BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

PETITION FOR INCREASE IN RATES BY PROGRESS ENERGY FLORIDA, INC.
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DOCKET NO. 090079-EI

PETITION FOR LIMITED PROCEEDING TO INCLUDE BARTOW REPOWERING PROJECT IN BASE RATES, BY PROGRESS ENERGY FLORIDA, INC.
_______________________________/

DOCKET NO. 090144-EI

PETITION FOR EXPEDITED APPROVAL OF THE DEFERRAL OF PENSION EXPENSES, AUTHORIZATION TO CHARGE STORM HARDENING EXPENSES TO THE STORM DAMAGE RESERVE, AND VARIANCE FROM OR WAIVER OF RULE 25-6.0143(1)(C), (D), AND (F), F. A. C., BY PROGRESS ENERGY FLORIDA, INC.
_________________________________/

DOCKET NO. 090145-EU

VOLUME 5

Pages 428 through 619

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PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING:
CHAIRMAN MATTHEW M. CARTER, II
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER KATRINA J. McMURRIAN
COMMISSIONER NANCY ARGENZIANO
COMMISSIONER NATHAN A. SKOP

DATE: Tuesday, September 22, 2009

TIME: Commenced at 9:35 a.m.

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

REPORTED BY: LINDA BOLES, RPR, CRR
Official FPSC Reporter
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PARTICIPATING: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
24			512
25			512
26			512
47	PEF-1	548	548
55			515
56			515
57	SAW-1	526	526
58	SAW-2	526	526
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P R O C E E D I N G S

(Transcript follows in sequence from Volume 4.)

CHAIRMAN CARTER: We are back on the record. Good morning to everyone. Yesterday we left off on the cross-examination of Mr. Sorrick. But before we begin, let's look to the parties and the staff. Are there any preliminary matters?

First from the parties, any preliminary matters?

MS. VAN DYKE: Mr. Chairman, I would just like to introduce the other attorney from my office.

CHAIRMAN CARTER: Ms. Van Dyke, good morning to you.

MS. VAN DYKE: Good morning, sir. Ellen Evans.

CHAIRMAN CARTER: Ms. Evans, welcome to the Florida Public Service Commission. Good deal.

Anything further from the parties?

Staff, any preliminary matters?

MS. FLEMING: No, Chairman, I'm not aware of any preliminary matters. The parties and I did meet last night after we adjourned the hearing, and we have an aspirational goal for the number of witnesses that we hope to get through today, and I hope the parties can either meet or exceed that goal for today.

CHAIRMAN CARTER: All right. We're always looking to do better. We've got to have, as Commissioner Edgar says, some stretch goals. Try to do better.

I think when we left last night, it was Mr. Rehwinkel.

MR. REHWINKEL: Yes, sir.

CHAIRMAN CARTER: You're recognized. Good morning.

MR. REHWINKEL: Thank you. Good morning, Mr. Chairman, Commissioners.

CROSS EXAMINATION CONTINUED

BY MR. REHWINKEL:

Q. Good morning, Mr. Sorrick.

A. Good morning.

Q. Mr. Sorrick, yesterday as we were winding down there were several questions that I had asked you that I think you indicated your willingness to take a look at some additional information, and one of them had to do with overhaul expense. And I referenced you to interrogatory -- Public Counsel's interrogatory, your response to Public Counsel's Interrogatory 150. Do you recall that?

A. Yes, sir.

Q. And before we recommenced today I provided counsel, and I think you probably already had looked at this, but I asked you -- my question to you was, was your 2010 projected overhaul expense at least double that of the overhaul expense in each of the prior four years. That would be 2006, '07 and '08 actual and 2009 budget. Do you recall that?

A. Yes, sir, I do.

Q. After looking at that, could you verify whether that's true or not?

A. I can verify. I guess this is where the subject to check to comes in. I've checked and I can verify that that is true.

Q. Okay. So the amount of $53,641,870 for overhauls for unplanned and planned outages is the 2010 projected amount; is that correct?

A. Yes, sir.

Q. Okay. I also had asked you a series of questions about MFR Section C-6. Do you recall that?

A. Yes, sir, I do.

Q. And my questions were geared towards the power and operations maintenance expense, O&M expense under your, in your budget responsibility area. Do you recall that?

A. Yes, sir.

Q. Okay. And I asked you a bunch of questions subject to check, and I was wondering, did you do any checking?

A. I did. Primarily the one that I, that I checked on was the -- if you recall, we got into the uncertainty, if you will, on the system control and load dispatch portion, which for 2010's budget was I think right at $2.1 million.

Q. Yes, sir.

A. And that portion is, is not in the PGF budget as it rolls up. And so we -- I do recall the exercise that we went through with the additions and subtractions. The one thing, however, in reviewing this last night that I believe should -- well, let me preface it this way. And so as I recall last night, we got down to about a $173 million number instead of the $175 million number. And through checking with some of our finance folks and so forth, I think the one thing that we have failed to add back in to get it to the 175 is the 1.9 million in security costs that are coming out of, out of one of the clauses and into base rates to get it back to the 175. That's my understanding.

Q. Okay. And when you talk about coming out of the clauses, you mean coming out of one of the -- the fuel or one of the recovery clauses?

A. Yes. Yes. One of the recovery clauses.

Q. And for what year is it, is it out of the clause and into the base rates? When did that start?

A. Well, it's my understanding that we're proposing that to go into the base rates in 2010.

Q. Okay. So I would ask you these questions based on that information and what you learned overnight with respect to the, the dollars on Line 9 of Page 4 of 7 of C-6, which is the system control and load dispatch --

A. Yes.

Q. -- and other power supply expenses items; right?

A. Can you repeat that? I'm sorry.

Q. That's, that's -- Line 9 is comprised in some years of two components, not every year, but in some years of two components, mostly system control and load dispatch, and then every now and then an other supply, very minor expense.

A. I see. Yes, sir.

Q. Okay.

A. I was not able to do the homework with the other homework we were doing to follow up on, on those other power supply expenses, so I --

Q. Very minor, immaterial numbers; right?

A. They have been historically, yeah.

Q. Yes. Okay. My question to you is -- and I understand about the security expenses. So the, the dollars that are, that we could look at for comparative purposes for 2006, '07, '08, '09, and your projected 2010 would be those items that we went through in the, in the questioning yesterday minus the Line 9 items on Page 4 of 7 of C-6; is that correct?

A. I would still agree with that. Yes.

Q. Okay. So -- okay. Could I ask you to turn to C-41? Do you have C-41 of the MFRs with you?

A. Yes, sir.

Q. And I would ask you to turn to Page 149 of the MFRs, which is Page 2 of 18 of Schedule C-41.

A. Page 149?

Q. Yes, sir.

A. Okay.

Q. Okay. Now is this where -- are these three pages, 2 of 18, 3 of 18 and 4 of 18, are those your responsibility within the C-41 schedule?

A. Yes, sir.

Q. Okay. Now can you tell me with respect to your direct testimony what these three pages represent as far as, as the justification that you contribute to Progress Energy's 2010 rate case?

A. Yes. These all try to capture the amount, again, primarily of major maintenance, and I think I discussed that in some detail last night, that is, that is due in 2010. And it consists -- we've tried to, I wouldn't say prioritize it, but put these in categories to maybe better understand the groupings. And we do have major maintenance drivers from new units, the newer units on the fleet, and, and I explained last night how the major maintenance intervals on our combined cycle fleet register and we work towards those intervals. And between staffing of the new plants and the major maintenance requirements of those plants, we have about a $21.3 million need for those activities.

Again, on the cost side, when you talk about projects, we've got 15, a little over $15 million for projects at Crystal River. We've got some Crystal River 4 turbine work, we've got some Crystal River 2 turbine work in that $15 million. And then we have another $14.7 million for maintenance that's due, again, combustion turbine and combined cycle, but we called (phonetic) that from the existing fleet, which would be, in our definition, pre Hines power block 3. And those are just major maintenance items that are coming due, including some generator work.

We've got some material, labor and material cost increases at Crystal River associated with some boiler work, and then the incremental security costs for the 1.2 million or, I'm sorry, 1.9 million.

Q. Okay. Now the purpose of this schedule, is it not, to, is to provide your justification for why these different components vary from the benchmark; is that correct?

A. That's my understanding.

Q. Okay. Now do you know how --

A. Well, can I ask a clarifying question? By the benchmark, you're talking the PSC utility benchmark?

Q. Yes. I'm talking about the O&M benchmark that is referenced in C-41 here.

A. Yes.

Q. Okay. Now do you understand how that O&M benchmark is calculated?

A. I would say I have an elementary understanding of that.

Q. Okay. What is that elementary understanding?

A. My, my elementary understanding is that the 2006 year level of O&M expenses were taken and a factor was applied, and why I believe this is elementary, I'm not sure exactly all the components of the factor that was applied to escalate the 2006 cost into a, what I would call a projected or benchmark cost for either, I think 2010.

Q. Okay. So if -- and I know this is not your schedule, but if you look on Page 147 of the C-41 MFRs, is this, is this what your understanding is, is these factors that are developed here are applied to your 2006 numbers to get to 2010 benchmark and then the Commission; is that correct?

A. Yes, sir.

Q. Okay. So, and what your schedules describe here on Page 3 and 4 of 18 are the reasons why, if, if they do, these elements of the O&M expenses that are under your responsibility, why those expenses exceed that developed benchmark; is that correct?

A. Yes. That was our intent.

Q. Okay. So the, the description, the -- strike that.

So the text on Pages 3 and 4 of C-41, which is on Pages 150 and 151, are your explanations for those variances; is that right?

A. Yeah.

Q. Yes, sir?

A. Well, I mean, let me be clear. What we've tried to do is one of the, one of the problems, one of the practical issues -- I guess not necessarily a problem -- with the benchmark is it did not, it did not consider in my opinion the major maintenance requirements for new generation to the fleet. And that is a large driver for what we have.

It also doesn't -- and, again, I'm not an accountant and I still don't want to be an accountant, even though I did some accounting homework overnight. But it, it took a single point in time in 2006 and escalated it and it did not necessarily give room to consider for actually what's going on in the fleet.

Q. Okay.

A. With new additions and the major maintenance requirements that come due.

Q. Well, let me ask you about these items. Now Page 2 of 18 summarizes the variances that are generated by the calculations that you do to get your benchmark number and then compare those to your projected numbers; is that right?

A. Yes.

Q. Okay. And then on Page 3, let's take in the new generation section, you have a variance, a positive variance of $21.3 million; is that right?

A. Yes.

Q. And what that represents is that your 2010 O&M expenses for new, projected O&M expenses for new generation exceed the benchmark for those same categories by $21.3 million; is that right?

A. I'm not sure what you mean by the same categories.

Q. Well, when you develop the benchmark, you go to the 21 -- these same items that go in the new generation category, you take those items and you factor them up by these factors that are on Page 47 -- Page 147 to get your benchmark; right?

A. My understanding was that we took the, just the 2006 number and factored it up, not necessarily the way we've broken it out here.

Q. Okay. So what I'm trying to figure out is you're trying to compare apples to apples; is that right?

A. What I'm trying to explain here are the drivers for why the 2010 ask is more than the 2010 benchmark.

Q. Okay.

A. On an aggregate overall basis.

Q. I just want to make sure I understand. You have identified an overall variance from the benchmark of $53.1 million; correct?

A. Correct.

Q. Okay. And that's on Page 2 of 18. And you have identified variances within six categories: New generation, retirement, additional outage projects, maintenance on existing fleet, labor and material cost increases and incremental security; is that right?

A. Yes.

Q. Okay.

A. What I'm not sure, however, to your earlier question is if those same categories were, were part of the 2006 benchmark. We, we tried to categorize them in a way that made sense that people can understand what was driving these variances from an overall perspective.

Q. Okay. So what the -- the language -- what you're describing here in your, in the text of your explanation is not comparing new generation expenditures projected for 2010 to the same types of expenses for 2006?

A. No. We, again, it's my understanding that we just had a 2006 number for production steam, a 2006 number for production other, and that's what the benchmark was based on. And when you roll those up in aggregate, we were 51, or, I'm sorry, 53.1 million, and I guess we needed 53 million more dollars. And so in C-41 I tried to explain the categories of the cost drivers to get to that $53 million variance.

Q. Okay. Well, on Page 3 of 18 under New Generation, you have a discussion there about the Bartow combined cycle plant. Do you see that?

A. Yes, sir.

Q. Okay. And part of the statement is there that, that the costs will increase significantly over 2006 levels since 2010 is the first scheduled year of full operation of the plant; is that right?

A. Yes. It didn't exist in 2006.

Q. I understand. Are there expenses associated with maintenance of the Bartow plant that you will incur in the first year of operation that you do not expect to reoccur in subsequent years, other types of expenses, maintenance expenses?

A. I'd say actually I believe it'll be the other way. Because since it's a new plant, since it's a new plant, a lot of the equipment and components are under warranty. And so as we have what we would term infant mortality issues on different components within the plants, as we have other types of issues within the plants, those will generally be covered under manufacturer or contractor warranties for the first year. And so actually the first year O&M -- and our, and we're basing, I'm basing this off of some of the other units, the Hines units that we brought into commercial operation, for example -- the first year O&M expenses can actually be somewhat depressed from what you'll see going forward because warranties handle a lot of issues. Where once you get past that first year of commercial operation, those, those are all on the O&M tab or capital tab, depending on what they are.

Q. Okay. So your testimony is that there are not O&M expenses associated with Bartow that, that are a level that you don't expect to reoccur in the future?

A. All right. Can you ask that one again?

Q. Yes. Your testimony is that there are expenses associated with O&M maintenance at Bartow that are of a level -- let me, let me try it one more time.

Your testimony is that there are expenses associated with maintenance at the Bartow plant that will reoccur at the same or greater level in the future?

A. I'm still having a hard time weeding through that question. I'm sorry.

Q. Okay. Well, I may address that at a later point. Let me move on to, to Page, the bottom of Page 3 of 18 and the top of Page 2 of -- 4 of 18.

A. Okay.

Q. You discuss these additional outage projects and you're discussing a $9.9 million expenditure related to a major boiler and turbine outage. Do you see that?

A. Yes.

Q. At the bottom of Page 3 of 18?

A. Yes.

Q. And the discussion goes on to the next page, and you, you state, starting on Line 2 of that page, "PEF would normally schedule these maintenance outages in the normal course of its operations, but PEF decided to accelerate them to capture synergies and outage costs with the outage for the FGD." That's flue gas desulfurization?

A. That's right.

Q. "And SCR work as well as minimize lost generation instead of taking on additional outage." Do you see that?

A. Yes. What we, what we basically decided to do, because of our clean air construction, and we've done the same thing at Crystal River 5, those outages to tie in the clean air equipment are about 90 days in duration. And it did not make sense to us to perform a 90-day outage in the spring of 2010 on Unit 4 and then wait for a year and perform another 60-day outage on Crystal River 4 when all that could be combined into one outage, therefore, or thereby foregoing the spring turbine outage, turbine and boiler outage in 2011.

Q. Okay.

A. And so that's, that's the, excuse me, that's the, what I'm referring to here on the end of Line 3 and

Line 4, as well as minimize lost generation due to taking an additional outage. I think Mr. Young talked a little bit about a mid-cycle outage and trying to avoid that with a steam generator replacement. It's a similar concept. We were trying to avoid double outages on a unit when we could fit one within the other.

Q. Okay. Isn't it, isn't it true when you talk about accelerate, that the, that this work would have originally been done at a later period in time?

A. It would have been done in 2011.

Q. Okay. So the work that you did here, this $9.9 million, was originally going to be done in 2011. It will not now be done in 2011; is that right?

A. Not the total amount of the 9.9 million, because part of that is for turbine outage at Crystal River 2.

Q. Okay.

A. But, but a portion of that would have been.

Q. When you say would have been, would have been in '11 --

A. Would have been normally -- absent, absent the clean area projects, would have normally been scheduled in 2011.

Q. Okay. And what was that portion?

A. I don't have the exact breakdown, but, subject to check, it would be probably about six of the 9 million.

Q. Okay.

A. Roughly two-thirds, I think.

Q. Has your -- go ahead.

A. I'd just like to say one thing. Had we, had we kept it on that schedule though and performed that work in 2011, with the other projects that we see rolling up in 2011, which are actually rolling up to be our overall needs, if you'll remember that was one of the other homework assignments that I had, are, are above the 2010 asked already. So, and so, again, that's very preliminary numbers in where we're at, but this would have just shoved even more into 2011, making 2011 an even bigger year.

Q. So you had a roughly 25 percent increase in your O&M expense for, from '09 to projected '10, and you're expecting that '11 is going to be even greater?

A. Right now our preliminary work that we've pulled together shows 2011 on a -- if you look at it apples to apples from the 175 that we were at yesterday, it's at about 177. And 2012 appears to be right now about 180. And, again, that's driving, that's all driven by the major maintenance requirements on the fleet as we run the fleet.

We talked some last night about the different types of outages, and we're beginning on Hines power block 2 and power block 3 to get into the major, the major inspection type outages, which again are the very expensive outages to perform on these combustion turbines. And, interestingly enough, in 2012 we believe we'll start seeing some hot gas path inspections on the new Bartow units already.

Q. So you didn't expect to, when you, when you put these CTs in, you did not expect to achieve efficiencies in O&M?

A. We expected to see increases in our major maintenance requirements because we understand these are expensive machines to maintain. Again, the design of a combustion turbine is to literally consume itself. And if you don't do this periodic maintenance, that is what it'll do, it'll consume itself. And instead of being able to take the various parts and components out and refurbish them over a few cycles, you'll burn the parts up in one cycle and you'll be paying full replacement costs to replace parts instead of being able to refurbish the parts and reuse them.

So we expected, we expected major maintenance requirements to go up. And we also expected from an operational standpoint, you used the word efficiency, as we continue to operate our combined cycle fleet, we'll see, we'll see efficiencies across our operations. But, again, the major driver here from a cost standpoint is, is the major maintenance on the units.

Q. Can I ask you to turn to Page 25 of your direct?

A. Yes.

Q. And ask you to look at Lines 9 through 22.

A. Okay.

Q. Okay. Is it your testimony here that the costs have nothing to do with mere escalation?

A. No. My, my point here was that we have $7.3 million of additional costs, that some of that portion of 7.3 can be attributed to escalation.

The other point that I make is the large part of that 53 million is driven by, by basically the physical requirements to maintain the equipment. That it's not -- I'm not standing behind saying we're, we need $53 million because our costs have escalated that much. That's, that's not what I'm saying. I'm saying that we have these requirements to perform the major maintenance on the fleet. And certainly some of those costs have escalated, but a lot of this is, is based on what's coming due and the outages that we need to perform.

Q. Is it your testimony -- have you done any studies that show that maintenance costs have increased above CPI?

A. I personally have not done any studies to that effect.

Q. Okay. Has the company done any that you're aware of?

A. Not that I'm aware of.

Q. Okay.

A. But the thing I'd say again is it's not just maintenance costs. It's the type of maintenance and the timing of maintenance as it comes due. It would be one thing to have a, a year full of combustion inspections. It's another when you get into this cycle where you've got a lot of hot gas paths and major inspections that are planned on top of that. So that's where I'm not saying that that's a cost escalation. I'm saying that's an additional maintenance requirement to the fleet.

Q. So your testimony here is that CPI is, is not appropriate to use for benchmarking because facts and circumstances are what's driving the cost?

A. My testimony here is that if you just take a number and a point in time and escalate it, whether it's by CPI or, or any other escalation -- well, not any other, but other escalation indexes to that extent, it may not cover the whole picture. It may not cover the new equipment that you've installed and now have to maintain. It may not cover the types of maintenance that you have to do.

Q. What is your definition of supporting documentation with respect to justifying your O&M expenses?

A. My definition would be the documentation that we use to, to identify the cost.

Q. And did you provide that documentation as part of your direct testimony?

A. I provided the documentation that was asked for in the, in the discovery phase.

Q. Okay. But not as part of your, what you filed as your, with your testimony?

A. I'm not sure I follow.

Q. Well, do you consider the explanation on C-41 to be your documentation for the increase in O&M expenses?

A. I would say I provided our documentation in the MFR preparation and the, and the discovery.

One of the things that we have from our experience in operating and maintaining the fleet is we have a, we have a lot of historical knowledge and understanding of what different things cost. So I know there were some questions raised of why we don't have either invoices or, or formal quotes for a lot of our work. And it just doesn't make sense to us to necessarily go out for a formal quote for hundreds of lines of maintenance when we have a good understanding of what that cost is.

It's almost like saying how long is it going to take to drive from, from St. Petersburg to Tallahassee? Well, by experience we know it takes four to four and a half hours. We don't necessarily need to go out and ask a lot of people to confirm that.

Q. Let me ask you to look on Page 26 of your direct.

A. Okay.

Q. And take you down to Line 21 and 22. It states there, the maintenance work in 2010, "The maintenance work in 2010 under the LTSA is estimated at $4.6 million." Do you see that?

A. Yes.

Q. And the LTSA is the Long-Term Service Agreement for Bartow?

A. Yes.

Q. Is that the warranty that you referred to, or no?

A. No. We have a, we have a Long-Term Service

Agreement with Siemens to perform the major maintenance on the engines at Bartow.

Q. Okay. Now let's go back to C-41, Page 3 of 18. Do you have that?

A. Yes, sir.

Q. Now your -- you discuss the LTSA.

A. On Line 21, is that were you're at?

Q. Yes. Well, in that paragraph there. I think it starts further up.

A. Yeah, in that paragraph. Yeah. Let me, if you don't mind, read that for a second.

(Pause.)

Yes.

Q. Okay. Now do you recall being asked in discovery to provide supporting documentation for this LTSA expense?

A. I do.

Q. And is it true -- isn't it true that the response referred us to look at this C-41, Page 3 of 18, for that?

A. I believe we had two responses or two requests.

Q. Okay.

A. And one did reference back to C, C-41. The other one pulled out the information from the LTSA in line item form and provided that information on line item form from the LTSA.

Q. Okay.

A. We typically would not make a contract like an LTSA public. Those are typically held very close to the vest for business purposes, not only from our standpoint but also from the OEM standpoint.

Q. OEM meaning?

A. Original equipment manufacturer.

Q. Okay.

A. Which in this case would be Siemens.

Q. All right. So is it your testimony that Page 3 of 18 is supporting documentation for the $4.6 million LTSA cost?

A. I'd say that's part of the supporting documentation. Again, we pulled out what the line items are that make up that $4.6 million in another, in another discovery request and provided that.

Q. Do you know what the number of that discovery request was?

A. Offhand I do not.

Q. Okay. Can you tell me -- can the, can someone look at what's on 3 of 18 with respect to the LTSA and determine how the estimate that's, that's in your projected 2010 expenses, how that was developed?

A. Can you ask that again?

Q. Yes. Can, can someone look at the description here of the LTSA related expense of $4.6 million, and can they tell from this to the extent it is supporting documentation how that number was developed?

A. Probably not in detail. But the answer to the other piece of discovery they could.

Q. Okay. Let me ask you hypothetically, if you, if you have a major repair done to your car, like a transmission replacement that is not under warranty, would you require that to be provided -- would you require to be provided some form of estimate that provides some level of detail as to how the cost estimate was determined?

A. It depends on the situation.

Q. Okay. Well, in that --

A. And when I say that is if, if I had, if I had a fleet of, let's say, 20 or 30 service trucks and I used a garage or we had our own mechanics that perform that, then, no, I wouldn't, because I would have a good understanding of the cost already.

Q. Well, in my hypothetical, if you took that car to a, to a place that you had never been to before.

A. Yes. Yeah. Then we would certainly, I would certainly want an idea of what it was going to cost.

Q. Isn't it true that when the company was asked for supporting documentation for the $63 million of increased costs in this area, that you, the response was to see Page 3 of 18 of MFR C-41?

A. That may have been one of the responses. I know that we received several other requests and we provided a lot of discovery on, on different cost basis.

Q. Okay.

A. And I -- and, again, I know that some of the responses may not have met some, some of the parties' expectations.

Q. Let me ask you about 2009. What is in the MFR is a budget for 2009 in your area. And I think that, for the areas that we talked about, excluding the Line 9 on Page 4 and any security costs, which I don't think were in there in 2009; correct?

A. Correct.

Q. I think those sum to 137,304,000. Does that sound right, subject to check?

A. To be honest with you, I left the sheet of paper that I wrote all that down on last night. So, subject to check, I would --

Q. Okay.

A. I'd prefer not to add those back up in my, in my head again.

Q. I understand. And I won't make you do it on the stand.

Has that number changed in any way? Is that still your budget?

A. The '09 budget?

Q. Yes.

A. We, we are right now forecasting to come in about $3.5 million below that.

Q. Okay. Why is that?

A. Because of cost cutting initiatives that we've done, primarily what I would call belt tightening type activities with, with travel and, and more discretionary type spending.

Q. Did you do a similar belt tightening for 2010 projections?

A. We have looked at rolling those forward, yes, sir.

Q. So what would that impact be?

A. Well, that's included in our number, in our ask.

Q. Okay. Well, let me, let me then ask you this. My assumption was that, that when you did the MFRs, the C schedule for the MFRs, you developed, or you had a budget for $136 million, subject to check.

A. Subject to check, yes, sir.

Q. And the same process or the same processes that you used to do that generated a 2010 projected number of about 173.7 million, subject to check, ignoring the security stuff.

A. Yeah.

Q. Is that correct?

A. Yes, sir.

Q. Okay.

A. Okay. I see what you're getting at.

Q. So my question is that now that you've done a little more belt tightening and looking at 2009, what has been the carryover of that process to the projected 2010?

A. Yeah, I see what you're saying. We, we have not changed anything in the C-41. We, we will continue to look at managing our cost, as we have in our regular course of business, not just in 2009. We've, we've taken the long view here and we continually try to manage our costs and keep our costs low. For one thing, just from a selfish standpoint, from the generation fleet, the, the better we can manage our costs, the more maintenance we can perform on our equipment, the better it's going to perform.

Q. So I guess my question to you is, have you, is there a, is there a different number -- would -- let me -- well, let me step back and ask it to you this way.

Would, wouldn't it be fair for the customers to expect that, for purposes of setting rates that your request to the Commission in this area of O&M expense would be based on what you expect to spend, not what you might have filed on March 20th?

A. I would say that would be fair.

Q. Okay. So is there a new number in that --

A. No, I don't have a new number at this time.

Q. Okay. Has one been looked at at some level?

A. The number we're still working towards in my department is this, I think you've got it written down, the 173.7.

Q. Seven. Yeah.

A. Okay. Plus the 1.9 million in security costs, subject to check.

Q. Okay. Okay. So your testimony is you've looked at and you've tightened the belt in 2009, but you haven't done that for 2010?

A. We haven't finished 2009 yet, so --

Q. But your latest view of the 2009 budget is that you're going to come in some 3-point something million dollars lower than the budget?

A. We're working that way. Yes, sir.

Q. Okay. But you don't know similar kind of processes generating a different number for 2010?

A. No, we have not gone back, at least in my department, to, to look at that, the implications for 2010 yet.

Q. Okay. Do you know whether in the process of looking at a 2010 budget whether there were any expenses that were planned for, originally planned for 2009 that were deferred into 2010?

A. I'm not aware of any. I mean, that's a difficult question to answer because we do have moving parts back and forth. And part of what drives that is when you, when you make a forecast of how much a particular unit is going to run, especially a simple cycle combustion turbine, that there are a lot of variables in that. I mean, there could be variables on how the baseloaded fleet performs. There are variables on how our neighboring utilities perform. The weather can be a variable. And so there are certainly times that you'll see puts and takes.

So, for example, a unit may run a lot more than you expect it to because of a certain issue that's specific to that unit, and its maintenance pulls back into a current year or a, or a earlier year. And you may have a unit that, that doesn't quite run as much as you expect, and so that may fly back. So I'm not sure I can answer that with the information I have right here.

Q. Okay. Do you -- isn't it true that the company -- well, I'm not going to ask that.

MR. REHWINKEL: Mr. Chairman, those are all the questions I have of Mr. Sorrick on his direct.

Thank you, Mr. Sorrick.

THE WITNESS: Thank you.

CHAIRMAN CARTER: Thank you, Mr. Rehwinkel.

Ms. Bradley.

MS. BRADLEY: No questions.

CHAIRMAN CARTER: Thank you.

Mr. Moyle.

MR. MOYLE: Yes. Thank you, Mr. Chairman.

CHAIRMAN CARTER: You're recognized.

CROSS EXAMINATION

BY MR. MOYLE:

Q. I just want to follow up on that point that Mr. Rehwinkel raised with you about your 2009 budget. As I understand it, you had testified that because of belt tightening there was approximately a $3 million savings; is that right?

A. About 3 million.

Q. Okay.

A. About 3.5.

Q. And you also indicated that you anticipate that would be carried forward in 2010; correct?

A. I would anticipate that we'll continue looking at, at how we can manage our costs better on an ongoing basis. But I'd also say that's nothing that we just started. We've been, we've been trying to do that for the last, I mean, since I've been involved in management since like 1994. So that's been, that's been what we've tried to do is manage our costs the best we can.

Q. As we sit here today, you're not aware of anything that would prevent you from carrying forward that $3 million savings into 2010, are you?

A. I think there are some of the details in that that I don't believe are going to be sustainable. If you cut out certain expenses that aren't sustainable, then, then in time it may be a temporary solution, but it doesn't necessarily translate into a permanent ability to do that. So I guess I say that to say not exactly. I mean, it may, there may be things in there that don't carry over.

Q. Right. I guess what I was trying just to pin down and focus on is, as we sit here today, you're not aware of anything specifically that's going to say or dictate, you know what, that $3 million savings is not available in 2010 because of X or Y; correct?

A. I think, I think -- I can't agree with that, because we, we have gone into areas and cut things like travel for regional engineers and travel for shop surveillance on, on, on parts that are being refurbished during major maintenance outages. And with the amount of major maintenance that's coming up, it's not sustainable to depress those levels of travel expenses if we want to make sure that we're getting the best job in the shops from a technical standpoint.

We'd all love to be able to send our parts to vendors and just let them do the repairs and not have to check on them, but that's really not the world we live in. We have to put technical experts in those shops. And so this year we've been able to depress the travel for things like that. But as we go into more and more major maintenance and more and more parts refurbishment requirements, we're going to have to put people in those shops.

So that's an example that I just can't agree that, that that's, it's necessarily going to be an automatic rollover from year to year.

Q. And just so I'm clear with respect to that answer, you have high quality vendors, correct, that you contract with?

A. We do.

Q. But, but you, when you have a part that needs to be repaired by them, you're not comfortable just shipping it back to them and asking them to make the repair without also sending personnel to go along with the part to make sure the repair is done properly?

A. Well, let's take, let's take an example of a, of a first stage bucket and an advanced technology combustion turbine. A set of those will cost between 3.5 and $4 million to replace. A repair on those will cost roughly four or five hundred thousand dollars. And if they get those wrong, then it can crash the whole machine. And so what we try to do -- we certainly go into our shops and we have a process to approve a shop to be able to work on certain components. And we have some shops that we allow to work on, on some components and not other components because that's where their strengths lie. So we do have a technical process to qualify a vendor's shop.

But we also, I guess, live by the, by the motto of trust but verify. We know they can do the work. But when you're talking about the kind of money and if they get something wrong, the stakes are too high to just let them have their way.

Because I'd say even though we have high quality vendors, they're trying to cut their costs in ways too, and we need to make sure that we get a quality product back. I don't think it would be very prudent otherwise to just let them ship stuff back if we don't understand the quality of it.

Q. The, let me direct you to some of your testimony, if I could. On Page 1, on Line 18 you talk about, and I quote, you recommend retirement of generation facilities. I didn't see anything in your testimony in which you were talking about specific dates of retirement for generation facilities. Am I correct in that?

A. That's correct. I work with our system planning folks on a myriad of issues, and that is one. I give input and consideration for new units and what the operational and maintenance requirements would be for, for whatever new units they consider. And I also talk to them about our fleet in general, the condition of the fleet, what units may or may not be ready for retirement. So I'd say that's also a Mr. Crisp question, but that's what I was alluding to.

Q. Okay. You talk about part of your responsibilities are to attract, hire and retain employees on Page 2 your testimony, Line 8. I'll just direct you to it.

A. Yes.

Q. Wouldn't you agree or haven't you found that in this economic environment with unemployment at high levels that the ability to hire and attract employees has, has increased?

A. Not necessarily. I'll give you an example. Because some of these -- and, again, it depends on the position, granted, but some of our positions require an extensive technical knowledge. And we've had a position open for probably -- well, I know it was open for over a year to hire a principal electrical engineer to help us with generators and large motors. And you would think that, with the situation as it is, that there would be a lot of viable candidates for that, that position. It just hasn't been so. So I wouldn't necessarily agree with that. Some positions, yes, but not all positions.

Q. You would agree from a, from a general market standpoint that there's -- you know, you referred me to a specialized position. I'm just trying to understand from a general market standpoint, you would agree that there is quite a bit of supply right now in terms of the workforce, correct, as compared to past years?

A. Well, quite a bit's relative. So I would say there are people out looking. But I would also say a lot of people are more and more satisfied with what they have, and, and the job they have and the known that they have in their company in an uncertain time is more attractive I think to a lot of people than jumping to a brand-new company and an unknown situation.

Q. So with respect to retainage, given your answer, you would indicate that, given this economic environment, you'd find it easier to retain people; is that right?

A. I'm not sure easier, if I would use the word easier. We've had, we've had some people decide that they want to leave. And so I think it just depends on everybody's personal situation. I do believe that most people that have a job want to keep their job during this time.

Q. Do you know what the unemployment rate currently is in, in Florida?

A. I don't. I heard some discussion on that yesterday, and I don't remember what was shown to Mr. Dolan.

Q. On Page 4, Line 20, you use the term "foreign fuel," and I was curious as to what you were trying to communicate by the use of the term "foreign fuel."

A. Well, the Bartow steam plant burns Number 6 fuel oil, which is a bunker C type, type fuel oil, and we basically replaced that with domestic natural gas.

Q. So would, would it maybe be more accurate to indicate to reduce the dependence on oil as compared to foreign fuel? Is that right?

A. I think either one of those is fair.

Q. Okay.

A. Yes.

Q. And as we sit here today, what percentage of oil does Progress have in its system, oil-fired generating units?

A. I don't have that information. I know that we, we have a fair amount of peakers that are all running on Number 2 fuel. The Anclote unit, we've made modifications to it where it can burn natural gas up to 40 percent of its capacity, and we're able to dispatch that unit more and more on natural gas and get off Number 6 oil there. But I don't have the percentages for you. That would be something Mr. Weintraub could probably provide, or maybe did in his testimony. I don't know.

Q. Let me -- I want to ask you about the Bartow unit. And does it help if I refer you to pages of your testimony or can we just have a conversation?

A. We can have a conversation, and if I need a reference, I'll ask for it. How's that?

Q. Okay. That'll save us a little time.

A. Okay.

Q. Bartow is a four-on-four-on-one; correct?

A. It's a four-on-one, which means it's got four combustion turbines that feed one steam turbine. And so, so really the configuration, you have four combustion turbines that feed four heat recovery steam generators or four HRSGs is what we call them that create the steam to go into one steam turbine. So you have four CTs on the site, you have one steam turbine on the site, you have five generators on the site.

Q. Okay. And I did -- in your testimony I guess you say four times four times one. I guess that confused me.

A. The second four would be the HRSGs. Yes, sir.

Q. Okay. And that's Page 6, Line 11, if you need to look at it, refer to it.

You could replicate that, could you not, if all of the sudden, you know, your company needed another 12, 1,300 megawatts in power, you know, you could, assuming you could get site certification and need determination, you could replicate that four-on-one design; correct?

A. I guess if your question is from a hypothetical could we build another four-on-one or could any company go build another four-on-one, the answer would be yes, you could, from a hypothetical.

Q. Right. And even beyond a hypothetical. I mean, you did it in Bartow. You could do it.

A. Yeah. Practically you could -- any company with the means could go build a four-on-one.

Q. Okay. And the cost on this, the capital cost roughly $800 million; is that correct?

A. I believe that's true.

Q. Are you, do you have any information, are you aware, do you track the purchased power agreements that you all have?

A. No, I really don't.

Q. So you don't -- you're not aware of purchased power agreements that have been turned back to the company in the amount of approximately 250 megawatts?

A. No, I'm not. That's, that's out of my area of responsibility.

Q. Okay. Do you have any -- I was going to ask you a question about the cost of the four-on, four-on-one unit as compared to the, you know, the Levy project. Do you have any information about the Levy project capital costs?

A. I do not.

Q. So if I told you it was 17.2 billion, you wouldn't have information one way or the other on that?

A. No. I --

Q. If you assumed it was 17.2 billion, you would agree that, that there's a lot more four-on-ones that could be built from a capital aspect than Levy; correct?

MR. BURNETT: Objection, Mr. Chair. This is getting into system planning and economics and the economic evaluation, and this witness testified he has no knowledge.

CHAIRMAN CARTER: To the objection, Mr. Moyle.

MR. MOYLE: I'll move on.

CHAIRMAN CARTER: Okay.

BY MR. MOYLE:

Q. Did you happen to read other witnesses' testimony?

A. No.

Q. So let me ask you to assume something. Assume that Mr. Dale Oliver -- you know Mr. Oliver; right?

A. I do know Mr. Oliver.

Q. Okay. And assume that he indicated in his rebuttal testimony that, that O&M costs are reasonable on their face because they are at the Commission's O&M benchmark. Does that, does that seem to make sense to you?

A. I guess I'd prefer not to assume that that's what Mr. Oliver said, since I haven't read any of his testimony or rebuttal testimony. And I would add further that I don't know the specifics of Mr. Oliver's request or, for that matter, his business.

Q. All right. Well, let's just leave, leave him out of it. Let's leave Mr. Oliver out of it.

And would you agree that it, that the O&M benchmarks established by this Commission set reasonable levels for O&M?

A. Again, I believe, and I believe I answered this previously, I believe what the O&M benchmark misses as it specifically relates to my business is the addition of new units and the additional major maintenance requirements that are brought in for those units.

I, I would say in a hypothetical, if you had, if all your costs were constant and, and there's no variability with new scope or anything like that, then I would believe that they would be reasonable. However, I don't believe the utility benchmark takes into consideration new scope and new requirements.

Q. So, so you had indicated in response to a question by Mr. Rehwinkel that you weren't real sure of the, of all of the components and the inputs with respect to the, to, to the benchmark. What understanding, if any, do you have with respect to new units coming in, how it's treated with respect to the benchmark?

A. Actually, actually what I think I responded to Mr. Rehwinkel was I was not, I was not aware of all the components of the factor that was made up.

Q. Fair enough.

A. And so my understanding, again, elementary understanding of this is that you take the 2006 number and you escalate it by these factors. And I don't believe that takes into consideration if you add new units or new scope or scope, again, from a combined cycle standpoint that start rolling in with these big hot gas paths and majors into the years. That the only way in my opinion from a mathematical standpoint that could be handled is if you had that scope in 2006, if you had the same exact scope in 2006 and you escalated it, then that would be a reasonable proxy for what you should see with the same exact scope in 2010.

And I guess what I've tried to convey through my testimony and through answering, especially Mr. Rehwinkel's questions, is we, we certainly don't have the same amount of scope in 2010 as we had in 2006.

Q. Are combined cycle units typically serving intermediate load?

A. Typically I would say intermediate to baseload.

Q. Okay. And just so we're clear, when we say intermediate or baseload, just explain that.

A. I would define baseload to be a unit that is on as much as it can physically run. Crystal River 3 is a good example of that. Once you get beyond the nuclear unit, then a lot of that is driven by the dispatch order, fuel costs. And so you'll see some combined cycles that unit, that run quite a bit because of the low cost of natural gas right now. Typically Crystal River and the coal units, 1, 2, 4 and 5, will be baseloaded. So that means that they turn on and don't come off too much. They may ramp down in load some for low load periods at nights and maybe the weekend, but they don't come off a whole lot.

Q. You spent some time in your testimony, specifically with respect to O&M, talking about combined cycle and combustion turbine units; correct?

A. Yes.

Q. Okay. And I think you indicate that there's variability or ranges in which the combined cycles can operate. And I guess what I was going to ask you is isn't it largely true that with respect to combined cycles, given that they're serving intermediate and baseload, that the maintenance for, for them is analogous to the length of time it takes to drive from Tallahassee to St. Pete?

A. The maintenance is driven -- certainly if you turn on a combined cycle and you let it run 8,000 hours a year, then you know you're going to have a combustion inspection every year. And that would make, make planning much, much easier. As they run more or less, if you run 6,000 hours a year, if you run 8,200 hours a year, you're compiling major maintenance at different rates.

Now what makes this somewhat variable is what is the next maintenance interval that you're about to trigger? Is it a hot gas path, is it a combustion inspection, is it a major inspection?

Q. You would agree that, that it's easier to predict the operations and the run time of combined cycles than it is combustion turbines; correct?

A. Simple cycle units?

Q. I'm sorry. Simple cycle.

A. As a general statement, I would agree with that. However, I think there are a lot of different variables that go into even that -- I mean, simple cycle units, their position on the grid, what other ancillary services that they may provide in the form of system support or in the form of fast start to cover reserve calls -- generally I would agree with that. But weather and different system conditions can, can change the best-laid plans.

Q. Let me direct your attention to your direct testimony, Page 26, Line 4. And actually it's just the top of that page, sentences 1 through 5. If you'd take a quick look at that.

A. Okay.

Q. The, the use of the terms "unique mechanical and operational characteristics of CC," which I presume means combined cycle; correct?

A. Yes, sir.

Q. And CT means combustion turbine; correct?

A. Yes, sir. And I would use, I would further clarify that to mean simple cycle combustion turbine.

Q. Okay. And it was my impression that these machines made by major vendors were pretty much the same, whether you had one operating in Florida or Texas or, or California, and -- would you agree with that?

A. I would agree with that if you had the same makeup. Our, our fleet of combustion turbines, we have -- bear with me for just a second. If you'll indulge me here.

Q. Take your time.

A. We have, we have nine or ten different types of combustion turbines on our fleet that all carry unique characteristics. An example would be we have several aero-derivative based units. Those are Pratt & Whitney type engines that are more jet engines that have been modified for power turbine applications that are fast start units. They can go from the push of a button to be at baseload at 40 megawatts within five minutes, and they serve one application. And the maintenance requirements on those units are different than a 70A with a dry load noncombustion system that you start it, it goes through a purge cycle, takes 25 minutes to half an hour to hit the line, and then you ramp it up a lot slower. It's a much bigger machine. Those are heavy frame units.

So I can't just agree with the general statement -- and maybe I'm misunderstanding it. But a combustion turbine is a combustion turbine whether it's in Florida or in Texas. There are a lot of differences.

Q. I guess what I'm trying to understand, I think you've explained it, is when you talk about unique mechanical and operational characteristics of these units and refer to a combined cycle and combustion turbine, you're not suggesting that the combined cycles and combustion turbines that are deployed on Progress Energy Florida's system are unique in that they're one of a kind coming out of a manufacturer; correct?

A. Right.

Q. You're saying that you have a wide variety of them.

A. Yes.

Q. Therefore, you have, it's kind of like -- to use TVs. If you had four TVs in your house, you know, you might have them from four different manufacturers; correct?

A. Well, even, even beyond that. You may have, you may have an old tube, tube TV with a new plasma screen with something in the middle.

Q. Let me direct you to Page 24, and you have on Line 3 a statement about reserve calls.

A. Yes, sir.

Q. And you say that you, Progress Florida represents about 25 percent of the state's generating capacity but was responsible for only 12 percent of the, of the reserve calls. What is a reserve call?

A. A reserve call would be when a unit trips, a call from neighboring utilities for reserves to cover the trip of that unit.

Q. Do you know, who has the most reserve calls, if you know?

A. I don't know that.

Q. You would agree, would you not, that when you, when a unit trips, that's an unforced (sic.) outage; is that right? I'm sorry. A forced outage typically?

A. It may not turn into a forced outage. It would be a, certainly a system upset, an unplanned system upset. But it may not -- so, for example, you may have, you may have a situation in the power plant, let's call it one of the coal units, and you may trip a piece of equipment that will trip the boiler off line. Well, there's enough residual energy in the steam system that the turbine may not immediately trip. And if it's as simple as starting another piece of equipment, you may be able to get the boiler back before the unit trips. That wouldn't necessarily turn into a forced outage.

Another example would be if the unit does trip and come all the way down, you may understand quickly why the unit tripped, and it may not, may not turn into a forced outage. It's a unit trip that you can turn around quickly.

Q. Okay. But with respect to maintaining the system, reserve calls generally are measured by in excess of a 200-megawatt loss, is that right, according to your testimony?

A. Yes.

Q. Okay. And in terms of managing the system, you would also agree, would you not, that the ability to shed load through interruptible customers is a, is a benefit to the company?

A. I'd say you're getting out of my area of, of expertise there. I would characterize my job as trying to make sure from an unplanned basis that never happens. My job is to try to keep as, enough generation on to match whatever load we have. So I --

Q. So you don't consider yourself qualified to answer, to answer that question?

A. No, I don't.

Q. Let me -- I have a few other things I just want to ask you about on your direct testimony.

A. Okay.

Q. You refer to the HPI Program. And --

A. Can I get to that?

Q. Eighteen, Page 18 is where it is.

A. Okay.

Q. The Number 5, you talk about an event deemed by management to be significant by virtue of the value of lessons learned. I was a little unclear as to what you were trying to communicate there. Would you give me an example of a, of a Type 5 event, please?

A. Yes. You may have -- well, if you look at a safety event, for example, it may not result in an OSHA recordable accident, but it may have significant, it may be a significant near miss, and it may have been precipitated by a human performance activity that you certainly want to get out to the rest of the fleet because it could have caused a significant event. And I'm being vague because I don't have a ready example.

But it's not inconceivable that if a person was working with an electrical piece of equipment and they manipulated the equipment where an arc flash occurred but the employee didn't get hurt, okay, by, by the letter of the law -- not the law -- by the letter of our, of our process and program, we would not have to call that a significant human performance event because an OSHA recordable event didn't happen, it didn't cause asset damage more than $25,000, and so forth.

But that may be something that we want to say, hey, everybody in our system here in Florida and in the Carolinas needs to know that when you take this action, it may cause an electrical flash and the next employee may not be as lucky. He may not have been standing just off to the side enough.

And so that would be one that management would say, no, we need to, we need to call this one a significant human performance event, and we need to not only capture it as such, but we need to communicate it throughout the system so that nobody else puts themself in this situation.

Q. Thank you. That's helpful.

And then, and then you have measured this, this human performance improvement, you all have made improvement with respect to this measurement; is that correct?

A. Yes, we have.

Q. Okay. And with respect to significant environmental impact, what's the threshold that you use for measuring that significant environmental impact, and has it changed over the period of your measurement?

A. From the standpoint of a significant environmental impact, there is a corporate definition. I don't have that with me right now. But it would be one that, something that would rise to the level of this would be more than just a reportable spill of oil to the ground. This would be one that would, as an example, is if you had a massive oil release in Tampa Bay, that would be a significant environmental event. And, I mean, that's obviously something that we work very hard to avoid.

Q. A couple of questions about deferred maintenance on Page 30. Now isn't it a practice that can be used in the utility industry to defer maintenance?

A. Yes, it can be used.

Q. Okay. And, I mean, that can be used to, to manage cash flow, to manage cost. If something can be put off for some time and not materially affect the performance of, of your units, then that might be an example of a deferred maintenance item; correct?

A. It might be. What, what we talk to here is as these maintenance activities come due, we want to, we want to continue to be proactive for the benefit of our fleet. And once you get into a situation where you're deferring maintenance, you're taking an awful lot of risk on the equipment that you defer, on your reliability measurements, and on your costs, quite frankly, because you'll run into more forced outages and you'll run into higher repair costs.

Q. And, and do you have any studies or have you conducted any analysis to support that, that conclusion, that by deferring maintenance, that you're going to have more forced outages?

A. I would say that, no, I don't have any --

Q. Okay.

A. -- studies.

Q. And let's use a, a commercial rental property as a hypothetical. If you had an apartment building that had four units and the roof was past its life, if you will, but it was watertight and it wasn't necessarily leaking, that might be an example in that context of a, of an item where you could say let me see if I can get a few more years out of this roof before I replace it; correct?

A. With minimal risk. We could also use the example of an airplane engine, that if you defer maintenance, there's a lot more risk to something like that.

Q. And to talk about risk, the risk, if you deferred maintenance, would be the unit might not work as, as designed; correct? You might have a problem crop up.

A. That would be one risk.

Q. Okay.

A. Catastrophic failure of components would be one risk. Prolonged outages, even if you don't have a catastrophic failure of components, would be one risk, and you could have a unit down for, for several weeks to months at a time.

Q. As part of your belt tightening efforts, did, did you look at and -- well, as part of your belt tightening efforts, did you defer maintenance on, on any items?

A. In 2009, those belt tightening activities?

Q. 2009 or 2010.

A. No.

Q. And, and with respect to -- and if this isn't your area of, of expertise, let me know.

A. Okay.

Q. But, you know, we talk about risk. Do you know that, that as, as to whether Progress Energy was able to operate its system in a safe, efficient and reliable manner at a reserve margin of 15 percent from a historical perspective?

A. That would be outside of my area of expertise.

Q. One, one final line. You talk about the fossil dismantlement cost study. Do you see that on Page 31 of your testimony?

A. Yes, sir.

Q. You're familiar with the terms brownfield and greenfield?

A. Yes.

Q. Okay. And a greenfield is, is, is essentially a virgin site capable of being used for just about anything, a park, a residential development; you would agree with that generally?

A. I would generally, yes.

Q. And a brownfield is a site that probably had a previous use, oftentimes industrial, where there may be some, some soil issues or some pollution issues; correct?

A. Generally I would agree. Yes.

Q. Okay. And with respect to the dismantlement studies, does Progress strive to restore sites to a greenfield level, or do you know?

A. Well, here's, here's what I would say about the dismantlement study. The answer is, no, I'm not sure. And what I would say about this is the generation witness has historically sponsored portions of the dismantlement study. And so I have sponsored this to the extent to that we've hired Burns & McDonnell to do the study. And so, really, if you want to ask any of the dismantlement questions, I believe we have Mr. Kopp from Burns & McDonnell that'll be here later in the proceedings, and he, he would be much more qualified to answer detailed questions like that.

Q. Okay. And that's fair, and I may explore that with him.

But just a couple more general questions, and I think you're conversant on, on the idea. You would also agree that it would cost more money to restore a site to a greenfield status as compared to a brownfield status; correct?

A. Yes. In general I agree with that principle.

Q. And, and you would also agree that to the extent that there was a desire to, you know, all other things being equal, to put in something like a park or a residential community, that, that might be better suited for a greenfield site as compared to a brownfield site; correct?

A. Yeah. I guess I would say all other things being equal -- well, I'm not sure I could agree with that. All other things being equal, which in my experience has been they never are, I think it would just depend on the specifics of the situation, and I guess I'm not comfortable speculating on that.

MR. MOYLE: If I could have just one second.

CHAIRMAN CARTER: Absolutely.

(Pause.)

MR. MOYLE: Thank you for your, for your time.

THE WITNESS: Thank you.

CHAIRMAN CARTER: Thank you, Mr. Moyle.

Mr. Brew, good morning.

MR. BREW: Good morning, Mr. Chairman.

CROSS EXAMINATION

BY MR. BREW:

Q. Good morning, Mr. Sorrick.

A. Good morning.

Q. It's an interesting process, isn't it?

A. Yes, it is. I think there are other words for it, but interesting is --

Q. Touché. We had that discussion earlier.

A brief discussion about your CTs.

A. Yes, sir.

Q. They will typically run one to 300 hours a year?

A. You're talking our simple cycle CTs?

Q. Yes.

A. Most of our simple cycle fleet we don't measure in hours, we measure in starts.

Q. Okay.

A. And now the aero-derivative engines, the Pratt & Whitneys that I was talking about, those do accrue on hours basis and not starts basis. But most of the heavy frames are on starts, so we measure them more in starts than we necessarily do in hours. And I would say it depends on the year and depends on a lot of factors. Again, system and transmission issues can, can cause more or less runs. Weather is certainly a big factor, so --

Q. Well, let's back down a little bit. Would you agree that most of the time they're not running?

A. Well, it depends on how you --

Q. Out of the 8,760 hours in a year.

A. Yeah.

Q. At least 80 percent of the time they're not running?

A. I would say most of the time they're not running.

Q. Okay.

A. However, we do have units that run, that are started upwards of 250 or 300 days a year.

Q. Okay.

A. So.

Q. When they're -- but so normally they're in a cold mode, they're not running?

A. Well, again, normally -- there are a lot of times when they're off, if that's what you mean.

Q. Well, if you measure them in terms of starts, starting them is a start from a cold condition?

A. Yes.

Q. Okay. And accepting for a moment the aero-derivative --

A. Yes.

Q. -- the, the, you mentioned the older GE type machines. They would take, I think you said, a half hour or so to get started up?

A. Roughly. Yes.

Q. From black start. So from a, an ancillary service perspective in terms of providing spending reserve, those units typically wouldn't be available in, in ten minutes to, to connect to load.

A. That's right. Typically they wouldn't. But the fleet of aero-derivative units that we have would be.

Q. Okay. And, and so the aero-derivatives can start up quicker and so they can be online, say, within ten minutes, which is typically what you'd look for for spending reserves?

A. Yes. Typically they can be at baseload within five minutes.

Q. Okay. And, but you said they have different maintenance requirements, the aero-derivatives?

A. They do.

Q. Okay. And so the, the aero-derivative CTs would be more valuable to you operationally in terms of being able to account for spending reserves.

A. Our aero-derivative fleet provides us with a tremendous amount of flexibility.

Q. Okay. More so than the older CTs that take longer to start up from black start.

A. Well, I think they provide some flexibility. But if you're just talking the ability to get online and produce a lot of megawatts quickly, our aero fleet, our aero-derivative fleet is, is very valuable. Yes.

Q. And that's what you'd be looking at, the ability to quickly provide a lot of megawatts to the system.

A. Yeah. I think in the situation that you're talking about.

Q. Right.

A. Yes.

Q. Okay. You talked earlier about reserve calls.

A. Yes.

Q. Do you recall that? And that's generally calls from related interconnected systems?

A. I believe that's correct.

Q. When there's a problem in their system and you need to supply generation to help them out?

A. Yes.

Q. Okay. And that typically would be when you have a major generating unit or a transmission line trip?

A. I'm aware of the generation piece of that. I'm not as sure on the transmission piece of that.

Q. Okay. But there would be a system condition, a drop in frequency or something like that that you would need to respond?

A. I think that's fair. Yes.

Q. Okay.

A. And typically what we would do is we would start the appropriate number of aero-derivative units, or we may have units that aren't at baseload yet and are already online but can be ramped up. So it just depends on -- I mean, there again, it could be a lot of factors. Time of day, season of the year, outage season, or if you're in the middle of the summer. But we would start aero-derivative units up, and if it's going to be a prolonged issue, then we'll also start the frame units up because those are typically cheaper to run than the aero-derivative units. And we would run the jets until we, we have the frame units on and loaded. A lot of different configurations there.

Q. So -- are you done?

A. Yes. I'm sorry.

Q. So the jets are faster startup?

A. The aero units. Yes, sir.

Q. But they're more expensive to run.

A. A little higher heat rate. Mostly on, they operate mostly on fuel oil. And we have, we have a reasonable number of our heavy frame units that burn natural gas.

Q. So, so you like the aero units to be available quickly, but you don't want to run them for a long time?

A. Yes.

Q. Okay.

A. In general I'm saying that.

Q. In general. Okay. And in general you, you'd like to have resources on your system that can respond quickly and reliably?

A. Yes.

Q. Particularly in response to a reserve call or a system -- or a problem on your system?

A. Yes. Absolutely.

Q. Whether it's voltage or frequency?

A. Yes.

Q. Okay. Don't interruptible loads on your system provide that same benefit?

A. I'll be honest, I have not delved into interruptible loads, customers or whatever. I've, I've --

Q. You're a generation guy?

A. I'm a generation guy. Yes, sir.

Q. Okay. So if I could drop 50 megawatts as fast as you could start up your aero-derivative turbines, that might provide a comparable system benefit?

A. I think you'd have to ask Mr. Crisp or one of the other witnesses.

Q. Okay. On Page 19 of your testimony you have a question and answer that talks about organizational changes in the Progress Energy Florida Power Generation Group. Do you see that?

A. Yes, sir.

Q. And you specifically talk about the Crystal River Maintenance Organization. Do you see that?

A. Yes, sir.

Q. And moving over to Page -- the sentence that begins at the bottom of the page and moves over to Page 20 says, "This realignment has resulted in efficiency gains, enhanced forced outage response, which minimizes impacts to EFR," which is equivalent forced outage rate?

A. Yes, sir.

Q. "And overtime savings." Do you see that?

A. Yes.

Q. Now the next sentence quantifies savings, overtime savings of a million dollars. Do you see that?

A. Yes, sir.

Q. Is that an annual figure or is that over the three years?

A. That, that was -- I'm not sure. I believe that was an annual figure.

Q. Okay. And the efficiency gains you're talking about, is that in fuel savings, O&M savings?

A. Well, what, what -- the context there was actually the efficiency, one of the organization and the efficiency of responding to forced outages.

We had a situation -- and Crystal River is a large energy complex, and we had a situation before this site maintenance based on requirements from our collective bargaining contract with our union and the way things were done on that site to -- first of all, we didn't cover a lot of off hours on straight time. And so if you had an upset, for example, before this change in the middle of the night that required an electrician and an mechanic, then you would have to go through an extensive call-out list, sometimes calling up to 80 or 100 people to get the two people out there that you needed to work on the problem. So, as you can see, there are some logistical issues that sometimes could take hours to get somebody to work on the equipment.

What we've done in this organization is now we cover six days a week, 24 hours a day with maintenance resources onsite on straight time. So if you need that same electrician and mechanic, they're already onsite at straight time rates.

Q. Okay. So on Line 1, when you refer to efficiency gains, you mean in your organization. You don't mean fuel savings or some other savings that you're quantifying?

A. Yes. By and large that's true. Now I do think there are some, some probably benefits that would roll over to that. That if you have the electrician and mechanic in this example that can address something in an hour instead of taking three hours to call out and get onsite, then you can sometime return the unit either to full power, if it's a derate, or return the unit to service quicker. So there, there may be some there. But in the context, that efficiency gains was really in the organization.

Q. So, but with respect to the latter, you haven't quantified any of those potential gains in your testimony here?

A. No.

Q. Okay. So the only quantified savings that you're pointing to is the million dollars in overtime savings?

A. Yes.

Q. And the next sentence says that money has been reinvested into additional maintenance activities. Does that mean you haven't reviewed your budget by that million-dollar savings, so it doesn't go back to ratepayers?

A. That's right.

Q. Okay.

A. That means that we're getting to maintenance on the site that we otherwise would not have necessarily gotten to.

Q. So you haven't reduced your budget in any sense to reflect those savings?

A. No.

Q. Okay. Are you projecting any overall productivity improvements as a result of this realignment?

A. From, from this realignment?

Q. Yes.

A. For the CRMO (phonetic)? We would expect to continue to see some of this savings roll forward. However, I think that's, I think that one has been included in our number for C-41.

Q. Okay.

A. Because we went to this in, I believe, 2006.

Q. That's what your testimony says.

A. Yes.

Q. So are you, so are you projecting ongoing productivity savings as a result, or are you reinvesting the money? I'm trying to figure out if there's any reduced cost for ratepayers.

A. Well, I would say that we've projected down in overtime, in the overtime budget, and we've re, reinvested this in plant maintenance activities.

Q. Okay. So there's no reduction in overall budget?

A. No, I don't believe so.

MR. BREW: Okay. That's all I have. Thank you.

CHAIRMAN CARTER: Thank you, Mr. Brew.

Ms. Van Dyke.

MS. VAN DYKE: No questions.

CHAIRMAN CARTER: Thank you.

Mr. Wright, before you go, give me some kind of idea, because Linda is going to be with us all morning and I wanted to find a proper breaking point for her.

MR. WRIGHT: Mr. Chair -- Mr. Chairman, I truly believe that my cross is fairly brief. I think less than 15 minutes.

CHAIRMAN CARTER: Okay. Let's give it a shot. You're recognized. Mr. Wright.

MR. WRIGHT: Time me.

CHAIRMAN CARTER: I won't time you. Go ahead.

THE WITNESS: Can I time you? No, I'm just kidding.

MR. WRIGHT: Put the lights on. Put the lights on him, too.

THE WITNESS: I should have pushed a button, huh?

(Laughter.)

CROSS EXAMINATION

BY MR. WRIGHT:

Q. Good morning, Mr. Sorrick.

A. Good morning.

Q. We haven't met, but I'm Schef Wright and I represent the Florida Retail Federation in this proceeding. I have just a few questions for you or a few brief lines.

First, to follow up on, on some discussion you had with Mr. Rehwinkel and Mr. Moyle, do you know exactly how the Commission benchmark O&M for production steam is calculated?

A. Exactly, no.

Q. Okay.

A. I think I went through my elementary understanding.

Q. All righty. You reference an industry benchmarking study called the GKS Gold benchmarking study in your testimony.

A. Yes.

Q. Okay. Do you know specifically what the inputs are into, into the analyses reflected in that study?

A. Can you help me with a reference, first of all, just to get grounded?

Q. I can. Give me just a second.

A. Yeah. I'll keep looking, too.

Q. I believe -- hang on.

A. I've got it. It's at the bottom of Page 24.

Q. I was close. 25.

A. Yeah. Specifically with me I do not have those inputs. I know this was a point of discovery, and we provided both the benchmark study and a letter from GKS.

Q. Okay. But as you sit here today, you can't tell us exactly what the inputs are; is that true?

A. I don't recall. And I guess I need a little more granularity on exactly what you mean by, by inputs. I know it was several utilities that, that units were, their different units were segmented in different large-size coal, medium-size coal, large-size oil, so forth. But the details I don't have in front of me.

Q. Well, you just mentioned several utilities. Do you know how many utilities?

A. I don't offhand. But, again, it's included in that study.

Q. Okay. Do you know how many units?

A. I don't.

Q. Generating units? Are you familiar with any adjustments to the input data that GKS Gold might have made in that analysis?

A. I'm not.

Q. So basically your testimony really is just based on the results of that analysis; is that accurate?

A. Yes.

Q. Okay. Thank you. At Page 1 of your testimony, you test -- you state that it's part of your responsibility to develop and implement strategic and tactical plans to operate and maintain Progress's generation fleet.

My question, follow-on question is does this mean that you are the senior management person within Progress Energy Florida who signs off the generation O&M plans?

A. Within Progress Energy Florida, yes.

Q. Okay. And also on, are you the senior person who signs off on how those plans are implemented within Progress Energy Florida?

A. Within Progress Energy Florida, yes. Now just to clarify, I, I do have a boss and she's not in Progress Energy Florida. She -- we report to the overall -- I report to the Senior Vice President of

Power Operations Group. And so ultimately my manager would certainly have input and veto authority on, on this as well.

Q. And that Senior Vice President is in Power Operations Group, did you say?

A. Yes.

Q. Is she an employee of Progress Energy Corporation or Service Corp, or do you know?

A. I don't know specifically.

Q. It's all right.

A. I know where her office is in Raleigh and I know who her boss is.

Q. Well, that's, that's a good answer. Who's her boss, by the way? Who's in that position?

A. Bill Johnson.

Q. Oh, there you go.

Thank you. At Page 14 of your testimony, I just want to talk a little bit about your testimony and then a couple of questions.

With regard to your heading, Fleet Major Maintenance Program, you state that the majority of the PGF -- that's Power Generation Florida; correct?

A. Right.

Q. Annual project budget is spent on major maintenance activities; correct?

A. Yes.

Q. And that the purpose of these, these are designed to invest O&M and capital dollars so as to optimize Progress's generating fleet; correct?

A. Yes.

Q. And then down at the bottom of the page you talk about parts repairs that are designed to extend the beneficial use of most unit parts, thus prolonging their useful life. Is that accurate?

A. Yes. And I --

Q. I left out a couple of words, but --

A. Yes. And I alluded to that in my earlier conversations that while these, especially the combustion turbine based generation units consume themselves, the idea is that you can take parts out if you do it proactively and refurbish them and use them for several cycles instead of just burning them up and buying new.

Q. Thank you. Is it a fair inference from your testimony here about optimizing the fleet and prolonging the useful life of -- let me ask you this. Forget that line.

When you say thus prolonging their useful life, are you talking about the unit parts or are you talking about the power generation units themselves, or both?

A. Both. Both. I'm sorry.

Q. Thank you.

A. Yeah. Because if you extend the lives of the parts, then, then the units can operate longer.

Q. So it would be a fair inference, wouldn't it, that, that a major purpose of Progress's major maintenance program is to extend and prolong the useful life of your generating plants?

A. I'd say that our, our major purpose is to perform proactive maintenance that keeps the units reliable and, and we're able to run it as cheaply as we can instead of reducing a lot of parts and throwing units away before we would otherwise have to.

These, these units are, and I know I'm being redundant here, but if you treat these units badly, it's not unlike your car. If you drive your car and you decide you're just never going to change the oil in your car, eventually you're going to throw that car away or at least the engine in that car and you're going to incur a major expense.

And so that's what this is getting to, is to, is to try to say we don't, we want to treat these units right, we want to be proactive on the maintenance, and we certainly don't want to throw them away before their useful life would have otherwise been, been expended, I guess. And the "I guess" is on the expended, not on my thought. I'm sorry. I was looking for that word.

Q. Well, let me try again. Is it then a purpose of your maintenance program to keep the units running as long as they're supposed to?

A. Yes.

Q. Does it have the effect of extending their lives beyond that?

A. Well, and, again, it depends on the situation, Mr. Wright. It could, it could in certain situations. In certain situations, as you near the end of the useful service life, you may be faced with some extensive O&M and capital expenditures to prolong that life. A good example is the Bartow steam units that we just retired, the Unit 2 boiler, it basically leaked like a sieve at the end of its life. And had we decided we needed to prolong the life there, we would have been looking at a very expensive, basically a boiler replacement to extend that life. So I believe it depends on a lot of different factors.

Q. Okay. Back at Page 1 you also testified that it is your responsibility to recommend retirement of generation facilities; correct?

A. Yes.

Q. Do you have the primary responsibility for recommending retirements of Progress generating units?

A. I would call it more of a shared responsibility, working with the system planning organization.

Q. And that's Mr. Crisp; right?

A. Yes.

Q. Now the way -- I know Mr. Crisp and I know what he does, and from your testimony and your, written and live, I think I have a pretty good idea of what you do. Would I be correct that you're, you're more the mechanical unit specific guy in the, in the retirement evaluation?

A. Yes.

Q. And Mr. Crisp is more the long-term system reliability guy?

A. Yes. Yes.

Q. Okay. Who ultimately decides whether a unit is going to be retired?

A. That's a good question. It's been my experience that that rolls up and there's a lot of discussion within the organization, certainly within my organization, Mr. Crisp, Mr. Crisp's organization. And then that would roll up through our senior management committee ultimately to, to make those types of decisions.

Q. Are the projected retirements of Progress's generating units as shown in Progress's Ten-Year Site Plan based at least in part on your recommendations?

A. They're, they're based on certainly collaboration between Mr. Crisp and I.

MR. WRIGHT: Mr. Chairman, I'd like to ask a colleague to -- well, maybe I get to do it this morning.

CHAIRMAN CARTER: Mr. Rehwinkel would be glad to help you.

MR. WRIGHT: Thanks.

CHAIRMAN CARTER: Do you need a number?

MR. WRIGHT: I do, Mr. Chairman. Maybe 269?

CHAIRMAN CARTER: No.

MR. WRIGHT: No? Sorry.

CHAIRMAN CARTER: 268. Good effort.

How about a short title, Mr. Wright?

MR. WRIGHT: PEF 2009 TYSP Excerpt.

CHAIRMAN CARTER: PEF 2009 TSYP Excerpt.

MR. WRIGHT: Yes, sir.

CHAIRMAN CARTER: Okay.

MR. WRIGHT: I do have, I have a single copy of the entire document right, right here. It's, as you can see, it's somewhat thick. But if Progress wants to preserve optional completeness, I'm happy for them so to do.

(Exhibit 268 marked for identification.)

CHAIRMAN CARTER: Okay. You may proceed.

MR. WRIGHT: Thank you, Mr. Chairman.

(Pause.)

Mr. Chairman, thanks.

BY MR. WRIGHT:

Q. Mr. Sorrick --

A. Yes, sir.

Q. -- have you had a chance to look over this document?

A. Yes.

MR. WRIGHT: Okay. Good. I was pausing, Mr. Chairman, to give the witness a chance to review it. He was making some notes and I didn't want to interrupt his train of thought.

CHAIRMAN CARTER: Okay.

BY MR. WRIGHT:

Q. To the best of your knowledge, Mr. Sorrick, are the retirements reflected in this schedule accurate?

A. Yes.

Q. Okay. I'd like to just ask you --

A. Well, just let me clarify. In my short perusal of this, you're talking under Column 11; right?

Q. Yes, sir.

A. Yes.

Q. And so the, I see that the Bartow 1, 2 and 3 units were projected to be retired in June of 2009; correct?

A. Yes. And they were coincident with the Bartow combined cycle commercial operation.

Q. Thank you. That was my understanding. So that's good.

There's a footnote that is repeated some nine times in the, in Column 11, and it's identified by five asterisks or maybe we can call it the five-star footnote. That identifies projected retirements or cold storage actions; is that correct?

A. Yes.

Q. And I know the type is small and sketchy because this is a Xerox copy of a print of a PDF from the PSC's website, but I read this to indicate with respect to the Suwannee steam units that they are estimated to be shut down by October of 2015. Is that correct?

A. To the best that I can make out on this document, I would agree with you, yes.

Q. Well, and based on your knowledge of the system, is that about right?

A. Yes. It's about right.

Q. Okay. And similarly the remainder of the five-star footnote indicates that the Avon Park, Higgins, Rio Pinar and Turner CTs, at least those flagged by the footnote, are estimated to be put in cold standby or retired by what I think is June of 2016.

A. Yes.

Q. Is that accurate?

A. Yes.

Q. Okay. Are there any projected retirement dates, to your knowledge, for the Bartow CTs Numbers P1 through P4?

A. Not to my knowledge.

Q. Same question for the Bayboro CTs, P1 through P4.

A. Not to my knowledge.

Q. Same question for the DeBary CTs, P1 through P6.

A. No. Not to my knowledge again.

Q. Same --

A. Same for all the DeBary units and the Intercession City units.

Q. Great.

MR. WRIGHT: Then you answered the rest of my questions, and I'm done, Madam Chairman.

Thank you very much, Mr. Sorrick.

THE WITNESS: Thank you.

COMMISSIONER EDGAR: Thank you. Are there -- and that does complete -- yes. Are there questions from staff for this witness?

MR. YOUNG: No, Madam Chairman. But in lieu of cross questions, the parties have agreed to, that staff can enter items Number 24 on the Comprehensive Exhibit List and 25.

COMMISSIONER EDGAR: Is that everyone's understanding?

MR. YOUNG: And 26.

COMMISSIONER EDGAR: No objection, 24, 25 and 26?

MR. YOUNG: Yes.

MR. WRIGHT: No objection, Madam Chairman.

MR. YOUNG: I don't see Mr. Moyle, but it's my understanding that's the agreement among the parties.

COMMISSIONER EDGAR: Okay. Okay. Then at this time, hearing no objection, we will enter Exhibits 24, 25 and 26 into the record.

(Exhibits 24, 25, and 26 admitted into the record.)

MR. WRIGHT: If it's appropriate, Madam Chairman, I would move 268.

COMMISSIONER EDGAR: Well, I'm not sure we're quite there yet, so hold on just a moment. That is basically in lieu of cross; is that correct?

MR. YOUNG: Yes, ma'am.

COMMISSIONER EDGAR: Okay. Commissioners, are there any questions on cross for this witness?

Hearing none, is there any redirect?

MR. BURNETT: Yes, ma'am. Thank you.

REDIRECT EXAMINATION

BY MR. BURNETT:

Q. Mr. Sorrick, do you still have in front of you the response to a rate case in our question 150 that was presented to you by Mr. Rehwinkel?

A. Yes.

Q. And do you recall that Mr. Rehwinkel asked you some questions with respect to the, the numbers for 2010 versus the other years on there?

A. Yes.

Q. Why are the 2010 overhaul expenditures larger than those seen in prior years?

A. Well, again, those are driven by our major maintenance requirements. The new units, the existing combined cycle and combustion turbine requirements and some requirements at our steam turbine units are all drivers in that, in that cost increase. And, again, those major maintenance intervals are driven by, by time of service, and so they're, they're required for us to do if we're going to maintain a proactive maintenance program.

Q. Thank you, sir. And do you also recall that Mr. Rehwinkel asked you some questions about supporting documentation for your O&M expenses; do you recall that?

A. Yes.

Q. And in response to one of his questions with regard to some of the discovery, you gave the response that some of the discovery responses you provided did not meet some of the parties' expectations. Do you remember saying that?

A. I did.

Q. What did you mean by that?

A. Well, I know that in some of the Intervenor testimony there were -- again, I guess some of the Intervenors' witnesses did not believe that we had proved that we needed what we said we needed based on the discovery that we presented.

Q. And, Mr. Sorrick, is this a topic that you address in several pages of your rebuttal testimony?

A. Yes, I did.

Q. Thank you.

MR. BURNETT: Nothing further, Madam Chair.

COMMISSIONER EDGAR: Okay. Thank you. I think that concludes the testimony for this witness.

And, Mr. Wright, that now brings me to you.

MR. WRIGHT: Thank you, Madam Chairman. I would move 268.

MR. BURNETT: No objection, ma'am. And I would also move 55 and 56.

COMMISSIONER EDGAR: Okay. Then at this time 268, exhibit marked 268 will be entered into the record.

(Exhibit 268 admitted into the record.)

And, Mr. Burnett, did you say 55?

MR. BURNETT: Yes, ma'am. 55 and 56.

COMMISSIONER EDGAR: Okay. Hearing no objections, Exhibits 55 and 56 are admitted into the record at this time.

(Exhibits 55 and 56 admitted into the record.)

MR. WRIGHT: Thank you, Madam Chairman.

COMMISSIONER EDGAR: Thank you. The witness is excused.

THE WITNESS: Thank you.

COMMISSIONER EDGAR: Thank you.

Am I correct that that brings us to the next two witnesses who have been stipulated?

MR. BURNETT: Yes, ma'am.

COMMISSIONER EDGAR: Okay. Let's go ahead and do what we need to do for those, and then we'll take a short break.

MR. BURNETT: Yes, ma'am. With your leave, if I could pass the mike to Mr. Melson.

COMMISSIONER EDGAR: Absolutely. Mr. Melson.

MR. MELSON: Commissioners, as you indicated, the next witness is Kevin Murray. His testimony had actually been filed in the Bartow limited proceeding docket, and when that docket was consolidated with this one, was moved into this docket. So we'd ask that his prefiled direct testimony be inserted into the record as though read.

COMMISSIONER EDGAR: Okay. And with again the understanding that that was stipulated and agreed to at the beginning of the hearing, the prefiled testimony of Witness Murray will be entered into the record as though read.

MR. MELSON: And Mr. Murray had no exhibits.

COMMISSIONER EDGAR: Thank you.

MR. MELSON: Did staff have some stipulated exhibits for him?

MS. FLEMING: All of the staff exhibits for Murray and Weintraub were already moved into the record as part of staff's composite Exhibit 20.

In re: Petition of Progress Energy Florida for limited proceeding To include the Bartow Repowering project in base rates Docket No ________

DIRECT TESTIMONY OF

KEVIN MURRAY

I. <u>Introduction and Summary.</u>

Q. Please state your name and business address.

A. My name is Kevin Murray. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

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

A. I am employed by Progress Energy Florida ("PEF" or "Company") as General Manager of Plant Construction Projects.

Q. What are the duties and responsibilities of your position with Progress Energy Florida?

A. As General Manager of Plant Construction Projects, I am responsible for the oversight of PEF's major fossil generation projects, including the Bartow Repowering Project.

Q. Please describe your educational background and professional experience.

A. I received my Bachelor of Science Degree in Mechanical Engineering from the University of Arizona. I have 15 years of professional experience in engineering and project management within the electric power industry. I started my career in the power industry with Westinghouse Power Generation (now Siemens) based in Orlando, where I was employed as an engineer working on power plant proposals. During this time, I received an award for my work on a project in Thailand. I then went to work for El Paso Corporation as an engineer and then as a project manager. I was involved in the development and construction of power projects in both North and South America, including a 1-year residency in Brazil. I joined Progress Energy in 2004 and served as the director of engineering for the Company's new fossil power projects. In 2008, I was promoted to General Manager of Projects for Progress Energy Florida, which includes responsibility for implementing the Bartow Repowering Project.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to describe the Company's Bartow Repowering Project, including the key benefits that the project will provide to the Company and its customers.

Q. Please summarize your testimony

A. Progress Energy Florida is in the process of repowering the Bartow Power Plant in Pinellas County to upgrade the existing conventional heavy oil-fired steam units to state of the art natural gas-fired combined cycle technology with distillate oil backup. All four combustion turbines were first test fired in November and December 2008 and we expect the plant to commence operation by its scheduled June 1, 2009 in-service date.

The Bartow Repowering Project is part of the Company's "Balanced Solution," which includes upgrading existing plants to provide safe, cost-effective and environmentally responsible sources of large-scale power generation.

The project is designed to nearly triple the plant's generating capacity while at the same time reducing air emissions and eliminating the use of heavy fuel oil. The project will increase electric system reliability by increasing dispatch flexibility and by providing additional generating capacity near the Pinellas County load center. It will also satisfy the Company's need for additional capacity beginning in the summer of 2009 in a cost-effective manner. The repowered Bartow Plant will reduce future fuel costs and result in cleaner air. By utilizing an existing plant site, the project will avoid the need to develop a new site in the area.

We have managed the project to minimize construction impacts on the surrounding community. It has had a positive economic impact on the Pinellas County region by bringing approximately 500 high-quality construction jobs to the area and increasing tax payments to Pinellas County and the local school system.

The project is the most cost-effective alternative for meeting the Company's capacity needs while at the same time ensuring compliance with environmental requirements. Finally, we have managed the Bartow repowering in a manner that ensures a high quality result at a reasonable cost.

II. <u>The Bartow Repowering Project.</u>

Q. Please describe the Bartow repowering project.

A. The current Bartow Power Plant operates on 1950s-era technology. It generates power from three units fired on heavy (No. 6) fuel oil and is capable of generating approximately 450 MW of power.

In 2005, the Company studied ways to meet its need for additional capacity by summer 2009 in a cost-effective, environmentally sensitive manner. The analysis showed that repowering the Bartow facility to operate as a natural gas-fired, combined cycle plant was the most cost-effective way to meet the Company's reliability needs, while at the same time substantially reducing SO_2 and NOx emissions from the site.

Additional analysis during the study phase showed that the best configuration would be to replace the three existing steam units with four gas-fired combustion turbines (CTs), four heat recovery steam generators (HRSGs), and one steam turbine – or what is referred to as a 4x4x1 combined cycle configuration.

The repowering project will increase the generating capacity of the Bartow Power Plant to about 1,279 MW, or an increase of approximately 827 MW. The project will take advantage of existing site assets, such as the water intake structures, discharge canals, the fuel oil barge unloader, existing 115kV lines, existing 230kV lines, and the 230/115 kV switchyards. The project includes additional transmission and substation improvements required to integrate the project into the electric grid and to handle the increased electric output from the site.

Q. Has the repowered Bartow plant been designed to increase the Company's dispatch flexibility?

A. Yes. The plant design includes auxiliary duct firing for the HRSGs and steam power augmentation for the CTs to provide optimum peaking capacity. By-pass stack dampers installed on all four CTs will provide the option to operate the plant in simple cycle mode, as well as in combined cycle mode. This plant can also be operated in a 3x3x1, 2x2x1 or 1x1x1 combined cycle mode during periods of low system load. Because the steam turbine can be kept warm even during periods of low load, the design significantly reduces plant start-up time compared to the existing oil-fired units. Taken together, these design features provide maximum output, operational ease, and system dispatch flexibility.

Q. What transmission and substation improvements are being made to support integrating the project into the electric grid?

A. The transmission improvements associated with the project include: expansion and upgrades to the Bartow and Northeast substations; the addition of three 230 kV underground circuits between those two substations; rebuilding an existing 230 kV line between the Northeast and 40^{th} Street substations; installing a new 115 kV line between the Northeast and 32^{nd} Street substations; installing a new transformer at the 51^{st} Street substation and looping an existing 230 kV line into that substation; and replacing a 115 kV breaker at the Central Plaza substation.

Q. Has PEF secured a reliable and adequate source of natural gas fuel supply?

A. Yes, PEF has entered into an agreement with Gulfstream Natural Gas System for Firm Pipeline Transportation (FT) capacity to access gas supply for the

Bartow plant. The total FT capacity contracted for is 155,000 Dths/day for a term of 23 years. This is roughly equivalent to the total daily gas demand of the re-powered plant at full load for 16 hours. To provide natural gas to the plant, Gulfstream has constructed approximately 17 miles of 20" pipeline from its existing pipeline in the Tampa Bay to the Bartow site. In addition, Gulfstream has added compression at its compressor station in Coden, Alabama, and constructed a new compression station in Manatee County, Florida, to support the project.

The gas transportation contract provides for an initial 80,000 Dths/day of natural gas to support testing and startup of the CTs in 2008. The contract provides for the full 155,000 Dths/day to be available by January 1, 2009. The terms of the contract with Gulfstream are reasonable and consistent with industry standards.

III. Benefits of the Project

Q. Please summarize the benefits of the repowering project.

A. Repowering the Bartow plant will add approximately 827 MW of capacity in June 2009. This increase avoids a capacity purchase in summer 2009, the Hines 5 combined cycle unit, and CTs originally planned for 2010 and 2012. Under current planning assumptions, PEF still requires additional capacity by summer 2009 to meet its 20% minimum reserve margin obligation and the Bartow repowering meets that need.

The design of the Bartow repowering reduces plant start-up time and increases dispatch flexibility. The addition of new capacity near the Pinellas

County load center, and the related transmission upgrades, will address low voltage conditions that can exist in the area during periods of peak demand.

The Bartow repowering will significantly reduce the site's emissions, including a 98 percent reduction in SO_2 emissions and reduced NOx emissions. This will enable the Company to meet the Clean Air Interstate Rule (CAIR) requirements without installing costly Selective Catalytic Reduction ("SCR") at the Anclote Plant.

The Bartow repowering project has become part of the Company's "Balanced Solution" for meeting its customers' needs, and the project is consistent with the goals set forth in Florida's Energy and Climate Change Action Plan, submitted to the Governor by his Action Team. Part of this plan emphasizes achieving efficiency improvements at existing plants by repowering existing plants to use natural gas in place of oil, which is what the Bartow repowering project will do.

During construction, PEF has added nearly 500 jobs to the area workforce which has provided an economic boost to the community. In addition, the local economy has received a financial boost from taxes and increased revenue during the construction project and will benefit from a higher tax base in the future.

IV. Implementation of the Bartow Repowering Project.

Q. Please describe how the Bartow Repowering Project is managed.

A. A key project team was organized to consider alternatives for projected generation needs. A portfolio of initiatives was developed to analyze generation and transmission alternatives. The project team, together with PEF's System

Planning & Regulatory Performance Unit, developed an Integrated Project Plan summarizing the key project decision points. The integrated resource planning process essentially matches PEF's projected needs with the most cost-effective power plant additions.

The project team is responsible for approving project milestone progression and funding for both generation and transmission upgrades. The team also developed a contracting and procurement strategy and assembled predominantly firm-price contracts with qualified suppliers that are responsible for the execution of various aspects of the project. The team mitigated cost and performance risk by capturing favorable contract terms and conditions such as retention provisions, performance guarantees, and reliability guarantees. The project team provides regular updates to Senior Management in the areas of cost, schedule, performance, risk, safety and environmental issues.

Q. When will the project be complete?

A. Both the generation and transmission components of the project are on-schedule for commercial operation by June 1, 2009.

Q. What is the estimated cost for the Bartow Repowering Project?

A. The estimated cost for the project is $800.2 million. This includes new generation capital expenditures of $560.3 million, transmission capital expenditures of $143.0 million, and $96.9 million in AFUDC.

Q. In your opinion, is the project prudent and will it be completed at a reasonable cost?

A. Yes. The initial study of the 4x4x1 configuration showed $171 million NPV of after-tax cash flow savings from the Bartow repowering project compared to the base case alternative. Although the projected savings has varied over time as the project has evolved, the project continues to provide significant savings to our customers by meeting our generation and environmental needs in a cost-effective manner. As I have described in my testimony, the reasonableness of the project costs has been assured by our procurement practices, including competitive bidding and the use of predominantly firm price contracts where appropriate, the purchase of a secondary market steam turbine, and our cost control activities.

Q. Does this conclude your testimony?

A. Yes.

MR. MELSON: Thank you. We would also ask that the prefiled direct testimony of Sasha Weintraub be entered into the record as though read.

COMMISSIONER EDGAR: Okay. And, again, per the discussion and agreement at the beginning of the hearing, the prefiled testimony of Witness Weintraub will be entered into the record as though read.

MR. MELSON: And we would move Exhibits 40 -- excuse me, 57, 58, 59, 60 and 61, which were his SAW-1 through SAW-5.

COMMISSIONER EDGAR: Okay. And hearing no objection, exhibits marked 57 through 61 will be entered into the record.

(Exhibit 57 through 61 identified and admitted into the record.)

In re: Petition for rate increase by Progress Energy Florida, Inc.
Docket No. 090079-EI

DIRECT TESTIMONY OF
SASHA WEINTRAUB

I. INTRODUCTION AND SUMMARY.

Q. Please state your name and business address.

A. My name is Sasha A. J. Weintraub. My business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601.

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

A. I am employed by Progress Energy Carolinas, Inc. ("PEC") as Vice President Fuels and Power Optimization.

Q. What are your duties and responsibilities in that position?

A. I am responsible for the procurement of coal, natural gas, and fuel oil for the Progress Energy Florida, Inc. ("PEF" or the "Company") and PEC generation fleet. I am also responsible for portfolio management and short term power trading for both PEF and PEC. In addition, I am responsible for the Company's coal, natural gas, and fuel oil price forecasts used for fuel filings and resource planning purposes in connection with the Company's Ten Year Site Plan filing each year.

Q. Please describe your educational background and professional experience.

A. I have a Bachelor of Science ("BS") degree in Engineering from Rensselaer Polytechnic Institute, I have a Master's in Mechanical Engineering from Columbia University, and I have a Ph.D. in Industrial Engineering from North Carolina State University. From February of 2003 until June of 2005 I was the Director of Coal Marketing and Trading for Progress Fuels Corporation, a former subsidiary of Progress Energy. Before assuming my current position, I was the Director of Coal Procurement for PEF and PEC.

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

A. Yes. I have previously testified for PEF in a proceeding involving coal procurement for two of PEF's coal-fired units. I also testified for PEF in the Company's need determination proceeding for Levy Units 1 and 2.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the Company's fuel price forecasts and inventory target levels.

Q. Have you prepared exhibits to your testimony?

A. Yes. I sponsor the following exhibits, which are attached to my prefiled testimony:

- Exhibit No. ___ (SAW-1), a list of the Minimum Filing Requirements (MFR) schedules I am sponsoring or co-sponsoring;
- Exhibit No. ___ (SAW-2), the Company's fuel price forecast;
- Exhibit No. ___ (SAW-3), the Company's fuel inventories;

- Exhibit No. ___ (SAW-4), a comparison of the Company's fuel inventory levels to the Florida Public Service Commission (the "Commission") guidelines; and
- Exhibit No. ___ (SAW-5), the Company's 2005 actual coal inventory levels.

These exhibits are true and accurate.

Q. Are you sponsoring any Minimum Filing Requirements (MFRs)?

A. Yes, they are listed in Exhibit No. ___(SAW-1). I have reviewed them and they are true and correct, subject to their being updated in the course of this proceeding.

II. THE FUEL PRICE FORECAST

Q. Please describe the basic components of the Company's fuel price forecast.

A. The Company's fuel price forecast includes the fuel types that PEF expects to utilize over the forecast period. Exhibit No. ___ (SAW-2) shows the projected spot market commodity prices for 2010 for coal, oil, and natural gas. Different grades of coal and oil are used at different generating units, therefore the Company prepares separate forecasts for each grade. The delivered fuel price to each plant varies based on transportation costs to the site and the mix of contract and spot market purchases. The forecasted delivered prices to each plant are shown on MFR B-18.

Q. Exactly what type fuels are included in the forecast?

A. The forecast contains spot market commodity price projections for the following fuels:

- Coal - 1.3% sulfur (2.1 lbs SO_2 /MMBtu) and a weighted average of 0.7% and 2.9% sulfur (1.2 and 5.0 lbs SO_2/MMBtu)
- Residual/Heavy/No. 6 Oil - 1.0% and 1.34% sulfur (1.1 and 1.5 lbs SO_2/MMBtu)
- No. 2/Light/Distillate Oil - 0.0015 lbs SO_2/MMBtu and 0.5 lbs SO_2/MMBtu
- Natural Gas

Q. Turning now to the individual fuels included in the forecast, will you please explain why PEF's forecast reflects two different coal price projections?

A. PEF's forecast reflects different coal prices because the Company utilizes different grades of coal at its Crystal River Plant. Specifically, Crystal River Units 1 & 2 burn coal with an approximate 2.1 lbs. SO_2/MMBtu and Crystal River Units 4 & 5 burn coal with an approximate 1.2 lbs. SO_2/MMBtu. In the latter part of 2010, Crystal River Units 4 & 5 will be capable of burning higher sulfur coal (5.0 lbs. SO_2/MMBtu) due to the installation of wet scrubber flue gas desulfurization (FGD) systems. Different grades of coal are sold at different prices in the market. Thus, the Company must forecast prices for each of the different grades of coal it plans to utilize at its Crystal River Plant. The spot market commodity price projection shown for Crystal River Units 4 and 5 on Exhibit ___ (SAW-2) is the weighted average price for 2010 of the low and high sulfur coals.

Q. What factors are taken into account in developing the Company's coal

price forecast?

A. The Company's coal forecast is impacted by a variety of factors, including the source of the coal, the varying type and quality characteristics, forecasted burn requirements, price and volume commitments under existing contracts, the forecasted market and conditions for spot purchases, and transportation costs to the point of use.

Most of the coal currently consumed at PEF's generating plants is mined in the Central Appalachian region and South America. In the future, the addition of wet scrubber FGD systems to comply with environmental regulations will allow the Company to further diversify its fuel portfolio and procure coal from other regions, such as the Illinois Basin. The Company calculates the volume of coal needed to fulfill the burn requirements at the Crystal River Units. The Company then reviews the price and volume commitments in its current coal contracts. If further volume is needed, the Company utilizes the market for spot purchases to fulfill this requirement. This analysis results in an overall commodity price forecast that includes the expected mix of contract and spot market coal. The Company also prepares a separate transportation price forecast for both water and rail transport. The delivered price of coal shown in the MFRs represents the sum of the commodity and transportation price forecasts.

Q. **Focusing next on oil prices, please explain why several different prices have been projected in the Company's study for oil.**

A. The Company procures and burns different qualities of oil. The 1.0% sulfur residual oil is currently used by the Company at the Suwannee River steam plants. The Anclote steam plant can use up to an annual maximum of 1.5% sulfur residual oil. The different grades of No. 2 oil are used at PEF's combustion turbines for generation and at steam plants for start-up. Like coal, different grades of oil are sold at different market prices based on type and quality. Accordingly, the Company forecasts each of them separately.

Q. Other than the type of oil, what are the key assumptions that affect the price forecast for oil?

A. The projected oil prices are based on estimates of the contract prices for oil, spot prices of oil, and the cost of delivery to PEF's plant locations. The fuel oil prices all assume bulk, waterborne deliveries to the West Coast Florida Terminal used by the Company indexed to U. S Gulf Coast market prices. As in the case of coal, transportation costs to individual plants are forecasted separately and are added to the commodity prices to produce a delivered price forecast for each site.

Q. How is the price of natural gas forecasted?

A. The natural gas forecast is based on the contract structures and estimates of spot market prices expected to be in effect during the forecast period for the cost of the fuel into the pipelines which deliver it into Florida. Transportation costs, including fixed demand charges and variable transportation charges to specific plants, are forecasted separately.

III. FUEL INVENTORIES

Q. Which of these fuels does the Company keep in inventory?

A. As shown in Exhibit No. ___ (SAW-3), the fuels currently maintained in inventory are coal, natural gas, residual oil and No. 2 oil. The Company also maintains nuclear fuel in inventory, as reflected in MFR B-16.

Q. What is the objective of the Company's fuel inventory target levels for coal, natural gas, residual oil, and No. 2 oil?

A. The Company's objective in establishing fuel inventory target levels is to maintain fuel inventories that ensure a competitively priced, reliable and secure fuel supply to support the economic dispatch and operation of the Company's generation fleet. In determining adequate inventory levels, the Company considers several factors, including:

1. Projected system fuel requirements and costs based on the system constraints and estimated demand;
2. Fuel storage, transportation source and flexibility, and fuel handling capabilities;
3. Lead times to secure supply and deliver to on-site and off-site inventory locations under different market and operating conditions;
4. Potential delays and interruptions in fuel supply caused by events outside the control of the Company; and,
5. Current and future fuel market conditions.

Q. Would you describe generally the procedure followed in establishing the Company's fuel inventory target levels?

A. Using the factors identified above, target inventory levels are evaluated for each fuel type both on a total system basis and for each generating facility. Actual inventory levels are monitored daily. Inventory targets are reviewed and revised as necessary when warranted by changes in unit availability, dispatch economics, and transportation or logistics constraints. The target levels are used as inputs to the Company's financial model for the projection of fuel expense and inventory balances.

Oil Inventory

Q. How were the oil inventory target levels identified in this case developed?

A. The inventory target level for each generating plant that uses oil as a primary or back-up fuel was established by the process that I have described. In establishing these targets, the Company also considered the storage capacity at each plant site, the source of the fuel oil supply, the amount and location of off-site storage leased by PEF, expected plant burn requirements, the specific delivery modes used to deliver fuel oil to each plant, and fuel supply risks that the Company cannot control. Based upon this analysis, the Company established the inventory target levels for oil that are recorded in the MFRs. The system target levels are also shown by oil type in Exhibit No. __ (SAW-3).

Q. What is PEF's inventory plan for residual oil?

A. The Company's residual oil inventory plan is to maintain the level of oil necessary to provide for the reliable and economic operation of its generating units. Generation facilities that run on residual oil are critical to maintain the Company's overall system reliability. The Company projects an average of approximately 745,000 barrels of residual oil in inventory in 2010, as reflected in Exhibit No. ___ (SAW-3). This amount is made up of approximately

650,000 barrels (18.2 days at full burn) for Anclote and approximately 95,000 barrels (14.9 days at full burn) for Suwannee. These amounts are consistent with the inventory levels the Company has been maintaining for Anclote and Suwannee; however, the system-wide residual fuel inventory for 2010 is lower than recent levels due to the repowering of the Bartow oil-fired plant with natural gas by June 1, 2009.

Q. What is PEF's inventory plan for No. 2 fuel oil?

A. The Company's No. 2 fuel oil inventory plan is to maintain the level of oil necessary to provide reliable supply for its peaking facilities and adequate back-up fuel supply for its combined cycle ("CC") units. The Company has added several new intermediate CC units to the system since the Company's last fuel inventory levels were approved, including the repowered Bartow Plant which is scheduled for commercial operation by June 1, 2009. These units run mostly on natural gas, but use No. 2 oil as a back-up fuel.

The Company projects to average approximately 1,106,700 barrels of No. 2 oil inventory in 2010, as reflected in my Exhibit No. __ (SAW-3). Approximately 60% to 65% of the inventory (660,000 to 720,000 barrels) will be stored at the Company's ten separate CT peaking unit sites. An additional 218,000 barrels will be stored at the Hines and Bartow CC unit sites as back-up fuel to natural gas. The Company projects storing approximately 15,000 barrels at the Crystal River and Anclote sites as start-up fuel for the steam generators. Finally, 150,000 to 210,000 barrels will be stored at the Martin Storage facility, which is a storage facility for which PEF contracts at the Port of Tampa. The total amount of No. 2 fuel oil inventory is consistent with the amount the

Company has been maintaining, when adjusted for the additional No. 2 back-up fuel required for the repowered Bartow plant.

Q. Why is it important that the Company maintain adequate oil inventory at each separate plant site?

A. PEF's oil peaking units are critically important to maintain reliable operations during peak demand periods. They are also necessary to provide generation when unplanned supply curtailments occur and unforeseen generation events impact the Company's other baseload and intermediate generation units. For example, unscheduled outages at either of the major coal-fired units, the nuclear unit, or the large combined cycle natural gas facilities can cause significant variations in the amount of fuel oil burned. In addition, interruptions to the natural gas supply and/or higher than expected load requirements could result in the need to run the oil peaking units longer than expected.

Each site must have adequate onsite storage to ensure sufficient fuel supply during these times of need. Because the units are in different geographic locations, PEF's inventory plan must address inventory needs and storage capacity at each generating site. Inventory is not easily moved between CT unit locations. At the Intercession City site, PEF must maintain an inventory of two different grades of No. 2 fuel, since fuel oil is not interchangeable between all units at the site due to quality specifications and environmental permit requirements.

Typically it takes two to three weeks from the moment PEF places a delivery order for No. 2 fuel oil to the moment the oil reaches the site. Any number of events can interrupt the delivery of light oil. In particular, barge delays due to potential or active storms, rough seas, and refinery outages can all affect product availability. For example, during the summer of 2008, Hurricanes Gustav and Ike resulted in the temporary closing of several refineries and ports and the interruption of PEF's normal shipments of No. 2 oil. Without on-site storage, PEF would not be able to ensure the reliable operation of its peaking units during normal and contingency situations.

Q. Could PEF simply move fuel oil from one site to another if shipments to a particular site were delayed?

A. No. Moving fuel oil between locations is not operationally practical or prudent. For example, the Company maintains approximately 240,000 barrels of No. 2 oil inventory at the Intercession City combustion turbine site. PEF cannot rely on that inventory to readily fuel the CT units at Shady Hills, which are located some 85 miles away. The fuel oil would have to be trucked from Intercession City to Shady Hills, which takes time and money. Further, Intercession City has only one connection available to load trucks. Assuming that the Intercession City units did not need the oil to operate, and that trucks were available, it would take 274 truck loads to provide the 48,000 barrels to Shady Hills. At the rate of one truck per hour loading 24 hours a day, seven days per week, it would take 11 days to provide Shady Hills with 51 hours (or 2.1 days) of light oil supply. When the PEF Energy Control Center notifies the CT unit operators to begin generating electricity, these units must be ready at that moment and cannot wait for a shipment of inventory from another site. Thus, a sufficient amount of No. 2 oil inventory at each CT site is imperative.

Q. Why does the Company maintain an inventory of No. 2 oil at the Port of Tampa?

A. PEF maintains storage at the Port of Tampa to reduce the significant logistical risk and time lag that exist for the Company in procuring and shipping No. 2 oil to its units when needed. Supplying fuel oil to PEF's plants has inherent risks due to the way the product is procured and transported to the state and ultimately to PEF's generating sites. The offsite storage provides a significant benefit to PEF as it gives the Company much greater flexibility to secure No. 2 oil in advance and to schedule deliveries from suppliers at more regular intervals or with broader delivery windows. The availability of the off-site inventory increases supply security and reliability by allowing PEF to buy fuel oil over time, and to effectively schedule fuel deliveries to its generation fleet from the Port of Tampa inventory without being concerned with the timing of any one barge or series of barge shipments. This flexibility is even more important during extreme load events or during supply disruptions, when PEF could otherwise face both supply risks and transportation risks and delays.

The need for and value of this storage was evident after PEF struggled in 2005 to get and maintain sufficient fuel oil supply to our units in the face of significant delays caused by hurricanes, higher loads, and unexpected and unforeseen unit derates that put greater demand on our peaking units. In addition, during the 2008 hurricanes, when the refineries in the Gulf of Mexico closed, it was difficult to procure supplies of oil.

In addition to these supply and delivery risks, forecasting fuel oil burns at peaking units is more difficult than forecasting other fuels, such as coal and natural gas, which are used at base-load and intermediate plants. As such, PEF must be prepared to deliver large quantities of fuel oil at any time to respond to load variation, unforeseen unit outages and other fuel events. The inventory of No. 2 oil at the Port of Tampa meets this objective.

Q. How does the State of Florida and the Company obtain its fuel oil?

A. According to the Department of Environmental Protection's Florida Energy Plan released in January 2006, the State of Florida depends almost exclusively on other states and nations for supplies of oil and ranks first among all states in the amount of electricity produced from oil. Florida receives approximately 98 percent of its fuel oil by sea via barge and tanker ships. Fuel oil is supplied by domestic and international refineries as well as the pipeline spur in Bainbridge, Georgia. PEF purchases its fuel oil from suppliers who have access to inventories, refineries, and terminals in the Gulf Coast, Midwest and West and transport the fuel oil to Florida and ultimately to PEF generation facilities via barge, pipeline, rail, and truck.

With respect to managing and meeting its No. 2 oil system generation and inventory requirements, PEF purchases No. 2 oil primarily under term agreements based on published market based indexes and utilizes leased off-site inventory at the Port of Tampa for delivery of No. 2 oil to its plant facilities by barge, pipeline, rail, and truck.

With respect to residual fuel oil, the Anclote plant is supplied via a 33.5 mile oil pipeline which originates from dedicated inventory located at the Bartow plant site. The Bartow plant site has unloading facilities where residual fuel oil is delivered via barges which originate from the Gulf Coast. Residual fuel oil is delivered to the Suwannee plant by truck deliveries from terminals located in Florida and by rail from sources outside the state.

Q. What impact do these fuel supply arrangements have on PEF's fuel inventory management?

A. Fuel oil deliveries must be managed and arranged in advance given the relatively long lead times to obtain the fuel supply and transport it to PEF's facilities. In addition, PEF faces significant risks to the timely delivery of fuel oil. These include rail congestion, strikes, flooding, fogs, river flooding, tropical storms, hurricanes, refinery outages, and equipment breakdowns. All of these factors can increase the time from when an order is placed for delivery of fuel oil to when it reaches the site. The farther the supply point is from the delivery point, or the more variables that exist, the longer the time period could be for delivery. As noted above, barge shipments were significantly impacted as a result of the hurricanes in 2005. This also occurred during the hurricanes in 2008. In addition, the amount of fuel oil that is available can be impacted as a result of sustained refinery outages in the Gulf Coast.

Q. How do the residual and No. 2 oil inventory target levels compare with the Commission's guidelines established in Order No. 12645 in Docket No. 830001-EU?

A. As can be seen in Exhibit No. ___ (SAW-4), PEF's residual and No. 2 oil inventory targets exceed the guidelines.

Q. Please explain why the residual and No. 2 oil inventory levels exceed the guidelines.

A. For all the reasons discussed above, sound fuel management practices require PEF to maintain oil inventory levels that exceed the 1983 guidelines. The factors supporting the fuel inventory levels above the guidelines include:

- the difficulty in predicting fuel oil needs due to the fact that oil-fired combustion turbine units are called on both during periods of peak demand and in the event of unplanned outages or derates of intermediate or baseload units;
- the diverse geographic location of the generating sites, and the impracticality of transferring fuel between those sites, which necessitates maintaining inventory at a variety of locations;
- the fact that units at a large generating site may have different fuel quality requirements, which requires the Company to maintain inventories of multiple grades of fuels at a single site;
- the relatively long lead time to obtain fuel supplies or to replenish inventories due to the fact that PEF, like other Florida utilities, must import virtually all of its fuel oil from sources outside the State; and
- the risk of supply curtailments or transportation delays posed by hurricanes and tropical storms which can impact both PEF's service territory as well as fuel handling facilities along the Gulf coast.

If PEF fails to maintain fuel oil inventories at the planned levels, it exposes the Company and its customers to fuel cost, operations, and reliability risks. These risks include buying much more expensive oil, running out of fuel oil prior to shipments arriving, buying more expensive purchased power, and putting the power grid at greater risk due to fuel shortages. The Company needs fuel inventory levels above the guideline amounts not only to support the projected burn levels, but also to effectively manage a secure and reliable supply of fuel for normal and contingency circumstances.

Q. Is it speculative to plan for the contingency events you describe?

A. Absolutely not. Experience shows how critical the steam and peaking units, and thus the oil inventory levels, can be. In 2005, the effects of Hurricanes Katrina, Rita, and Wilma disrupted coal barge shipments into Crystal River and decreased the supply of natural gas from the Gulf of Mexico. In addition, because these storm events interrupted the delivery of oil shipments to the various oil plants, PEF relied solely on on-site inventory for days. These fuel supply disruptions were coupled with higher load requirements due to warmer weather, as well as an unexpected de-rate at Crystal River 5, a coal-fired unit. The combination of these events resulted in the inventory levels for Anclote dropping to 6.4 days (based on the units running at full load). After these events, the Company decided to target, and has generally targeted to maintain, an inventory level of approximately 18 days of full burn for the Anclote plant.

To further illustrate this risk, if there are prolonged natural gas curtailments and/or fuel oil delivery delays, PEF may have to solely rely on its No. 2 fuel oil inventory at its large combustion turbine sites and at its intermediate natural gas generation sites. If this were to occur, the Intercession City, Debary and Hines sites, which maintain PEF's largest on-site inventories, have on average only 104 hours of inventory, meaning those units could only operate 4.3 days. It is thus imperative for the Company to have sufficient inventory levels of oil to adequately protect its ratepayers in the event of supply interruptions.

Coal Inventory

Q. How does PEF develop its coal inventory levels?

A. PEF uses its fuel inventory objectives and procedures to maintain coal inventories at optimum levels consistent with operational and financial considerations. For coal inventory, additional considerations include potential supply problems with mining sources, barge transportation, and rail transportation. The storage capacity available near New Orleans (International Marine Terminal or "IMT") and at the United Bulk Terminal ("UBT") is also a consideration when evaluating coal inventories at Crystal River. In addition, the Crystal River coal inventory levels are affected by the risk that hurricanes and tropical storms in the Gulf of Mexico pose to the supply of coal to the site.

Q. Can you provide any specific examples to illustrate the impact that hurricanes can have on coal inventory levels at PEF?

A. Yes. The 2005 hurricane season, which I described above in connection with oil inventories, also severely impacted coal inventories at Crystal River, where all PEF's coal-fired generating units are located. Coal can be delivered by rail or barge to Crystal River, but the majority of coal is delivered by barge. Domestic barge coal comes down the Mississippi River on river barges, and is then loaded onto Gulf barges at one of two terminals for shipment across the Gulf of Mexico. All the coal PEF purchases from South America are shipped across the Gulf of Mexico as well.

During 2005, hurricanes in the Gulf of Mexico prevented coal barges from being delivered into Crystal River, causing inventory levels at Crystal River to drop significantly. Generally the Company targets coal inventory levels equal to 45 days of running the plants at full capacity. As can be seen in Exhibit No. __ (SAW-5), by December 2005, the Company's inventory levels dropped to 22 days for all four Crystal River units. In the last four months of the year, PEF burned more coal than was delivered to the site.

Q. Has the Company seen any interruptions in coal deliveries since 2005?

A. Yes, the summer of 2008 was particularly challenging in terms of obtaining timely coal shipments. First, an oil spill in the Mississippi River interrupted shipments of barge coal. Then Hurricanes Gustav and Ike, while they fortunately did not directly impact PEF's service territory, did prevent barges from crossing the Gulf of Mexico. In addition, congestion on the railroads can also interrupt or delay coal deliveries. In September 2008, coal inventory levels at Crystal River fell to 22 days (at full burn), as compared to the target of 45 days.

Q. What is the Company's projected coal inventory for 2010?

A. For 2010, the Company projects to average 360,000 tons of coal inventory at Crystal River 1 & 2, 600,000 tons of coal inventory at Crystal River 4 & 5, and 827,200 tons of coal either in transit or at off-site storage, as reflected in my Exhibit No. __ (SAW-3).

Q. How do the coal inventory target levels compare with the guideline established in Order No. 12645 in Docket No. 830001-EU?

A. As can be seen in Exhibit No. ___ (SAW-4), PEF's coal inventories exceed the guideline established in 1983. The on-site inventory levels are consistent with the target of 45 days at full burn that we have attempted to maintain since our experience with supply interruptions during the 2005 hurricane season. The off-site inventories are larger than we have maintained in recent years. The increase in off-site inventories is required to support fuel switching to higher sulfur coals, such as Illinois Basin coal, in 2010 in response to the installation of scrubbers at Crystal River Units 4 & 5. The Company will begin building an off-site inventory of higher sulfur coal in 2009. At the same time, we need to maintain an inventory of lower sulfur coal to support plant operations until the scrubbers have been installed and tested, and the change-over to higher sulfur coal can be completed in late 2010.

Natural Gas Inventory

Q. Is there a target inventory level for natural gas in the Commission's guidelines established in Order No. 12645 in Docket No. 830001-EU?

A. No, there is no Commission guideline for natural gas inventory levels.

Q. What natural gas inventory does the Company maintain?

A. As shown on Exhibit No. ___ (SAW-3), the Company maintains a total of 1,250,000 MMBtu's of contracted natural gas inventory. This contracted for inventory level was established in accordance with the Company's objectives that I have previously described. The natural gas inventory level is represented by contracts that began in May of 2008, in which PEF leases natural gas storage capacity from two companies for a total of five years. The first contract is with

Bay Gas Storage Company for high deliverability natural gas storage from an onshore salt cavern facility in Mobile, Alabama with capacity of 500,000 MMBtu's. The second contract, with SG Resources Mississippi, L.L.C. ("SGR"), permits PEF to store up to 750,000 MMBtu's at SGR's onshore salt cavern facility in Greene County, Mississippi.

Q. What are the reasons to maintain an inventory of natural gas?

A. PEF contracted for this natural gas storage for a few key reasons. First, PEF has a growing portfolio of natural gas-fired generation. Approximately 47 percent of actual generation from PEF's owned generation in 2010 is expected to come from combined cycle or combustion turbine units fueled by natural gas. Thus it is increasingly important that PEF has a secure and reliable natural gas supply to support its natural gas generation needs. Diversifying its flowing supply and providing for back-up are both essential components of the Company's strategy to meet this need. The contracted storage will increase the reliability of gas supply by providing backup supply in emergency conditions. For example, PEF withdrew gas from storage to meet system needs when normal gas supplies were disrupted by hurricanes in 2008. Under the storage contracts, PEF has the capability to withdraw the storage gas at the rate of 125,000 MMBtu/day over a 10-day period. This can meet a portion of the Company's natural gas requirements when supplies are curtailed. Second, natural gas storage can be used to manage price risk. For example, because PEF has natural gas in storage, it may be able to minimize fuel costs by utilizing storage gas versus buying from the market when the market price is higher than its average cost of gas in storage. Finally, the storage capacity can provide PEF more opportunities to manage daily and monthly pipeline imbalances.

Q. In your opinion, are PEF's projected fuel inventory levels appropriate?

A. Yes. For all the reasons I have discussed, I believe that maintaining these fuel inventory levels is reasonable and prudent, and in the best interest of the Company and its ratepayers.

Q. Does this complete your testimony?

A. Yes, it does.

MR. MELSON: And, Commissioner, one more procedural matter. We had talked yesterday about moving the MFRs into the record, and Mr. Rehwinkel had made the excellent suggestion that we provide a list of the supplemental and revised MFRs. I've got that. The parties have seen it. If you'd like, I could hand that out now and we'd move that exhibit.

COMMISSIONER EDGAR: Okay. Let's go ahead.

Mr. Rehwinkel, does that work for you?

MR. REHWINKEL: Yes. I appreciate the consideration. And after discussion with Mr. Melson, we're satisfied that the list here is the MFRs that we've all been provided copies with.

COMMISSIONER EDGAR: Okay. And that is the exhibit marked on the Comprehensive, thank you, Exhibit List as 47?

MR. MELSON: Yes, ma'am.

COMMISSIONER EDGAR: Okay. And so with that discussion, Exhibit 47 is entered into the record at this time.

(Exhibit 47 identified and admitted into the record.)

MR. MELSON: And Commissioner?

COMMISSIONER EDGAR: Yes, sir.

MR. MELSON: I would ask that you mark this single sheet as the next numbered exhibit.

COMMISSIONER EDGAR: Okay, Mr. Melson, we will mark as 269.

MR. MELSON: Document title, PEF Supplemental/Revised MFRs.

COMMISSIONER EDGAR: Which will be so titled.

MR. MELSON: And we would move that exhibit.

COMMISSIONER EDGAR: And as Mr. Rehwinkel has concurred earlier, hearing no objection, Exhibit 269 is entered into the record.

(Exhibit 269 marked for identification and admitted into the record.)

MR. BURNETT: And, Madam Chairman, PEF owed the record a complete copy of Exhibit 265. We have that available, if it's your pleasure to take it up at this time, or we can do it at any time.

COMMISSIONER EDGAR: That was the exhibit that Mr. Wright had supplied an excerpt, and then per the discussion yesterday, you were going to distribute and mark for -- okay. So we can go ahead and note for the record that the exhibit marked 265 which was discussed as an excerpt yesterday, that the full and complete report is being submitted to all parties and to the Clerk and will be so admitted as Exhibit 265.

(Exhibit 265 admitted into the record.)

MR. BURNETT: Yes, ma'am. Thank you.

COMMISSIONER EDGAR: Okay. Anything else that we can take care of? Okay. Hearing none, we had promised our court reporter and the rest of us a short break, so we will come back and pick up with the next witness at quarter to. We are on break.

(Recess taken.)

If we could all gather. Okay. We are back from break and we are back on the record.

Mr. Burnett, your witness.

MR. BURNETT: Thank you, ma'am. We call Dale Oliver.

DALE OLIVER

was called as a witness on behalf of Progress Energy Florida and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BURNETT:

Q. Good morning, Mr. Oliver. Will you please introduce yourself to the Commission and provide your business address?

A. I will. Dale Oliver, Vice President, Transmission Operations and Planning for Progress Energy Florida, 299 1st Avenue North, St. Petersburg, Florida.

Q. And you've been previously sworn, correct, sir?

A. I have.

Q. And have you filed direct testimony and exhibits in this proceeding?

A. I have.

MR. BURNETT: And, Madam Chair, for the, for the information, those have been premarked, the exhibits, as 62 and 63.

COMMISSIONER EDGAR: Thank you.

(Exhibits 62 and 63 identified for the record.)

BY MR. BURNETT:

Q. Do you have any changes to make to your prefiled testimony or exhibits?

A. I do not.

Q. If I asked you the same questions in your prefiled direct testimony today, would you give the same answers that are in that testimony?

A. I would.

MR. BURNETT: Madam Chair, we request that the prefiled direct testimony be entered into the record as read today.

COMMISSIONER EDGAR: The prefiled testimony of this witness will be entered into the record as though read.

Petition for increase in rates by Progress Energy Florida

DOCKET NO.090079-EI

DIRECT TESTIMONY OF

DALE OLIVER

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Dale Oliver. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

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

A. I am employed by Progress Energy Florida, Inc. ("PEF" or the "Company") as its Vice President, Transmission Operations & Planning Department ("TOPD", "Transmission" or the "Department"). In this role, I have overall responsibility for PEF's transmission system, including its design, construction, operation and maintenance, in order to provide reliable transmission service to PEF's retail and wholesale customers. I am also responsible for the integration of PEF's transmission system with the Florida transmission grid.

Q. Please describe your educational background and professional experience.

A. I received a bachelor's degree in electrical engineering from Georgia Tech in 1981 and an MBA from Georgia State University in 2001. Prior to assuming my current role in February, 2007, I was the Regional Vice President for PEF's South Coastal Region from October, 2005 to February, 2007, and from May 2004 to

October, 2005 the Company's Regional Vice President for the South Central Region. From 2001 to 2004, I was PEF's Director of Transmission Engineering and the Director of the Company's Commitment to Excellence ("CTE") program. Prior to joining PEF in January 2001, I held a number of supervisory and management positions in the transmission maintenance and operations areas for the Southern Company's Georgia Power subsidiary in Atlanta, Georgia. I am a registered professional engineer in the states of Florida and Georgia.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to support the reasonableness of PEF's transmission capital and O&M expenses.

Q. **Are you sponsoring any Minimum Filing Requirements Schedules?**

A. Yes. The Minimum Filing Requirements (MFRs) Schedules that I sponsor or co-sponsor are listed in Exhibit No. ___ (JDO-1) to my testimony. These MFR Schedules are true and correct, subject to being updated during the course of this proceeding.

Q. Do you have any exhibits to your testimony?

A. Yes, I have prepared or supervised the preparation of the following exhibits to my direct testimony:

- Exhibit No. __ (JDO-1), a summary of sponsored or co-sponsored schedules of the Company's Minimum Filing Requirements (MFRs); and

- Exhibit No. __ (JDO-2), a summary of Transmission capital projects, with total capital project cost, (1) to comply with federal reliability standards, (2) to comply with regional reliability initiatives, (3) to accommodate new generation and reliability needs from expansion, and (4) to maintain the system.

These exhibits are true and correct.

Q. Please summarize your testimony.

A. PEF requires transmission capital expenditures of $185.2 million and O&M expenses of approximately $45.3 million in 2010. These expenditures enable the Company to strike a reasonable balance between the high quality of service that our regulators and our customers expect and a reasonable cost for transmission service. PEF's O&M expenses are further reasonable and necessary because they are $ 0.03 million or 0.0% above the Commission O&M benchmark cost of $38.4 million.

PEF has successfully provided reliable transmission service to its customers at a reasonable cost for years. PEF's reliability performance is consistent and at levels that drive customer satisfaction with our service. PEF's transmission reliability and operations has consistently ranked high among forty utilities across the country. PEF needs its requested transmission capital and O&M expenditures to meet the expanded capacity demands placed on the system, increasingly stringent federal reliability standards, and the Commission's storm hardening initiatives, while maintaining the reliable system operation that our customers expect. PEF has demonstrated an ability to successfully operate the Transmission side of its business by balancing the need to maintain excellence in reliability with providing transmission service at a reasonable cost.

II. PEF'S TRANSMISSION SYSTEM.

Q. Please generally describe PEF's transmission system.

A. PEF is part of a nationwide interconnected and Florida intraconnected power network that enables interconnected utilities to exchange power. As a result, PEF's transmission system is subject to regulation with respect to the reliability of its system by both the Federal Energy Regulatory Commission ("FERC") and the Florida Public Service Commission ("PSC" or the "Commission"). PEF's transmission system includes approximately 5,000 circuit miles of transmission lines, including 500 kV, 230kV, 115 kV, and 69 kV lines, transmission substations, towers, poles, and related equipment and material across 20,000 square miles in west central Florida and the densely populated areas around Orlando, St. Petersburg, and Clearwater. Within Florida, PEF's system is interconnected with the other investor-owned utilities, twenty-two municipal electric utilities, and nine rural electric cooperatives. By improving, maintaining, and adding to this transmission system when necessary, PEF reliably delivers power from generation resources to be distributed to its customers' homes and businesses around-the-clock, each day.

Q. What has the Company done to maintain and improve transmission system reliability since 2005?

A. Our base line for transmission system reliability was our 2002-2004 CTE program. The CTE program included a number of capital and O&M initiatives that improved the reliable delivery of power to our customers. From this base line, in each of the past four years we have assessed our system performance in the previous year and established priorities for the next year. For example, our annual, targeted maintenance capital expenditure plan prioritizes the replacement of transmission capital units according to the age, condition, and significance of the replacement of that unit to the overall reliability of the system. This maintenance capital expenditure plan focuses on transmission poles, pole insulators, static wire, transmission line conductor, substation transformers, breakers, capacitors, relays, and battery banks.

Our transmission O&M initiatives the past four years also built upon our CTE initiatives by focusing on initiatives that offered the greatest benefit to system reliability. To illustrate, O&M initiative spending since 2005 included vegetation management, line bonding and grounding, relay calibration, and transformer inspections in addition to our routine O&M expenditures for the transmission system.

Our annual process of planning our capital, maintenance capital, and O&M expenditures has resulted in the strengthening of our transmission grid and the enhancement of the operation of our transmission system, with continued, improved reliability performance for our customers over the last four years.

Q. How does the Company measure transmission reliability performance?

A. PEF regularly analyzes reliability data to assess and track the performance of its transmission system using generally accepted reliability measures or indices in the electric utility industry. These indices include (1) the Circuit System Average Interruption Duration Index or "Circuit SAIDI", which tracks the average duration of a transmission-related outage; (2) the System Average Interruption Frequency Index ("SAIFI"), which tracks the average frequency of transmission-caused outages; (3) the System Average Interuption Frequency Index for Momentaries ("SAIFI-M"), which tracks the average frequency of transmission-caused outages for outages of less than a minute; and (4) the System Average Restoration Index ("SARI"), which tracks the time required to re-energize circuits following an outage. These reliability indices are regularly used by utilities and regulators to assess reliability performance by tracking changes in the results of these indices from one period of time to another, later period and comparing the direction of the change and the magnitude of the change from the earlier period to that later period of time.

Q. What are the results of these reliability performance indices for PEF's transmission system?

A. For the latest completed five-year window (2003-2007), PEF's transmission system reliability improved. All of these reliability indices that PEF regularly tracks showed positive trends. Specifically, Circuit SAIDI decreased by 23.4%, SAIFI decreased by 7.9%, SAIFI-M decreased by 10.1%, and SARI decreased by 20.6%. These positive trends demonstrate that PEF is providing customers with reliable transmission service. They further demonstrate that PEF has reasonably and prudently maintained its transmission system over time, when the transmission system has expanded and the existing transmission assets have further aged, adding to the cost to maintain and improve system reliability. Our reliability performance under increasing cost pressures indicates our commitment to excellent customer service.

Q. Are there other ways that PEF monitors its transmission performance?

A. Yes. PEF annually participates in a benchmarking study managed by an outside contractor. This benchmarking study, known as the *SGS Transmission Reliability Benchmarking Study*, includes approximately 40 other utilities from around the country comprising almost half of the transmission circuit miles in the United States. PEF has consistently compared well against the benchmark group for several years now, and particularly given the often harsh conditions under which our system operates.

Q. Has PEF maintained the reliable transmission of power to customers at a reasonable cost?

A. Yes. Since 2005, PEF has continued to incorporate best practices in the industry to manage and control its transmission-related capital and O&M costs. For example, we set up an organizational model that includes a unit in the

Transmission Maintenance Section called Maintenance Resource Management that is comprised of Resource Coordinators who are responsible for planning and scheduling all capital and O&M-related work performed in our transmission areas. This group provides efficient and organized maintenance work scheduled and monitored at 15-minute increments, where appropriate. They also procure necessary materials and closely monitor their delivery to ensure their timely and cost-effective use to maintain the system. Our results over the last three years demonstrate that the Maintenance Resource Management processes are working and contributing to overall reliability improvement at a reasonable cost.

Additionally, in 2007 we created a new Project Support group in our Project Management unit that focuses on optimizing the scheduling, procurement of materials, and management of contract support work. This Project Support group improved the organization of maintenance, planning, engineering, and construction group projects with resulting cost savings. Also in 2007, a Transmission Finance group comprised of several business financial analysts was created to more efficiently achieve our operational objectives by providing improved budgeting, cost management, and business planning support. Transmission Finance continuously works with Transmission to facilitate informed decision making, increase productivity, decrease costs, and establish effective internal controls. As a result, of these measures and others, PEF's Transmission management efficiently provides our customers with reliable transmission service.

Q. Can you provide us with some of the other ways Transmission ensures the Company is providing reliable transmission service to customers in an efficient, cost-effective manner?

A. Yes. Our improved safety record has also contributed to the delivery of reliable transmission service to customers at a reasonable cost. Transmission has demonstrated continually improving safety records since 2002. Our OSHA-recordable injury totals have improved from eleven injuries for 2002 to five injuries for 2008. The corresponding improvement in OSHA injury rates was from 3.04 in 2002 to 1.05 in 2008. These improvements were made with increases in employees and, accordingly, the hours worked. Transmission employs over 400 employees working nearly 1,000,000 hours annually, performing tasks that have inherent risk much of that time. As a result, we have an excellent safety record that demonstrates our commitment to a safety culture. Customers benefit directly from our exemplary safety record in transmission because the Company does not experience the lost time and inefficiencies that result from job-site injuries and the required investigations, "lessons learned" practices, and time and cost of dealing with potential employee and third party claims.

Additionally, our training programs benefit our customers by improving our ability to efficiently and reliably provide customers transmission services. One example is the training program for System Dispatchers at our Energy Control Center (ECC). PEF Dispatchers must be certified at the Reliability Authority level by the North American Reliability Corporation ("NERC"), which was established as a result of the Federal Energy Policy Act of 2005 ("EPAct") to develop and enforce mandatory transmission reliability standards. As a result, they are required to obtain 200 Continuing Education Hours (CEH's) over a three-year period to maintain their certification. To acquire these CEH's, the ECC Training team annually provides 80 hours of training classes that consist of presentations, discussions, simulation (including hours of one-on-one simulation training), and debriefs on operational and other issues. Additional training hours consist of computer-based and written material based on Plantview modules and PEF ECC Procedures and Policies. Overall, PEF System Dispatchers will receive 120 to 140 hours of training annually to maintain their performance skills in an ever changing transmission system. This training is also required for PEF to comply with Federal Energy Regulatory Commission ("FERC"), NERC, and Florida Reliability Coordinating Council ("FRCC") regulation.

All other Transmission personnel are required to receive training as well. This training includes OSHA Compliance, Safety, Environmental, and skill-based technical training. Our training programs continually increase our employees' ability to provide efficient, safe, and reliable transmission service to our customers.

Our new outage management software application, known as the Transmission Outage Management System (TOMS), implemented since 2005, also improves the efficient delivery of reliable transmission service to our customers. TOMS manages outages in a well-organized manner, listing the physical location of the event (i.e. nearest street address and nearest substation or transmission line structure number), tracks the number of customers affected by the particular event, and tabulates the number of calls that have been received for the event. TOMS also provides information on the location and magnitude of the short circuit associated with the outage, if there is one. This information is not only extremely helpful in a storm scenario when multiple outages are underway, but it is also useful for any outage that occurs on the transmission system. TOMS has resulted in our ability to respond to transmission outages in a very organized and thus efficient fashion, in both storm and non-storm conditions.

Q. Can the Company continue to provide customers with reliable transmission service?

A. Yes, but maintaining our record of reliable transmission service requires additional capital and O&M investment in the transmission system. One reason is that PEF's transmission system is simply larger today compared to 2005. The transmission system therefore includes additional transmission assets that must be maintained. Another reason is that PEF must continue to invest in capital additions to the transmission system to meet increased customer capacity demand on the system and to replace a continually aging infrastructure. These capital and O&M investment needs coincide with labor, material, fuel, real estate corridor, and permitting cost escalations, requiring additional funding for these investments.

There is another reason too for our additional capital and O&M investments in the transmission system. Regulatory initiatives at both the federal and state level mandate changes in the way transmission planning occurs and change the way we operate and maintain our transmission system. These regulatory initiatives further require PEF to incur additional capital and O&M expenditures to comply with the regulatory initiatives.

III. FEDERAL AND STATE REGULATORY RELIABILTY INITIATIVES.

Q. What are the federal reliability initiatives that affect Transmission planning and investment?

A. EPAct in 2005 directed the FERC to establish an Electric Reliabilty Organization ("ERO") to establish and enforce national transmission reliability standards. The FERC complied by certifying NERC as its ERO and the FERC authorized NERC to make the previously voluntary reliability standards mandatory, adopt new or more stringent mandatory reliability standards, and enforce them. The NERC adopted more stringent and new mandatory reliability standards pursuant to the FERC's authorization and direction. Noncompliance with these reliability standards subjects electric utilities to enforcement actions and penalties.

The FERC further issued various Orders directing the operation and regulation of electric utility transmission systems and requiring increased transparency in the planning of transmission systems between electric utilities and/or any interested stakeholders in the transmission system. Also, in conjunction with NERC's transmission planning and reliability activities, the FRCC has taken an increasingly active role in transmission planning and reliability from a regional perspective.

Compliance with the FERC, NERC, and FRCC orders, reliability standards, and planning coordination initiatives requires Transmission to implement new processes and augment existing planning processes. Transmission must also incur capital and O&M expenses to comply with these standards and initiatives.

Q. Can you explain how these federal regulatory directives or initiatives have influenced PEF's transmission planning?

A. Yes, I can. The most straight-forward impact results from the NERC designation as the ERO with increased control over transmission reliability. The NERC adopted and the FERC approved more stringent transmission reliability standards. An administrative process and potentially significant fines follow from noncompliance with these standards. To comply with these NERC reliability standards, PEF must plan for and invest in Transmission capital projects that, absent these standards, are not mandatory and therefore required.

Additionally, FERC Order 890 establishes Nine Principles of Transmission Planning. These principles mandate more transparency in the transmission planning process and require additional administrative processes and increased regulatory scrutiny to ensure that transparency is achieved. PEF has historically been open and helpful in the transmission planning process with PEF's customers, and with the NERC and FRCC, but the additional administration and regulatory scrutiny means additional cost to PEF in the transmission planning process for both PEF's internal transmission planning analyses and analyses performed in joint planning efforts with other utilities.

The increased federal activity in transmission planning and reliability through the FERC and the NERC has also led to additional transmission planning and reliability activity at the regional level. Within Florida, the FRCC provides technical assistance to identify the reliability need for large transmission projects. As the NERC's activity in transmission planning has increased so has the FRCC's, resulting in a several-fold increase in the FRCC reliability workload since the beginning of 2005. The increased FRCC activity resulted in increased findings of the need to construct transmission capital projects to mitigate reliability excursions from FRCC and NERC criteria. These findings translate into increased transmission costs for PEF.

Finally, the FRCC's increased activity in transmission reliability planning has led the FRCC to focus on the reliability of the PEF 69 kV system. PEF presently has over 2,000 circuit miles of 69 kV lines serving dozens of PEF and Rural Electric Cooperative substations. A significant portion of the 69 kV system provides flow-through, grid-related reliability support, and thus it functions practically the same as the Bulk Electric System ("BES"). Thus, the 69 kV system is important to the reliability of PEF's system even though it is not covered by any existing NERC standard. PEF has continually invested in the 69 kV system to maintain its reliability because of its importance to PEF's overall system and customers. With the additional emphasis that the FRCC has placed on the 69 kV system, PEF is making even further investments in that system.

Q. You also mentioned state regulatory initiatives that have impacted PEF's transmission capital and O&M requirements. Can you explain what those state regulatory initiatives are?

A. Yes. The Commission has issued two Orders and enacted Rule 25-6.0342, Florida Administrative Code (F.A.C.), to require Florida investor owned utilities ("IOUs") to harden their systems against potential storm outages and damage. In February 2006, the FPSC issued Order No. PSC-06-0144-PAA-EI, requiring all Florida IOUs to implement an eight-year wood pole inspection cycle program. Consequently, PEF now files a Wood Pole Inspection Plan every three years with an inspection report submitted annually. The annual reports contain 1) the methods PEF used to determine National Electrical Safety Code ("NESC") compliance, 2) an explanation of the inspected poles selection criteria including geographic location and the rationale for including each selection criterion, 3) summary data and results of PEF's previous wood pole inspections addressing the strength, structural integrity and loading requirements, and 4) the cause for the poles failing inspection and actions taken by PEF to correct each pole failure.

In April 2006, the Commission also issued Order No. PSC-06-0351-PAA-EI, requiring all IOUs to file plans and estimated implementation costs for ten ongoing storm preparedness initiatives identified by the Commission. PEF consequently filed its Storm Preparedness Plan on June 1, 2006. PEF's Plan implemented processes meeting the requirements of the Commission's ten storm preparedeness initiatives. In February 2007, the Commission enacted Rule 25-

6.0342, F.A.C. This rule mandates various storm hardening requirements for Florida electric utility transmission and distribution systems.

The Rule requires, at a minimum, that each IOU's storm hardening plan address the following: (1) Compliance with the NESC; (2) Extreme wind loading (EWL) standards for: (i) new construction, (ii) major planned work, including expansion, rebuild, or relocation of existing facilities, and (iii) critical infrastructure facilities and along major thoroughfares; (3) Mitigation of damage due to flooding and storm surges; (4) Placement of facilities to facilitate safe and efficient access for installation and maintenance; (5) A deployment strategy including: (i) the facilities affected, (ii) technical design specifications, construction standards, and construction methodologies, (iii) the communities and areas where the electric infrastructure improvements are to be made, (iv) the impact on joint use facilities on which third-party attachments exist, (v) an estimate of the costs and benefits to the utility of making the electric infrastructure improvements, and (vi) an estimate of the costs and benefits to third-party attachers affected by the electric infrastructure improvements; and (6) Attachment standards and procedures for third-party attachers.

On May 7, 2007, PEF filed its 2007 Electric Infrastructure Storm Hardening Plan (Docket No. 070298-EI). This Plan consolidated the requirements of the previous Orders and the new Rule into a single plan. As a result, PEF is meeting all storm hardening requirements and initiatives for its transmission system, at additional capital and O&M cost to PEF.

IV. TRANSMISSION CAPITAL AND O&M REQUIREMENTS.

Q. What are PEF's transmission capital and O&M expenditure requirements for 2010?

A. PEF requires $185.2 million in transmission capital spending and $45.3 million in O&M expenses.

Q. How much of the required transmission capital spending is required by NERC and FRCC reliability initiatives and expansion?

A. $140.3 million of the $185.2 million in transmission capital spending is allocated for planning, engineering, and construction expenditures for expansion of the PEF transmission system for NERC reliability initiatives and additional generation. The scope of PEF's transmission work required by the NERC Standards, in particular the NERC Transmission Planning (TPL) Standards, has increased significantly. PEF has successfully managed this increase in scope by recently completing several major capital projects and remaining on schedule to complete many others. Examples include the Vandolah - Hardee 230 kV line upgrade and the Lake Bryan – Windmere 230 kV circuit number 2 construction and circuit number 1 rebuild. Implementation of these projects and others assist PEF in complying with the NERC TPL standards, increase the reliability of the grid in the Central Florida area, and demonstrate our continuing commitment to our customers and stakeholders to provide reliable transmission service in compliance with regulatory reliability standards. My Exhibit No. ___ (JDO-2), has a more detailed list of PEF NERC compliance-related transmission projects in Section A of that Exhibit.

PEF is also expanding its transmission system to accommodate new generation on the system and additional transmission reliability needs. Sections B and C of my Exhibit No. ___ (JDO-2) provide detailed lists of major transmission projects relating to the generation additions and other major transmission reliability needs. Additionally, PEF is building additional new 69 kV lines or rebuilding existing ones. All new 69 kV construction is built to 115 kV specifications to provide increased reliability and performance. As I explained, PEF's additional investment in its 69 kV system in part satisfies the FRCC's interest in enhanced reliability of the 69 kV system. PEF's major 69 kV transmission capital projects are listed in Section D of Exhibit No. ___ (JDO-2).

Q. How did PEF determine that these transmission projects were required?

A. Each calendar year, transmission planning performs analyses for the long-term, ten-year transmission planning cycle, i.e. beginning one year out from present day through year ten. These analyses are performed from three distinct planning perspectives. First, the analyses by transmission planning must demonstrate that the PEF system will be in compliance for the ten-year planning period with the mandatory NERC reliability standards, specifically NER Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0, TPL-004-0 and FAC-010-2. If the analysis shows that the PEF system deviates from these standards PEF must initiate either an operational mitigation strategy or a new transmission capital project to bring the system back in compliance with the standards.

Second, an analysis is performed to demonstrate transmission system compliance with FRCC reliability standards. This analysis is similar to the analysis performed to ensure system compliance with the NERC reliability standards. The primary difference between the two analyses is that the FRCC treats the 69 kV system as if it is part of the BES. The lower bound under current NERC Reliability Standards is 100 kV. Third, additional analysis is performed to address the interconnection of new retail delivery points, such as new residential or commercial developments that require capital expansion of PEF's existing transmission system.

After these analyses are complete, PEF's transmission planning process requires the review of proposed transmission projects by other PEF areas affected by the proposal for feasibility and possible alternatives, if necessary. PEF's Project Review Group (PRG) subjects proposed transmission projects to multiple phases of review before a project is approved and included in the Transmission capital budget. All transmission capital projects are therefore carefully reviewed and scrutinized to ensure they are needed to provide customers with reliable transmission service at a reasonable cost.

Q. How much of the required transmission capital is for maintenance capital expenditures?

A. PEF needs $44.9 million for maintenance capital expenditures. Required maintenance capital expenditures are generally based on assessments of our system performance the previous year, with priority assigned to replace transmission capital property units according to age, condition, and significance with respect to system reliability. Additional maintenance capital work is required to comply with NERC TPL reliability activities. Further, PEF must perform maintenance capital work as part of its storm hardening plan to comply with the Commission's storm preparedness initiatives in the storm hardening orders and rule. In sum, PEF prioritizes maintenance capital expenditures to deliver the most cost-effective, reliable power that its customers already enjoy and have come to expect, consistent with federal and state regulations, initiatives, and policies.

PEF's $44.9 million maintenance capital expenditures include $16.8 million for line improvements. An additional $12.9 million is for emergency spare power transformers, $12.0 million is for substation equipment replacement and refurbishment, and $3.2 million is for needed vehicle replacements, operating system upgrades, tools and test equipment. All of these maintenance capital expenditures are required to replace aging infrastructure, strengthen the transmission grid, and enhance the operation of our system, resulting in safe and reliable service to the Company's customers.

Q. Please explain PEF's required transmission O&M expenses.

A. PEF needs $45.3 million for transmission O&M expenses. This funding is needed to perform required maintenance to maintain reliability and to satisfy federal and state regulatory requirements and policies.

For example, PEF has undertaken measures to significantly increase its tree-trimming initiatives in order to comply with NERC Standard FAC-003-1. Enhanced vegetation management is also an aspect of the Commission's storm hardening initiatives. Vegetation management within and adjacent to existing transmission corridors is a critical component of transmission maintenance, assuring the safe and reliable operation of the transmission system. It includes tree trimming, hand cutting, mowing, danger tree removal, a proactive herbicide program and aerial patrols to assess system conditions. The $45.3 million O&M costs includes a $2.1 million increase to the transmission vegetation management program as compared to benchmark spending, bringing the overall program spending up to $9.3 million for 2010.

PEF has also undertaken major initiatives to maintain relays, instrument transformers, Special Protection Systems (SPSs), Under-Voltage Load Shedding Schemes (UVLS), Under-Frequency Load Shedding Schemes (UFLS) and substation control house battery banks to comply with the NERC Protection and Control (PRC) Standards. Additional maintenance capital is required for substation maintenance, the inspection of transmission lines, dispatch load, and planning the transmission system. Also included in the $45.3 million O&M expenses are specific reliability initiatives of $2.0 million for line bonding and grounding, bushing replacements, and cap and insulator replacements. These reliability programs are incremental to base funding and assist PEF in preventing outages before they occur, enabling PEF to continue to deliver the cost-effective, reliable power to our customers that they expect.

Q. Are PEF's required 2010 Transmission capital and O&M expenses reasonable?

A. Yes, they are reasonable and necessary for PEF to continue to provide reliable transmission service to its customers in compliance with NERC and FRCC reliability standards and the Commission's storm hardening initiatives.

PEF's O&M expenses are further reasonable and necessary because they are $ 0.03 million or 0.0% above the Commission O&M benchmark cost of $38.4 million. This calculation excludes the $6.9 million PEF will incur to comply with FERC Order 890. FERC Order 890 did not exist in 2006 and therefore these costs were not and could not be included in the base costs for the Commission's O&M benchmark test. Further, because PEF must incur these costs to comply with a FERC Order, they are beyond PEF's control.

PEF's required O&M expenses will support basic operation and maintenance activities to strengthen the grid and enhance the operation of our system. These expenditures are therefore reasonable and necessary to ensure compliance with NERC and FRCC Reliability Standards, to comply with Commission storm hardening initiatives, and to provide excellent customer service.

Q. Does this conclude your testimony?

A. Yes.

BY MR. BURNETT:

Q. And, Mr. Oliver, do you have a summary of your prefiled direct testimony?

A. I do.

Q. And keeping in mind the lights in front of you, please give your summary.

A. I will.

Good morning, Commissioners. I am the Vice President of Progress Energy Florida's Transmission Operations and Planning Department. In this role I have overall responsibility for PEF's transmission system, including its planning, design, construction, operations, and maintenance in order to provide reliable transmission service to PEF's retail and wholesale customers.

PEF requires $185.2 million in transmission capital expenditures and 45 million -- 45.3 million in transmission O&M expenses in 2010. These expenditures enable the company to strike a reasonable balance between the high quality of service that our regulators and our customers expect and a reasonable cost for transmission service.

PEF has been successfully provided -- has successfully provided reliable transmission service to its customers at a reasonable cost for years. PEF's reliability performance is consistent and at levels that drive customer satisfaction with our service. PEF's transmission reliability and operations has consistently ranked high among Florida utilities across the country.

PEF needs its requested transmission capital and O&M expenditures to meet the expanded capacity demands placed on the system, increasingly stringent federal reliability standards, and the Commission's storm hardening initiatives, while maintaining the reliable system operations that our customers expect.

PEF has demonstrated an ability to successfully operate the transmission side of its business by balancing the need to maintain excellence and reliability with providing transmission service at a reasonable cost.

This concludes my summary, and I am prepared to answer any questions that you may have.

MR. BURNETT: Madam Chair, we'd tender Mr. Oliver.

COMMISSIONER EDGAR: Okay. Before we begin cross, Mr. Burnett, let me just check with you, this that has been passed out that is red but 265, this is not confidential; correct?

MR. BURNETT: Madam Chairman, it is, in fact is.

COMMISSIONER EDGAR: It is.

MR. BURNETT: And Ms. Triplett advised me I should have told you so when we moved that. So my apologies.

COMMISSIONER EDGAR: Okay. Well, then, I was not aware of that, but for me and for anybody else who was not aware of it, please note that 265, which is the full report, is in a red folder purposely.

MR. BURNETT: Yes, ma'am. Sorry about that.

COMMISSIONER EDGAR: That's all right. All right. Thank you, Mr. Burnett.

Mr. Rehwinkel for cross.

MR. REHWINKEL: Thank you, Madam Chairman.

CROSS EXAMINATION

BY MR. REHWINKEL:

Q. Good morning, Mr. Oliver.

A. Almost.

Q. My name is Charles Rehwinkel. I'm with the Office of Public Counsel.

A. Good morning.

Q. Can I ask you, please, to turn to your direct testimony at Page 3, and once you're there, look at Lines 13 through 15.

A. Okay.

Q. Is it your testimony there on Page 3, Line 13 through 15, that the costs for transmission O&M in this 2000 -- projected test year 2010 are reasonable because they're within the Commission's O&M benchmark?

A. It is.

Q. Mr. Oliver, do you have MFR C-6 with you?

A. I do.

Q. I'm going to ask you a series of questions -- well, let me ask you this. Were you here for Mr. Sorrick's testimony last night?

A. I was.

Q. Okay. I'm going to ask you a series of questions similar to what I asked him about the transmission O&M costs. And what I would like to do is ask you if I'm correct that for 2010 that the O&M for transmission in your responsibility area is on Page 4 and Page 6 of C-6, on Page 4, Line 25, and on Page 6, Line 28. Are those the amounts?

A. They are.

Q. Okay. And I'm going to ask you about the dollar amounts. And if you agree with them, you can state so. If you want to agree subject to check, I will accept that as well. Or if you disagree, certainly you can state.

If I look for 2010, the projected amount, is it true that it is 45.3 million?

A. That's correct.

Q. Okay. And that is in Column G of those two pages, 4 and 6, Lines 25 and 28 respectively; is that correct?

A. Uh-huh. That's right.

Q. Okay. For 2009, the corresponding amount, is it, isn't it true that it's $35.085 million?

A. That's correct.

Q. Okay. And for 2008 -- and 2009 is a budgeted amount; correct?

A. That's correct.

Q. For 2008 your reported actual amount of transmission O&M is 35.241 million?

A. Correct.

Q. And for 2007 the actual reported amount is 34.016 million?

A. That's correct.

Q. And for 2006 the actual reported amount is 33.675 million?

A. Correct.

Q. Okay. Would you agree with me that for 2006 through 2009 the O&M expense for transmission is a fairly level amount?

A. I would.

Q. Okay. And for 2010 would you agree with me that the increase from the budgeted amount to the projected amount -- budgeted amount for 2009 to the projected amount for 2010 is approximately 29 percent?

A. It is. Yes.

Q. Okay. Is it just a coincidence that this increase in transmission O&M coincides with the 2010 test year?

A. No, it's not.

Q. It's not a coincidence?

A. It's not a coincidence.

Q. Okay. Can you refer, look to Page 21 of your direct testimony, please?

A. Let me go back. Would you re -- would you ask that question again?

Q. Which one?

A. Is it a coincidence?

Q. Yes. My question to you, is it a coincidence that that 2010 projected expense is 29 percent higher than 2009, is it a coincidence that that increase comes in a test year?

A. I think it is a coincidence that it does, yes.

Q. Okay.

A. What was that page again to refer to?

Q. It's Page 21. I just wanted to see if Mr. Burnett would do redirect on that question.

A. I had to think, I had to think about it a second.

Q. I understand.

On Page 21 do you suggest that because of the favorable benchmark, the favorable performance of 2010 projections against the PSC's O&M benchmark, that the $2.1 million increase in vegetative management expenses is reasonable?

A. I would say that the $2.1 million in vegetation management is reasonable because of some NERC compliance requirements that we have undertaken that really came into effect in the 2008 time frame that have caused us to ramp up our vegetation management on lines that are 200 kV and above.

And so for, for this year we had utilized vegetation management money from some of the other voltage levels to reach that. So it's kind of a robbing Peter to pay Paul kind of, kind of exercise. We need to refund back into the lower voltage vegetation management where we're having to step up to the higher voltage levels.

Q. Okay. So is it your testimony that the O&M benchmark, the performance against the O&M benchmark is, has nothing to do with the reasonableness of the number?

A. You know, I don't really know what goes into the benchmark multiplier and those calculations, to be honest with you.

What I do know is, you know, what we require to do our business to meet the standards that the Commission and our customers require.

Q. Okay. What was requested -- well, let me ask you this. The NERC standard that you're referring to is FAC-003-01?

A. Correct. That's it.

Q. Okay. What was requested in 2010 for vegetative management? Is it $9.3 million?

A. 9.3 million total. Yes.

Q. Okay. And that's the same number that's on Page 21, Line 14?

A. That's it. Yes.

Q. Okay. Isn't it true that the effective date for NERC standard FAC-003-01 was April 7, 2006?

A. FAC-003 was actually June of '07.

Q. Okay. So when did you start taking action with respect to vegetative management related to that NERC standard?

A. Well, we've always -- we have always trimmed and maintained our rights-of-way to a manner to really kind of coincide with our customers and really, since in all the time that I have been involved in this program, we've really maintained the rights-of-way and have had very few vegetation management issues on our rights-of-way.

What FAC-003 mandated in '07 was a full width clearing of 200 kV and above right-of-ways from floor to ceiling, and really kind of mandated how unacceptable, or the unacceptability and the enforcement that would be handed out if you had a grow-in to those 200 kV and above lines.

So we've always maintained those rights-of-way well, but we had done the maintenance in consideration of our customers. I'm not sure there's another thing in our business that is as sensitive as when we began to cut customers' trees. And, you know, going into this level of vegetation management on these 200 kV and above lines has gotten us into cutting a lot of oak trees and a lot of very decorative and ornamental trees that reside on customers' property.

The Commission has probably heard about some of those, and it has, it has just raised that level of vegetation management to a whole different magnitude of importance to us.

Q. You say it has. Are you talking about NERC?

A. Yes.

Q. The standard FAC --

A. FA -- well, there's FAC-003 and the mandatory or the -- mandatory compliance as well as the enforcement that can be handed down if you violate those rules, up to a million dollars a day.

Q. Okay. And just for the court reporter's benefit, NERC is N-E-R-C, all caps?

A. N-E-R-C, all caps. Yes.

Q. I just want to make sure I understand. The factor -- the standard went into effect in June of 2007, you say.

A. Right.

Q. Did the standard, when it went into effect in June of 2007, did it change the way you perform vegetative management?

A. It did on 200 kV and above lines. Yes.

Q. And in that year?

A. In, in that year.

Q. Okay. And for the year prior you did not change anything?

A. No. No. We had a good vegetation management program that was part of our storm hardening agreements with the Commission and we were abiding by those. But the NERC FAC-003 goes over and above the hardening requirements.

MR. REHWINKEL: Okay. Madam Chairman, at this time I'd like to pass out an answer to an interrogatory. I really don't need this marked as an exhibit. I just want to ask him some questions about it.

CHAIRMAN CARTER: Okay. You may proceed.

MR. REHWINKEL: And if I could ask for -- Mr. Poucher will help.

BY MR. REHWINKEL:

Q. I'm going to ask you some questions as soon as this document has been distributed, Mr. Oliver, about the company's response to Interrogatory 238. Are you familiar with that?

A. I am.

Q. Is this an answer that you assisted in answering?

A. It is.

Q. Okay. And I'm really just passing this out for your recollection purposes.

Would you agree with me that in 2006 you expended $6,347,798 on vegetative management activities?

A. Yes.

Q. And you trimmed as a part of those activities 966 miles?

A. Correct.

Q. And would you also agree with me that for 2007 you expended $6,939,355?

A. Yes.

Q. And in doing so trimmed 843 miles?

A. Yes.

Q. Okay. And then in 2008 you expended $5,916,832?

A. Yes.

Q. And, as a part of that, trimmed 360 miles; is that correct?

A. Yes. That's right.

Q. And for 2009 the budget for vegetative management was nine -- was $6,554,550?

A. Correct.

Q. Okay. Can you explain to me or to the Commission why a vegetative management program that went into, that was modified as the result of a federal NERC standard did not significantly impact vegetative management spending in 2007, 2008 or 2009?

A. Say that again.

Q. Can you explain to me why vegetative management, why the NERC mandated changes did not impact your expenditures for 2007, 2008 and 2009 relative to the $9.3 million requested in 2010?

A. I believe I can. The -- and I mentioned this before. What -- you know, our, our vegetation management budgets are, are budgets and we fix those and, and have tried to live within those for all of our vegetation management programs.

In '07, as we mentioned, the standard went into effect. In '08 was the first full year of our trimming of these what I'll call NERC compliant 200 kV and above lines.

So what you'll see there is we actually -- a predominance of our system is 69 kV. We have roughly 5,000 miles of transmission line, roughly half of that 69 kV. And so most of our trimming dollars each year are expended on that 69 kV system. It's the one that we serve most of our customers off of and it's probably the one that courses through some of the more rural and forested areas of our service territory.

So what, what we, what we did is, maintaining the same budget, is we had to move funds over from the trimming of the 69 kV lines to doing, if you see the double star down at the bottom, what we call emergent and reactive trimming on the 230 and above lines to make sure that we, we cleaned those rights-of-way from full width to the ceiling.

And so I think it's reasonable that you see a reduction in the number of miles trimmed because we had treated those as emergent and reactive during the '08 time frame. And really what our intent to do by increasing the vegetation management budget for '10 and going forward is to, is to treat that as part of our, our routine trimming and to put the, to do the 69 kV back to the amounts that we were.

Q. Okay. Thank you. Can you please turn to Page 22 of your direct testimony.

A. Okay.

Q. What are the, the costs for compliance with FERC 890 that you're requesting for 2010?

A. We have estimated our costs to comply with FERC Order 890 for the 2010 and going forward periods to be $6.9 million per year. And what this, what this amounts to is we have a number of transmission lines that reside in our control area that belong to Seminole Electric Cooperative as well as Florida Municipal Power Agency that we use in day-to-day transactions on the system. With FERC Order 890, beginning this year and continuing on we have to provide payments and credits to those transmission owners for the use of their system.

This has not been an expenditure that we've had to, payments that we've had to make to them before. It actually started this year and continues, continues on. But it's for the, for using their transmission system that's part of our system.

Q. Okay. Just so I understand your answer, when you say this year, you mean 2009?

A. Actually we will expend some funds in 2009 to comply with this.

Q. Okay. And the $6.9 million that are shown in your testimony on Page 22, Line 12, actually are payments to the other companies?

A. Uh-huh. Right. Those will be payments to Seminole and FMPA for the right to use their transmission system that is in our control area.

Q. When was FERC, FERC 890, when did that requirement become a law?

A. The first customers went on to, into those requirements beginning in September of this year, and FMPA actually begins next year.

Q. Okay. So was the, the regulation issued in 2007?

A. The regulation -- and, and as we began to -- the notification of it came out in 2007. By the time the rules, regulations and those type things and the actual order came out as to how we were going to have to do this was actually earlier this -- early '08, I'm sorry, in '08.

Q. Okay.

A. And it was really across the country. This is, this was applied to all utilities really across the country as a form of kind of the open access transmission reform that became FERC Order 890, which really addresses how we jointly plan and, with other utilities within the state, and gives the other utilities in the state recognition for the systems that they have.

Q. Okay. So you stated that the, the first customers that would impact this order with respect to your use of transmission came online in 2009?

A. 2009.

Q. Okay. So there would be, there would have been no costs incurred in 2008 in relation to this order?

A. No. No. No costs in '08.

Q. Okay.

A. A small cost in '09, but the full hit will be in 2010.

Q. Okay. And the small cost is solely related to the customer?

A. That's right.

Q. Okay. Can you please turn to Page 21, back to Page 21, and look at Lines 21 through 23?

A. Right.

Q. This is where you state that, you reference $2 million in 2010 projected expenses for line bonding and grounding, bushing replacements, and cap and insulator replacements; is that correct?

A. That's correct.

Q. And the $2 million refers to all four of those activities?

A. Actually it's three. Line bonding and grounding is one activity, bushing replacements are one activity, and cap and insulator replacements are one activity.

Q. Okay. Is that the total amount for those activities, or is that the amount of increase for those activities?

A. This is, this is an incremental over and above in these areas. What we do today, we do these programs today that provide significant reliability enhancements to our customers, and they're ones that we want to -- we get a, I think a huge value for doing these, and these are programs that we want to add to what we're currently doing.

Q. Can you tell me what the -- with that $2 million incremental change, can you tell me what the total amount in 2010 is for those activities?

A. It would be 2 million.

Q. So 2 million is the total cost?

A. Is the, is the total among those three.

Q. Okay. I, and I, I think -- my confusion was I thought you used the term incremental, so I thought it was the increase.

A. It is -- what we are, what we're asking for here is a total of $2 million to do additional line bonding and grounding, bushing replacements, and cap and insulator replacements going forward.

Q. Okay. So does that suggest that there, there are, there's a base amount of dollars?

A. There is a base amount that you would find in some of these FERC amounts that we already do today. Yes.

Q. Okay. Do you know what that base amount is?

A. I do not.

Q. Is it as ascertainable?

A. I don't know how easily it would be. I can, I can, I can try to get that number for you at a break. It would not, it would, it would not be at a level that we're asking for here. I think it would be less than that.

Q. Okay. If you got it for me on a break and you were not coming back, is there anyone else who would be able to answer it?

A. I mean, I could give the information to Mr. Burnett.

Q. Okay.

MR. BURNETT: Mr. Chair, we could certainly provide it when he comes back for rebuttal, if that works.

THE WITNESS: Oh, yeah. I'll be back for rebuttal.

BY MR. REHWINKEL:

Q. All right. What I would like to do is ask if -- I tell you what, let me ask the last question here and then maybe we can, if we need to do any additional information gathering, we can maybe combine it.

Can you turn to MFR C-41, please, and I would ask you to turn to Page 8.

A. Okay.

Q. I'm sorry. Do you -- I think I need to ask you to look at MFR C-41 for 2009, and I don't think that's in these.

MR. REHWINKEL: Mr. Chairman, if I could just get a moment, I need to refer to one of the supplemental MFRs, I think.

CHAIRMAN CARTER: Absolutely. Not a problem.

While Mr. Rehwinkel is looking, Commissioners, for planning purposes, we're going to maintain our calendar. We'll probably do our normal lunch break 1:00 to 2:15. We'll go again until 8:00 tonight, and until further notice we'll be on that schedule. With the way we're doing with our court reporters, we've agreed to give them a break in the morning and a break in the afternoon. And that, that also will help the parties too.

And also to the parties, if any time you guys need an opportunity to visit with one another, please let me know and we'll, we'll accommodate you. Staff, that means you guys too. If you need to talk with the parties about something, just let us know.

Mr. Rehwinkel.

MR. REHWINKEL: Mr. Chairman, if I could approach the witness --

CHAIRMAN CARTER: You may approach.

MR. REHWINKEL: -- I'd like to show him MFR C-41, Page 8 of 18 for the year 2009. And I have given counsel this citation earlier, but I forgot it was from a 2009 document.

BY MR. REHWINKEL:

Q. If you could take a second to familiarize yourself with that document. Does -- are you familiar with it?

A. I'm not. That's the first I've seen it.

Q. Okay. This document, I will represent to you, is, is the corresponding O&M benchmark variance explanation for part of your transmission area for 2009 rather than projected 2010. Would you agree with that?

A. I agree.

Q. And part of what that document contains is a variance explanation for line bonding and grounding; is that correct?

A. It does.

Q. Okay. Can you explain to me what the -- is it ascertainable what the amount for line bonding and grounding was in 2006 and what you're proposing for 2009 in your budget?

A. Again, subject to check, and I believe that I will, in, in 2006 we did expend what I would call some significant dollars on line bonding and grounding as part of our Commitment to Excellence Program during that time frame. And what that exact amount is I do not know, but I know that we have those numbers and that I can get those for you. And then, you know, we can do that next week when I'm back for rebuttal, if that will be sufficient.

Q. Okay. And as a part of that, can you tell me what is in the budget for 2009?

A. I can do that, too, I believe.

Q. Okay.

MR. REHWINKEL: Mr. Chairman, and for

Mr. Burnett, if, if I could get that answer as well as the, for 2010, the base amount, if you will, of line bonding and grounding.

BY MR. REHWINKEL:

Q. Does that, do you understand what I'm asking?

A. Yeah. Base amount. I understand.

MR. REHWINKEL: Okay. Then, then I'll be satisfied and I'll ask about those on rebuttal.

CHAIRMAN CARTER: On rebuttal? Okay.

BY MR. REHWINKEL:

Q. Mr. Oliver, one last line of questions. I think we went over some amounts for your transmission O&M earlier, and I think you agreed with me that for 2009 the amount was 35 million 085; is that right?

A. That's right.

Q. And this was the budget at the time, the budget amount at the time the MFRs were filed or prepared, which would be sometime in advance of March 20th of this year; correct?

A. Right. Right.

Q. Have there been any updates or revisions to your transmission O&M budget since then?

A. There have not.

Q. So that number is still what it is?

A. That number is still our budget target for this year.

Q. Okay. What about for 2010, the 45.3 million projected amount?

A. That is our budget for 2010 at this time.

Q. Okay. And there have been no changes to that?

A. No changes.

Q. No belt tightening going there?

A. Well, you know, as, as Mr. Sorrick discussed, I think we're always looking for opportunities. And in some of those cases it's an opportunity to maybe be more efficient in one area where we may need to deploy resources in another to maintain the service levels that our customers expect. And so belt tightening, all the time. But I think it's, you know, an opportunity to also look and see where we may, there may be a higher and more efficient use of the resources.

MR. REHWINKEL: Okay. Mr. Chairman, those are all the questions I have.

CHAIRMAN CARTER: Thank you, Mr. Rehwinkel.

MR. REHWINKEL: Thank you, Mr. Oliver.

CHAIRMAN CARTER: Ms. Bradley.

MS. BRADLEY: Thank you.

CROSS EXAMINATION

BY MS. BRADLEY:

Q. Mr. Oliver, I just have a few questions. I believe in your testimony that you talked about having the overall responsibility for operation and maintenance of your transmission system and the reliability of that system?

A. That's correct.

Q. Okay. Did you go to any of the customer service hearings?

A. I did not.

Q. Did you get any briefings or read the transcripts or do anything?

A. I got briefings when issues came up that were transmission-related from the, the distribution regional executives when those issues came up. If I remember, there were very few. I did not read the transcripts.

Q. Okay. Are you aware that there were complaints involving power surges, power outages, complaints about tree trimming, that type thing?

A. I mean, that's what I heard, I heard you say yesterday, yes.

Q. And did you hear that from your staff as well?

A. I heard, again, I only heard the ones that were directly related to the transmission system issues. And most of those were, if I remember right, were issues related to vegetation management and some of the tree trimming activities. I do not remember any issues that were transmission-related that were -- most of those issues would occur on the distribution system.

Q. So you don't deal with the vegetation and all of that?

A. On the transmission, yes, and we addressed those. Not on distribution.

Q. Okay. Do you remember seeing a complaint from a Mr., I think it was Grallinger in Clearwater, who was complaining about numerous power surges, and they, apparently they found a spliced service drop line when they went out to check?

A. That would be a distribution issue.

Q. That would be distribution as well? Who covers that?

A. Mr. Joyner will cover that.

MS. BRADLEY: Okay. I may have fewer questions than I thought.

THE WITNESS: I think that's good.

(Laughter.)

MS. BRADLEY: I'm not sure how to take that. Actually I think that's all of my questions. I'll save the rest for Mr. Joyner.

CHAIRMAN CARTER: It was a compliment. It was a compliment, Ms. Bradley.

MS. BRADLEY: Oh, okay.

CHAIRMAN CARTER: Mr. Moyle.

MR. MOYLE: Thank you, Mr. Chairman.

CHAIRMAN CARTER: Hang on. Mr. Rehwinkel is retrieving his document. Did you get what you needed?

MR. REHWINKEL: He can have it. I think he's going to use it to help him --

CHAIRMAN CARTER: Oh, with the questions?

THE WITNESS: Yeah, I made my notes on that.

CHAIRMAN CARTER: Excellent. Excellent.

MR. REHWINKEL: I'd rather him have it than me in that case.

CHAIRMAN CARTER: Good.

Mr. Moyle, you're recognized.

MR. MOYLE: Thank you.

CROSS EXAMINATION

BY MR. MOYLE:

Q. Good afternoon. Jon Moyle on behalf of FIPUG.

A. Good afternoon.

Q. You're a ramblin' wreck engineer; correct?

A. I am.

Q. Okay. And you have overall responsibility for the transmission system of Progress Energy Florida; correct?

A. I do.

Q. And you've had that since 19, I'm sorry, since

2007?

A. 2007. Yes, sir.

Q. Okay. And since 2007 the transmission system of Progress Energy has operated in a safe, reliable fashion; correct?

A. I think it has, yes.

Q. And also it's operated in accordance with all laws, rules, regulations as far as you know?

A. To my knowledge.

Q. Okay. You were asked a little bit about belt tightening, and you would agree that, that from a general sense that belt tightening has gone on with a number of businesses throughout the State of Florida in the last few years; correct?

A. I do.

Q. Okay. And specifically with respect to belt tightening within the transmission area for which you have responsibility, has there, has there been any belt tightening that can be quantified to say, well, you know, here's where we were and we reduced expenditures by X, by Y as a specific result of an effort to reduce expenditures?

A. Well, I think we have, you know, we've looked at things like meals and travel, other, what I would call some discretionary activities, going to conferences and those type things, where we could, you know, that may not be the highest and best use of the resources we have. And I think if you look in, in, actually in some of the testimony, we've employed a number of activities within the business unit, work scheduling, management, project management, project controls to help us be much more efficient about how we do our business on a day in, day out basis.

Q. Did you undertake any efforts within the last -- well, since you've been in charge since 2007 to try to reduce expenditures by a certain percentage? Some businesses and others have said, look, we need to cut costs by 5 percent, 10 percent, 15 percent. Has your organization with respect to transmission gone through any kind of similar exercise where a targeted reduction number was identified and steps were taken to try to hit that number?

A. I wouldn't say that we've gone after any specific targeted numbers. We've, as I, as I said earlier, we've tried to operate and set the budgets in the most efficient manner that we can to meet the, to meet the requirements, you know, that our customers and the Commission desire us to operate at.

Q. And you were having a discussion with Mr. Rehwinkel about some requirements that were the result of a regulation 003. That has resulted in a, in an increase of nearly 30 percent from 2006 to 2009, and then in 2010 you have about a 30 percent increase; is that right?

A. Well, I, you know, let's get, let's get the numbers. FAC-003 is the vegetation management standard, and what we're asking for between '09 and '10 is 2 million additional, roughly 2 million, a little bit more. FERC Order 890, which is a FERC mandate on how we treat others that have transmission lines in our control area, is a separate issue.

Now if you go back and look on top of, of just those two requirements, NERC has added over 90 additional mandatory requirements over the last two years that have -- if you drill down through these budgets, we have been able to comply and meet all the requirements of those without any additional funding.

So it's not just those two, it's many, many more that have added to our business. Our business over the last two to three years has become much more demanding from a regulatory and compliance standpoint.

Q. Yes, sir. And we'll have a chance to go through those 90 NERC things after lunch. But before then --

A. Okay.

Q. No. I'm kidding. Before, before then, you, you would agree that the level of increase from 2009 to 2010 is 29, approximately 30 percent; correct?

A. It is. If you look at the numbers, it is, yes.

Q. Okay. Let me refer you to certain portions of your testimony. And on Page 11, Line 12, you state, quote, "One reason is that the PEF transmission system is simply larger today compared to 2005."

And how, how, how do you define larger? Can you tell me how many additional transmission miles are, are on the system from 2005 compared to today?

A. I can. And that is -- there is a chart in my rebuttal that addresses that. But I believe if you go back to '05, to this point in time, we're looking at roughly about 200, roughly 200 miles of additional transmission line have been added since 2005. I would say we've added probably two dozen substations, a number of transformer assets, circuit breakers. And, you know, during that time the system was still experiencing a tremendous growth in our customer base.

Q. And with respect to the -- transmission mileage, you would agree that that's a common data point for measuring transmission systems; correct?

A. It is. It is.

Q. All right. And you had referenced a chart in your rebuttal -- and I don't, I don't know if we want to get into it, but --

A. I don't have it with me, but --

Q. All right. I, I had glanced at it briefly. And not to hold you to it or subject to check, but, but can you tell me from a percentage basis what the increase from 2005 to today represents with respect to transmission miles?

A. Without the numbers, that would be hard for me to do.

Q. Does, for 2005 would between 4,200 miles and 4,250 miles sound about right?

A. I would have to see -- I don't have, I don't have the rebuttal.

MR. MOYLE: Can I approach?

CHAIRMAN CARTER: You may approach. Is this rebuttal, Mr. Moyle?

MR. MOYLE: Well, it's a chart that he had in his rebuttal.

CHAIRMAN CARTER: You want to cite it so we can all be on the same page?

MR. MOYLE: Sure. It's found on Page 8, and it's on 21 to 24.

CHAIRMAN CARTER: Okay. You may proceed.

THE WITNESS: I think what I was referring to earlier was the growth from '03 to '08 was roughly 200 miles. From -- you mentioned '05?

BY MR. MOYLE:

Q. Yes, sir. And really what I want to do is I want to track your direct testimony, the line I read where you said the system is larger, and then, you know, there was not any additional information about larger. And so what I want to do is ask you, if you would, to tell us how much larger the system is in terms of transmission mileage.

A. Well, back to my testimony on Page 11, Line 12 and 13, I believe what I was referring to there was just the physical line miles of the system. As far as a percentage, it would be in the probably 5 percent range.

Q. And you would agree that with respect to the transmission system operations that the transmission lines typically constitute the majority of the costs; correct?

A. They're probably a little bit more on the, on the line side. Because it's so spread out, the geography lends to that. So I think that would be, that would be accurate.

Q. Okay. And if we just looked at the, the increase in transmission lines and compared it to the increase in O&M budget, you would agree that the O&M budget has increased more than 5 percent from 2005; correct?

A. That's -- just on the transmission line -- I'm looking at the, at C-6, just looking at FERC Code 571, and those numbers seem to be fairly consistent across the board, with the exception of 2010 where we're asking for the additional vegetation management.

Q. And, and there's a marked increased in 2010; correct?

A. There is an increase in 2010 for, for what I've already explained.

Q. Back on your Page 11, another reason that you indicate you're investing in the transmission is because of, on Line 16, quote, "increased customer capacity demand on the system."

A. Right.

Q. What were you referring to there?

A. What I'm referring to is when you, when you plan a power system, you have to plan for the demand that's placed on the system, not necessarily the day-to-day energy sales. And so the demand we set, we actually set a winter peak this past February. And so that's really from a, from an infrastructure standpoint you have to plan for that demand. Even though I know we've, we have evidence such that the customer numbers have, have dropped, the demand is still there on the system and we have to plan for that demand, peak demand.

Q. And just hypothetically, I mean, if customer numbers drop, then it would follow that demand would likely drop as well; correct?

A. Not necessarily. No, sir. Energy sales, energy -- the energy component would drop, but not necessarily the demand. Demand is a function of an instantaneous requirement that the customer places on the system. And, again, in February of this past year we set a new winter peak.

Q. But from a standpoint of transmission planning, to the extent, I -- mean, you could have say, let's say a utility in Michigan or Ohio, they may have set a peak back when the auto industry was going great guns that arguably would not be particularly relevant for analysis today; correct?

A. It could -- that's -- it could be. Yes. But I think still, you know, we've demonstrated in February that we set a peak, even with the economic times what they are. So, you know, from a planning standpoint -- and then also when you look at transmission planning standards, and I think they're again referenced in the testimony, TPL 001, 2, 3 and 4, you also not plan for that peak, but any contingency that may occur during that peak, which is loss of an element or multiple elements.

So it's, it's not an easy exercise to do. But the fact that we did set a new peak this year does mean that the customers are still demanding a very high amount of energy at an instantaneous point on a, on a certain day.

Q. Yes, sir. Now there was some discussion earlier about, about interruptible customers. Are you familiar with interruptible customers and any value they may provide to your system?

A. I'm not familiar with, with -- I'm familiar with interruptible customers. But from a rate standpoint, those type things, I am not.

Q. How about from a system operation standpoint?

A. I, from a system operation standpoint I do, yes.

Q. And from a system operation standpoint, to the extent that you had a system issue come up and to the extent that there was the ability to shed load related to an interruptible customer, you would agree that is a beneficial operational tool in your toolbox; correct?

A. It is.

Q. On Page 13, Line 17, you use the term "transparency" with respect to the transmission planning process. And I was unclear what you were trying to communicate with the sentence found on Page 13, Lines 16 through 18. Would you please elaborate on that, if you can?

A. Yeah. This is back in the FERC 890 order, and which established these nine principles. And really what it did is when you look at -- if you look at modern day planning, we can't do planning in isolation, which means when you, when you look at the State of Florida, we have four investor-owned utilities, we have the cooperatives, we have the municipals. And there was probably a point in time when each, each did independent planning, didn't consider the others.

I mean, I think what we mean by transparency is that the process is very open, it is really facilitated by the FRCC, the Florida Reliability Coordinating Council, which ensures that we're all using the same numbers, the same metrics, the same standards and models when we do this planning. And I believe that that is in FERC Order 890 what, what transparency means.

Q. Do you interact, you being Progress Energy Florida, do you interact in and plan jointly with SERC, the Southeastern Reliability Council?

A. We, we, we do not plan necessarily with SERC except as part of the eastern interconnect. We do do joint planning studies with the SERC utilities to our north and to our west. Southern Company -- well, really Southern Company all around. We do joint planning studies with them, yes.

Q. Let me -- I want to talk to you a little bit about, about storm hardening and extreme wind loading. If you need to refer to your testimony, it's Pages 15, 16, so, but I don't know if it's essential.

A. Okay.

Q. Let me ask this question with respect to, you use the term "extreme wind loading standards" on Page 16, Line 4. What are extreme wind loading standards?

A. Well, I think when you -- the, the extreme wind loading standards are what can the, what can the structure, whether it be a pole or whatever, what can it stand from a wind, a, a wind coming straight across with all of the wires and attachments that it has on it?

Q. And as we sit here today, what's the answer to that question with respect to transmission poles?

A. Well, I think if, if, you know, you go back to the '04, '05 storm time, we still on Progress Energy's system have a number of wood poles. And in the areas that the storms came through, quite honestly they did not stand up very well. I was not in transmission at the time, but I do know that a lot of those poles have been replaced and that we, part of our storm hardening process that's explained here is a six-year routine schedule on pole inspections and a changing of all of our wooden poles over a certain period of time to either lightweight steel, light duty steel or concrete.

Q. And I used the term "generally transmission poles." I presume that, that when I said that I was talking 69 kV and above.

A. 69 and above. Yes, sir.

Q. Okay. And in -- thank you for clarifying the old wood poles. But those are less and less on the system today; correct?

A. That's correct.

Q. Okay. How many percentage wise are the, are the old wood poles, if you know?

A. I don't have that number, but I think there were some of those in the discovery. I think there's some information on that. I just cannot recall it.

Q. All right. Similar to Mr. Rehwinkel, would you mind taking a look at that before you get back on for rebuttal?

A. And that would be, let me clarify, the number of just really the percentage of, the percentage of each type pole on the system, or just wood?

Q. The wooden poles that you were referring to that were problematic during '04, '05. Are we good to go on that?

A. Got it.

Q. As we sit here today, back on the extreme wind loading discussion, what are your transmission poles, the steel or the concrete, what are the design standards for those on a wind --

A. I don't have, I don't have the design standards with me. I can, again, on rebuttal I can, I can bring that if you're interested in that information.

Q. I think I would be. But do you know, aren't they designed to withstand hurricane strength winds?

A. They are. But I hesitate because I -- on what category of hurricane strength winds?

Q. And would you provide that information to me on rebuttal?

MR. BURNETT: Mr. Chair, if I, if I could get --

CHAIRMAN CARTER: Mr. Burnett.

MR. BURNETT: Thank you, sir. If I could get clarification if Mr. Moyle has a specific event, moment (phonetic), parameter and specification class from the NERC that he has in mind, perhaps we could be more focused.

CHAIRMAN CARTER: Mr. Moyle.

MR. MOYLE: Well, I just, in discussions with the witness I think we've talked about there's a one through five hurricane category. I was interested in understanding as to what level the poles are designed to, the transmission poles are designed to.

MR. BURNETT: Mr. Chair, perhaps we can work offline for the specifications, but we're happy to be helpful with Mr. Moyle.

CHAIRMAN CARTER: Okay. And you're just going to bring it when you do rebuttal?

THE WITNESS: I mean, I can do that. If we're just looking for whatever the wind speed is, I think we can do that.

BY MR. MOYLE:

Q. Yes, sir. And you would agree, would you not, as we continue this conversation, that to the extent something is designed to withstand a wind speed, let's say of, you know, 100 miles an hour, that if it's designed properly and installed properly, then it still ought to, you know, work in the 100-mile-an-hour wind event; correct?

A. Everything else isolated, yes.

Q. Okay. And, and you would also agree, would you not, from an engineering perspective that to the extent that design standards have been strengthened following '04 and '05, that the company's risk of damage related to hurricane events has been reduced; correct?

A. I'm not sure.

Q. All other things being equal, as it relates to the design --

A. I'm not sure. I would, I would, I would rather qualify that by understanding the number of wood poles that we've still got left on the system, and I think it would be a function of the number of wood poles and the area where the storm hits, before I would be comfortable answering that question.

Q. Let's come at it this way. Let's just assume that, that, that previously you had ten wood poles that weren't as good to standing up on hurricane force winds of 100 miles an hour as compared to concrete and steel. You replaced four of them, so now you have six wooden poles and four concrete or steel. You would agree that the system has improved with respect to its ability to withstand 100-mile-an-hour winds based on that simple hypothetical?

A. In that application and example, I would agree. But I would think the orders of magnitudes of wood poles would be quite, you know, if you looked at the actual system, would be much different.

Q. Okay. And I appreciate your willingness to help with that.

The other point is with respect to vegetation management, you would also agree that vegetation management activities have been enhanced following '04, '05; correct?

A. I would say that -- let me qualify. Prior to FAC-003, which has required us to put more resources on the 200 and above kV lines, we, we have had to kind of reallocate resources and move resources off of the 69 part of the system to the 200 kV and above to address these mandatory issues.

So I would say that our 69 kV system is in good shape, but we do need to, we do need to spend more money there to get it, to get it to really what our customers expect, I believe.

Q. Yes, sir. And I appreciate that. I'm just trying to get from a general perspective. We would be in agreement, would we not, that following the storm events of 2004, 2005, after that this Commission moved forward with some storm hardening measures; correct?

A. Right.

Q. And the result of those storm hardening measures, they entered an order and you referenced the order in your testimony. You would agree that the, the transmission system of Progress Energy, as a result of the vegetative management portion, is also in better shape as it relates to potential damage from a hurricane as compared to before the entry of that order, all other things being equal; correct?

A. All other things being equal, yes, sir.

Q. Now you don't have any information, do you, about, you know, the, the hurricane accrual monies or funds?

A. No.

Q. No one has asked you to estimate damages related to a potential hurricane?

A. No.

Q. Has Mr. Harris had any conversations with you? Do you know Mr. Harris?

A. I do not.

Q. He's a hurricane witness, expert from Oakland, California, that has some testimony in this case. But y'all haven't consulted?

A. No.

Q. Let me direct you, if I could --

CHAIRMAN CARTER: You're going to another line, Mr. Moyle?

MR. MOYLE: Yes, sir.

CHAIRMAN CARTER: Let's break then. You look like you're getting your second wind there.

Let's go to lunch, everybody. We'll come back at 2:15.

(Transcript continues in sequence with Volume 6.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, RPR, CRR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorneys or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 25th day of September, 2009.

Linda Boles

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