through AE-6.3, and Appendices A through E. Mr. Garry Miller will be co-sponsoring portions of

Schedule AE-6 and sponsoring Schedules AE-6A through AE-7B. These NFR Schedules are presented for 2013 because the CR3 Uprate project was not cancelled until February 2013.

These exhibits are true and accurate.

Q. What are Schedules AE-1 through AE-7B?

A. A brief description of Schedules AE-1 through AE-7B is provided below:

- Schedule AE-1 reflects the actual/estimated total retail revenue requirements for the period.
- Schedule AE-2.2 reflects the calculation of the actual/estimated preconstruction costs for the period.
- Schedule AE-2.3 reflects the calculation of the actual/estimated carrying costs on construction expenditures for the period.
- Schedule AE-4 reflects CCRC recoverable Operations and Maintenance ("O&M") expenditures for the period.
- Schedule AE-4A reflects CCRC recoverable O&M expenditure variance explanations for the period.
- Schedule AE-6 reflects actual/estimated monthly expenditures for site selection, preconstruction, and construction costs for the period.
- Schedule AE-6A reflects descriptions of the major tasks.
- Schedule AE-6B reflects variance explanations of major tasks.
- Schedule AE-7 reflects contracts executed in excess of $1.0 million.
- Schedule AE-7A reflects details pertaining to the contracts executed in excess of $1.0 million.

- Schedule AE-7B reflects contracts executed in excess of $250,000, yet less than $1.0 million.

Q. What are the Levy AE-Appendices A through E?

A. A brief description of the Levy AE Appendices is provided below:

- Appendix A reflects the reconciliation of the beginning balances on Schedules AE-2.2 thru AE-4.
- Appendix B reflects the jurisdictional separation factors.
- Appendix C reflects the approved Rate Management amortization schedule through year end ("YE") 2014.
- Appendix D reflects the Schedule AE2.2 support.
- Appendix E reflects the reconciliation of the 2011/2012 Over / (Under) recovery by cost category.

Q. What are the CR3 Uprate AE-Appendices A through E?

A. A brief description of the CR3 Uprate AE Appendices is provided below:

- Appendix A reflects the reconciliation of the beginning balances on Schedules AE-2.3 thru AE-4.
- Appendix B reflects the jurisdictional separation factors.
- Appendix C the revenue requirement calculation supporting line 5 of Schedule AE-1.
- Appendix D provides support for prior period over/under recoveries.
- Appendix E provides support for the appropriate rate of return consistent with the provisions of FPSC Rule 25-6.0423(6).

Q. What are Schedules P-1 through P-8?

A. A brief description of Schedules P-1 through P-8 is provided below:

- Schedule P-1 reflects the projection of total retail revenue requirements for the period as well as true-ups for prior periods.
- Schedule P-2.2 reflects the calculation of the projected preconstruction costs for the period.
- Schedule P-2.3 reflects the calculation of the projected carrying costs on construction expenditures for the period.
- Schedule P-4 reflects CCRC recoverable O&M expenditures for the period.
- Schedule P-6 reflects projected monthly expenditures for site selection, preconstruction, and construction costs for the period.
- Schedule P-6A reflects descriptions of the major tasks.
- Schedule P-7 reflects contracts executed in excess of $1.0 million.
- Schedule P-7A reflects details pertaining to the contracts executed in excess of $1.0 million.
- Schedule P-7B reflects contracts executed in excess of $250,000, yet less than $1.0 million.
- Schedule P-8 reflects the estimated rate impact.

Q. What are the Levy Appendices associated with Schedules P-1 through P-8?

A. A brief description of the Levy Appendices associated with Schedules P-1 through P-8 is provided below:

- Appendix A reflects the reconciliation of the beginning balance of Schedule P-1 through P-4.
- Appendix B reflects the jurisdictional separation factors.
- Appendix C reflects the allocation of revenue requirements to cost category and the rate management plan amortization schedule of the 2010 Regulatory Asset.
- Appendix D is the Preconstruction and Regulatory Liability Schedule.
- Appendix E is the 2014 Regulatory Asset Amortization Schedule.

Q. What are Schedules TOR-1 through TOR-7?

A. A brief description of Schedules TOR-1 through TOR-7 is provided below:

- Schedule TOR-1 reflects the jurisdictional amounts used to calculate the final true up, projection, deferrals and recovery of deferrals.
- Schedule TOR-2 reflects a summary of the actual to date and projected costs for the duration of the project compared to what was originally filed.
- Schedule TOR-3 reflects the calculation of the actual to date and projected total NCRC retail revenue requirement for the duration of the project.
- Schedule TOR-4 reflects CCRC actual to date and projected O&M expenditures.
- Schedule TOR-6 reflects actual to date and projected annual expenditures for site selection, preconstruction and construction costs for the duration of the project.

- Schedule TOR-6A reflects descriptions of the major tasks.
- Schedule TOR-7 reflects a summary of project cost.

Q. Are NFR Schedules P-1 through P-8, their Appendices, and the NFR TOR Schedules necessary for the CR3 Uprate project?

A. No. These NFR Schedules were developed for active nuclear power plant projects and the CR3 Uprate project was cancelled and is no longer an active project. As a result, there are no projected costs to complete the project and total project costs that need to be tracked for the project and, therefore, no need for these NFR Schedules for the CR3 Uprate project. DEF has provided the 2013 Schedule and 2014 Schedule in Exhibit No. ____ (TGF-6) to identify and explain the recoverable costs pursuant to Rule 25-6.0423(6), F.A.C.

III. COST RECOVERY FOR THE LEVY COUNTY NUCLEAR PROJECT.

A. <u>ACTUAL/ESTIMATED LNP COSTS.</u>

Q. What are the total estimated revenue requirements for the LNP for the calendar year ended December 2013?

A. The total projected revenue requirements for the LNP are $35.9 million for the calendar year ended December 2013, as reflected on Schedule AE-1, page 2 of 2, Line 5. This amount includes $21.3 million in preconstruction costs, $14 million for the carrying costs on the construction cost balance, and $0.5 million in recoverable O&M costs. These amounts were calculated in accordance with the provisions of Rule 25-6.0423, F.A.C.

Q. What is the carrying cost rate used in Schedules AE-2.2 through AE-2.3?

A. The carrying cost rate used on Schedule AE-2.2 through AE-2.3 is 8.848 percent. On a pre-tax basis, the rate is 13.13 percent. This rate represents the approved rate as of June 12, 2007, and is the appropriate rate to use consistent with Rule 25-6.0423(5)(b), F.A.C. The rate was approved by the Commission in Order No. PSC-05-0945-S-EI in Docket No. 050078-EI. The annual rate was adjusted to a monthly rate consistent with the Allowance for Funds Used During Construction ("AFUDC") rule, Rule 25-6.0141, Item (3), F.A.C.

Q. What is included in the Preconstruction Plant & Carrying Cost for the Period on Schedule AE-2.2, Line 10?

A. The annual total of $21.3 million reflected on Schedule AE-2.2, Line 10, page 2 of 2 represents the total preconstruction costs for 2013. This amount includes expenditures totaling $13.5 million along with the carrying cost on the average net unamortized plant eligible for return. The total return requirements of $7.8 million presented on Line 9 represents the carrying costs on the average preconstruction balance.

Q. What is included in the Actual Estimated Carrying Costs for the Period on Schedule AE-2.3, Line 9?

A. The total return requirements of $14 million on Schedule AE-2.3 at Line 9 represent carrying costs on the average construction balance. The schedule starts with the 2013 beginning CWIP balance, adds the monthly construction expenditures, and computes a return on the average monthly balance. The equity component of the return is grossed up for taxes to cover the income taxes that will need to be paid upon recovery in rates.

Q. What is included in the Recoverable O&M Expenditures on Schedule AE-4?

A. The expenses included on this schedule represent the O&M costs that the Company expects to incur in 2013 related to the LNP that DEF is seeking recovery of through the NCRC.

Q. What is included in the Recoverable O&M Variance Explanations on Schedule AE-4A?

A. The schedule provides explanations for any significant changes in O&M costs from what the Company projected to incur in 2013 and the actual/estimated costs related to the LNP that DEF is seeking recovery of through the NCRC.

Q. What is Schedule AE-6 and what does it represent?

A. Schedule AE-6 reflects actual/estimated monthly expenditures for site selection, preconstruction, and construction costs by major task for 2013. This schedule includes both the Generation and Transmission costs. These costs have been adjusted to a cash basis to calculate carrying costs. The appropriate jurisdictional separation factor was applied to arrive at the total jurisdictional costs. These costs are further described in the testimony of Mr. Fallon.

Q. What are the total actual/estimated preconstruction costs for the period January 2013 through December 2013?

A. As shown on Line 29 of Schedule AE-6.2 in Exhibit No.___(TGF-3), total actual/estimated jurisdictional preconstruction costs for 2013 are $13.5 million. The costs have been adjusted to a cash basis for purposes of calculating the carrying charge and the appropriate jurisdictional separation factor has been applied. More information about the types of costs included in this amount is provided on Schedule AE-6A.2 and addressed in Mr. Fallon's testimony.

Q. What are the total actual/estimated construction costs for the period January 2013 through December 2013?

A. As shown on Line 35 of Schedule AE-6.3 in Exhibit No.___(TGF-3), total actual/estimated jurisdictional construction costs for 2013 are $72.1 million. The costs have been adjusted to a cash basis for purposes of calculating the carrying charge and the appropriate jurisdictional separation factor has been applied. More information about the types of costs included in this amount is provided on Schedule AE-6A.3 and addressed in Mr. Fallon's testimony.

Q. What was the source of the separation factors used in Schedule AE-4 and AE-6?

A. The jurisdictional separation factors are consistent with Exhibit 1 of the Stipulation and Settlement Agreement ("Settlement Agreement") approved by the Commission in Order No. PSC-12-0104-FOF-EI in Docket No. 120022-EI.

Q. What is the estimated true-up for 2013 expected to be?

A. The total true-up is expected to be an over-recovery of $4.4 million as can be seen on Line 7 of Schedule AE-1.

B. <u>LNP COST PROJECTIONS.</u>

Q. What is included in the projected period Revenue Requirements for 2014?

A. The period revenue requirements of $30.8 million in 2014, as depicted on Schedule P-1, Line 5, includes period preconstruction costs of $11.1 million, carrying costs on construction cost balance of $19.2 million, and O&M expenditures of $0.5 million.

Q. What is included in the Total Costs to be Recovered on Schedule P-2.2 Line 10?

A. The $11.1 million included on Line 10, page 2 of 2 includes the total projected preconstruction costs of $12.1 million and carrying costs on the average unamortized preconstruction balance for 2013 of ($1.0) million.

Q. What is included in the Total Return Requirements on Schedule P-2.3, Line 9?

A. The Total Return Requirements of $19.2 million depicted on this schedule represents carrying costs on the average construction balance. The schedule starts with the 2014 beginning balance, adds the monthly construction expenditures, and computes the carrying charge on the average monthly balance. The equity component of the return is grossed up for taxes to cover the income taxes that will be paid upon recovery in rates. The LNP balance of land at year end 2012 was removed from the nuclear cost recovery clause ("NCRC") and reclassified to FERC Account 105 Plant Held for Future Use on DEF's books pursuant to the terms of the Settlement Agreement approved by the Commission in Order No. PSC-12-0104-FOF-EI in Docket No. 120022-EI. See Exhibit 5 to the Settlement Agreement.

Q. What is the carrying cost rate used in Schedule P-2.2 and P-2.3?

A. The carrying cost rate used on Schedule P-2.2 and P-2.3 is 8.848 percent. On a pre-tax basis, the rate is 13.13 percent. This rate represents the approved rate as of June 12, 2007, and is the appropriate rate to use consistent with Rule 25-6.0423(5)(b)1, F.A.C. The rate was approved by the Commission in Order No. PSC-05-0945-S-EI in Docket No. 050078-EI. The annual rate was adjusted to a monthly rate consistent with AFUDC rule, Rule 25-6.0141, Item (3), F.A.C.

Q. Why isn't DEF using Schedule P-3A.2 to calculate the revenue requirement in 2014?

A. DEF is not using this Schedule to calculate the revenue requirement in 2014 because DEF agreed to the transfer of the annual revenue requirements for the carrying costs on the deferred tax asset ("DTA") from the NCRC to base rates. Settlement Agreement, ¶ 4, p. 4. As a result of this agreement, DEF is not requesting recovery of the carrying cost on the DTA through the NCRC over the settlement term in the Settlement Agreement.

Q. What is the total projected preconstruction costs that will be incurred for the period January 2014 through December 2014?

A. As shown on Line 29 of Schedule P-6.2 in Exhibit No.___(TGF-4), total projected jurisdictional preconstruction costs for 2014 are $12.1 million. The costs have been adjusted to a cash basis for purposes of calculating the carrying charge and the appropriate jurisdictional separation factor has been applied. More information about the types of costs included in this amount is provided on Schedule P-6A.2 and addressed in Mr. Fallon's testimony.

Q. What is the total projected construction costs that will be incurred for the period January 2014 through December 2014?

A. As shown on Line 35 of Schedule P-6.3 in Exhibit No.___(TGF-4), total projected jurisdictional construction costs for 2014 are $20.6 million. The costs have been adjusted to a cash basis for purposes of calculating the carrying charge and the appropriate jurisdictional separation factor has been applied. More information about the types of costs included in this amount is provided on Schedule P-6A.3 and addressed in Mr. Fallon's testimony.

Q. What are the projected total revenue requirements that DEF will recover in 2014?

A. DEF is requesting recovery consistent with the terms of the Settlement Agreement. This means DEF will recover revenues consistent with application of the factors in Exhibit 5 of the Settlement Agreement to the sales forecast presented in the CCRC later in the year. Consistent with the implementation of the Settlement Agreement last year when setting the 2013 revenues for recovery, DEF has an estimate of what this will be, but the estimate will be updated when DEF files for recovery in the CCRC. DEF calculated the estimated revenue requirement by applying the rates in Exhibit 5 of the Settlement Agreement to the sales forecast included in Schedule P-8 of Exhibit No. ____ (TGF-4) to generate the projected revenue for 2014. As can be seen in Schedule P-8 in column 2, this amount is $106.1 million. This amount is further reflected on Schedule P-1, Line 11.

Q. Can you explain how DEF will collect the revenues recovered pursuant to the terms of the Settlement Agreement?

A. Yes, as I explained above, DEF projects that DEF will collect $106.1 million in 2014 under the terms of the Settlement Agreement. These revenues include carrying costs on uncollected preconstruction costs, carrying costs on construction costs, prior period over/under recoveries, O&M, current period preconstruction costs, and prior period preconstruction costs. In order to efficiently track the Commission-approved revenues under the Settlement Agreement for the different cost categories DEF proposes in 2013, for 2014 rates, to apply the agreed-upon revenues subject to collection to the LNP costs in the following manner:

- First, the revenues will be applied to recover carrying costs on any regulatory assets, unamortized preconstruction costs, or construction cost balances;
- Second, the revenues will be applied to any prior period over/under recovery;
- Third, the revenues will be applied to O&M costs;
- Fourth, the revenues will be applied to current period preconstruction investment;
- Fifth, the revenues will be applied to prior period unrecovered preconstruction costs; and
- Sixth, any remaining revenues will be captured as a regulatory liability and applied to future costs, as appropriate, and administratively tracked in Schedule 2.2.

DEF will keep track of any remaining revenues as a regulatory liability and calculate a return on this liability consistent with how returns are calculated for unrecovered investment balance. These remaining revenues will be applied to future period recoverable LNP costs. As DEF looks forward, there are periods of net over and under recovered LNP balances over the settlement period. By applying this methodology, the Company, over time, will lower the rate impact in the year of the true-up under the terms of the Settlement Agreement. Appendix C of Exhibit No.___(TGF-4) provides the breakdown of how the $106.1 million is applied in 2014.

Q. What was the source of the separation factors used in Schedule P-4 and P-6?

A. The jurisdictional separation factors are consistent with Exhibit 1 of the Settlement Agreement approved by the Commission in Order No. PSC-12-0104-FOF-EI in Docket No. 120022-EI.

Q. What is the rate impact to the residential ratepayer in 2014?

A. The LNP residential rate impact is $3.45/1,000kWh pursuant to the terms of the Settlement Agreement. See Settlement Agreement, ¶ 4. This appears in Exhibit No. ___ (TGF-4), Schedule P-8.

Q. Does the LNP residential rate established in the Settlement Agreement affect the LNP Rate Management Plan?

A. Yes. The Settlement Agreement fixes the LNP NCRC rate for the period 2013-2017 and provides for a true-up in the last year. See Settlement Agreement, ¶ 4. Prior to the Settlement Agreement, in Order No. PSC-09-0783-FOF-EI, the Commission approved the deferral of LNP costs, approved a rate management plan for the recovery of the deferred LNP costs, and required DEF to update its rate management plan each year. The agreement to the fixed LNP NCRC rate in the Settlement Agreement necessarily drives the rate management plan updates subsequent to the Settlement Agreement. Last year, in Order No. PSC-12-0650-FOF-EI, the Commission approved amortization of $88 million of the deferred balance in 2013. This year, application of the revenues generated by the fixed LNP NCRC rate to the deferred LNP balance results in the full amortization of the deferred balance and the collection of the remaining $29.2 million in 2014.

Q. Have you provided schedules that show the impact of this proposed amortization as well as an update to the overall plan?

A. Yes. As I explained, Appendix C attached to Exhibit No. ___ (TGF-4) provides an overview of DEF's methodology used to allocate the 2014 revenue requirement resulting from the Settlement and the resulting updated rate management plan.

C. LNP TRUE-UP TO ORIGINAL.

Q. What do the TOR schedules reflect?

A. The TOR Schedules reflect the total estimated costs of the LNP until the project is placed into service. Further details on the total project cost estimate are provided in Mr. Fallon's testimony.

IV. COST RECOVERY FOR THE CRYSTAL RIVER 3 UPRATE PROJECT.

Q. What is the status of the CR3 Uprate project?

A. As discussed more fully in the testimony of Mr. Garry Miller, the CR3 Uprate project was cancelled because the Company decided to retire the CR3 Unit.

Q. What are you requesting with respect to the CR3 Uprate project?

A. DEF requests that the Commission approve recovery of the remaining unrecovered investment in the CR3 Uprate project and the future payment of all outstanding costs and any other reasonable and prudent exit costs consistent with Section 366.93(6), Florida Statues, and Rule 25-6.0423(6), F.A.C. In support of this request, DEF has prepared Exhibit Nos. ____ (TGF-6) and ____ (TGF-7), which show the unrecovered investment and expected future payments and exit costs through the end of 2014 for purposes of setting 2014 rates. DEF is requesting Commission approval of recovery of the remaining balance over a seven (7) year period beginning in 2013 and ending in 2019. DEF requests that the Commission approve the revenue requirements for 2014 to be placed into the CCRC of $68.6 million before revenue tax multiplier as shown on page 3 line 6 of Exhibit No.___(TGF-6).

Q. Is the seven year recovery period appropriate?

A. Yes. This recovery period is dictated by Rule 25-6.0423(6)(a), F.A.C., which provides in relevant part that the utility shall recover its costs through the CCRC "over a period equal to the period during which the costs were incurred or 5 years, whichever is greater." The CR3 Uprate costs were incurred over a period of seven years from November 2006 through January 2013.

Q. How does DEF propose to amortize this investment?

A. DEF is not proposing to change the 2013 rate. DEF proposes to begin amortizing the remaining investment in 2014 and amortize an amount equal to $1/6^{th}$ of the year end 2013 unrecovered investment through 2019. Any true-up can be addressed in the final year of recovery. The annual amortization amount is calculated in Appendix A of Exhibit No.___(TGF-6) lines 16-19.

Q. Will DEF account for salvage or CR3 Uprate asset sales?

A. Yes. To the extent DEF receives any salvage or re-sale value for the CR3 Uprate assets currently recovered through the NCRC, DEF will apply that value to reduce the unrecovered balance. DEF has not estimated the salvage or re-sale value for the CR3 Uprate assets at this time because that value is presently unknown and uncertain.

Q. How is DEF calculating the carrying cost collected over this amortization period?

A. Prior to the decision to retire CR3, DEF is using the same rate and performing the same calculations previously used for new nuclear investment. Support for the components of this rate is shown in Appendix C of Exhibit No.___(TGF-6). Beginning in February of 2013, DEF is using the rate specified in Rule 25-6.0423(6) (b), F.A.C. Support for the components of this rate is shown in Appendix B of Exhibit No.___(TGF-6).

Q. What was the source of the separation factors used in your Exhibits?

A. The jurisdictional separation factors are consistent with Exhibit 1 of the Settlement Agreement approved in Commission Order No. PSC-12-0104-FOF-EI in Docket No. 120022-EI.

Q. What are the total estimated revenue requirements for the CR3 Uprate project for the calendar year ended December 2013?

A. The total estimated revenue requirements for the CR3 Uprate project are $27.6 million for the calendar year ended December 2013, as reflected on page 4 line 29 of Exhibit No.___(TGF-6). This is also reflected in Schedule AE-1, page 2 of 2, Line 6 of Exhibit No.___(TGF-7). This amount includes $27.1 million for the carrying costs on the construction cost balance and

$0.5 million in recoverable O&M costs. These amounts were calculated in accordance with the provisions of Rule 25-6.0423, F.A.C. As discussed above, DEF has not reflected amortization of the unrecovered construction cost investment in 2013.

Q. What is the total estimated over or under recovery for the CR3 Uprate project for the calendar year ended December 2013?

A. The total estimated over recovery is $2.8 million as shown in Exhibit No.___(TGF-7) schedule AE-1 line 8 column (N).

Q. What is the total estimated unrecovered investment in the CR3 Uprate project that will be amortized as of year-end 2013?

A. The total estimated unrecovered investment to be amortized is approximately $265.2 million at the end of 2013 as shown on lines 16-18 in Appendix A of Exhibit No.___(TGF-6). This amount is the construction cost spend that has not been placed in service. This amount does not include prior period over/under recoveries or period costs like O&M.

Q. What are the total estimated revenue requirements for the CR3 Uprate project for the calendar year ended December 2014?

A. As can be seen in Exhibit No. ____ (TGF-6), page 3 line 6, the total estimated revenue requirements are $68.6 million. This consists primarily of $44.2 million associated with amortizing the unrecovered construction cost spend and $24.2 million in period carrying costs.

Q. Does this conclude your testimony?

A. Yes, it does.

IN RE: NUCLEAR COST RECOVERY CLAUSE
BY PROGRESS ENERGY FLORIDA, INC.
FPSC DOCKET NO. 130009-EI
DIRECT TESTIMONY OF JON FRANKE

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Jon Franke. My business address is Crystal River Nuclear Plant, 15760 West Power Line Street, Crystal River, Florida 34428.

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

A. I am employed by Progress Energy Florida, Inc. ("PEF" or the "Company") and serve as Vice President – Crystal River Nuclear Plant.

Q. What are your responsibilities as the Vice President at the Crystal River Nuclear Plant?

A. As Vice President I am responsible for the safe operation of the Crystal River nuclear generating station. The Plant General Manager, Site Support Services and training sections report to me. Additionally, I have indirect responsibilities in oversight of major project and engineering activities at the station.

Q. Did your role or responsibilities change with respect to the CR3 Uprate project as a result of the July 2, 2012 merger between Progress Energy, Inc. and Duke Energy Corporation?

A. No. My role and title remained the same and my responsibilities with respect to the Crystal River Unit 3 Nuclear Power Plant ("CR3") and the Extended Power Uprate ("EPU") project ("CR3 Uprate") did not change as a result of the merger between Progress Energy, Inc. and Duke Energy Corporation ("Duke Energy").

Q. Has the merger impacted the CR3 Uprate project organizational structure?

A. Yes. In the fall of 2012, as a result of the merger integration process, the project management organizational structure for the CR3 Uprate project was adjusted and the Manager, Major Projects – EPU reports to the General Manager, Fleet and Stand Alone Projects, a new position in the combined company. In addition, the CR3 Uprate Engineering Manager was a direct report to the Nuclear Engineering Department and is now a direct report to the Manager, Major Projects – EPU. These changes did not affect my responsibilities. I remain the CR3 Uprate project sponsor.

Q. Please summarize your educational background and work experience.

A. I have a Bachelor's degree in Mechanical Engineering from the United States Naval Academy in Annapolis, MD. I have a graduate degree in the same field from the University of Maryland and Masters of Business Administration from the University of North Carolina at Wilmington.

I have over 20 years of experience in nuclear operations. I received training by the United States Navy as a nuclear officer and oversaw the operation and maintenance of a nuclear aircraft carrier propulsion plant during my service. Following my service in the Navy, I was hired by Carolina Power & Light and was with that company through the formation of Progress Energy and the subsequent merger with Duke Energy. My early assignments involved engineering and operations, including oversight of the daily operation of the Brunswick Nuclear Plant as a U.S. Nuclear Regulatory Commission ("NRC") licensed Senior Reactor Operator. I was the Engineering Manager of that station for three years prior to assignment to Crystal River as the Plant General Manager in 2002. I was promoted to my current position in April 2009.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your direct testimony?

A. My direct testimony supports the Company's request for cost recovery pursuant to the nuclear cost recovery rule for costs incurred in 2012 for the CR3 Uprate project. I will explain that these costs were prudently incurred for the CR3 Uprate project. I will also address PEF's 2012 project management, contracting, and cost oversight policies and procedures for the CR3 Uprate project and explain why they are reasonable and prudent.

On February 5, 2013, Duke Energy announced that the Duke Energy Board of Directors decided to retire and decommission the CR3 nuclear power plant. As a result of this decision, the CR3 Uprate project was cancelled. The prudence of the decision to retire rather than repair CR3 will be addressed in

Phase 2 of Docket No. 100437-EI, accordingly, I will not address the decision to retire CR3 in my testimony. My direct testimony addresses the prudence of the Company's CR3 Uprate project expenditures in 2012, prior to the Duke Energy Board decision to retire CR3, consistent with the provisions of the nuclear cost recovery clause rule. In my May 1, 2013 direct testimony, I will address the cancellation of the CR3 Uprate project as a result of the Board's decision to retire CR3, and the actual and estimated, and projected costs necessary to cancel and wind-down the CR3 Uprate project.

Q. Do you have any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibits to my testimony:

- Exhibit No. ___ (JF-1), Project Management and Fleet Operating Procedures applicable to the CR3 Uprate project revised in 2012; and
- Exhibit No. ___ (JF-2), Project Management and Fleet Operating Procedures applicable to the CR3 Uprate project new in 2012.

In addition, I am sponsoring Schedules T-6A, T-6B, T-7, T-7A and T-7B and Appendix D and co-sponsoring the cost portions of Schedules T-4, T-4A, and T-6 of the Nuclear Filing Requirements ("NFRs") for the 2012 CR3 Uprate project costs, which are included as part of Exhibit No. __(TGF-2) to Thomas G. Foster's testimony. Schedule T-4 reflects Capacity Cost Recovery Clause ("CCRC") recoverable Operations and Maintenance ("O&M") expenditures for the 2012 period. Schedule T-4A reflects CCRC recoverable O&M expenditure variance explanations for the 2012 period. Schedule T-6.3 reflects the construction expenditures for the project by category. Schedule T-6A.3 reflects descriptions of the major cost categories of the expenditures and Schedule T-6B.3 reflect explanations for the significant variances between these expenditures and previously filed estimates for 2012. Schedule T-7 is a list of the contracts executed in excess of $1.0 million for 2012. Schedule T-7A reflects details pertaining to the contracts executed in excess of $1.0 million for 2012. Schedule T-7B reflects contracts executed in excess of $250,000, but less than $1.0 million for 2012.

All of these exhibits, schedules, and appendices are true and accurate.

Q. Please summarize your testimony.

A. In this direct testimony, I am supporting the Company's request for a prudence determination and approval for recovery of the actual costs it incurred in 2012 for the CR3 Uprate project. PEF incurred CR3 Uprate project costs in 2012 in preparation for Phase 3, the EPU phase of the project, consistent with the Company's plan in 2011 and 2012 to repair the CR3 containment building, complete the CR3 Uprate project, and return CR3 to commercial service at the end of the existing CR3 outage. The Company primarily incurred EPU costs in 2012 for (1) EPU long lead equipment ("LLE") milestone payments contractually committed to prior to 2012; (2) licensing and engineering costs associated with responding to Requests for Additional Information ("RAIs") for the NRC's review of the Company's EPU License Amendment Request ("LAR"); and (3) engineering analyses for the engineering change ("EC") packages for the EPU Phase work, with project management costs associated with this work. PEF continued to take appropriate steps to minimize CR3 Uprate project spend in 2012 to ensure that only those costs necessary for completion of the CR3 Uprate project in the current, extended CR3 outage were incurred in 2012, consistent with the project management plan implemented by the Company in 2011 and reviewed by the Commission in the nuclear cost recovery clause docket last year. Accordingly, PEF's 2012 CR3 Uprate project costs are reasonable and prudent and PEF requests that the Commission grant PEF's request for recovery of these costs pursuant to the nuclear cost recovery statute and rule.

III. ACTUAL COSTS INCURRED IN 2012 FOR THE CR3 UPRATE PROJECT.

Q. Can you please explain the status of the CR3 Uprate project in 2012?

A. Yes. PEF continued the CR3 Uprate project in 2012 consistent with the determination PEF made in 2011 that the reasonable course of action was to preserve the option of completing the CR3 Uprate project during the current, extended CR3 outage, if the Company determined to repair CR3 upon completion of the Company's evaluation of the decision to repair or retire CR3. At that time, the Company planned to repair CR3 and complete the CR3 Uprate project. The Company continued required EPU work for this plan in 2012, while deferring EPU work activities and costs that were not necessary in 2012 to successfully complete this plan. As a result, only those activities were performed and those costs incurred in 2012 that were necessary to complete the EPU project during the current, extended CR3 outage in the event the Company decided to repair CR3.

Q. What costs did PEF incur for the CR3 Uprate project in 2012?

A. PEF incurred construction costs for the CR3 Uprate project in 2012. The total capital expenditures for 2012, gross of joint owner billing and exclusive of carrying cost, were $44.3 million. This is $7.2 million less than PEF estimated it would spend in 2012 for the CR3 Uprate project. This reduction in expenditures from what PEF estimated that it was going to spend in 2012 is the result of PEF's efforts to efficiently manage the CR3 Uprate project and to push out milestones to later years as necessary to ensure only those costs were incurred that were necessary to complete the EPU work if PEF decided to repair CR3. These costs were incurred in the categories of: (1) license application, (2) project management, (3) permitting, (4) on-site construction facilities, and (5) power block engineering, procurement and related construction. Schedule T-6 in Exhibit No. ___ (TGF-2) to Mr. Foster's testimony provides further details about these costs.

Q. Please describe the total License Application costs incurred and explain why the Company incurred them.

A. Actual 2012 License Application costs were about $2.9 million. The Company's EPU LAR was submitted to the NRC on June 15, 2011 and the NRC accepted the EPU LAR for review on November 21, 2011. In the NRC's Acceptance Review letter, the NRC indicated it might defer portions of its review of the EPU LAR pending a more final CR3 repair schedule. Later, however, the NRC initiated the Technical Review phase of the LAR process and, in practice, did not defer any portion of the NRC review. As a result, the Company had to incur costs in 2012 for the work required for the NRC Technical Review.

In 2012, the Company prepared and submitted responses to 176 RAIs to support the NRC's Technical Review of the EPU LAR. In 2012, the NRC made substantial progress toward completing its review of the EPU LAR, in fact, many NRC technical branches completed their reviews. The EPU LAR was on target for receipt in time for plant start-up based on the Company's schedule to repair CR3 and complete the EPU work during the current, extended CR3 outage. The License Application work and associated costs were necessary in 2012 for the NRC Technical Review of the EPU LAR and to preserve the option to complete the EPU phase in the current, extended CR3 outage.

Q. Please describe the total Project Management costs incurred and explain why the Company incurred them.

A. Actual CR3 Uprate project management costs in 2012 were approximately $3.3 million. The Company's Project Management costs included the following project management activities for the CR3 Uprate project in 2012:

(1) project administration, including project instructions, staffing, roles and responsibilities, and interface with accounting, finance, and senior management;

(2) contract administration, including status and review of project requisitions, purchase orders, and invoices, contract compliance, and contract expense reviews;

(3) project controls, including schedule maintenance and milestones, cost estimation, tracking and reporting, risk management, and work scope control;

(4) project management, including project plans, project governance and oversight, task plans, task monitoring plans, lessons learned, and task item completions; and

(5) overall management of CR3 Uprate licensing and EPU LAR work.

Each activity was conducted under the Company's project management and cost oversight policies and procedures consistent with industry best practices for a major project like the CR3 Uprate project. The Project Management work and associated costs were necessary for the EPU work and to preserve the option to complete the EPU phase in the current, extended CR3 outage.

Q. Please describe the total Permitting costs incurred and explain why the Company incurred them.

A. The Company incurred $10,709 for permitting costs for the CR3 Uprate project in 2012. These costs were incurred for evaluations by Golder Associates associated with limited permitting activities for the Point of Discharge ("POD") Cooling Tower. The limited permitting work and associated costs were necessary to preserve the option to complete the EPU phase in the current, extended CR3 outage.

Q. Please describe the total On-Site Construction Facilities costs incurred and explain why the Company incurred them.

A. The Company incurred $35,242 for On-Site Construction Facilities costs for the CR3 Uprate project in 2012. These costs were incurred for storage for components and tools. These limited on-site construction facilities costs were necessary for the project and to preserve the option to complete the EPU phase in the current, extended CR3 outage.

Q. Please describe the total costs incurred for the Power Block Engineering, Procurement and related construction cost items and explain why the Company incurred them.

A. The Company incurred approximately $38.1 million for Power Block Engineering, Procurement, and related construction cost items for the CR3 Uprate Project in 2012.

The Company incurred EPU costs for contract milestone payments for fabrication of LLE items that were contractually committed for the project prior to 2012. PEF received and stored several LLE items for the CR3 Uprate project in 2012. Manufacturing of these LLE items was completed in accordance with the terms of material fabrication and procurement contracts entered into prior to 2012. PEF placed the following LLE items in storage at CR3 in preparation for Phase 3 installation: Condensate Pump Motors; High Pressure Turbine Rotor; Low Pressure Turbine Rotors and Casings; In-Core Detector Assemblies; Low Pressure Injection Cross Tie Valves; and Feedwater Valves.

PEF also incurred costs in 2012 for engineering work to support and respond to NRC RAIs for the EPU LAR application and to develop the EC packages for the EPU Phase 3 work. Only engineering work necessary to preserve the option to complete the EPU work during the current, extended CR3 outage was performed in 2012. By May 2012, the EPU phase EC packages were approximately 70 percent complete; EPU phase EC packages are now approximately 75 percent complete. PEF effectively managed the EPU phase engineering work through proper prioritization for completion of vendor contracted ECs and owner review and acceptance of LLE. For example, PEF managed its time and materials engineering scope changes and labor resources to respond to high priority NRC information requests and pushed out less critical path EC work in order to minimize costs without jeopardizing the implementation of the EPU during the extended outage.

PEF appropriately minimized these EPU costs in 2012 where possible. All of the 2012 Power Block Engineering, Procurement, and related construction costs were necessary for the implementation of the CR3 Uprate work in the current, extended CR3 outage, and they were prudently incurred in 2012.

Q. Please describe the total Non-Power Block Engineering, Procurement and related construction costs and explain why the company incurred them.

A. Overall, PEF incurred net expenses of ($48,019) of Non-Power Block Engineering costs related to the EPU POD lay-down yard. There were non-power block engineering costs in 2012 incurred to meet environmental compliance regulations and to maintain the integrity of the stored equipment. Offsetting these costs was an accounting entry to reverse an expense accrual booked in 2011 that was no longer necessary as a result of closing a contract.

Q. How did actual capital expenditures for January 2012 through December 2012 compare to PEF's actual/estimated costs for 2012 for the CR3 Uprate Project?

A. PEF's actual capital expenditures for the CR3 Uprate project in 2012 were lower than PEF's actual/estimated costs for 2012 by $7.2 million. This variance is based on PEF's actual expenditures for 2012 compared to the Actual/Estimated ("AE") Schedules attached to Mr. Foster's April 30, 2012 testimony, which reflected actual/estimated 2012 CR3 Uprate costs, prior to the Commission's approval of the Company's Motion to defer Commission review of the 2012 CR3 Uprate construction expenditures and associated carrying costs to this docket. As a result of the Commission's decision to grant that Motion, I understand Mr. Foster filed revised NFR AE schedules with the Commission to reflect that deferral.

This variance is the result of the Company's efficient project management of the CR3 Uprate project work to ensure that the only costs incurred were necessary to complete the project during the current, extended CR3 outage if the Company decided to repair CR3. I will explain the reasons for the major (more than $1.0 million) variances below:

Power Block Engineering, Procurement and related construction costs:

Power Block Engineering, Procurement and related construction cost capital expenditures booked on Schedule T-6.3 were $38.1 million for 2012. The estimate for these costs in 2012 was $45.4 million, resulting in a favorable variance of ($7.3 million). The majority of the variance is attributed to deferral of contract payments, control and reduction of engineering work scope, and lower warehouse inventory expenses than projected as a result of deferring EPU work and costs beyond 2012.

This variance, again, demonstrates the results of the Company's efforts to minimize CR3 Uprate project costs in 2012 while still preserving the Company's ability to complete the project in the current, extended CR3 outage if the Company decided to repair CR3.

Q. Were there any other major variances in 2012 for license application, project management, permitting or on-site construction facility costs?

A. No. As described on Schedule T-6B.3, the variances for these categories were all minor variances.

Q. Did PEF incur O&M costs in 2012 for the CR3 Uprate project?

A. Yes. PEF incurred necessary O&M costs to support the CR3 Uprate project work in 2012. These O&M costs are identified and included in Schedule T-4 in Exhibit No. ___ (TGF-2) to Mr. Foster's testimony.

Q. How did actual O&M expenditures for January 2012 through December 2012 compare with PEF's actual/estimated O&M expenditures for 2011?

A. Schedule T-4A, Line 15, on Exhibit No. ___ (TGF-2) to Mr. Foster's testimony shows that total O&M costs were $0.5 million or $65,356 more than estimated. Schedule T-4A shows the minor variances for the O&M costs categories. There were no major (more than $1 .0 million) O&M cost variances to report in 2012.

Q. Were PEF's 2012 CR3 Uprate project costs reasonably and prudently incurred?

A. Yes, they were. PEF incurred only those CR3 Uprate project costs in 2012 necessary to preserve the option to complete the EPU phase during the current, extended CR3 outage, if the Company decided to repair CR3. PEF implemented a project management plan to minimize project costs until the Company made the decision to repair or retire CR3. PEF diligently worked to minimize project costs consistent with that plan throughout 2012. As a result, in 2012 PEF was in position to proceed with the CR3 Uprate project work to implement the EPU phase during the current, extended CR3 outage if the Company decided to repair CR3, but the Company had not unnecessarily incurred costs to move forward with the project. All of PEF's 2012 CR3 Uprate project costs were reasonably and prudently incurred.

Q. Can you please explain how PEF minimized CR3 Uprate project costs in 2012?

A. Yes, I can. In 2012, PEF was proceeding with a CR3 Uprate project plan and schedule to complete the EPU work during the current, extended CR3 outage. PEF understood that completion of this work in accordance with this schedule depended on the Company deciding to repair CR3 after evaluating the decision to repair or retire CR3. As a result, the CR3 Uprate project plan in 2012 was designed to minimize project costs in 2012 while preserving the Company's ability to complete the EPU phase during the current, extended CR3 outage if the Company decided to repair CR3.

As part of the CR3 Uprate project plan in 2012, PEF evaluated the EPU phase work to identify what work was critical to proceed with to maintain a schedule to complete the EPU phase work during the current CR3 outage and what work was not on this critical path. Based on this evaluation, PEF slowed down and postponed work on the EPU phase in 2012 to minimize the CR3 Uprate project costs while preserving the Company's ability to complete the EPU work during the current CR3 outage and implement the power uprate. No EPU phase work was accelerated and mainly regular work hours were permitted on EPU work that PEF had determined needed to be done to maintain this CR3 Uprate project schedule.

PEF delayed the selection of a construction contractor for the EPU phase work from 2012 to the 2013 time frame. PEF individually evaluated each contract and change order for the EPU phase work before execution. For contracts or change orders below $100,000, the EPU phase project manager performed this evaluation; for contracts or change orders at or above $100,000, the project manager conducted this evaluation and made recommendations with respect to execution of the contract or change order that were reviewed by the manager of nuclear projects and senior management. No contract or change order at or above $100,000 for the EPU phase work was executed without senior management approval. That approval was not granted unless there was a demonstration that the work under the contract or change order was reasonable and necessary to preserve the Company's ability to complete the EPU work on the current CR3 Uprate project schedule.

This type of evaluation was conducted for each item of work for the EPU phase of the CR3 Uprate project. PEF, accordingly, continued payments on the critical path LLE items to implement the EPU phase in the current extended CR3 R16 re-fueling outage. LLE progress payments in 2012 reflect pre-existing contractual commitments. Deferral of these payments was not a viable option in 2012 without cancellation or suspension of contracts, which would result in penalties and an uncertain future regarding LLE contract renewals to meet the EPU phase work schedule if the decision was made to repair CR3. Accordingly, only those LLE contractual payments necessary for the EPU phase work for the project were incurred in 2012.

Q. During 2012, were other steps taken by the Company to minimize EPU phase work costs?

A. Yes. As 2012 progressed, PEF took several additional steps to ensure that only costs necessary to maintain the option of implementing the final phase of EPU during the extended CR3 outage were incurred. First, on a staffing level, the EPU staffing plan was limited to filling open positions only, and no additional staffing occurred for the project in 2012. In fact, during 2012, the Company reduced Project Support staffing for the CR3 Uprate project. Engineering resources also were reduced in 2012 as development of the EPU EC packages reached 75 percent complete. The Company also continued its practice of sending EPU personnel to provide additional outage support at other plants across the fleet to reduce staffing for the EPU phase work. In this way, the Company ensured the minimal workforce needs for the CR3 Uprate project in 2012.

PEF rigorously reviewed CR3 Uprate costs in 2012 to ensure that only those costs necessary for completion of the EPU work in the extended outage were incurred until a final decision to repair or retire CR3 was made. PEF acted reasonably and prudently in managing the CR3 Uprate project in 2012 to achieve this result. The costs the Company did incur in 2012 for the CR3 Uprate project, therefore, were reasonably and prudently incurred.

Q. **Have the Company's efforts to minimize the CR3 uprate costs in 2012 actually resulted in the avoidance or deferral of costs to a later time period?**

A. Yes. As I explained above, PEF's actual capital expenditures for the CR3 Uprate project in 2012 were lower than PEF's actual/estimated costs for 2012 by $7.2 million. This is the result of the Company's decision to postpone construction work for the CR3 Uprate project and to minimize staffing and other CR3 Uprate project costs, as I have described above, until management's final decision on whether to repair or retire CR3.

Q. Was the Company's decision in 2012 to continue with the CR3 Uprate project reasonable and prudent?

A. Yes. The Company had not yet completed the extensive analysis of the CR3 containment building repair decision necessary to decide to repair or retire CR3. That analysis was on-going in 2012, and it depended on continued technical design, engineering, and construction work to determine the scope of the repair work, the technical, engineering, construction, and licensing costs and risks, and the schedule for the repair, together with an economic evaluation of repairing or retiring CR3. During this period, the only options available to the Company for the CR3 Uprate project were cancelling the project, accelerating the project, or preserving the ability to complete the project during the current, extended CR3 outage if the decision was made to repair CR3. The Company reasonably and prudently chose to continue the CR3 Uprate project to preserve the ability to complete the EPU phase work if CR3 was repaired while minimizing the project costs until the decision to repair or retire CR3 was made.

IV. ALL COSTS INCLUDED FOR THE CR3 UPRATE ARE "SEPARATE AND APART FROM" THOSE COSTS NECESSARY TO RELIABLY OPERATE CR3 DURING ITS REMAINING LIFE.

Q. Are the CR3 Uprate project costs included in this NCRC docket for recovery separate and apart from those that the Company would have incurred to operate CR3 during the extended life of the plant?

A. Yes, PEF has only included for recovery in this proceeding those costs that were incurred solely for the CR3 Uprate project. In other words, the Company only included project costs that would not have been incurred but for the CR3 Uprate project.

V. PROJECT MANAGEMENT, CONTRACTING, AND COST OVERSIGHT.

Q. Were the CR3 Uprate Project Management, Contracting and Cost Control Oversight policies and procedures in 2012 substantially the same as the policies and procedures used prior to 2012?

A. Yes. The Company used substantially the same project management, contracting, and cost control oversight policies and procedures in 2012 that the Company used in prior years for the CR3 Uprate project. In fact, for the first six months of 2012, the EPU project management, contracting, and cost control oversight policies and procedures were exactly the same as the policies and procedures in effect in prior years for the project. On July 2, 2012, the merger between Progress Energy and Duke Energy was completed and the process to integrate the two companies commenced. This integration process is on-going, as the policies and procedures are fully integrated, and best practices employed in the new, combined company. In the meantime, the majority of the every-day project management and fleet policies and procedures have not changed substantially. The EPU project management team has remained the same as well. Some of the policy and procedure revisions incorporate Duke Energy governance practices or fleet best practices and lessons learned based on the integration process to date. Other policies and procedures were revised to reflect Duke Energy titles and organization structure. Exhibit No. ___(JF-1) to my direct testimony contains a list of the Project Management policies and procedures, as well as relevant Fleet and Plant operating procedures, that were revised during 2012 and the reason for the revision.

Through the merger integration process, some new project management, contracting, and cost control oversight policies and procedures were added in 2012 that apply to the CR3 Uprate project. Exhibit No. ___ (JF-2) to my direct testimony contains Project Management policies and procedures as well as relevant Fleet and Plant operating procedures that were newly created or new to and applicable to the CR3 Uprate project in 2012. These policies such as the Fleet Operating Model (PY-AD-ALL-0001), Fleet Standard Workday (AD-AD-ALL-0004), and Conduct of Nuclear Oversight (AD-NO-ALL-1000) procedures were made applicable to the CR3 Uprate project as a result of the merger. The Company is also in the process of transitioning to Duke Energy's project approval process. Duke Energy's Approval of Business Transactions policy ("ABT") and Project Funding Approval (BM-100) and Project Evaluation and Business Case Development (BM-500) superseded the Progress Energy Integrated Project Plan ("IPP") procedures. These procedures reflect what the integrated Company's approval process will be for the fleet on a going forward basis but did not impact the CR3 Uprate project in 2012.

Despite these minor revisions or new policies and procedures, for 2012 the Company's CR3 Uprate project management, contracting, and cost oversight control policies and procedures were essentially the same as the prior year CR3 Uprate project policies and procedures reviewed and approved as reasonable and prudent by this Commission. *See* Order No. PSC-09-0783-FOF-EI, issued Nov.

19, 2009; Order No. PSC-11-0547-FOF-EI, issued Nov. 23, 2011; and Order No. PSC-12-0650-FOF-EI, issued Dec. 11, 2012.

Q. Can you please provide an overview of the Company's CR3 Uprate project management and cost control oversight policies and procedures in 2012?

A. Yes. The Company uses several specific project management and cost oversight Nuclear Generation Group ("NGG") and Corporate procedures, as I describe in exhibit No. __(JF-1) to my direct testimony. In addition, other corporate tools are used to support the management of and cost control oversight for the CR3 Uprate. The Oracle Financial Systems and Business Objects reporting tools provide monthly corporate budget comparisons to actual cost information, as well as detailed transaction information. Key Performance Indicators ("KPIs") to monitor the status of the CR3 Uprate project are reviewed by the project team on a regular basis. Other examples include, EPU Level II Schedules and Action Items; EPU Look-Ahead Schedule; and Monthly Variance Reports. These tools were all used to prudently manage the CR3 Uprate project costs in 2012.

Q. How does the Company manage and control project costs for the CR3 Uprate project?

A. The Company has many control mechanisms in place to manage CR3 Uprate project costs. For example, the CR3 Uprate project management team conducts regular internal meetings to monitor the project schedule and its costs. The collective knowledge and experience of the project management team is used to address work scope, costs, and schedule performance through a continuous review of the project, including team roles and responsibilities, by creating and implementing lessons learned on an on-going basis, and through regular project management training. Project management regularly addresses equipment and material procurements under contracts, purchase orders, and invoices, and constantly monitors contracts with outside vendors. This includes regular meetings with outside vendors to discuss work scope and implementation, schedule, and costs.

Q. Does the Company verify that the project management and cost control policies and procedures are followed?

A. Yes, it does. PEF uses internal audits to verify that its program management and cost oversight controls are being implemented and are effective in practice. Quality Assurance ("QA") reviews and audits of external vendors are also conducted.

On December 6, 2012, the Audit Services Department issued the "Crystal River 3 (CR3) Financial Regulatory Compliance" audit. This audit included an examination of 2011 and 2012 capital and O&M charges related to CR3 for compliance with the 2012 Stipulation and Settlement Agreement. Other considerations included the NCRC and EPU filings. No specific audit observations or recommendations were identified.

On November 9, 2012, the internal audit department issued the "Crystal River 3 (CR3) Restart Program Management" audit. This audit included a follow up of the 2011 audit of the CR3 Program Management. The audit also included an assessment of the effectiveness of the oversight, governance, and site

Operational Readiness initiatives supporting the planned restart of CR3. Two moderate priority observations were identified that referenced the EPU including follow-up on enhancements recommended in a 2011 audit and 16R start-up plan effectiveness. All of the management action plans in response to these observations are complete or scheduled to be completed.

Several contractor and quality assurance evaluations were also performed in 2012 including audits and surveillance follow-up of Siemens for the Low Pressure Turbines; Flowserve for the Condensate Pump; Sulzer for the Feedwater Booster Pump; and SPX for the Feedwater Heaters 3A and 3B. The audits were generally satisfactory. Several open issues were identified; however, they were either corrected during the surveillance or are being corrected and will be confirmed closed in the surveillance process. None of these issues identified had any impact on 2012 CR3 Uprate costs.

In addition, Nuclear Procurement Issues Committee ("NUPIC") joint external audits were performed on two PEF suppliers in 2012. Scientech/Curtis Wright Flow Control Audit #23239 was performed March 12-16, 2012, which identified nine findings related to the vendor's quality program. The NUPIC audit team, lead by utility Xcel Energy, concluded that with the exception of the nine findings Scientech was adequately implementing their overall QA program and that the findings did not have a significant adverse affect on products or services provided to the nuclear utilities. As of July, 2012, a NUPIC surveillance team confirmed that the stated corrective actions had been implemented and the Findings and Audit were closed. Secondly, AREVA Audit #23171 was conducted from September 17-28, 2012, with lead utility Nebraska Public Power

District. This audit identified five findings to which AREVA responded and only two remain to be completed in 2013 related to necessary revisions to AREVA's QA manual and the creation of condition reports for any nonconformance identified. None of these issues had any impact on CR3 Uprate 2012 costs.

Q. Are the Company's project management and cost control policies and procedures on the CR3 Uprate project reasonable and prudent?

A. Yes, they are. These project management policies and procedures reflect the collective experience and knowledge of the Company and now the combined company, Duke Energy, and the companies have independently or collectively vetted, enhanced, and revised them, as necessary, to reflect industry leading best project management and cost oversight policies, practices, and procedures in 2012. These collective policies and procedures are essentially the same policies and procedures that have been vetted in an annual project management audit in this docket and have been repeatedly approved as prudent by the Commission. We believe, therefore, that the CR3 Uprate project management, contracting, and cost control oversight policies and procedures are consistent with best practices for capital project management in the industry and continue to be reasonable and prudent.

Q. Does this conclude your testimony?

A. Yes, it does.

IN RE: NUCLEAR COST RECOVERY CLAUSE

BY DUKE ENERGY FLORIDA, INC.

FPSC DOCKET NO. 130009-EI

DIRECT TESTIMONY OF GARRY MILLER

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Garry Miller. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Corporation ("Duke Energy") in the Nuclear Engineering Group and I am the Senior Vice President – Nuclear Engineering.

Q. What are your job responsibilities?

A. As Senior Vice President – Nuclear Engineering, I am responsible for all corporate engineering, design engineering, engineering technical programs, and nuclear fuels functions in Duke Energy's nuclear generation fleet. This includes engineering at the Crystal River Unit Number 3 ("CR3") nuclear power plant located at the Duke Energy, Florida, Inc. ("DEF" or the "Company"), Crystal River power plant site in

Florida. The CR3 extended power uprate ("EPU") project at CR3 ("CR3 Uprate") included engineering work under my overall executive oversight.

Q. What do your job responsibilities have to do with the EPU project at CR3?

A. As the Senior Vice President – Nuclear Engineering, I am a member of the senior management executive review board responsible for all nuclear operations within Duke Energy. As a result, I have executive-level oversight for the CR3 decommissioning plan and activities following the decision to retire CR3. Part of the CR3 decommissioning activities involves the wind down or close out of existing construction and engineering projects at CR3. This includes the CR3 EPU project. The CR3 EPU project was cancelled when the Company decided to retire CR3 and, as a result, the EPU project will be closed out. CR3 activities will be reviewed by the senior management executive review board.

Also, in my prior role as Vice President – Nuclear Engineering --- I had management oversight responsibility for the engineering work for the EPU project at CR3. This includes the engineering work for the EPU project during the majority of 2012. This work was described in the testimony of Jon Franke filed in March in this docket. Mr. Franke decided to take an executive opportunity at a nuclear power plant with another utility company and has left the Company. As a result, I am adopting Mr. Franke's testimony and exhibits and I will support the Company's request that the Florida Public Service Commission ("FPSC" or the "Commission") determine that its EPU project costs in 2012 were prudently incurred in the 2013 Nuclear Cost Recovery Clause ("NCRC") proceeding.

Q. Please summarize your educational background and work experience.

A. I have a Bachelor of Science degree in Nuclear Engineering from the North Carolina State University. I also have a Masters degree in Mechanical Engineering from North Carolina State University.

I have over 30 years of experience in the nuclear industry. My experience involves engineering and maintenance experience at all of Duke Energy's nuclear plants and the corporate office for nuclear operations. I have held Engineering Manager positions at the Brunswick Nuclear Plant and Robinson Nuclear Plant. I was also the Chief Engineer for the Nuclear Generation Group ("NGG") for Progress Energy. Additionally, I was the Maintenance Manager at Progress Energy's Harris Nuclear Plant. I also hold a BWR/SRO (senior reactor operator) certification. Prior to the merger, I was the Vice President of Nuclear Engineering for Progress Energy. I assumed my current position with Duke Energy following the merger between Duke Energy and Progress Energy.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your direct testimony?

A. My direct testimony will explain that, as a result of the February 5, 2013 Duke Energy Board of Directors decision to retire the CR3 nuclear plant, the CR3 Uprate project is no longer needed and was cancelled. My testimony will further describe how the CR3 Uprate project was demobilized and will be closed-out. Finally, my testimony will support the reasonableness and prudence of DEF's 2013 actual/estimated and 2014 projected costs associated with the cancellation and close-out of the EPU project, pursuant to Section 366.93, Florida Statutes, and Rule 25-6.0423, Florida Administrative Code ("F.A.C.").

Q. Do you have any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibits to my testimony:

- Exhibit No. ___ (GM-1), the Company's February 7, 2013 EPU License Amendment Request ("LAR") application withdrawal letter to the Nuclear Regulatory Commission ("NRC");
- Exhibit No. ___ (GM-2), the Company's notification letters to EPU project vendors with open contracts and purchase orders to suspend all EPU project work activities;
- Exhibit No. ___ (GM-3), the EPU Project Close-Out Plan.

I am also co-sponsoring portions of Schedules AE-6.3 and sponsoring Schedules AE-6A.3 through AE-7B of the Nuclear Filing Requirements

("NFRs"), included as part of Exhibit No. __ (TGF-7) to Mr. Thomas G. Foster's testimony. The NFR Schedules, Schedules "P" and "TOR" previously filed by the Company, are unnecessary because the EPU project has been cancelled. In their place, I am co-sponsoring the capital spend on Line 1 (a-f) on both the 2013 & 2014 Detail - Calculation of Revenues Requirements schedule included in Exhibit No. ___ (TGF-6) to Mr. Foster's testimony. A brief description of the other Schedules that I sponsor or co-sponsor follows:

- Schedule AE-6 reflects actual/estimated monthly expenditures for preconstruction and construction costs for the period.
- Schedule AE-6A reflects descriptions of the major tasks.
- Schedule AE-6B reflects annual variance explanations.
- Schedule AE-7 reflects contracts executed in excess of $1.0 million.
- Schedule AE-7A reflects details pertaining to the contracts executed in excess of $1.0 million.
- Schedule AE-7B reflects contracts executed in excess of $250,000, yet less than $1.0 million.

These exhibits, schedules, and appendices were prepared under my direction and control, or they are documents routinely relied upon by me and others in the Company in the usual course of our business as a regular practice for our Company, based on the most current information available to the Company at the time the exhibits were prepared, and they are true and correct.

Q. Please summarize your testimony.

A. As a result of the Duke Energy Board of Directors decision to retire CR3, the EPU project was not needed and was accordingly cancelled. DEF immediately notified the NRC of the retirement decision and withdrew the Company's EPU LAR application. DEF immediately suspended all contractor and purchase order work activities on the EPU project. DEF demobilized the EPU project team and released or reassigned project personnel. DEF developed and is implementing an EPU Project Close-Out Plan. Pursuant to this plan, DEF is conducting an analysis to determine the cost effective and beneficial disposition decision for each EPU contract and purchase order pending at the time the CR3 retirement decision was made and for each item of installed or stored EPU equipment received at that time. Only those project close-out and contractual exit costs necessary to efficiently close-out the EPU project will be incurred. For these reasons, the Company requests that the Commission determine that its 2013 actual/estimated and 2014 projected costs are reasonable and that DEF is entitled to recover CR3 EPU project close-out and exit costs.

III. CR3 RETIREMENT AND CANCELLATION OF THE EPU PROJECT.

Q. When did the Company decide to retire CR3?

A. The Board of Directors decision to retire CR3 was announced February 5, 2013. The prudence of this decision will be addressed in Docket No. 100437-EI.

Q. What effect did the decision to retire CR3 have on the EPU project?

A. Once the decision was made to retire CR3 the CR3 Uprate project was no longer needed and was accordingly cancelled. The decision to cancel the EPU project was made the same day the decision to retire CR3 was announced.

IV. CLOSE-OUT OF THE EPU PROJECT.

Q. What did the Company do to cancel the EPU project?

A. When the Company decided to retire CR3, the Company then decided to cancel the EPU project. The same day the Company verbally notified the NRC that the Company had decided to retire CR3 and cancel the EPU project. The Company further explained this decision cancelled the NRC EPU LAR review. Thereafter, on February 7, 2013, DEF formally notified the NRC in writing that the Company was cancelling the EPU project and withdrawing its EPU LAR application as a result of the decision to retire CR3. See the Company's EPU LAR Withdrawal Letter to the NRC attached as Exhibit No. __(GM-1) to my direct testimony. The NRC confirmed that the EPU LAR review was cancelled and stopped all work on the EPU LAR effective February 5, 2013. There are no new NRC charges for the NRC review of the EPU LAR after February 5, 2013.

The Company also notified the Florida Department of Environmental Protection ("FDEP") that the Company had decided to retire CR3 and cancel the EPU project. The Company and the FDEP have ceased EPU project permitting activities. The discharge canal cooling tower Point of Discharge ("POD") project that was part of the EPU project was also cancelled when the EPU project was cancelled.

When the Company cancelled the EPU project the Company also sent a formal notification to all vendors with open contracts and purchase orders for the EPU project to suspend all EPU project work activities immediately. A similar suspension notice letter was sent to AREVA to suspend all engineering work in support of the Company's pending EPU LAR application and the EPU project effective immediately. Copies of these letters are included as Exhibit No. ___ (GM-2) to my direct testimony. EPU project work was suspended until an EPU Close-Out Plan was developed for the EPU project to plan the disposition of EPU contracts, purchase orders, and equipment.

Finally, when the Company decided to cancel the EPU project, the Company demobilized the EPU project team. All EPU project engineering contractors, except for personnel required to maintain existing EPU equipment, were released. All EPU project management and operations support staff were released except for three EPU project team members. By the end of February 2013, the remaining EPU project team members included the EPU manager, the EPU project manager, and the EPU project specialist. These EPU project personnel are necessary to perform the EPU project close-out work under the EPU Close-Out Plan and are expected to remain on the project through the close-out.

Q. What is the EPU Close-Out Plan?

A. The EPU Close-Out Plan is the project plan to wind down and close out project contracts and other project documents, to address the disposition of EPU equipment and material, and to close out project regulatory activities. The EPU Close-Out Plan addresses: (1) EPU project contracts and purchase orders; (2) EPU equipment maintenance and disposition; (3) EPU documentation close-out; (4) EPU financial impact and close-out; and (5) EPU project regulatory activities close-out. The EPU Close-Out Plan is attached as Exhibit No. __(GM-3) to my direct testimony.

Q. Can you describe the process to close-out contracts and purchase orders for the EPU equipment?

A. Yes. As I explained above, when the Company decided to retire CR3 and cancel the EPU project all EPU project vendors with open contracts and purchase orders for EPU equipment were notified to immediately suspend all EPU work activities. Under the EPU Project Close-Out Plan, each vendor will be contacted individually to discuss the possible completion of the contract or purchase order work, if that is the economically beneficial decision, or termination of the contract or purchase order. To make this decision the Company will assess the contract and purchase order status by determining the percent complete of equipment fabrication, any partial deliverables already provided, the feasibility of accepting shipment if delivery is imminent, and the percentage of full price payment left under the contract or purchase order. In the event of contract or purchase order termination, the Company will also consider the benefits from either (1) refusing delivery of and abandoning the incomplete EPU equipment or (2) selling the incomplete EPU equipment through the vendor. Based on this assessment, the Company will determine if contract or purchase order termination or completion of the work under the contract or purchase order is the economically beneficial decision.

Q. What does the Company plan to do with EPU equipment it already has received or will receive if the Company decides to complete the contract or purchase order for the equipment?

A. EPU equipment installed in the plant will be properly maintained. Any decision to complete a contract or purchase order for EPU equipment will include a determination that the EPU equipment can be efficiently maintained by the vendor or contractor or on site until it is sold. The EPU contract or purchase order Designated Representative ("DR") will oversee this decision and the Component Engineering and Project Specialist will be responsible for maintaining the EPU equipment until final disposition of the equipment.

Q. What happens to existing EPU Work Orders and Engineering Changes in the EPU Project Close-Out Plan?

A. There is no further work under the EPU project work orders or Engineering Changes ("ECs") for the project under the EPU Project Close-Out Plan. No EPU EC work order tasks are to remain open, however, they will be maintained on the system to ensure that there is documentation for them until the documentation is transitioned from the EPU project to the project to decommission CR3. The process to decommission CR3 will be described in the Decommissioning Program Manual that is being developed for CR3.

Q. Does the EPU project budget for 2013 reflect the decision to cancel the EPU project and implement the EPU Project Close-Out Plan?

A. Yes. The revised EPU project budget includes estimates for EPU project close-out activities and estimated EPU contract cancellation or wind down costs. The Company's actual/estimated 2013 EPU project costs reflect this revised EPU budget for 2013. This EPU project 2013 financial budget does not include any future credit from the sale or disposition of EPU assets because the disposition decisions were not made at the time the budget was prepared and, therefore, estimated disposition proceeds were unavailable and uncertain. As each EPU contract and purchase order disposition decision is made, the Company will revise the EPU project budget to reflect the final decision. Any appropriate credits upon disposition of EPU assets will be trued-up in the NCRC docket, as explained in Mr. Foster's testimony, as part of the regulatory close-out process under the EPU Project Close-Out Plan. An Investment Recovery Team, which will be part of the CR3 Decommissioning organization, will be formed to assist with the possible sale or disposition of EPU assets.

V. CR3 UPRATE ACTUAL/ESTIMATED 2013 AND PROJECTED 2014 COSTS.

Q. What are the actual/estimated costs for the EPU project in 2013?

A. DEF incurred $1.5 million in actual construction costs for the EPU project from January 1, 2013 through February 4, 2013. From February 5, 2013 to December 31, 2013 DEF estimates that it will incur an additional $12.6 million for EPU project close-out activities. As indicated on Schedule AE-6.3 of Mr. Foster's Exhibit No. __ (TGF-7) the total 2013 actual/estimated costs are about $14.1 million.

A breakout of these costs by category is as follows: (1) License Application costs estimated at $539,026; (2) Power Block Engineering, Procurement, and related construction costs estimated at $13.1 million; (3) Non-Power Block Engineering, Procurement and related construction costs estimated to be $37,756; and (4) Project Management costs estimated at $434,628.

Q. What costs are projected to be incurred for EPU project close-out activities in 2014?

A. As shown in Mr. Foster's schedule in Exhibit No. __ (TGF-6), the 2014 projected EPU close-out costs are estimated at $244,080.

Q. Please explain the License Application costs incurred for the CR3 Uprate project in 2013.

A. Prior to the decision to retire CR3 and cancel the EPU project, the Company reasonably incurred License Application costs for 2013 that reflect the cost of the work necessary to obtain NRC approval of the EPU LAR. More specifically, these costs reflect the fees due to the NRC for its review of the EPU LAR in 2013. As I explained above, DEF immediately notified the NRC of its decision to retire CR3, cancel the EPU project, and withdraw the EPU LAR application. Upon receipt of that notification, the NRC confirmed that it stopped its EPU LAR review. The 2013 actual/estimated costs in Schedules TGF-6 and TGF-7 reflect only the NRC fees in 2013 for EPU LAR review work performed prior to February 5, 2013. These are actual NRC fees for NRC EPU LAR review work and, therefore, they are reasonable.

Q. Please describe the Power Block Engineering, Procurement and related construction costs for the CR3 Uprate project in 2013 and 2014.

A. Power Block Engineering, Procurement, and related construction costs in the amount of $987,107 were incurred prior to February 5, 2013, for the CR3 Uprate project for continued engineering design work for implementation of the EC packages for the EPU phase work and continued progress payments based on pre-existing contractual commitments for the long lead equipment ("LLE") necessary for the EPU phase of the CR3 Uprate project based on the then current implementation schedule. Following the decision to retire CR3 and the cancellation of the CR3 Uprate project, the remaining $12.1 million in 2013 actual/estimated costs is for EPU project close-out activities identified in the EPU Project Close-Out Plan attached as Exhibit No. ___ (GM-3) to my testimony. More specifically, DEF estimates that it will incur approximately $7.6 million for LLE contract close-out in 2013; however, this is not taking into account any potential resale or salvage value of LLE items, which cannot be accurately estimated at this time.

In 2014, the projected $244,080 costs are for EPU LLE equipment maintenance and storage necessary to preserve the equipment that is intended for resale until all equipment is dispositioned.

Q. Are the Power Block Engineering, Procurement and related construction costs and activities described above for 2013 and 2014 reasonable?

A. Yes. DEF immediately notified vendors to suspend work and is working diligently to obtain the cost-effective, negotiated result with each vendor for DEF and its customers. DEF is now reasonably gathering information from its vendors and is conducting an analysis to determine the cost effective and beneficial disposition decision for each EPU contract and purchase order, taking into account potential resale value and maintenance and storage costs, which will provide the basis for disposition decisions for each EPU contract, purchase order, and EPU equipment item in the best interest of the Company and its customers.

Q. Please describe the Non-Power Block Engineering, Procurement and related construction cost activities for the CR3 Uprate project in 2013.

A. Estimated Non-Power Block engineering, procurement and related costs are $37,756. Limited permitting activities continued in 2013 for the POD cooling tower prior to the CR3 retirement decision. Following the CR3 retirement decision, these activities were fully suspended and the POD project was cancelled because it was no longer needed. The FDEP has been notified of the cancellation. Any LLE associated with the POD project will be dispositioned utilizing the same procedures described above to disposition the EPU equipment.

Q. Can you explain the Project Management work in 2013 for the CR3 Uprate project?

A. Yes. DEF continued to incur costs to manage the CR3 Uprate project through February 5, 2013, the date that the CR3 retirement decision was announced. Additional project management costs were incurred following the CR3 retirement decision for DEF to implement its EPU project demobilization and EPU Project Close-Out Plan for a total of $434,628 in 2013. DEF's project management costs include the activities conducted pursuant to our project management and cost control oversight policies and procedures necessary to support, supervise, and manage, and now close-out, the EPU phase of the CR3 Uprate project.

Q. Are the actual/estimated 2013 and projected 2014 costs for the CR3 Uprate project separate and apart from costs that the Company would have incurred to operate CR3 or to decommission the plant?

A. Yes, they are. DEF included for recovery in this proceeding only those costs that were incurred or that will be incurred solely for the EPU project or for EPU close-out activities under the EPU Project Close-Out Plan. No costs are included in this request for decommissioning the plant.

VI. RULE 25-6.0423(5)(c)5, F.A.C.: LONG-TERM FEASIBILITY OF COMPLETING THE CR3 UPRATE PROJECT.

Q. Is the Company filing a feasibility analysis this year?

A. No, we are not. The Company decided to retire CR3 and decommission the plant, as a result, the EPU project is no longer needed and was cancelled. Therefore, no forward looking feasibility analysis is required.

VII. PROJECT MANAGEMENT AND COST CONTROL OVERSIGHT.

Q. Did the Company utilize prudent project management and cost oversight controls when implementing the close-out of the EPU project?

A. Yes it did. The Company developed its close-out plan utilizing the project management policies and procedures that have been reviewed and approved as prudent by this Commission in prior year's dockets and that were described in Mr. Jon Franke's testimony filed on March 1, 2013, which, as I explained above, I will be adopting in this proceeding.

Q. Please explain the project management and cost control oversight processes used for the EPU Close-Out.

A. As an initial matter, the EPU Close-Out Plan was developed as a guide for project personnel as the EPU was demobilized and closed-out. Each close-out decision is and will be documented utilizing the Company's existing Integrated Change Form ("ICF") documentation and approval process that is part of the CR3 Uprate project management and cost control policies and procedures previously reviewed and approved as prudent by the Commission. The EPU Close-Out Plan outlines the process for the transition of the EPU work orders and ECs to the CR3 Decommissioning organization consistent with the guidance contained in procedure EGR-NGGC-0005. DEF is also utilizing Nuclear Generation Group standard procedure MCP-NGGC-0001, *Contract Initiation, Development and Administration,* for EPU vendor contractor close-out and oversight guidance. These procedures are also part of the project management and cost control procedures previously reviewed and determined to be prudent by the Commission.

VIII. CONCLUSION.

Q. Was the cancellation of the EPU project reasonable and prudent?

A. Yes it was. As a result of the decision to retire CR3, the CR3 Uprate project was no longer needed and was immediately cancelled. Based on the circumstances, this was the only decision the Company could have made regarding this project.

Q. Are DEF's CR3 Uprate project close-out costs in 2013 and 2014 reasonable?

A. Yes they are. The Company immediately suspended any additional licensing, contract, and purchase order work, demobilized the EPU project team except for management necessary to wind down the project, and developed and implemented the EPU Project Close-Out Plan. DEF is currently working through its Supply Chain, Investment Recovery, and CR3 Decommissioning organizations to ensure that the close-out of the EPU contracts and purchase orders and disposition of EPU LLE is cost effective for both the Company and its customers. Any proceeds from the resale of EPU equipment will be credited to customers. As a result, the Company has minimized EPU project costs in 2013 and 2014. Only those costs that were reasonable and prudent project exit or wind-down costs were incurred. For these reasons, as more fully explained above, these costs are reasonable and should be approved for recovery.

Q. Does this conclude your testimony?

A. Yes, it does.

IN RE: NUCLEAR COST RECOVERY CLAUSE

BY PROGRESS ENERGY FLORIDA, INC.

FPSC DOCKET NO. 130009-EI

DIRECT TESTIMONY OF CHRISTOPHER M. FALLON

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Christopher M. Fallon. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy, Corporation ("Duke Energy") as Vice President of Nuclear Development. Progress Energy Florida, Inc. ("PEF" or the "Company") is a fully owned subsidiary of Duke Energy as a result of the merger between Duke Energy and Progress Energy, Inc. which was finalized on July 2, 2012.

Q. Please summarize your educational background and work experience.

A. I received Bachelor of Science and Master of Science degrees in electrical engineering from Clemson University in 1989 and 1990, respectively. I am also a registered professional engineer in North Carolina.

I began my career with Duke Energy's predecessor company Duke Power in 1992 as a power quality engineer. After a series of promotions, I was named manager of transmission planning and engineering studies in 1999, general manager of asset strategy and planning in 2006, and the managing director of strategy and business planning for Duke Energy starting in 2007. In this role, I had responsibility for developing the strategy for the company's operating utilities; commercial support for operating utility activities such as acquisition of generation assets and overseeing Requests for Proposals for renewable generation resources; and major project/initiative business case analysis. In 2009, I was named Vice President, Office of Nuclear Development for Duke Energy. In that role, I was also responsible for furthering the development of new nuclear generation in the Carolinas and Midwest. This included identifying and developing nuclear partnership opportunities, as well as integrating and advancing Duke Energy's plans for the proposed Lee Nuclear Station in Cherokee County, S.C. I was promoted to my current position on July 1, 2012.

Q. **Please describe your responsibilities for the Levy Nuclear Project ("LNP") as Vice President of Nuclear Development.**

A. As Vice President of Nuclear Development, I am responsible for the licensing and engineering design for the Levy nuclear power plant project ("LNP" or "Levy"), including the direct management of the Engineering, Procurement, and Construction ("EPC") Agreement with Westinghouse and Shaw, Stone & Webster (the "Consortium") and the project control functions for the LNP.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your direct testimony?

A. My direct testimony supports PEF's request for cost recovery and a prudence determination, pursuant to the Nuclear Cost Recovery Rule, Rule 25-6.0423, Florida Administrative Code, for the Company's LNP generation and transmission costs incurred from January 2012 through December 2012. I will explain the Company's 2012 LNP costs and the major variances between actual LNP costs and actual/estimated costs included in the Company's April 30, 2012 filings in Docket No. 120009-EI. I will also explain the prudence of the Company's 2012 LNP project management, contracting, and cost oversight controls.

Q. Do you have any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibits to my testimony:

- Exhibit No. ___ (CMF-1), Project Management and Fleet Operating Procedures applicable to the LNP, revised in 2012;
- Exhibit No. ___ (CMF-2), Project Management and Fleet Operating Procedures, new to the LNP in 2012;

In addition, I will be co-sponsoring the cost portions of Schedules T-4, T-4A, and T-6 of the Nuclear Filing Requirements ("NFRs"), which are included as part of the exhibits to Mr. Thomas G. Foster's testimony, Exhibit No. ___(TGF-1). I am also sponsoring Schedules T-6A, T-6B, T-7, T-7A, and T-7B and Appendix D of the NFRs. Schedule T-6A is a description of the major tasks. Schedule T-6B reflects capital expenditure variance explanations. Schedule T-7 is a list of the contracts executed in excess of $1.0 million and Schedule T-7A provides details for those contracts. Schedule T-7B reflects details pertaining to contracts executed in excess of $250,000, but less than $1.0 million.

All of these exhibits, schedules, and appendices are true and accurate.

Q. Please summarize your testimony.

A. PEF requests that the Commission find its actual costs incurred in 2012 for the LNP reasonable and prudent. PEF also requests that the Commission approve such costs for recovery. In 2012, the Company continued to implement the management decision it made to proceed with the LNP on a slower pace for in-service of Unit 1 in 2024 and Unit 2 eighteen (18) months later in 2025. LNP costs were incurred in support of (1) the Levy Combined Operating License Application ("COLA") to the Nuclear Regulatory Commission ("NRC"), (2) engineering activities in support of the COLA, (3) activities under PEF's LNP EPC Agreement with the Consortium, and (4) strategic land acquisitions for Levy transmission needs. PEF took appropriate steps to ensure that its 2012 costs were reasonable and prudent and that all of these costs were necessary to the LNP according to the current integrated project schedule. Therefore, the Commission should approve PEF's 2012 LNP costs as reasonable and prudent pursuant to the nuclear cost recovery rule.

Additionally, the Company used substantially the same project management and contracting procedures and cost oversight controls for the LNP in 2012 that were used in prior years for the LNP. These project management and contracting procedures and cost oversight controls were reviewed and approved as reasonable and prudent by the Commission in prior dockets. PEF's 2012 project management policies and procedures reflect the collective experience and knowledge of the Company and its new parent Duke Energy, and they have been and will continue to be vetted, enhanced, and revised to reflect industry leading best project management and cost oversight policies, practices, and procedures. Therefore, the Company respectfully requests that the Commission approve PEF's 2012 project management, contracting, and cost oversight policies and procedures as reasonable and prudent.

III. 2012 LNP CAPITAL COSTS.

Q. What were the total LNP actual 2012 costs?

A. Total actual LNP costs for 2012, inclusive of transmission and generation costs, were [redacted]. This is [redacted] more than PEF's actual/estimated costs for 2012. The reasons for this variance are described below.

Q. Please describe the categories of work that were performed for the LNP in 2012 to incur these costs.

A. PEF performed work and incurred generation preconstruction and generation and transmission construction costs in the following categories of expenditures for the LNP in 2012: (1) licensing, (2) engineering, design and procurement, (3) real estate acquisition, (4) power block engineering and procurement, and (5) other.

A. GENERATION COSTS.

Q. Please explain what licensing work was done for the LNP in 2012.

A. During 2012, the LNP team worked with the NRC to advance the LNP COLA toward final approval and issuance. A significant milestone was achieved in April 2012 when the NRC issued the Final Environmental Impact Statement ("FEIS"). In addition, the Advisory Committee on Reactor Safeguards ("ACRS") review of the Advanced Final Safety Evaluation Report ("SER") was completed on January 24, 2012. The Final SER schedule is currently under review.

As a result of the Fukushima event in Japan, the NRC required PEF to provide additional information to questions specific to the Fukushima event. This response included detailed evaluations and an update of seismic information to incorporate the updated Central Eastern United States ("CEUS") seismic source data. The team completed this evaluation and update and submitted an update to the Levy COLA to the NRC on July 30, 2012. In addition, supplemental information was provided to the NRC that described the COLA changes that will achieve compliance with the revised NRC Emergency Plan Rule.

In early 2012, the Atomic Safety and Licensing Board ("ASLB") conducted a site visit of the Levy site prior to its scheduled contested hearings. The LNP team facilitated this site visit and also prepared testimony and supported the ASLB evidentiary hearings for environmental Contention 4A. These hearings were completed on October 31, 2012 and November 1, 2012 in Bronson, Florida. PEF submitted its Findings of Fact and Conclusions of Law brief related to environmental Contention 4A to the ASLB on December 5, 2012. A decision from the ASLB panel is expected in the first quarter of 2013.

In 2012 a U.S. Court of Appeals (DC Circuit) court vacated the NRC waste confidence rule regarding spent nuclear fuel storage. As a result of this ruling, on September 6, 2012, the NRC directed its Staff to develop an Environmental Impact Statement ("EIS") and a revised waste confidence decision and rule within 24 months. Evaluation of new reactor license applications and license renewal applications will continue, but no new licenses will be issued until the DC Circuit court's concerns regarding the waste confidence rule are addressed. The NRC's decision to pursue generic resolution of the waste confidence rule will impact the schedule for issuance of the Levy Combined Operating License ("COL"). Assuming the entire 24-month period is required for promulgation of a new waste confidence rule, pending COLs will not be issued until September 2014 at the earliest. As discussed above, the NRC indicated that it will continue with licensing activities, such as conducting mandatory hearings, prior to issuance of the final waste confidence rule; but it has not yet determined a schedule for the Levy mandatory hearings. If the Levy COL application mandatory hearing is conducted in 2013 and the waste confidence issue is resolved within two years as directed by the NRC, the Levy COL can be issued as early as the fourth quarter of 2014. If the waste confidence issue is resolved within this time frame, this licensing issue will not impact the project timeline for commercial operation of Unit 1 by 2024.

Q. Was any environmental work for the Levy COLA performed in 2012?

A. Yes. Major environmental work completed in 2012 for the Levy COLA included satisfactorily addressing U.S. Army Corps of Engineers ("USACE") concerns regarding potential wetland impacts from groundwater withdrawals by preparing and submitting the Aquifer Performance Test Plan ("APT") and Environmental Monitoring Plans ("EMP"). PEF also finalized the cultural resources review of the accessory parcels at the LNP site (i.e., the triangle, access road parcels) and the blow-down pipeline route and submitted reports to the Division of Historical Resources, Florida Department of State. Thereafter, in February 2012, PEF received concurrence letters from the Division of Historical Resources for the LNP site accessory parcels and the blow-down pipeline. In addition, the draft of the proposed cultural resources education program and unanticipated finds for cultural resources for the LNP required by the Division was completed. This program will remain in draft form until the project construction start date is established and then the program will be finalized in conjunction with Levy contractors.

PEF also worked with the USACE to finalize the approach on cultural resource surveys on the transmission line routes to ensure that the Seminole Tribe of Florida would have the opportunity to review cultural resource surveys when complete. The Levy transmission work plan has now been established and approved by the Division of Historical Resources. The Levy team also continued planning for environmental compliance for construction mobilization in 2012. In addition, the Levy team completed preliminary documents and surveys on the Chiefland-Dunnellon owned right-of-way for compliance with the State of Florida Cross Florida Greenway easement which requires PEF to provide the State with an easement to construct a trail once the Levy COL is issued. PEF also managed the completion of a Withlacoochee Bay Trail extension on the Cross Florida Greenway which was an easement condition.

Q. What licenses and permits are required for the LNP?

A. PEF must obtain required environmental permits to support the Levy plants construction and operation. Environmental permitting for the LNP involves several basic steps: (1) application to the NRC for a COL; (2) application to the State of Florida for site certification; and (3) applications for certain additional federal environmental permits, including (a) a National Pollutant Discharge Elimination Permit ("NPDES") for water discharge, (b) Prevention of Significant Deterioration ("PSD") air permit, (c) a 316(b) demonstration for the proposed cooling water intake, (d) USACE Section 404 and Section 10 permits to construct structures in wetlands and regulated waterways, (e) hazardous waste management and disposal, and (f) a determination of consistency under the requirements of the Coastal Zone Management Act to ensure the LNP is consistent with existing federal and state coastal zone management plans.

The Site Certification was approved by the State on August 26, 2009. Post-certification activities will be performed in accordance with the Conditions of Certification provided with the Site Certification.

The Final EIS was prepared by the NRC with the USACE as a cooperating agency. The NRC and USACE published the Draft EIS for comment in August 2010. The USACE will use the Final EIS as a basis for their Record of Decision granting the Clean Water Act Section 404 Dredge and Fill Permit, which will be needed to allow construction activities in waters of the State. The 404 Permit can be issued after publication of the Final EIS. The Final EIS was published in April 2012, so the 404 Permit is expected around mid-2013. All necessary permits will be obtained prior to and during the pre-construction and construction phases of the project.

Q. What engineering work was performed for the LNP in 2012?

A. The LNP team conducted engineering activities in support of its COLA for the LNP. This included ongoing engineering support to assist the licensing activities in response to the NRC Requests for Additional Information ("RAIs").

Further, Levy Engineering accomplishments in 2012 included (1) Owner Acceptance Reviews of the detailed evaluations and calculations to update the Levy site specific seismic information to incorporate the updated CEUS seismic source data and address issues identified from the Fukushima event, and (2) Owner Acceptance Reviews for the conceptual design of a contingency desalination plant for the LNP.

Pursuant to the Levy EPC contract, the Levy team also identified Witness and Hold points to be performed by Duke Energy during the manufacture/fabrication of several items of long lead equipment ("LLE") including the Core Makeup Tanks, Steam Generator tubing, and Pressurizers. A Witness Point is an identified point in the process where the contract administrator may review or inspect any component, or process of the work, while the work proceeds. A Hold Point is a mandatory verification point beyond which work cannot proceed without authorization by the contract administrator. Costs for engineering activities in 2012 were also attributable to milestone payments for LLE items required for LNP construction.

Finally, PEF also continued its active participation in APOG AP1000 Design Reviews throughout 2012. APOG is the industry group of utilities pursing the deployment of the AP1000 nuclear reactor technology.

Q. Please describe in general the Generation-related Real Estate Acquisitions for the LNP in 2012.

A. The Company incurred surveying and other costs related to the conveyance of an easement for the Dunnellon to Chiefland trail as a condition of the previously required barge slip easement. The Company also incurred internal labor costs for oversight of the Levy plant site.

i. <u>Preconstruction Generation Costs Incurred.</u>

Q. Did the Company incur any Generation preconstruction costs for the LNP in 2012?

A. Yes. As reflected on Schedule T-6.2, the Company incurred preconstruction costs in the categories of (1) License Application and (2) Engineering, Design, and Procurement.

Q. For the License Application costs, please identify what those costs are and why the Company had to incur them.

A. As reflected on Line 3 of Schedule T-6.2, the Company incurred License Application costs of [redacted] in 2012. These 2012 actual costs were incurred for the licensing activities supporting the LNP COLA and the additional licensing activities that I described above.

Q. For the Engineering, Design and Procurement costs, please identify what those costs are and why the Company had to incur them.

A. As reflected on Line 4 of Schedule T-6.2, the Company incurred Engineering, Design, and Procurement costs of [redacted] in 2012. The costs incurred related specifically to: (1) approximately [redacted] in contractual payments to the Consortium for project management, quality assurance, purchase order disposition support, and other home office services such as accounting and project controls; and (2) approximately [redacted] for direct PEF oversight of engineering activities of the Consortium including project management, project scheduling and cost estimating.

Q. How did Generation preconstruction actual capital expenditures for January 2012 through December 2012 compare to PEF's estimated/actual costs for 2012?

A. LNP preconstruction generation costs were [redacted], or [redacted] less than PEF's actual/estimated costs for 2012. The reasons for the major (more than $1.0 million) variances are provided below.

License Application: License Application capital expenditures were [redacted], which was [redacted] more than the actual/estimated License Application costs for 2012. This variance is attributable to higher than originally estimated NRC review fees and outside legal counsel fees associated with the LNP COLA activities and regulatory reviews, including the ASLB contested hearings and Fukushima-related RAI responses.

Engineering, Design, and Procurement: Engineering, Design, and Procurement capital expenditures were [redacted], which was [redacted] less than the actual/estimated Engineering, Design, and Procurement costs for 2012. This variance is driven primarily by lower than estimated internal labor and expenses and deferral of Conditions of Certification ("CoC") engineering scope into future years.

ii. <u>Construction Generation Costs Incurred.</u>

Q. Did the Company incur any Generation construction costs for the LNP in 2012?

A. Yes. As reflected on Schedule T-6.3, the Company incurred generation construction costs in the categories of Real Estate Acquisition and Power Block Engineering and Procurement.

Q. For the Real Estate Acquisition costs, please identify what those costs are and why the Company had to incur them.

A. As reflected on Line 3 of Schedule T-6.3, the Company incurred Real Estate Acquisition costs of approximately [redacted] in 2012. Costs incurred are related to the conveyance of an easement for the Dunnellon to Chiefland trail and oversight of the LNP site, as I described above.

Q. For the Power Block Engineering and Procurement costs, please identify what those costs are and why the Company had to incur them.

A. As reflected on Line 8 of Schedule T.6-3, the Company incurred Power Block Engineering and Procurement costs of [redacted] in 2012. These costs were for accounting accruals for partially completed LLE milestones under the EPC contract.

Q. How did actual Generation construction capital expenditures for January 2012 through December 2012 compare to PEF's actual/estimated costs for 2012?

A. LNP construction Generation costs were [redacted] or [redacted] greater than PEF's estimated projected costs for 2012. The reasons for the major (more than $1.0 million) variances are provided below.

Power Block Engineering and Procurement: Power Block Engineering and Procurement capital expenditures were [redacted], which was [redacted] greater than the actual/estimated Power Block Engineering and Procurement costs for 2012. This variance is attributable to the accrual of costs for partially completed LLE milestones, which were included as 2013 costs in the prior-year projection, but were actually incurred in 2012 based on the percentage of LLE milestones completed during the year.

B. **TRANSMISSION.**

Q. Please describe what transmission work and activities were performed in 2012 for the LNP.

A. The majority of transmission work in 2012 related to Real Estate Acquisitions and was for strategic land acquisitions for the Levy Common Transmission Corridor and associated Levy transmission labor and related expenses to perform general project management and acquisition activities. More specifically, the Company negotiated purchase agreements on 19 parcels of land as strategic Right of Ways in the Levy Corridor.

i. **Preconstruction Transmission Costs Incurred.**

Q. Did the Company incur Transmission-related preconstruction costs for the LNP in 2012?

A. No. As reflected on Schedule T-6.2 the Company did not incur Transmission-related preconstruction costs in 2012.

Q. Were actual Transmission-related preconstruction capital expenditures for January 2012 through December 2012 consistent with PEF's actual/estimated costs for 2012?

A. Yes. PEF did not incur preconstruction capital transmission costs in 2012, which was consistent with PEF's 2012 actual/estimated filing.

ii. Construction Transmission Costs Incurred.

Q. Did the Company incur any transmission-related construction costs for the LNP in 2012?

A. Yes, as reflected on Schedule T-6.3, the Company incurred Transmission-related construction costs in the categories of Real Estate Acquisition and Other.

Q. For the Real Estate Acquisition costs, please identify what those costs are and why the Company had to incur them.

A. As reflected on Line 21 of Schedule T-6.3, the Company incurred Real Estate Acquisition costs of approximately [redacted]. These costs were incurred for the strategic land acquisitions in the Levy Common Transmission Corridor, I described above.

Q. For the Other costs, please identify what those costs are and why the Company had to incur them.

A. As reflected on Line 24 of Schedule T-6.3, the Company incurred Other costs of approximately [redacted]. These costs were incurred for Levy transmission labor and expenses related to transmission general project management and the strategic land acquisition activities I described above.

Q. How did actual Transmission-related construction capital expenditures for January 2012 through December 2012 compare to PEF's actual/estimated 2012 costs?

A. LNP transmission construction actual costs were [redacted], or approximately [redacted] less than PEF's actual/estimated construction transmission costs for 2012. Consequently, there were no major (more than $1.0 million) variances between the actual/estimated costs and the actual costs incurred for 2012.

IV. OPERATION & MAINTENANCE COSTS INCURRED IN 2012 FOR THE LNP.

Q. What Operation & Maintenance ("O&M") costs did the Company incur for the LNP in 2012?

A. As reflected on Schedule T-4 the Company incurred O&M expenditures in the amount of $1.1 million for internal labor and outside legal services that were necessary for the LNP. There were no major (more than $1.0 million) variances between the actual/estimated O&M costs and the actual O&M costs incurred.

Q. To summarize, were all of the costs that the Company incurred in 2012 for the LNP reasonable and prudent?

A. Yes, the specific cost amounts for the LNP contained in the NFR schedules, which are attached as exhibits to Mr. Foster's testimony, reflect the reasonable and prudent costs PEF incurred for LNP work in 2012. All of these activities and associated costs were necessary for the LNP.

V. PROJECT MANAGEMENT, CONTRACTING, AND COST OVERSIGHT.

Q. Did the Company use substantially the same Project Management, Contracting, and Cost Oversight policies and procedures in 2012 for the LNP that were used prior to 2012?

A. Yes. The Company used substantially the same project management and contracting procedures and cost oversight controls for the LNP in 2012 that were used in prior years for the LNP. These project management and contracting procedures and cost oversight controls were reviewed and approved as reasonable and prudent by the Commission.

More specifically, in the first six months of 2012, prior to the July 2012 merger between Duke Energy and Progress Energy, the LNP project management and contracting procedures and cost oversight controls for the LNP were exactly the same as the LNP procedures and controls previously reviewed and approved by the Commission. Subsequent to completion of the merger between Duke Energy and Progress Energy, the process of formally integrating the policies and procedures of the two companies commenced; however, this process takes months before the policies and procedures are fully integrated and best practices employed in the new, combined company. This is a gradual process to ensure continual, effective project management while the teams are integrated, the policies and procedures modified, revised, or adopted to implement best practices, and the policies and procedures fully employed by project management team members. In the meantime, the Company continued to implement the existing LNP project management and contracting policies and procedures and cost controls until new policies, procedures, and controls were developed or implemented, or existing ones were maintained, revised, or modified. As a result, the LNP project management and contracting policies and procedures and cost controls are substantially the same after the merger as they were prior to the merger.

Q. Explain how this integration process was implemented for the LNP in 2012.

A. After the merger was completed in July, the Levy project was managed by Duke Energy's Energy Supply Project Management and Construction ("PMC") group. The PMC group was analogous to the former Progress Energy group known as New Generation Programs and Projects ("NGPP"). Consequently, during this period in 2012, Duke Energy was in the process of integrating the Levy project management, contracting, and cost oversight policies and procedures with Duke Energy project management governance, but for all practical purposes the LNP project management, contracting, and cost oversight policies and procedures remained the same. Later, Duke Energy decided to move management of LNP from the Energy Supply Department to the Nuclear Generation Department. This decision aligned accountability for contract management and project management of the LNP with the organization that is responsible for licensing of the LNP as well as the licensing and project management of all new nuclear projects within Duke Energy. As a result, all new nuclear projects reside in a single organization which facilitates the transfer of best practices and lessons learned.

Q. Describe how this organizational change impacted the LNP project management, contracting, and cost control oversight policies and procedures.

A. My group, the Nuclear Development ("ND") group, assumed responsibility for the LNP and the integration of the LNP project management and contracting policies and procedures with the ND project management and contracting policies and procedures. As an initial phase of the integration and transition process several Progress Energy legacy policies and procedures were revised and updated and new policies and procedures were developed to reflect the assumption of responsibility for the LNP by the Duke Energy ND group and the merger integration of nuclear operations in both companies. A list of the revised and updated policies and procedures is included as Exhibit No. __ (CMF-1) to my direct testimony. A list of the new policies and procedures applicable to the LNP is included as Exhibit No. __(CMF-2) to my direct testimony. These revisions and new policies and procedures are limited, consistent with the prior scope of the policies and procedures to provide reasonable, effective project management and cost control for the LNP and the Levy EPC, and they are necessary to integrate and incorporate the nuclear development, construction, and operational experience of both companies.

Q. Is there still senior management oversight responsibility for the LNP?

A. Yes. There remains and will continue to be senior management oversight responsibility for the LNP. There have been no substantive changes to the project management charter for the LNP since the merger with Duke Energy. The Integrated Project Plan ("IPP") was superseded by the Duke Energy Approval of

Business Transaction ("ABT") process, which is a senior management project oversight process similar to the IPP, but Duke Energy still uses the IPP for senior management guidance regarding evaluation and approval for the LNP. Currently, an updated status report and IPP for the LNP is targeted for presentation to Duke Energy senior management in April 2013. The plan in 2013 is to review the project management charter in light of Duke Energy governance procedures and make any changes as necessary. There will always be, however, appropriate senior management oversight for the LNP.

Q. Please provide an overview of other, applicable LNP project management processes, in particular, the cost control oversight processes.

A. In addition to the procedures mentioned above, other corporate tools are used to support the management of and cost control oversight for the LNP work. The Oracle Financial Systems and Business Objects reporting tools provide monthly corporate budget comparisons to actual cost information, as well as detailed transaction information. This information, along with other financial accounting data, allows PEF to regularly monitor the costs of the LNP work compared to budgets and projections. The project schedule is maintained in the Primavera (P6) scheduling tool. This detailed integrated project schedule is reviewed and updated on a monthly basis and refined as appropriate. Key Performance Indicators ("KPIs") to monitor the status of the LNP are reviewed by the project team on a regular basis, utilizing multiple project and vendor reporting mechanisms and project review forums. Examples of Nuclear Development LNP review meetings include: bi-weekly ND group meetings; monthly ND Integrated

Project Review Meetings; weekly ND Leadership meetings; bi-weekly Project Alignment meetings; monthly ND Cost Review meetings; and weekly COLA Change Management meetings, among others.

In addition, the Company's oversight and management plan for contractors did not change in 2012. As expected, field activity for both generation and transmission continues to be very limited based on the current NRC COLA review status and in-service dates. The Company, however, continued to meet on a quarterly basis with the EPC Consortium, and continued bi-weekly phone calls with the Joint Venture Team (Sargent & Lundy, Worley Parsons, and CH2M Hill) to review and discuss the work supporting the Levy COLA.

Q. Please explain how the Company ensures that its selection and management of outside vendors is reasonable and prudent.

A. First, PEF's policies and procedures for contractors and vendors have not changed materially with the merger. When selecting vendors for the LNP, PEF utilizes bidding procedures through a Request for Proposal ("RFP") when possible for the particular services or materials needed to ensure that the chosen vendors provide the best value for PEF's customers. Once proposals are submitted by potential vendors, formal bid evaluations are completed and a final selection is determined and documented.

When an RFP cannot be used, PEF ensures that contracts with sole source vendors contain reasonable and prudent contract terms with adequate pricing provisions (including fixed price and/or firm price, escalated according to indexes, where possible). When deciding to use a single or sole source vendor, PEF documents a single or sole source justification for the particular work. The Company requires that all sole or single source contract activity must be justified on the contract requisition and must be approved by the appropriate management level for the dollar value of the contract.

The contract development process starts when a requisition is created in the Passport Contracts module for the purchase of services. The requisition is reviewed by the appropriate Contract Specialist and appropriate technical and management personnel on the Levy project, to ensure sufficient data has been provided to process the contract requisition. The Contract Specialist prepares the appropriate contract document from pre-approved contract templates in accordance with the requirements stated on the contract requisition. Once the requisition is ready to be executed, it is approved online by the appropriate levels of the management. The invoices are validated by the designated representatives/project managers and contract administration team. Payment Authorizations approving payment of the contract invoices are then entered and approved.

Q. Does the Company verify that the Company's project management and cost control policies and procedures are followed?

A. Yes, it does. PEF continues to use internal audits, self assessments, benchmarking, and quality assurance reviews and audits, as appropriate, to verify that its program management and cost oversight controls are in place and being implemented. Internal audits are also conducted on outside vendors.

Each year the Company employs a planning process to identify those areas to be audited in the upcoming year based on relative risk across the Company. This risk-based process identified one potential audit for 2012 associated with the Levy project: an audit of the Levy EPC Contract. However, during 2012, as a result of the revised project schedule, along with results of prior audits, the Company's Audit Services Department revised its assessment of the relative audit priority and the proposed Levy EPC audit was removed from the 2012 plan and deferred for future consideration.

The Audit Services Department also determined that, based on prior years' audit results of the Nuclear Cost Recovery Clause, that an audit for 2012 was not warranted. A key factor in this decision is the determination that the Nuclear Cost Recovery Clause cost control processes were effective in prior Nuclear Cost Recovery Clause financial audits in 2008, 2009, 2010 and 2011. The need for future Nuclear Cost Recovery Clause audits will be assessed each year during the annual audit planning process.

As appropriate, the Company also performs audits of its contractors. An audit of the Shaw, Stone, and Webster ("SSW") invoice process was conducted April 24-25, 2012, at the SSW Charlotte, North Carolina office. The scope of the audit was to (1) assess and test the SSW internal project business processes and controls utilized to develop, review, and approve SSW invoices submitted to PEF to ensure compliance with contract terms and conditions related to financial and invoice or payment, (2) determine that appropriate SSW time, expense, and invoice procedures and processes are approved and followed, and (3) verify the propriety of the amounts paid for selected invoice periods. Based on the results of the audit, the SSW invoice process was found to be effective.

An audit of the Westinghouse Time and Expense ("T&E") and LLE invoice process was also conducted August 21-22, 2012 at the Westinghouse Cranberry, Pennsylvania office. The scope of the audit was to assess and test the Westinghouse internal project business processes and controls utilized to develop, review, and approve Westinghouse T&E and LLE invoices submitted to PEF, including under the Levy EPC contract. Based on the results of the audit, the Westinghouse T&E and LLE invoice process was found to be effective.

In addition the Nuclear Oversight Organization ("NOS") completed several Nuclear Quality Assurance reviews, including participating in a Nuclear Procurement Issues Committee ("NUPIC") limited scope audit of Westinghouse NPP (AP1000) on August 20-21, 2012; an Internal NOS Assessment of Levy Units 1 and 2 Nuclear Plant Development Activities on September 10-14, 2012; and two NOS surveillance reports associated with Witness Points on October 9-12 and October 30- November 1, 2012, respectively. Duke Energy continues to work with the other APOG utilities to perform these audit and surveillance activities and monitor the performance of these contractors in accordance with the requirements of its Nuclear Quality Assurance Program.

Q. Are these project management and costs control oversight procedures described applicable to both transmission and generation projects?

A. Yes. The generation and transmission projects associated with the LNP are subject to the same Company management, policies, and procedures.

Q. Are the Company's LNP project management, contracting, and cost control oversight policies and procedures reasonable and prudent?

A. Yes, they are. These project management policies and procedures reflect the collective experience and knowledge of the Company and now the Combined Company, Duke Energy. The on-going integration of the two companies brought about a comprehensive review of all processes and procedures to determine that best practices from both companies are retained. The integration process to date has revealed that the companies' nuclear development processes and procedures are substantively similar. Consequently, the 2012 LNP project management changed more in structure than substance. As a result, the LNP 2012 project management, contracting, and cost control policies and procedures are substantially the same as the collective policies and procedures that have been vetted in the annual project management audit in this docket and approved as prudent by the Commission. *See* Order No. PSC-09-0783-FOF-EI, issued Nov. 19, 2009; Order No. PSC-11-0095-FOF-EI, issued Feb. 2, 2011; Order No. PSC-11-0547-FOF-EI, issued Nov. 23, 2011; and Order No. PSC-12-0650-FOF-EI, issued Dec. 11, 2012. We believe, therefore, that the LNP project management policies and procedures are consistent with best practices for capital project management in the industry and continue to be reasonable and prudent.

Q. Does this conclude your testimony?

A. Yes, it does.

IN RE: NUCLEAR COST RECOVERY CLAUSE

BY DUKE ENERGY FLORIDA, INC.

FPSC DOCKET NO. 130009-EI

DIRECT TESTIMONY OF CHRISTOPHER M. FALLON

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Christopher M. Fallon. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. Who do you work for and what is your position with that company?

A. I am employed by Duke Energy Corporation ("Duke Energy") as Vice President of Nuclear Development. Duke Energy Florida, Inc. ("DEF" or the "Company") is a fully owned subsidiary of Duke Energy.

Q. Do your responsibilities as Vice President of Nuclear Development include senior management review for the Levy Nuclear Project ("LNP")?

A. Yes. As Vice President of Nuclear Development, I am responsible for the licensing and engineering design for the Levy nuclear power plant project ("LNP" or "Levy"), including the direct management of the Engineering, Procurement, and Construction ("EPC") Agreement with Westinghouse and Shaw, Stone & Webster (the "Consortium"), and I am responsible for reporting on the LNP to senior management, through the Transaction Review

Committee ("TRC") and Senior Management Committee ("SMC"), for Duke Energy. The TRC is responsible for project approval and ongoing funding authorization for the LNP on a project milestone basis. The TRC approved LNP funding authorization through one year after the next major LNP milestone, receipt of the LNP COL, for the LNP in April 2013. The SMC reviews the LNP project status and project management in quarterly project updates. The TRC and SMC provide senior management funding and project management oversight for the LNP.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your direct testimony?

A. My direct testimony supports DEF's request for cost recovery for DEF's LNP actual/estimated 2013 and projected 2014 costs pursuant to the Nuclear Cost Recovery Statute, §366.93, Florida Statutes, and Nuclear Cost Recovery Rule, Rule 25-6.0423, Florida Administrative Code ("F.A.C."). I will also provide and explain the Company's long-term feasibility analyses consistent with Rule 25-6.0423, F.A.C. and Commission Order No. PSC-09-0783-FOF-EI in Docket No. 090009-EI.

Q. Do you have any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibits to my testimony:

- Exhibit No. ___ (CMF-3), a confidential chart of the Company's long lead equipment ("LLE") purchase order ("PO") disposition status;

- Exhibit No. ___ (CMF-4), DEF's updated cumulative life-cycle net present value revenue requirements ("CPVRR") calculation for the LNP compared to the cost-effectiveness analysis presented in the Need Determination proceedings for the LNP;
- Exhibit No. ___ (CMF-5), a chart of the Nuclear Regulatory Commission ("NRC") review schedule and status for the LNP Combined Operating License Application ("COLA"); and
- Exhibit No. ___ (CMF-6) the Florida Legislature Office of Economic and Demographic Research ("EDR"), March 2013 Florida Economic Overview.

I am also sponsoring or co-sponsoring portions of the Schedules attached to Thomas G. Foster's testimony. Specifically, I am co-sponsoring portions of Schedules AE-4, AE-4A, and AE-6 and sponsoring Schedules AE-6A through AE-7B of the Nuclear Filing Requirements ("NFRs") included as part of Exhibit No. (TGF-3) to Mr. Thomas G. Foster's testimony. I am also co-sponsoring portions of Schedules P-4 and P-6 and sponsoring Schedules P-6A through P-7B included as part of the NFRs' included in Exhibit No. (TGF-4) to Mr. Foster's testimony. I am further co-sponsoring NFR Schedules TOR-4 and TOR-6, and sponsoring schedules TOR-6A and TOR-7, which is Exhibit No. ___ (TGF-5) to Mr. Foster's testimony. A description of these NFR Schedules follows:

- Schedule AE-4 reflects Capacity Cost Recovery Clause ("CCRC") recoverable Operations and Maintenance ("O&M") expenditures for the period.
- Schedule AE-4A reflects CCRC recoverable O&M expenditure variance explanations for the period.
- Schedule AE-6 reflects actual/estimated monthly expenditures for site selection, preconstruction, and construction costs for the period.
- Schedule AE-6A reflects descriptions of the major tasks.
- Schedule AE-6B reflects annual variance explanations.
- Schedule AE-7 reflects contracts executed in excess of $1.0 million.
- Schedule AE-7A reflects details pertaining to the contracts executed in excess of $1.0 million.
- Schedule AE-7B reflects contracts executed in excess of $250,000, yet less than $1.0 million.
- Schedule P-4 reflects CCRC recoverable O&M expenditures for the projected period.
- Schedule P-6 reflects projected monthly expenditures for preconstruction and construction costs for the period.
- Schedule P-6A reflects descriptions of the major tasks.
- Schedule P-7 reflects contracts executed in excess of $1.0 million.
- Schedule P-7A reflects details pertaining to the contracts executed in excess of $1.0 million.

- Schedule P-7B reflects contracts executed in excess of $250,000, yet less than $1.0 million.
- Schedule TOR-4 reflects CCRC recoverable actual to date and projected O&M expenditures.
- Schedule TOR-6 reflects actual to date and projected annual expenditures for site selection, preconstruction and construction costs for the duration of the project.
- Schedule TOR-6A reflects descriptions of the major tasks.
- Schedule TOR-7 reflects total project costs exclusive of carrying costs and fuel costs.

All of these exhibits and schedules are true and accurate.

Q. Please summarize your testimony.

A. The Company is executing its plan presented to the Commission last year to proceed with the LNP on a slower pace until the LNP Combined Operating License ("COL") is obtained from the NRC on a schedule that is currently estimated to place Levy Unit 1 in commercial service in 2024 and Levy Unit 2 in commercial service in 2025. As a result, the Company has reasonably estimated and projected its costs in 2013 and 2014, respectively, to obtain the COL, obtain other environmental permits for the project, and continue disposition of the LNP long-lead equipment ("LLE"), as well as other project management and engineering costs, consistent with this schedule. These costs are reasonably estimated based on existing contracts, purchase orders, and NRC estimates of review fees and the Company's estimating experience, consistent with industry best practices. The Company, therefore, requests that the Commission determine that DEF's actual/estimated 2013 and projected 2014 LNP costs are reasonable.

The Company has conducted the annual feasibility analyses for the LNP consistent with Commission rules and Commission Orders. The Company's current feasibility analyses demonstrate that the LNP is still feasible. Qualitatively, there remains near term uncertainty, which has been mitigated by the current LNP schedule presented to the Commission last year, thus, there is no reason to conclude at this time that these risks are so uncertain that the LNP is not qualitatively feasible at this time. The updated, quantitative feasibility analysis demonstrates that the LNP is still economically feasible at this time. For these reasons, the Company has determined that the current LNP project plan and schedule remains the reasonable course of action for the Company and its customers.

III. LNP WORK AND COSTS IN 2013 AND 2014.

Q. What work does the Company plan for the LNP in 2013 and 2014?

A. The primary LNP activities in 2013 and 2014 involve licensing and engineering work to obtain the COL for the LNP from the NRC, continued environmental permitting work, and management of the EPC agreement, including the LNP LLE disposition previously reviewed by the Commission. This work is consistent with the Company's implementation of the decision in 2010 to proceed with the LNP on a slower pace until the LNP COL is obtained that the Commission reviewed and determined to be reasonable in Order No. PSC-11-0095-FOF-EI. The Company will continue licensing and engineering work in 2013 and 2014 to obtain the LNP COL, which is not expected until the fourth quarter of 2014.

Q. Can you describe the licensing and engineering work expected for the LNP COLA in 2013 and 2014?

A. Yes. This work includes licensing and engineering activities to allow the NRC to finalize its safety review, including a final COLA revision that the Company plans to submit to the NRC in June 2013. The Company presented the results of its seismic update to incorporate updated Central Eastern United States ("CEUS") seismic source data to the NRC Advisory Committee on Reactor Safeguards ("ACRS"); and will provide any additional information requested by the NRC to develop the Final Safety Evaluation Report ("FSER") for the LNP. Licensing and engineering activities will also involve changes to the Levy Emergency Plan to satisfy the requirements of a late-2011 NRC Emergency Preparedness rule, revisions to proposed license conditions that address NRC Fukushima-related actions, and changes to resolve issues related to the Radwaste Building classification as part of the final COLA revision update.

Additional licensing and engineering work is required to address design changes identified by Westinghouse, including a design change to the reactor containment to maintain margins for post-accident cooldown requirements, and to evaluate a request for an exemption from certain design requirements. The Company will also monitor the NRC Waste Confidence rulemaking that is expected to continue through 2013 and most of 2014. The Company will prepare for and support the completion of the mandatory hearing for the LNP COL, which is expected some time in November 2013, although the NRC has not yet scheduled the mandatory hearing for the LNP COL.

Q. What environmental permitting work is required for the LNP in 2013 and 2014?

A. Licensing and engineering work is necessary in 2013 and 2014 to continue to support environmental permitting and implementation of conditions of certification ("CoC"). This work includes submittal of the Environmental Monitoring Plans ("EMP") and the Aquifer Performance Test Plan ("APT") to the State of Florida and the Southwest Florida Water Management District for review and approval. Environmental work scope will also include preconstruction environmental monitoring, wetland mitigation plan implementation, aquifer performance testing, and other site CoC. The environmental permitting work further includes continued licensing and engineering work for the United States Army Corps of Engineers ("USACE") Section 404 permit for the LNP. Work supporting the completion of the Section 404 Permit includes updates to the Wetland Mitigation Plan to address items identified by USACE and continued work with USACE to address wetlands mitigation and secondary impacts. The Company expects the USACE to issue the Section 404 Permit for the LNP in 2013.

Q. Can you explain what work is expected in connection with management of the EPC agreement, including the LLE disposition, in 2013 and 2014?

A. Yes. The Company will incur LLE disposition and storage costs based on the continued LLE milestone payments, and Quality Assessment ("QA"), supply chain management, project controls, and other vendor oversight activities associated with the continued LLE fabrication for the LNP. Consortium Project Management Organization ("PMO") costs are also expected in 2013 and 2014 as a result of this work scope. The Company will incur costs to administer the EPC agreement, including maintaining Consortium project status and performance indicators and complying with Consortium reporting requirements, in addition to other project management costs.

The Company expects to incur some engineering costs in 2013 and 2014 to monitor the AP1000 module program development and design and to support site specific engineering to determine resource loading and timing to meet the current, anticipated commercial operation dates for the Levy units. The Company also continues its participation in industry groups to advance the AP1000 design and operation. This includes participation in the AP1000 owners group ("APOG") committee. The Company will further continue its active involvement in industry groups such as the Nuclear Energy Institute ("NEI") New Plant Working Group, NEI New Plant Oversight Committee, and

Institute of Nuclear Power Operations ("INPO") New Plant Deployment Executive Working Group. Finally, the Company is also continuing its evaluation and disposition of AP1000 operating experience ("OE") in China and with the Vogtle and Summer AP1000 projects. This work involves benchmarking and monitoring of licensing and construction activities at these plants in 2013 and 2014.

Q. Does DEF have nuclear generation preconstruction costs in 2013 and 2014 as a result of the LNP planned work scope and activities?

A. Yes. DEF has 2013 actual/estimated and 2014 projected LNP preconstruction costs. Schedule AE-6 of Exhibit No. ___ (TGF-3) to Mr. Foster's testimony, shows LNP actual/estimated generation preconstruction costs for 2013 in the following categories: License Application development costs of [redacted] and Engineering, Design & Procurement costs of [redacted]. Schedule P-6 of Exhibit No. __ (TGF-4) to Mr. Foster's testimony shows the LNP 2014 projected generation preconstruction costs in the following categories: License Application costs of [redacted] and Engineering, Design & Procurement costs of [redacted].

Q. What are the License Application costs?

A. The License Application costs support the on-going LNP licensing, environmental review, and permitting activities that I described above that are necessary for the LNP. Consistent with past practice, DEF developed the preconstruction License Application cost estimates on a reasonable licensing and engineering basis, using the best available information to the Company, in accordance with utility industry and DEF practices. For the costs associated with the NRC COLA review and other permit processes, DEF used the terms of its existing contracts, approved change orders, as well as updated forecasts, which are provided on a monthly basis by the contractors, to estimate the costs they will incur for the technical and engineering support necessary for the on-going LNP license and permit review processes. DEF also based its projections on known project milestones necessary to obtain the requisite approvals. DEF is using actual or expected contract costs, NRC estimates, and its own experience, including industry lessons learned, therefore, DEF's cost estimates for the preconstruction License Application work are reasonable.

Q. Please describe the Engineering, Design & Procurement preconstruction costs.

A. The Engineering, Design & Procurement preconstruction costs in 2013 and 2014 are for the PMO activities, shared AP1000 module program development work, implementation and oversight of the LLE change order terms and conditions, engineering for the LNP CoC, and other LNP project management activities that I described above. DEF developed these preconstruction Engineering, Design & Procurement cost estimates on a reasonable engineering basis, using the best available information to DEF. Again, consistent with past practice, DEF based its cost estimates and projections on the LNP project schedule, staffing requirements, and known project milestones, utilizing cost information from the EPC Agreement, information obtained through negotiations with the Consortium, and other contractor cost information. As a result, DEF is using actual or expected contract costs and its own experience to develop reasonable 2013 and 2014 preconstruction Engineering, Design & Procurement costs for the LNP.

Q. Does DEF have LNP generation construction costs in 2013 and 2014?

A. Yes, DEF has 2013 actual/estimated and 2014 projected LNP construction costs. Schedule AE-6 of Exhibit No. __ (TGF-3) to Mr. Foster's testimony provides the 2013 actual/estimated generation construction costs in the following categories: Real Estate Acquisitions costs of [redacted] and Power Block Engineering, Procurement, and Related Costs of [redacted]. Schedule P-6 of Exhibit No. __ (TGF-2) to Mr. Foster's testimony provides the 2014 projected generation construction costs in the following categories: Real Estate Acquisitions costs of [redacted], Project Management costs of [redacted], and Power Block Engineering, Procurement, and related costs of [redacted].

Q. Please describe the Real Estate Acquisition costs.

A. LNP real estate acquisition costs will be incurred in 2013 and 2014 for payment for a portion of the remaining barge slip easement acquisition; for acquisition of a parcel near the barge slip needed for construction laydown; and for mitigation. These cost estimates were developed based on governing procedures for the acquisition of land needed for nuclear plant development. These governing procedures outline the acquisition procedure and payment process; document approval, management and retention procedures; and provide for cost oversight and management concerning land acquisition. Utilizing these procedures, DEF developed the construction Real Estate Acquisition cost estimates on a reasonable basis, using the best available information, consistent with utility industry and DEF practice.

Q. Please describe the Power Block Engineering, Procurement, and Related Costs.

A. LNP Power Block Engineering, Procurement, and Related Costs in 2013 and 2014 consist primarily of contractual milestone payments, and incremental storage and shipping, insurance, and warranty costs, on select LNP LLE items consistent with the Company's LLE disposition decisions summarized in the chart attached as Exhibit No. ___ (CMF-3) to my direct testimony. In 2013, LLE contractual milestone payments include [redacted], and [redacted], and incremental LLE costs include [redacted], and [redacted]. In 2014, projected LLE contractual milestone payments include [redacted]

[redacted], and [redacted] and incremental LLE costs associated with each of these components and [redacted], and [redacted]. DEF developed these cost estimates utilizing cost information from the EPC Agreement and executed LLE change orders with the Consortium. DEF's cost estimates for the LNP construction Power Block Engineering and Procurement work in 2013 and 2014 are reasonable.

Q. Does DEF have transmission-related preconstruction costs for the LNP in 2013 and 2014?

A. No.

Q. Does DEF have transmission-related construction costs for the LNP in 2013 and 2014?

A. Yes. DEF expects some 2013 actual/estimated and 2014 projected transmission-related construction costs for the LNP. In Schedule AE-6 of Exhibit No. ___ (TGF-3) to Mr. Foster's testimony there are estimated transmission construction costs for 2013 in the following categories: Real Estate Acquisition and Mitigation costs of [redacted] and Other costs of [redacted]. In Schedule P-6 of Exhibit No. __ (TGF-4) to Mr. Foster's testimony there are projected 2014 transmission construction costs in the following categories: Real Estate Acquisition and Mitigation costs of [redacted] and Other costs of [redacted].

Q. What are the LNP 2013 and 2014 estimated transmission-related Real Estate Acquisition and Mitigation and Other costs?

A. LNP Real Estate Acquisition activity in 2013 and 2014 includes ongoing costs related to strategic Right-of-Way ("ROW") acquisition for the LNP transmission lines. These costs are necessary to ensure that the ROW and other land upon which the transmission facilities will be located are available for the LNP. Mitigation costs are associated with Clean Water Act regulations requiring that the environmental effects of construction in wetlands and streams be mitigated. The Other LNP transmission costs include labor and related indirect costs, overheads, and contingency in support of strategic transmission ROW acquisition activities. They also include general project management, project scheduling, and cost estimating, legal services and external community relations outreach to local, state, and federal agencies. These construction costs are necessary for the transmission project work in support of the LNP.

Consistent with past practice for the LNP, DEF developed these LNP Real Estate Acquisition and Other transmission construction cost estimates on a reasonable engineering basis, in accordance with the Association for the Advancement of Cost Engineering International ("AACEI") standards, using the best available construction and utility market information at the time, consistent with utility industry and DEF practice. Real estate costs within the project estimates are based on an expected dollar per acre amount based on the type and location of the property using current route selection analysis. The management and indirect costs within the project estimates were developed based on the project schedule and staffing requirements. These estimates reasonably reflect the necessary LNP transmission project work for 2013 and 2014.

Q. Is all of this work necessary for the LNP in 2013 and 2014?

A. Yes. All of this work is necessary in 2013 and 2014 to obtain the LNP COL from the NRC and to move the LNP forward on a schedule with expected in-service dates for Levy Units 1 and 2 in 2024 and 2025, respectively. All of this work in 2013 and 2014 is reasonable and necessary to meet that schedule.

IV. FEASIBILITY.

Q. Did the Company prepare an updated LNP feasibility analyses?

A. Yes. The Company prepared the current feasibility analyses consistent with the feasibility analyses previously performed for the LNP that were reviewed and approved by the Commission in the prior four NCRC dockets. The Company employs both a qualitative and quantitative feasibility analysis. The qualitative analysis is an analysis of the technical and regulatory capability of completing the plants, the enterprise or external risks to the project, and the short- and long-term costs and benefits of completing the Levy nuclear power plants. The quantitative analysis is an updated CPVRR economic analysis that includes comparisons to the cost-effectiveness CPVRR analysis in the Company's need determination proceeding for the LNP described in Order No. PSC-08-0518-FOF-EI. The Company's updated CPVRR economic analysis for the LNP is included as Exhibit No. ___ (CMF-4) to my direct testimony. I explain the results of the Company's feasibility analyses for the LNP in my direct testimony and the exhibits to my direct testimony.

Q. How does the Company evaluate the LNP enterprise or external risks?

A. Consistent with past LNP feasibility analyses, the Company's qualitative analysis of the enterprise or external risks to the LNP is more of a holistic analysis rather than a pure measurable or computable analysis. The effects of most risks external to the project cannot be accurately quantified or measured in mathematical terms, they cannot realistically be weighed against other such risks, and, therefore, they cannot be compared using a quantifiable or measureable standard. The Company must instead evaluate them by identifying events or circumstances that have changed the LNP risk profile and then use its reasonable, business judgment to determine if those events or circumstances fundamentally change the holistic analysis comparing the risks and benefits associated with continuing the project. The Company continued this process for evaluating the LNP enterprise or external project risks as part of its qualitative feasibility analysis this year. These enterprise or external project risks include, but are not limited to, the LNP regulatory feasibility, the LNP technical feasibility, economic conditions, particularly in Florida, customer demand for energy and base load capacity, federal and state energy, environmental, and nuclear policy and regulation, capital markets, and long term fuel prices and diversity.

A. Regulatory Feasibility.

Q. Is the LNP feasible from a regulatory perspective?

A. Yes. All regulatory licenses and permits for the LNP can be obtained, including the LNP COL. I have attached as Exhibit No. ___ (CMF-5) to my direct testimony a chart of the current NRC review schedule and status for the LNP COLA. This chart shows that the Company is nearing completion of the NRC COLA process to obtain the LNP COL.

Q. Can you describe the NRC COLA process?

A. Yes. The Company filed its COLA with the NRC in July 2008 and it was docketed with the NRC for acceptance review in October 2008. This acceptance review initiated the NRC COLA review process. There are three parts to the NRC COLA review process: (i) the environmental review process; (ii) the safety review process; and (iii) the formal hearing process. All three parts of the NRC's review for the LNP COLA must be complete before the NRC will issue a COL for the LNP. See Exhibit No. ___ (CMF-5) to my direct testimony.

Q. What is the NRC environmental review process for the LNP?

A. The environmental review process involves the issuance of a draft environmental impact statement ("DEIS") followed by a public comment period before issuance of a final environmental impact statement ("FEIS") for the LNP.

Q. What is the status of the LNP environmental review process?

A. The LNP DEIS was issued in August 2010, the public comment period on the DEIS ended in October 2010, and the NRC Staff completed its responses to the public comments on the LNP DEIS in late 2011. DEF also completed responses to all identified U.S. Army Corps of Engineers ("USACE") information needs for the FEIS. The LNP FEIS was issued on April 27, 2012.

Q. What is the NRC safety review process for the LNP?

A. The second part of the NRC COLA review process is the review and issuance of a Final Safety Evaluation Report ("FSER"). This is preceded by NRC review of the LNP COLA and the NRC's issuance of an Advanced Safety Evaluation Report ("ASER") with no open items. Completion of the ASER signifies that the NRC Staff has completed the required safety review. The next step is review of the ASER by the Advisory Committee on Reactor Safeguards ("ACRS"). The ACRS is independent of the NRC staff and reports directly to the NRC Commissioners. The ACRS is an advisory body that is structured to provide a forum for experts representing different technical perspectives. The ACRS provides independent advice to the NRC Commissioners for consideration in their licensing decisions. The ACRS review and report is followed by NRC review and issuance of the FSER. NRC issuance of the FSER completes the NRC safety review for the LNP.

Q. What is the status of the NRC safety review process for the LNP?

A. The LNP ASER was completed on September 15, 2011. The Company and the NRC Staff met with the ACRS committee and completed review of the LNP ASER in December 2011. Subsequent to the ACRS review, the NRC Staff determined that certain recommendations from the NRC Fukushima Near Term Task Force should be implemented for new reactors prior to licensing. This NRC Staff determination was the basis for an additional RAI that was issued for the LNP COLA in March 2012 that required DEF to update its seismic information to incorporate the CEUS source data and computer model. DEF has updated its seismic information to incorporate the CEUS source data and model and DEF has provided a response to the NRC Staff to address issues identified as a result of the Fukushima event. The ACRS AP1000 subcommittee requested an additional meeting to review the actions taken to update the Levy COLA seismic information in response to Fukushima. This supplemental ACRS review was completed on January 18, 2013. The current NRC target for issuance of the LNP FSER is September 2013.

Q. Have the NRC Fukushima Near Term Task Force recommendations adversely affected issuance of the LNP COL?

A. No. DEF has addressed the NRC Fukushima Near Term Task Force recommendations that are relevant to the NRC's review of the LNP COLA by incorporating the CEUS source data and model in the seismic information for the LNP COLA and by establishment of license conditions for actions that needed to be completed post-COL. The NRC Task Force otherwise concluded in its Fukushima Near Term Task Force Report that the Fukushima event and resulting accident are unlikely to occur in the United States and that appropriate mitigation measures have been implemented, reducing the likelihood of core damage and radiological releases from United States nuclear power plants, in the unlikely event of a similar event and accident in the United States. The NRC Fukushima Near Term Task Force further concluded that many concerns inherent in an event like the Fukushima event are addressed in the passive design features in the Westinghouse AP1000 nuclear power plant design that is planned for the LNP. These conclusions support the continuation of the NRC's review of new plant licensing, in particular, the LNP COLA based on the AP1000 design. The NRC Fukushima Near Term Task Force further recognized that future regulatory or design modifications, which may be necessary based on further review of the Task Force recommendations, can be incorporated at a later date in NRC license conditions without impacting pending license approval reviews.

The NRC Fukushima Near Term Task Force recommendations and conclusions are a natural part of the NRC process of incorporating lessons learned into the NRC licensing review processes. The NRC and United States nuclear industry have a long history of continuously incorporating lessons learned from OE of nuclear power plants around the world. The careful analysis of the Japanese accident at Fukushima and incorporation of lessons learned into United States reactor designs and operating practices by the NRC and the nuclear industry was expected and will continue as the NRC and the industry continue to enhance planning and safety equipment to address any accidental and natural events. This is the way the United States nuclear industry operates to ensure safety at existing and planned nuclear power plants.

Q. What are the benefits of the AP1000 design that were recognized by the NRC Near Term Fukushima Task Force in its Report?

A. All existing and planned nuclear power plants, including AP1000 nuclear power plants, must be designed to address a wide range of natural disasters, whether they are earthquakes, tsunamis, tornados, hurricanes, storm surges, floods, or other extreme seismic or weather events. In the event of such natural disasters, the AP1000 nuclear power plant, in particular, does not rely on emergency diesel generators for safety related power to ensure core cooling. This is the passive design of the AP1000 nuclear power plant.

The AP1000 nuclear power plant relies on internal condensation and natural recirculation, natural convection and air discharge, and stored water all contained within the robust structures of the containment and its shield building to cool the reactor even without electrical power. With respect to the Fukushima event, for safety related cooling the damaged Japanese nuclear units depended on electrical power from diesel generators that were inoperable as a result of the tsunami. Unlike the Japanese reactors, then, the AP1000 nuclear power plant is designed to automatically place itself in a safe shutdown state, cooling the reactor passively without reliance on an external power source for some time until power is restored to the active coolant systems. The NRC Near Term Fukushima Task Force acknowledged the operation of these passive design features in an event like the Fukushima event in its review of the planned AP1000 nuclear power plants. The AP1000 nuclear reactor design planned for the Levy site will meet all requirements for operation under all potential conditions or circumstances, including the highly unlikely conditions and circumstances addressed in the NRC Fukushima Near Term Task Force Report.

Q. You mentioned the FSER schedule is delayed as a result of the Waste Confidence Decision, why has that Decision impacted the FSER schedule for the LNP?

A. The LNP COLA, similar to other pending license applications for new nuclear power plants and license renewals for existing power plants, relied on the

NRC Waste Confidence Decision and Rule. The NRC Waste Confidence Decision and Rule represent the NRC's generic determination that spent nuclear fuel can be stored safely and without significant environmental impacts for a period of time past the end of the licensed life of a nuclear power plant. This generic Decision and Rule, codified in Title 10 of the Code of Federal Regulations, was historically incorporated in the NRC's reviews for new reactor licenses and license renewals to satisfy the NRC's obligations under the National Environmental Policy Act ("NEPA") with respect to the storage of spent nuclear fuel on site after the end of the license for the nuclear power plant. NEPA requires a comprehensive evaluation of the potential environmental impacts of proposed agency action through an environmental assessment or an EIS before a final agency decision.

On June 8, 2012, the United States District Court of Appeals for the District of Columbia found that some aspects of the NRC's 2010 Waste Confidence Decision did not satisfy the NRC's obligations under NEPA and vacated the NRC's Waste Confidence Decision and Rule. In particular, the Court found that the NRC should have considered the potential environmental effects in the event the federal government fails to secure a permanent repository for disposing of spent fuel and should have included additional information regarding the impacts of certain aspects of potential leaks and fires involving spent fuel pools at nuclear power plant sites. The Court's decision required the NRC to address these concerns in any new Waste Confidence Decision and Rule.

On August 7, 2012, the NRC issued an Order that the NRC will not issue licenses dependent on the Waste Confidence Rule, which includes new reactor licenses like the LNP COL, until the NRC had appropriately addressed the Court's concerns in its decision vacating the NRC Waste Confidence Decision and Rule. The NRC's Order did not stay the review schedule for new reactor licenses including the LNP COLA. In fact, the NRC has proceeded with the review of the LNP COLA despite the Court's decision and the NRC Order; however, the NRC will not issue the LNP COL until the NRC has addressed the Court's concerns regarding the Waste Confidence Decision and Rule. As a result, the schedule for issuance of the LNP COL is impacted by the NRC Waste Confidence Decision and Rule.

Q. Is the NRC addressing the Court's concerns with respect to the Waste Confidence Decision and Rule?

A. Yes. On September 6, 2012, the NRC directed the NRC Staff to develop a generic EIS to support an updated Waste Confidence Rule no later than September 2014. The generic EIS will address the potential environmental impacts of the proposed Waste Confidence Rule, including the potential concerns raised by the Court in its decision vacating the prior Waste Confidence Decision and Rule, and it will form the technical basis for the proposed Waste Confidence Rule. The use of a generic EIS to address these concerns was approved by the Court in the decision that vacated and remanded the prior NRC Waste Confidence Decision and Rule.

The NRC is moving forward with the generic EIS and proposed Waste Confidence Rule. The NRC conducted an EIS scoping period between October 2012 and January 2013 for the proposed Rule and published a scoping summary report in early March, 2013. The NRC plans to publish the draft generic EIS for the proposed Waste Confidence Rule in September 2013. The draft generic EIS will be followed by a public comment period, and period for review and incorporation of comments into the generic EIS for the Waste Confidence Rule. Under the NRC's current Waste Confidence milestone schedule, the NRC currently expects to issue the final EIS for the Waste Confidence Rule, the Final Waste Confidence Decision, and the Final Waste Confidence Rule in August 2014.

Q. Does the Company still expect to receive the COL for the LNP from the NRC?

A. Yes. As I explained above, the NRC is proceeding with the LNP COLA review process, in parallel with the NRC's pending review of a new Waste Confidence Decision and Rule. In fact, the NRC has targeted issuance of the LNP FSER for September 2013 before a new Waste Confidence Decision and Rule are adopted. The NRC further expects to address and resolve the Court's concerns with the Waste Confidence Decision and Rule in a new Decision and Rule by August 2014. The NRC is already moving toward resolution of the Waste Confidence Decision and Rule by that date. Assuming that the NRC maintains its current schedule for the Waste Confidence Decision and Rule, pending COLs could be issued as early as September 2014. The Company expects the NRC to issue the LNP COL in December 2014, after completion of the formal hearing process this year or in 2014, which is the third part of the NRC COLA review process.

Q. What is the NRC formal hearing process for the LNP COLA?

A. There are two hearings as part of the NRC formal hearing process for the LNP COLA, a contested hearing process before the NRC Atomic Safety and Licensing Board ("ASLB") and a mandatory hearing process before the NRC. The contested hearing conducted by the NRC ASLB is for any contentions to the LNP COLA admitted by the ASLB. The ASLB is a three-member board of administrative judges independent of the NRC Staff who conduct adjudicatory hearings on major agency licensing actions. The mandatory hearing for the LNP COL is conducted by the NRC Commissioners. The focus of the mandatory hearing is on the adequacy of the NRC Staff review of the LNP COLA.

Q. What is the status of the NRC formal hearing process for the LNP COLA?

A. The contested hearing for the LNP COLA was conducted last fall and the ASLB issued a favorable decision this year. As background, in 2009, the ASLB allowed three private anti-nuclear groups, the Nuclear Information and Resource Service ("NIRS"), the Ecology Party of Florida ("EPF"), and the Green Party of Florida ("GPF"), to intervene in the NRC LNP COLA docket.

The ASLB ruled on their contentions and admitted parts of three contentions to the LNP COL. One of the three admitted contentions was dismissed by the ASLB in 2010. During the fourth quarter of 2011, the ASLB completed its review of the pending and revised contentions for the LNP COLA and, based on additional information provided by the Company, the ASLB dismissed another admitted contention. Only one environmental contention remained for consideration in the ASLB hearing. In this contention the interveners claimed the LNP FEIS failed adequately identify and assess the direct, indirect, and cumulative impacts of the LNP on wetlands and groundwater sources. DEF and the NRC responded to this contention that the LNP FEIS satisfied all NEPA requirements.

The ASLB conducted the contested hearing in Bronson, Florida, in late October and early November, 2012. The evidentiary hearing involved more than 300 exhibits and 24 witnesses. On March 26, 2013, the ASLB issued its decision finding in relevant part that the LNP FEIS fairly and reasonably described and addressed the site geology and hydrology and that the evidence did not support the interveners' claims. The ASLB concluded that the LNP FEIS complied with all legal and regulatory requirements. The ASLB decision is the NRC's final determination on the environmental issues raised by these interveners.

The LNP COLA mandatory hearing process cannot commence until the LNP FSER is issued. If the LNP FSER is issued by its NRC target date of September 2013, the mandatory hearing can be conducted as early as

November 2013. The NRC, however, has not yet scheduled the mandatory hearing for the LNP COLA. In any event, the Company currently expects the NRC to complete the mandatory hearing this year or next year, and then to issue the LNP COL in the fourth quarter of 2014. See Exhibit No. ___ (CMF-5) to my direct testimony for a chart and status of the LNP COLA process.

B. Technical Feasibility.

Q. Is the LNP feasible from a technical standpoint?

A. Yes, it is. Completion of the LNP is technically feasible because the AP1000 nuclear reactor design can be successfully installed at the Levy site. The AP1000 nuclear reactor design remains a viable nuclear reactor technology. The NRC has approved the AP1000 design, the AP1000 Design Control Document ("DCD"), and the AP1000 reference COL ("R-COL") for the AP1000 design when the NRC approved the Georgia Power Company Vogtle AP1000 COL. The NRC also approved the COL for the SCANA V.C. Summer AP1000 nuclear power units in South Carolina. Both the Southern Company and SCANA are moving forward with preconstruction and construction work for their AP1000 nuclear reactors. China is also constructing AP1000 nuclear reactors at Haiyang and Sanmen and the Chinese government has focused its nuclear generation development on the AP1000 nuclear reactor design. As I explained above, the NRC is continuing its review of the LNP COLA with the understanding that the AP1000 nuclear reactor design will be used at the Levy site. The ASLB recently issued its decision finding that the FEIS for the installation of the AP1000 nuclear power plants at the Levy site satisfied all legal and regulatory requirements. As a result, there is no reason to believe that the AP1000 nuclear reactor design cannot be successfully installed at the Levy site.

C. Enterprise or External Risks to the LNP.

Q. Did the Company evaluate the enterprise or external risks to the LNP this year?

A. Yes, it did. The Company conducted a qualitative analysis of the enterprise or external risks to the LNP that are beyond the control of the Company. This qualitative analysis included economic conditions, particularly in Florida, customer demand for energy and base load capacity, federal and state energy, environmental, and nuclear policy and regulation, capital markets, and long term fuel prices and diversity, among other qualitative factors. As I explain in more detail below, our qualitative analysis resulted in the determination that the LNP is still feasible from a qualitative perspective, and that there has been little change in the overall uncertainty, and thus, qualitative risk associated with the project is little changed from last year to this year. The Company continues to mitigate this uncertainty under the current project suspension through the anticipated receipt of the LNP COL and the revised project schedule that the Company presented to the Commission last year. This schedule is consistent with the Company's decision to move forward with the LNP on a slower pace with work focused on obtaining the

LNP COL and other, required permits for the project. The Company continues to believe this is the correct decision for the LNP at this time.

Q. What was the Company's assessment of the Florida economic conditions this year?

A. Economic conditions in Florida are slowly improving, with positive growth for two years, but the growth rate is still below the growth rate in Florida prior to the recession. Florida personal income is also growing slowly and the Florida unemployment rate is declining, with the rate just about equaling the national average for the first time since the recession. Florida population growth is also recovering. Florida, however, still has a lot of ground to make up following the worst economic recession in Florida since the Great Depression. The Florida Legislature Office of Economic and Demographic Research ("EDR") concluded in March 2013 that it still will take a long time for the Florida job market to recover with Florida having to create about 900,000 jobs for the same percentage of the total Florida population to be working after the recession as prior to the recession. See Exhibit No. ___ (CMF-6) to my direct testimony.

One reason is that the Florida housing and construction industries are improving, but they have not yet fully recovered from the recession. The housing and construction industries are important in Florida because they have led past Florida economic recoveries. Improving home sales and home prices are a boost to these industries, however, foreclosure activity in Florida is an impediment to growth in the Florida housing and construction industries. In 2012, for example, Florida had the highest foreclosure rate in the nation for the first time since the housing crisis began and, so far in 2013, Florida foreclosures continue to lead the nation. Between 2009 and 2011, Florida had the second highest number of foreclosure filings in the nation. Florida still has the third longest foreclosure resolution period in the nation at a little over two years from filing to resolution. See Exhibit No. ___ (CMF-6) to my direct testimony. The foreclosures will continue to be an impediment to growth in Florida's housing, real estate, and construction industries until they are brought in line with pre-recession foreclosure levels. Until then, the recovery will be slow and fragile in the Florida housing and construction industries.

As these examples illustrate, Florida's economy is recovering, there is growth, but it will still take time to make up ground lost during the recession. The EDR concluded in March 2013 that Florida growth rates are slowly returning to more typical levels, but drags are more persistent than in past recessions, and it will still take a few more years to climb completely out of the hole left by the recession. See Exhibit No. ___ (CMF-6) to my direct testimony.

Q. Was the Company impacted by the Florida economic conditions?

A. Yes. As the Company explained last year, the Company was not immune to the recession and its effects on Florida's economy. DEF lost customers during and immediately following the recession, DEF experienced dramatic declines in customer energy use and retail energy sales, and DEF experienced a dramatic increase in low use, vacant, but active accounts as a result of the residential and commercial vacancies and foreclosures, depressed real estate and construction industries, and high unemployment in Florida as a result of the recession. Since then, as the Florida economy has slowly recovered, DEF has experienced a slow recovery as well. DEF's customer growth returned and is expected to continue to grow, leading to increased retail energy sales. However, energy use per customer, while no longer declining, is growing slowly and remains below pre-recession energy use per customer rates, depressing the potential growth in retail sales revenues that the Company is experiencing from customer growth. As a result, near term energy sales remain at levels well below pre-recession levels. Over the long term, customer growth, customer energy use and, thus, retail energy sales and load will continue to increase as the Florida economy improves. An immediate return to pre-recession retail energy sales growth levels, however, is not expected. Rather, the Company expects a more gradual increase in retail load and resulting energy sales in the future.

Q. How did the Company evaluate the Florida economic conditions this year?

A. We explained last year that that the Florida economy was taking longer to rebound from the recession than expected. We observed the commencement of economic improvement last year and the Florida economy is continuing to slowly improve this year. We expect the Florida economy to continue to improve, but the economic recovery is going to take time. That economic recovery is also still fragile. In the near term, then, we do not see a return to the robust economic growth that existed prior to the recession and the Florida economy is susceptible to another economic downturn. As a result, we continue to believe that the Company's decision to continue with the LNP on a slower pace, focusing on obtaining the COL and revising its project schedule last year, is the right decision for the Company and its customers. This decision delays significant, near term capital investments required to commence construction of the LNP until after the COL is obtained, providing additional time for the Florida economy to strengthen, and, therefore, aligning the economic circumstances facing the Company and its customers with the current project plan.

As we also explained last year, the Florida economic conditions are one of the reasons for the levelized LNP costs in the 2012 Stipulation and Settlement Agreement between DEF and the customer group representatives that was approved by the Commission. This settlement reduces the near-term impact of the LNP costs on customer bills, thus providing customers rate relief until the Florida economy can more fully recover from the recession. The settlement continues the Company's efforts between 2009 and 2012 to balance the customers' ability to pay for the LNP and the need to develop the LNP for the customers' long term benefit.

Q. What changes were there this year in the Company's evaluation of the federal and state energy and environmental policy affecting the LNP?

A. The Company's evaluation of the federal and state energy and environmental policy, legislation, or regulation is essentially the same; little has changed since last year. There remains no federal or state climate control legislation or greenhouse gas ("GHG") legislation that implements a cap-and-trade system or carbon tax on fossil fuel generation. Congress has not taken action on any climate control, GHG emission, or clean energy bill and no Congressional action is expected this year. Likewise, the Florida Legislature repealed the Florida Climate Protection Act last year and no replacement state climate control or GHG legislation is expected. There is no proposed Florida legislation on climate control, GHG emission, clean energy or renewable energy standards. In sum, there continues to be near term uncertainty regarding the direction of federal and state energy and climate control policy.

Q. Is the Environmental Protection Agency still pursuing the regulation of GHG emissions?

A. Yes. The federal Environmental Protection Agency ("EPA") has aggressively pursued the regulation of GHG emissions under the Clean Air Act ever since the United States Supreme Court held in 2007 that GHG are covered by the Clean Air Act. That decision led to the EPA endangerment finding for GHG emissions from new motor vehicles, which triggered the regulation of GHG emissions by other sources, in particular stationary sources like electric power plants, under the Clean Air Act. In 2010, the EPA implemented the Tailoring Rule, which required limits on GHG emissions in air permits for new, large industrial sources and other, major, new and modified sources, leading to Prevention of Significant Deterioration ("PSD") permits implementing best available control technology ("BACT") for GHG emissions by 2011. The EPA completed the phase-in of the Tailoring Rule for GHG emissions for new power plants with Plant-wide Applicability Limits ("PALs") for GHG emissions in February 2012. The EPA has also implemented GHG emission reporting requirements for power plants and other GHG emission sources. And, in March 2012, the EPA proposed GHG emission standards for new power plants. This proposed new source performance standard ("NSPS"), for the first time, will set uniform national limits on the amount of GHG emissions new power plants can emit.

The EPA's regulation of GHG emissions from new power plants has not yet extended to existing power plants. Previously proposed legislation and litigation intended to reverse or delay EPA's efforts to regulate GHG emissions have not been effective, however, the EPA does not appear to be pursuing the regulation of GHG emissions from existing power plants. The EPA has not issued a Tailoring Rule and NSPS for GHG emissions from existing power plants, and it is unclear if and when the EPA would attempt such regulation without congressional legislation supporting it. As a result, the EPA regulation of GHG emissions from existing power plants remains uncertain; however, it is not expected at this time.

Q. Is this federal and state energy and environmental policy still relevant to your evaluation of the LNP?

A. Yes. Federal and state energy and environmental policy, in particular the regulation of power plant emissions including GHG emissions as a result of climate control legislation or regulation, is still fundamental to the Company's evaluation of the LNP against natural gas-fired, fossil fuel generation. Qualitatively, climate control or GHG emission legislation or regulation promotes nuclear over fossil fuel generation because nuclear energy generation produces no GHG emissions. Quantitatively, the potential effect of climate control or GHG emission legislation or regulation is reflected in an estimated carbon cost impact in the Company's economic, CPVRR feasibility analysis. This carbon cost impact is a significant driver in the Company's quantitative evaluation of generation resource options. As a result, federal and state energy and environmental policy continues to be a fundamental enterprise or external risk to the LNP.

Presently, climate control legislation is still being discussed at the federal level and the debate appears to be about how and when to implement such legislation rather than whether there is a need for future climate control legislation. Additionally, the EPA continues to regulate GHG emissions and the courts so far have upheld the EPA's existing GHG emission regulations. The EPA, therefore, is unlikely to recede from and will continue to regulate GHG emissions. As a result, DEF still expects a federal Clean Air Act standard for carbon and other GHG emissions in the future that extends the current regulation of carbon and other GHG emissions to existing power plants. However, what form a uniform climate control or GHG emission policy for all power plants will take and when that legislation or regulation will be implemented remains unclear. The effect of GHG emission legislation or regulation on the LNP, therefore, continues to be uncertain at this time.

Q. Is climate control or GHG emission legislation or regulation the only federal or state energy and environmental policy that affects the LNP evaluation?

A. No. The potential development of a "Clean Energy" standard, which includes new nuclear and other non-traditional renewable resources, or a renewable portfolio standard ("RPS") at the federal level or in Florida also can affect the evaluation of the LNP as a generation resource option. Obviously, a "Clean Energy" standard that promotes new nuclear as well as traditional renewable resources benefits nuclear generation in the evaluation of generation resource options. A RPS standard also affects the evaluation of generation resource options because RPS resource options generally are more costly on a dollar per energy output valuation than conventional generation resource options, like nuclear and fossil fuel generation, and RPS resources such as wind or solar are considered intermittent resources meaning they require conventional generation support during the periods they are unavailable. While a federal "Clean Energy" standard was proposed, no "Clean Energy" standard has been adopted at the federal or state level. Various jurisdictions across the country have adopted RPS, but there still is no federal or Florida RPS. In fact, the Florida Legislature has not approved the Commission's proposed RPS rule that the Florida Legislature directed the Commission to adopt and submit for legislative approval in 2008. A federal or Florida "Clean Energy" standard or RPS, therefore, is unlikely in the foreseeable future.

Other federal and state environmental legislation and regulation also affect the evaluation of the LNP by effectively narrowing the viable base load generation resource alternatives to natural gas-fired, fossil fuel generation or new nuclear generation in Florida. For example, proposed EPA regulations for cooling water intake structures under Section 316b of the Clean Water Act, the proposed Coal Combustion Residuals Rule ("CCR"), and the Mercury and Air Toxics Standards Rule ("MATS"), among other federal and state environmental regulations affecting fossil fuel generation, increase the potential for coal plant retirements that fail to meet these requirements and decrease the cost effectiveness of new coal generation as a viable resource alternative. As a result of such proposed and existing environmental regulation, the likelihood is that existing coal plants will be replaced with gas generation, and that gas generation will be the default alternative generation resource, absent consideration of new nuclear generation as a base load generation resource.

Finally, federal support for new nuclear development is also an important federal energy policy that affects the evaluation of new nuclear against other conventional, fossil fuel generation resource alternatives. Clear federal support for new nuclear generation benefits new nuclear generation in the utility's generation resource alternatives evaluation. Federal support for new nuclear generation, however, is currently unclear. The current Administration still supports the abandonment of Yucca Mountain as the federal nuclear waste storage option and no alternative federal nuclear waste storage option has been proposed by this Administration. Additionally, the current Administration has not clearly defined its stated support for the development of new nuclear generation. As a result, this support remains uncertain.

Q. What does the absence of an Energy Policy or Climate Change Regulations mean for your qualitative analysis of the feasibility of the LNP this year?

A. Similar to the Company's qualitative evaluation last year, there is no reason to expect more certainty this year with respect to federal or state energy and environmental policy affecting the evaluation of the LNP as a generation resource. Likewise, there is no clear federal nuclear generation policy that supports the development of nuclear generation in the face of this uncertain federal energy and environmental policy. In sum, the continued uncertainty as a result of the lack of clear federal or state legislative or regulatory direction that impacts the development of nuclear generation is a continuing risk in the qualitative evaluation of the feasibility of the LNP.

Q. Does state nuclear generation policy affect the Company's qualitative evaluation of the LNP?

A. Yes. In 2006, the Florida Legislature passed legislation with near unanimous support that created the nuclear cost recovery statute, Section 366.93, Florida Statutes, and amended the need determination statutory provision, Section 403.519, Florida Statutes, to promote fuel diversity and electric supply reliability by encouraging utility investment in nuclear power plants. This same legislation directed the Commission to develop alternative cost recovery mechanisms for the recovery of all prudently incurred preconstruction costs, as well as the carrying charges on prudently incurred construction costs, for nuclear power plants and related new, expanded, or relocated transmission lines and facilities. The Commission fulfilled this legislative directive when it adopted the nuclear cost recovery rule, Rule 25-6.0423, F.A.C. The Company developed and has continued to pursue the development of the LNP based on this legislation and the Commission rule promoting investment in new nuclear generation in the State.

Each year since this legislation promoting the development of new nuclear generation like the LNP was adopted by the Florida Legislature, the same individual state legislators have introduced bills to repeal the legislation, which so far, have proved unsuccessful. This year, however, there are also proposed bills to amend the nuclear cost recovery statute that alter the provisions promoting investment in new nuclear generation in the original nuclear cost recovery statute and provide for the sunset of the legislation in the near future unless legislative action is taken to renew the statute. These proposed bills to repeal or amend the nuclear cost recovery statute, in the Company's view, are inconsistent with and undermine the original and still purported legislative intent to promote fuel diversity and electric generation reliability by promoting utility investment in new nuclear generation.

The State's energy policy reflected in the nuclear cost recovery statute and amendments to the need determination statute has not changed. That express State energy policy is to increase fuel diversity and increase electric generation reliability by reducing Florida's dependence on fossil fuels subject to supply interruptions and price volatility through the investment in new nuclear generation. This express State energy policy cannot be met by the current bills to repeal or amend the very statute that implements this energy policy. Continued legislative support for the nuclear cost recovery statute promoting the development of new nuclear generation in Florida is necessary to fulfill this express State energy policy.

Q. Have there been other challenges to the nuclear cost recovery statute in Florida?

A. Yes. Since 2010, several purported class action lawsuits have been filed in the state and federal courts challenging the constitutionality of the nuclear cost recovery statute. Also, a group opposed to new nuclear development appealed the Commission's decision in the 2011 nuclear cost recovery clause docket to the Florida Supreme Court, challenging the decision and the constitutionality of the nuclear cost recovery statute. The Florida Supreme Court has not yet decided this appeal and it is unclear when the Court will issue its decision. As the Company explained last year, the Company does not believe that these legal challenges are well founded, and the state and federal courts have so far agreed. Repeated legal efforts to undermine the nuclear cost recovery statute, however, create additional risk and uncertainty for the LNP.

Q. Last year, the Company identified natural gas fuel prices as an increased qualitative risk, as well as a quantitative factor, in the LNP feasibility analysis. Have there been any changes in the Company's qualitative assessment of this factor this year?

A. The Company's assessment of near term natural gas fuel prices has not changed. Natural gas fuel prices remain at near historic low prices. The impact of the recession on natural gas fuel prices is less of a factor now, instead current, low natural gas fuel prices appear to be driven by over supply and near capacity natural gas storage conditions resulting from the development of unconventional shale gas resources. As a result, near term natural gas prices in recent natural gas forecasts continue to be depressed, reflecting the addition of unconventional shale gas resources to the supply of natural gas in the price forecasts.

This trend in near term natural gas fuel prices has led to another developing trend, the increase in demand for natural gas as a result of new natural gas-fired industrial plants and power plants and the conversion of other fossil fuel industrial plants and power plants to natural gas. This trend is exemplified by the country's relatively rapid conversion from an electric generation system fueled primarily by coal to one fueled more and more by natural gas. In 2000, coal fired generation accounted for over 50 percent of all electrical generation in the United States. That percentage has fallen to almost 40 percent in about a decade, and it is projected to continue to fall to less than 30 percent in the next two decades. The percentage of electrical generation from natural gas generation is rising and will continue to rise over the same time period. These percentage changes for the total electric generation by fuel type in the country are dramatic. Seasonal variations in the generation of electricity by fuel type are even more dramatic, with electricity production from natural gas equaling the generation of electricity from coal on a monthly basis for the first time in the spring of 2012. We expect the increased demand for natural gas fired generation will lead to increases in the long term forecasts of natural gas fuel prices.

There are other supply and demand factors that could also put upward pressure on natural gas prices over time. On the demand side, for example, the potential replacement of coal plants with natural gas generation is enhanced by the acceleration in coal plant retirements due to the current and proposed EPA environmental regulations I discussed briefly above, including MATS and CCR. Additionally, the demand for natural gas will expand with the development of domestic Liquefied Natural Gas ("LNG") projects to export domestic natural gas abroad. On the supply side, for example, new regulations associated with hydraulic fracturing are being developed that may increase the production cost for natural gas. For these additional reasons, over the long-term, natural gas fuel prices are forecasted to increase.

These trends in natural gas fuel prices are quantified in the Company's quantitative CPVRR feasibility analysis. As the Company has explained before, natural gas prices are a key driver in the CPVRR analysis. Generally, lower natural gas price fuel forecasts reduce, and higher natural gas price fuel forecasts increase, the cost-effectiveness of new nuclear generation. The current trends described above are reflected in lower, near-term natural gas prices, and slightly increasing longer term natural gas prices, in the Company's current fuel forecasts in the economic feasibility analysis for the LNP this year.

The qualitative assessment of the natural gas price forecasts considers a broader time period than the year-to-year quantitative CPVRR analyses. Qualitatively, for the reasons described above, the decline in near term natural gas prices appears to be offset now by increasing long term natural gas prices in the forecast. Thus, the downward trend in near term natural gas prices due to the advent of unconventional shale gas reserves does not appear to represent a long-term trend in natural gas price forecasts. The Company believes, then, that there will not be a fundamental shift in fuel prices reflecting a longer-term trend of historic low natural gas prices similar to recent, historically low natural gas prices in the fuel forecasts over the expected sixty-year life of the Levy nuclear units.

Q. Has the Company considered the access to the financial or capital markets for the LNP in its qualitative evaluation of the LNP?

A. Yes, the ability to finance the LNP is always an implicit if not explicit consideration in the evaluation of the LNP. One favorable factor, as I mentioned above, is the beneficial provisions of the nuclear cost recovery statute and rule that are designed to promote investment in new nuclear generation through the recovery of prudent nuclear preconstruction costs and carrying charges on prudent nuclear construction costs. The Company's ability to attract the capital necessary to finance the LNP is also enhanced by the merger between Duke Energy and Progress Energy, Inc. that was completed in July 2012. This merger creates the largest regulated electric utility in the country with a total market cap of approximately $50 billion and over $19 billion in operating revenues. The Company also maintains favorable credit ratings from the rating agencies. These factors, among others, position the Company well to access the capital markets for the capital necessary to build the LNP.

Q. Overall, has there been a significant change in the Company's qualitative feasibility analysis for the LNP since last year?

A. No. Our qualitative analysis of the LNP enterprise or external risks this year reflects continued near term uncertainty, however, the Company has mitigated those risks with its plan last year to commence construction of the LNP in time to place the Levy nuclear units in service in 2024 and 2025. As a result of this decision, the Company does not need to commence construction in the near term and the Company can continue to focus its efforts on obtaining the COL for the LNP from the NRC over the next two years. In the meantime, the Company will continue to evaluate the feasibility of the LNP each year consistent with the Commission's rule and Orders.

D. <u>Quantitative Feasibility Analysis.</u>

Q. Did the Company prepare a quantitative feasibility analysis this year?

A. Yes. DEF prepared a CPVRR analysis consistent with the economic analysis approved by the Commission in Commission Orders No. PSC-09-0783-FOF-EI, No. PSC-11-0095-FOF-EI, No. PSC-11-0547-FOF-EI, and No. PSC-12-0650-FOF-EI. The CPVRR analysis includes the required updated fuel, environmental, and carbon compliance cost estimates. The CPVRR analysis also includes a project cost estimate based on the estimated in-service dates for the Levy nuclear power plants. Similar to prior CPVRR analyses, the updated CPVRR economic analysis compares the LNP to an all natural gas-fired base load generation scenario using a range of fuel forecasts and a range of potential carbon compliance cost estimates. The current CPVRR analysis also includes CPVRRs for DEF ownership levels of the LNP of 100 percent, 80 percent, and 50 percent and total LNP project cost sensitivities for cases ranging from 15 percent less to 25 percent greater than the estimated total project cost. This is the same approach that the Company used to prepare the CPVRR cost-effectiveness analysis in the need determination proceeding for the LNP and in the 2009, 2010, 2011, and 2012 NCRC proceedings. See Exhibit No. __ (CMF-4) to my direct testimony.

Q. What were the results of the Company's quantitative feasibility analysis?

A. The updated CPVRR analysis shows that the LNP overall is more cost effective than the all natural gas generation resource plan. The CPVRR analysis shows that the LNP generation resource plan is more cost effective in 10 out of 15 cases at the 100 and 80 percent ownership levels, and 9 out of 15 cases at the 50 percent ownership level. See Exhibit No. __ (CMF-4), p. 8. The CPVRR analysis this year demonstrates that the LNP resource plan remains cost-effective.

Q. How does this updated CPVRR analysis compare to the CPVRR analysis in the LNP need case?

A. Just like last year, the results in the updated CPVRR analysis are similar to the results in the CPVRR analysis in the LNP need case. At the 100 percent ownership level, the LNP is more favorable than the all natural gas resource plan in 10 out of 15 potential fuel and carbon cost emission scenarios in the updated CPVRR analysis and in the CPVRR analysis in the LNP need determination proceeding. The difference is that the LNP is more cost effective in the current CPVRR analysis in all of the high and mid-fuel reference cases except the no carbon, mid-fuel reference case, and in only the highest carbon, low fuel reference case, while the LNP is more cost effective in the CPVRR analysis in the LNP need case in all of the high and mid-fuel reference cases, except the lowest carbon and no carbon cases, and more cost effective in the highest and second highest carbon cases in the low fuel reference case. See Exhibit No. ___ (CMF-4), pp. 7, 8. Both CPVRR analyses indicate that the LNP is more cost effective than the all natural gas resource plan in more potential fuel and carbon cost emission scenarios at the 100 percent, 80 percent, and 50 percent ownership levels. See Exhibit No. ___ (CMF-4), pp. 7, 8. The updated CPVRR analysis produces similar results to the CPVRR analysis results in the LNP need case even though the updated CPVRR analysis includes the current 2024 and 2025 in-service dates for the Levy nuclear units and a corresponding higher total project cost than the need case CPVRR analysis.

Q. What are your conclusions from the updated CPVRR feasibility analysis?

A. Again, just like last year, the updated CPVRR analysis continues to indicate that the LNP is cost effective and, therefore, an economically viable future generation resource. The updated CPVRR analysis continues to confirm the preference for the LNP as a future base load generation resource. The LNP still has the potential to provide customers with billions of dollars of savings over the expected sixty-year life of the project. The CPVRR analysis, however, is not a litmus test for the LNP. The CPVRR analysis is a snapshot of the project's estimated economic viability and the Company continues to believe that the long term projections upon which the CPVRR analysis are based on are necessarily uncertain and subject to change from year-to-year. For this reason, this type of analysis cannot be the sole basis for the Company to determine when to proceed with construction of the project. The CPVRR is simply one factor among many factors that must be considered in making a decision about moving forward with construction of the project.

V. LNP PROJECT RECOMMENDATION AND SMC DECISION.

Q. Did the Company's senior management evaluate the LNP this year?

A. Yes. Consistent with prior years, senior management for the Company evaluated the LNP to determine the optimal path forward on the LNP for the Company and its customers. The Company considered continuing with the current project plan, re-negotiating the EPC agreement while continuing the project, or cancelling the project in favor of the base case assumption of natural gas generation used in the CPVRR analysis each year in this evaluation. LNP project management completed this evaluation and recommended that the Company continue with the current LNP project plan.

Senior management accepted this recommendation and approved funding for the LNP consistent with the current LNP project plan.

Q. What did the Company evaluate in making the recommendation to senior management to continue with the current LNP project plan?

A. The Company's evaluation and recommendation was based on the Company's qualitative and quantitative feasibility analyses for the LNP. The Company determined that the LNP was both qualitatively and quantitatively feasible. The Company can complete the Levy nuclear power plants. The LNP COL and other necessary permits to construct the LNP have been or can be obtained and the AP1000 nuclear reactor design can be installed at the Levy site. The LNP is cost effective over the life of the Levy nuclear units for the Company's customers. Lower near term natural gas price forecasts and delayed expectations of carbon cost impacts presently diminish the economic benefits of the LNP, but they do not make it economically infeasible. The LNP still represents the best long-term, base load generation resource for DEF's customers. It will provide long-term fuel savings benefits to customers from a low-cost and clean energy fuel source. The LNP will also improve fuel diversity for the Company and the State and reduce their reliance on fossil fuels to generate electrical energy. The LNP will provide customers with a reliable, long-term source of base load generation.

The near term uncertainty associated with the enterprise or external LNP risks has been mitigated to a degree by the current LNP project plan that estimates the in-service dates for the Levy nuclear units in 2024 and 2025. The current LNP project plan puts off the construction of the LNP and, therefore, significant capital investments in the LNP until after the COL is obtained. The LNP COL is not expected before the end of 2014. In the meantime, economic conditions in Florida can continue to improve, federal and state energy and environmental policy can develop and, federal and state support for the development of nuclear generation to promote fuel diversity and base load generation reliability can stabilize. This provides time, then, for more certainty to develop with respect to the project's enterprise or external risks, thus, mitigating the impact of these risks on the project at this time. For all these reasons, as explained in more detail above, the LNP project management recommended and senior management accepted the decision to continue with the current LNP project plan.

VI. TRUE UP TO ORIGINAL COST FILING FOR 2013.

Q. Has the Company filed schedules to provide information truing up the original estimates to the actual costs incurred?

A. Yes. The true up to original cost ("TOR") schedules are attached as Exhibit No. ___ (TGF-5) to Mr. Foster's testimony. I am co-sponsoring schedule TOR-4 and sponsoring schedule TOR-6A attached as Exhibit No. ___ (TGF-5) to Mr. Foster's testimony.

Q. Do these schedules reflect the current LNP total project cost estimate?

A. Yes. The updated project estimate is consistent with the Company's estimated in-service for Levy Unit 1 in 2024 and estimated in-service for Levy unit 2 in 2025. The LNP total project cost estimate is still premised on a conservative Class 5 estimate consistent with the best practices of the Association for the Advancement of Cost Engineering ("AACE"), fundamental terms and conditions of the existing EPC Agreement and current market conditions, and the current project schedule for the LNP. For these reasons, the current total project cost estimate for the LNP is reasonable. The current total project cost estimate, however, is dependent upon, among other things, future Consortium negotiations to amend, modify, or alter the EPC agreement.

VII. JOINT OWNERSHIP.

Q. What is DEF's current position on joint ownership for the LNP?

A. DEF continues to believe that joint ownership in the LNP provides DEF and its customers the benefits of sharing the costs and risks of the LNP with other potential joint owners. DEF will continue to pursue joint ownership opportunities in the LNP.

Q. Has the status of joint ownership in the LNP changed?

A. No. As the Company explained last year, potential joint owners continue to express interest in the project; however, the delay in the receipt of the COL has shifted the time table for significant discussions with potential joint owners to the late 2014 timeframe. Potential joint owners still value the fuel diversity and clean energy production that new nuclear generation provides in a future that includes increasing fossil fuel environmental regulations and carbon and other GHG emission constraints. New nuclear generation is still a prudent future generation resource for Florida. Accordingly, potential joint owners are still interested in the LNP and the Company will continue joint ownership discussions and meetings with potential joint owners at the appropriate time.

VIII. PROJECT MANAGEMENT AND COST CONTROL OVERSIGHT.

Q. Has the Company implemented any additional project management and cost control oversight mechanisms for the LNP since your testimony was filed on March 1, 2013?

A. No, the Company has not implemented any significant, additional project management or cost control oversight policies or procedures for the LNP since my March 1, 2013 direct testimony. The Company continues to utilize the Company policies and procedures that I described in that testimony to ensure that costs for the LNP are reasonably and prudently incurred. The Company will continue to review policies, procedures, and controls on an ongoing basis, however, and make revisions and enhancements based on changing business conditions, organizational changes, and lessons learned, as necessary. This process of continuous review of our policies, procedures, and controls is a best practice in our industry and is part of our existing LNP project management and cost control oversight.

Q. Are these the same policies and procedures that the Commission has previously reviewed for the LNP?

A. Yes. The Commission has previously determined that the LNP project management and cost oversight controls were reasonable and prudent. The Company's current LNP management and cost oversight controls policies and procedures are substantially the same as the policies and procedures reviewed and previously determined to be reasonable and prudent by the Commission.

Q. Are these LNP management and cost controls policies and procedures consistent with best practices in the industry?

A. Yes. We believe that our LNP project management and cost oversight policies and procedures are consistent with best practices for capital project management in the industry. We believe the project management, contracting, and cost control policies and procedures that we have implemented for the LNP are reasonable and prudent and consistent with industry best practices.

IX. CONCLUSION.

Q. Does this conclude your direct testimony?

A. Yes.

CHAIRMAN BRISÉ: Okay. I think we have some staff witnesses that we have to deal with.

MR. LAWSON: Yes. At this time we would like to move in without changes the prefiled testimony of staff witnesses Coston, Hallenstein, and Small, and ask they be moved into the record at this time.

CHAIRMAN BRISÉ: Okay. We will move into the record witnesses Coston, Hallenstein, and Small into the record, seeing no objections. Okay. So they are moved into the record at this time.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT JOINT TESTIMONY OF

WILLIAM COSTON AND JERRY HALLENSTEIN

DOCKET NO. 130009-EI

JUNE 20, 2013

Q. Mr. Coston, please state your name and business address.

A. My name is William Coston. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850.

Q. By whom are you employed?

A. I am employed by the Florida Public Service Commission (Commission) as a Public Utilities Analyst IV, within the Office of Auditing and Performance Analysis.

Q. What are your current duties and responsibilities?

A. I perform audits and investigations of Commission-regulated utilities, focusing on the effectiveness of management and company practices, adherence to company procedures, and the adequacy of internal controls. Mr. Hallenstein and I jointly conducted the 2013 audit of Duke Energy Florida, Inc.'s (DEF) project management internal controls for the Extended Power Uprate (EPU) project at the Crystal River Unit 3 and Levy Nuclear Project.

Q. Please describe your educational and relevant experience.

A. I earned Bachelor of Arts and Master of Public Administration degrees from Valdosta State University. I have worked for the Commission for ten years conducting operations audits and investigations of regulated utilities. Prior to my employment with the Commission, I worked for six years at Bank of America in the Global Corporate and Investment Banking division.

Q. Have you filed testimony in any other dockets before the Commission?

A. Yes. I filed similar testimony in Docket No. 090009-EI, 100009-EI, 110009-EI and 120009-EI. This testimony addressed the audits of DEF's project management internal controls for the nuclear plant uprate at the Crystal River Unit 3 and the Levy Nuclear Project for the years 2009 through 2012. Additionally, in 2005 I filed testimony in Docket No. 050078-EI. The testimony addressed an audit of distribution electric service quality for Progress Energy Florida's vegetation management, lightning protection, and pole inspection processes.

Q. Mr. Hallenstein, please state your name and business address.

A. My name is Jerry Hallenstein. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850.

Q. By whom are you employed?

A. I am employed by the Commission as a Senior Analyst, within the Office of Auditing and Performance Analysis.

Q. What are your current duties and responsibilities?

A. I perform audits and investigations of Commission-regulated utilities, focusing on the effectiveness of management and company practices, adherence to company procedures, and the adequacy of internal controls. Mr. Coston and I jointly conducted the 2013 audit of DEF's project management internal controls for the nuclear plant uprate at the Crystal River Unit 3 and new construction underway at the Levy site.

Q. Please describe your educational and relevant experience.

A. I earned a Bachelor of Science in Finance from Florida State University in 1985. I have worked for the Commission for twenty-three years conducting operations audits and investigations of regulated utilities. Prior to my employment with the Commission, I worked for five years at Ben Johnson Associates, a consulting firm that specializes in providing economic and research services to state regulatory commissions.

Q. Have you filed testimony in any other dockets before the Commission?

A. Yes. I filed similar testimony in Docket No. 120009-EI. This testimony addressed the audits of DEF's project management internal controls for the nuclear plant uprate at the Crystal River Unit 3 and the Levy Nuclear Project for the year 2012. Additionally, I filed testimony in Docket 981488-TI, with an audit I conducted regarding the billing and sales practices of Accutel Communications, a reseller of telecommunications services.

Q. Please describe the purpose of your testimony in this docket.

A. Our testimony presents the attached confidential audit report entitled *Review of Duke Energy Florida, Inc.'s Project Management Internal Controls for Nuclear Plant Uprate and Construction Projects* (Exhibit CH-1). This audit completed to assist with the evaluations of nuclear cost recovery filings. The report describes key project events and contract activities completed during 2012 through April 2013 for the Crystal River 3 Uprate project and the Levy Nuclear Project. The report also presents descriptions of the current project management internal controls employed by DEF.

Q. Please summarize the areas examined by your review.

A. The Office of Auditing and Performance Analysis conducted an audit of the internal controls and management oversight of the nuclear projects underway at DEF. This is an ongoing annual review that examines the organizations, processes, and controls being used by the company to execute the Extended Power Uprate of Unit 3 at the Crystal River Energy Complex and the construction of Levy Nuclear Plant Unit 1 and Unit 2. The previous reviews were filed annually, since 2008, in the Nuclear Cost Recovery Clause dockets before the Commission.

The primary objective of this audit was to assess and evaluate key project developments, along with the organization, management, internal controls, and oversight that

DEF has in place or plans to employ for these projects. The internal controls examined were related to the following key areas of project activity: planning, management and organization, cost and schedule controls, contractor selection and management, and auditing and quality assurance.

Q. Are you sponsoring any exhibits?

A. Yes, our audit report is attached as Exhibit CH-1. The audit report's observations are summarized in the Executive Summary chapter for both the Extended Power Uprate project and the Levy Nuclear Project.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF JEFFERY A. SMALL

DOCKET NO. 130009-EI

JUNE 21, 2013

Q. Please state your name and business address.

A. My name is Jeffery A. Small and my business address is 4950 West Kennedy Blvd, Tampa, Florida, 33609.

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

A. I am employed by the Florida Public Service Commission as a Professional Accountant Specialist in the Office of Auditing and Performance Analysis.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission (FPSC) since January 1994.

Q. Briefly review your educational and professional background.

A. I have a Bachelor of Science degree in Accounting from the University of South Florida. I am also a Certified Public Accountant licensed in the State of Florida.

Q. Please describe your current responsibilities.

A. Currently, I am a Professional Accountant Specialist with the responsibilities of planning and directing the most complex investigative audits. Some of my past audits include cross-subsidization issues, anti-competitive behavior, and predatory pricing. I am also responsible for creating audit work programs to meet a specific audit purpose and integrating EDP applications into these programs.

Q. Have you presented expert testimony before this Commission or any other regulatory agency?

A. Yes. I have provided testimony in the Progress Energy Florida, Inc., (PEF) Nuclear Cost Recovery Clause filings, Docket Nos. 080009-EI, 090009-EI, 100009-EI, 110009-EI, and 120009-EI.

I have also testified in the Southern States Utilities, Inc. rate case, Docket No. 950495-WS, the transfer application of Cypress Lakes Utilities, Inc., Docket No. 971220-WS, and the Utilities, Inc. of Florida rate case, Docket No. 020071-WS.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor two staff audit reports of PEF which address the Utility's application for nuclear cost recovery in 2012. The first audit report was issued May 24, 2013, and addressed the pre-construction and construction cost as of December 31, 2012, for Levy County Nuclear Units 1 & 2. This audit report is filed with my testimony and is identified as Exhibit JAS-1. The second audit report was issued May 17, 2013, and addressed the 2012 power uprate costs for the Crystal River Unit 3 nuclear power plant. This audit report is filed with my testimony and is identified as Exhibit JAS-2.

Q. Were these audits prepared by you or under your direction?

A. Yes, these audits were prepared by me or under my direction.

Q. Please describe the work you performed in these audits.

For the first audit report, to address the pre-construction and construction costs as of December 31, 2012, for Levy County Nuclear Units 1 & 2:

- We reconciled the Company's filing to its general ledger and verified that the costs incurred were posted to the proper accounts.
- We reconciled and recalculated a sample of the monthly revenue requirement accruals displayed on Schedule T-1 to the supporting schedules in the Company's 2012 NCRC filing.
- We reconciled the monthly preconstruction, and construction carrying cost balances

displayed on Schedules T-2.2, and T-2.3, respectively, to the supporting schedules in the Company's 2012 NCRC filing. We recalculated the schedules and reconciled the Allowance for Funds Used During Construction (AFUDC) rates applied by the Company to the rates approved in Order No. PSC-05-0945-S-EI, in Docket No. 050078-EI, issued September 28, 2005.

- We reconciled the monthly preconstruction deferred tax carrying cost accruals displayed on Schedule T-3A.2 to the supporting schedules in the Company's 2012 NCRC filing. We recalculated a sample of the monthly carrying cost balances for deferred tax assets based on the equity and debt components established in Order No. PSC-05-0945-S-EI.
- We recalculated a sample of the monthly recoverable O&M expenditures displayed on Schedule T-4 of the Company's 2012 NCRC filing. We sampled and verified the O&M cost accruals and traced the invoiced amounts to supporting documentation. We verified a sample of salary expense accruals and recalculated the respective overhead burdens the Company applied.
- We recalculated a sample of monthly jurisdictional nuclear construction accruals displayed on Schedules T-6.2, and T-6.3, respectively, of the Company's 2012 NCRC filing. We sampled and verified the generation cost accruals and traced the invoiced amounts to supporting documentation. We verified a sample of salary expense accruals and recalculated a sample of the respective overhead burdens that the Company applied.

For the second audit report, to address the uprate cost as of December 31, 2012, for Crystal River Unit 3,

- We reconciled the Company's filing to its general ledger and verified that the costs incurred were posted to the proper accounts.
- We reconciled and recalculated a sample of the monthly revenue requirement accruals displayed on Schedule T-1 to the supporting schedules in the Company's 2012 NCRC

filing.

- We reconciled the monthly construction carrying cost balances displayed on Schedule T-2.3 to the supporting schedules in the Company's 2012 NCRC filing. We recalculated the schedule and reconciled the Allowance for Funds Used During Construction (AFUDC) rates applied by the Company to the rates approved in Order No. PSC-05-0945-S-EI.
- We reconciled the monthly construction deferred tax carrying cost accruals displayed on Schedule T-3A.3 to the supporting schedules in the Company's 2012 NCRC filing. We recalculated a sample of the monthly carrying cost balances for deferred tax assets based on the equity and debt components established in Order No. PSC-05-0945-S-EI.
- We reconciled and recalculated a sample of the monthly CPI accruals displayed on Schedule T-3B.3 to the supporting schedules in the Company's 2012 NCRC filing. We recalculated the Company's CPI rate and reconciled the component balances to the Company's general ledger.
- We recalculated a sample of the monthly recoverable O&M expenditures displayed on Schedule T-4 of the Company's 2012 NCRC filing. We sampled and verified the O&M cost expenditures and traced the invoiced amounts to supporting documentation. We verified a sample of salary expense accruals and recalculated the respective overhead burdens the Company applied.
- We recalculated a sample of monthly jurisdictional nuclear construction accruals displayed on Schedule T-6.3 of the Company's 2012 NCRC filing. We sampled and verified the capital cost expenditures and traced the invoiced amounts to supporting documentation. We verified a sample of salary expense accruals and recalculated the respective overhead burdens that the Company applied.

Q. Were there any audit findings in the audit report, JAS-1, which addresses the 2012 pre-construction and construction cost for Levy County Nuclear Units 1 & 2.

A. No.

Q. Were there any audit findings in the audit report, JAS-2, which addresses the 2012 power uprate costs for the Crystal River Unit 3 (CR3) nuclear power plant.

A. No.

Q. Does this conclude your testimony?

A. Yes, it does.

CHAIRMAN BRISÉ: Are there any other prefiled testimony that we are missing at this time?

MR. LAWSON: No. I believe we have all the relevant witnesses and exhibits related to the entirety of the Duke portion of this case. And if you just want to confirm with Duke real quick, I believe that's correct.

MS. GAMBA: I believe that's correct. I just wanted to clarify that Mr. Miller did adopt Mr. Franke's March 1 testimony. So that is the March 1, 2013, Miller testimony we're referring to. But otherwise that's accurate. Thank you.

MR. LAWSON: That's correct. Yes.

CHAIRMAN BRISÉ: Okay. Thank you.

Okay. So I think we've dealt with the motion that was made by Commissioner Edgar and seconded by Commissioner Balbis.

At this time we are at a decision point with respect to the motion to defer. I see a light. Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

At this point, recognizing the discussion, questions, and answers on the record, the posture that we are in vis-a-vis entering in the testimony and related exhibits, noting that we have before us a request to defer that has been submitted to us jointly by all parties and has been vouched to by all parties here before us, for, to put us in a posture of a vote, I recommend that we approve the motion to defer.

CHAIRMAN BRISÉ: Okay. It's been moved. Is there a second?

COMMISSIONER GRAHAM: Second.

CHAIRMAN BRISÉ: It's been moved and seconded. Any further discussion? Okay. Seeing no further discussion, ready to take a vote? All in favor, say aye.

(Vote taken.)

Any opposed? Okay. Seeing none, motion is carried. So the motion to defer has been granted.

MR. BURNETT: Thank you, Mr. Chairman.

May I excuse the Duke Energy Florida witnesses from this proceeding?

CHAIRMAN BRISÉ: The witnesses, yes.

MR. BURNETT: Thank you, sir.

CHAIRMAN BRISÉ: Thank you. I would like to remind Duke, however, that even though the motion to defer has been granted, there are still three legal issues that have not been resolved, and we ask that you stay around so that when those issues come up, that you may be available.

MR. BURNETT: Yes, sir. Understood. Thank you.

CHAIRMAN BRISÉ: Okay. Thank you. All right. So we'll give people some time to sort of move into different places at this time. All right. We will sort of take five minutes sort of in space so that everybody can move around and get to where they need to get to. I know that there's some documents that have to be distributed. They can be distributed at this time so that we can proceed.

(Recess taken.)

(Transcript continues in sequence with Volume 2.)

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

I, LINDA BOLES, CRR, RPR, 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' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 13th day of August, 2013.

Linda Boles

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