BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PETITION FOR INCREASE IN RATES BY PROGRESS ENERGY FLORIDA, INC. /	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 6
Pages 620 through 747

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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 2:15 p.m. Concluded at 5:06 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	CLARA C. ROTRUCK Court Reporter
PARTICIPATING:	(As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:	ID.	ADMTD.
Staff 27	649	649
Staff 28		
62		650
63		650

P R O C E E D I N G S

(Transcript follows in sequence from Volume 5.)

CHAIRMAN CARTER: We're back on the record. When we left, Mr. Moyle, you were on cross-examination. You're recognized, Mr. Moyle.

MR. MOYLE: Thank you, Mr. Chairman.

CROSS EXAMINATION (continued)

BY MR. MOYLE:

Q We were just going to turn, when we took a break, to page 17 of your pre-filed direct testimony.

A Yes, sir.

Q I want to spend a little time and talk about the capital spending that you testified is required by NERC and FRCC reliability initiatives and expansions. Do you see that?

A Right.

Q You say that there's approximately 140 out of 185 is being spent for NERC reliability initiatives and additional generation. Do you know the breakdown of that 140 between NERC reliability initiatives and the additional generation?

A I'm not sure that I have the, you know, I have the overall breakdown, and I think when we say "generation," a lot of the planning criteria is actually predicated by the generation that's in the generation queue, and so projects that we have planned one year out, five years out, ten years out, assume certain generating units that are in the generation queue. It would be hard to say right now unless we remodeled and removed certain generation that's in the queue as to what projects would go in or out, but it is all predicated on what's in the queue, and the queue is maintained really as a function of FERC, the OASIS.

Q Right. Interconnection studies, things like that?

A All of those type things are all predicated on generators that are in the queue and facilities that are in the queue, as well as purchase power transactions that are in the queue.

Q The reference there to the NERC Transmission Planning Standards, TPL, is that what we were talking about earlier when you talked about the 90-plus requirements?

A Well, the 90 -- the planning standards, maintenance standards, facility standards, are all different variations of NERC requirements. The TPLs are specific to transmission planning, and that would be TPL-001, 002, 003 and 004, yes.

Q So I'm just trying to understand this

140 million capital expenditure number, and I went back and looked at your exhibit to try to understand it better --

A Right.

Q -- and I'd asked you to refer to it. It is the JDO-2 exhibit.

A Right.

Q Now, that's a list of your compliance-related capital projects as required by NERC, correct?

A Major, these are major projects. There are probably a number of projects that underlie this, but I would say these appear to be the ones that are $5 million and above that are related.

There's also section B, which are those projects that were related to the Bartow repowering project, which is in service now, and then sections C and D are other major 115 and 500 projects, or 115 and transmission projects that are associated with the transmission plan.

Q When NERC puts out these regulations, they give you a pretty extensive period of time to come into compliance, don't they?

A Certain ones, you know, you generally have a period of time before you come into compliance. Now, compliance can mean one of a couple of things. You either solve the problem or you come up with an operational mitigation that will either allow you to avoid projects or will allow you to defer projects, and so when we kind of go through the plan, we utilize all those opportunities to defer where we can and -- but just in all actuality, some projects do come to the forefront that you're not able to mitigate around, and those are the ones that you see on the list here.

Q On page 18, line 19, you talk about a ten-year planning period --

A Sure.

Q -- for the mandatory NERC reliability standards. That to me suggests that there is a ten-year period in which to meet these reliability standards, is that correct?

A That's not true.

Q That's not?

A That's not true, that's just more of a planning horizon statement, not a compliance statement.

Q Well, let me ask you this: With respect to the projects that are listed on this exhibit --

A Right.

Q -- some of those can be completed in 2014, correct? On your first page, 40th Street?

A Yes. Yes.

Q All right, so as we sit here today, there's some variability with respect to when you would complete certain capital projects as suggested by NERC compliance guidelines, correct?

A Well, it really goes beyond that. Again, it goes by the projections of when new generation and purchase power agreements and different things show up in the queue. And that queue doesn't just -- is not just tied to this year or next year, it's really tied in to many future years, can go ten, 15 years out just based on when a company, whether it be Progress Energy or Seminole, Florida Power & Light, or really any of the FRCC members, have generations stacked in their queue.

And so all of the studies are predicated on that generation being on when it shows up in the queue, so these projects are staged out between now -- what you will see in our plan, in a ten-year plan, is really projects that are staged out between now, over the next ten years.

Now, I think to the point, as we go through time, things come into the queue, things go out of the queue and the plan changes. Is everything that's in this plan today going to stay in the plan? Some things may, some things may not, other things may come in and take their place. But as our planning requirements show right now, this is what is in our transmission plan for 2010, to meet the compliance requirements.

Q You would agree, would you not, for the purposes of the rate case, it would be more beneficial to have something be shown as a capital expenditure in 2010 as compared to 2011, correct?

A Well, I think in our business we really have to kind of look at it in several years out. And, again, this is just talking about our two thousand -- although we're showing you what's in the plan for the future, the capital needs that we're addressing here are what we need for construction for 2010 to meet those compliance requirements.

Q Yes, sir. And I'm not sure you answered my question, which was, from an aspect of benefit to the company for ratemaking purposes --

A Right.

Q -- it would be more beneficial for a project to be found in the 2010 year as a capital project as compared to 2011, correct?

A I'd say that's correct.

Q And that's because 2010 is your test year?

A That's right.

Q Okay. And you're aware that Public Counsel and some others have suggested that the test year might be a little heavy with respect to some projects, correct?

A I think from our standpoint, you know, we have the projects in the plan and in the budget that are required to meet those compliance requirements at this point in time.

Q If you wanted to find out the number of capital projects for 2010 based on your Exhibit JDO-2, wouldn't you just go through and add up the numbers that are found adjacent to months and years that say 2010?

A No. A lot of these projects are multi-year projects, so with a project that has an in-service date for 2014, we would probably begin doing land work and permitting work on that in the 2010 time frame.

So you will see projects in this list that all have dollars tied to 2010. Even though their in-service dates may be future, we will begin work, whether it's procurement of land, materials and those type things, in 2010. So each of these projects has some aspect or some phase of the project is tied to 2010.

Q So why would you list, like for the first one, Avalon-Gifford 230 kV line, May 2010, 39 million, are you saying that 39 million should not all be in May 2010?

A Now, that one is, that one is all 2010 because it goes in service that year. That project is well on its way at this point in time, and there's $39 million that's tied to that project for 2010.

Q Let's look at the next one, the Dundee 2010, June, 41 million. Is that 41 million number accurate, or should that be reduced, given your previous answer?

A Dundee/Intercession City, that's -- I would say a majority of that 41 million is tied to next year, because that's an in-service date of 2010.

Q Is there some that's not?

A I would say that in the -- maybe the next one might be an example, Central Florida South, install new substation with one 230 -- one 500 230 transformer. The total cost there is 28 million. I would say that that would probably be somewhat staged in, and a majority of that being spent probably in 12 and 13, and beginning procurement of land and materials next year.

Q I could walk you through each of these, but just so --

A I know. I see what you're saying. I see what you're saying.

Q Just so we're on the same page, we're not talking past each other, you would agree that with respect to what's found in 2010, that those figures accurately represent the capital cost in the line that's -- the column that's all the way to the right on your Exhibit JDO-2?

A Yes, sir.

Q And are those accurate numbers?

A Those are accurate project capital cost estimate numbers at this point in time.

Q And it's your testimony that all of those costs are 2010 costs?

A These numbers that are in the right-hand column?

Q Yes, sir.

A No. Those -- again, those are total project costs that may be staged in. I think we talked about, a while ago, those projects that are showing 2010, I would say that a majority of those costs are, since that's next year, are 2010 costs. The ones like the 2014 that we talked about, Central Florida, a portion of that would be 2010, but probably more in '12, '13, '14, as we get closer to in-service dates.

Q I don't know if you have added up the 2010 capital projects. I took a quick stab at it and came up with $126 million. Would you agree that that sounds about right?

A I would say I have not added it up, but I will -- just real quick here. I'd say that would be fairly close, yeah.

Q And then to try to understand how 2010 looked to 2011, if you add up 2011, you get a $47 million number, don't you?

A I think so.

Q And you would agree that that's a -- from an order of magnitude, that's a pretty wide difference, the difference between 47 million and 126 million, correct?

A Well, I think that we probably don't have all of the 2011 projects in here. We're only showing the ones that have a 2010 contribution. So with 2010 being the focus year, these are the projects that make a major contribution to the 140 million ask that we have on capital. So if you do add up the 2010 projects, you're going to come up with a number, like you said, around 100 million -- what was it, 140?

Q 147.

A 147. And there's going to be some, probably some small portion of some of these other projects that money is going to be spent in 2010 also.

Q But with respect to the information that's set forth on JDO-2, didn't you try to do an apples-to-apples analysis with respect to these projects and the numbers associated with them?

A Well, I'm not -- I think, there again, I think some of these projects are spread across multiple years. And, you know, we could go through and dissect out what the budget is for the particular year if you want me to come back and do that, but the projects that are like in 2014, you're not going to -- all of those dollars are not 2010 dollars.

Q Over the course of time it's been suggested by others, and kind of a saying in the industry that I wanted to get your view on, that to the extent a utility was looking to increase cash that would be available to it to do things with, that a place that's oftentimes looked to to make reductions is vegetation management. Have you ever heard that?

A I can say that I have heard that, yes.

Q Is there any truth to that?

A I'm not sure I understand what context "any truth to" --

Q To the idea --

A -- utilizing vegetation management to make O&M -- I guess what I'm trying to match up is are we -- have we switched -- we were on capital, now we're talking about vegetation management, and I'm --

Q Yes, sir, I'm sorry. I change --

A Okay. I would say that your statement, I have heard that statement. I have been in this business about 30 years, and I have heard that statement made. Whether it happens or not, I can say it has not happened on my watch here. I have not been in a position that I'm in now at another company, so it would be very hard to say about where -- you know, at my former employer. But I know as long as I've been in this position here, we have not done that.

Q Would you resist that effort if it were suggested?

A Absolutely.

MR. MOYLE: That's all I have, thank you.

CHAIRMAN CARTER: Thank you, Mr. Moyle.

Mr. Brew?

CROSS EXAMINATION

BY MR. BREW:

Q Good afternoon.

A Good afternoon.

Q If I have questions for you about FERC or NERC or the FRCC, you're the person?

A I'll give it a shot.

Q Okay. More generally, in terms of Progress's compliance with reliability standards, that would be basically you?

A Yes.

Q Okay. If I can refer you to page 14 of your testimony, on line 7, do you see the sentence that says, "The increased FRCC activity resulted in increased findings of the need to construct transmission capital projects"?

A Uh-huh.

Q "Increased findings," whose findings? Are those Progress's or the FRCC's?

A Well, if you look at our planning process, kind of the first cut of our planning process is a Progress Energy cut. But we utilize our models and FRCC models to run the data and understand kind of where the issues are on the system. Once we have come up with what we feel like are the issues, then it's jointly discussed at the FRCC. So once it goes through the planning process at the FRCC -- and some of this we discussed earlier, the transparency issue, it's discussed embedded at the planning committee level at the FRCC -- then a number of projects come out of that, and each company where there are issues on the system kind of deals with their projects. And so from -- it's kind of a joint process, although it starts out as an independent and then rolls up to that level.

Q Okay, so would it be safe to say that in the first cut, Progress, through its planning process, decides when, where, what and how much it's going to spend in terms of transmission upgrades?

A I would say at that point it's more of a collection of projects that are required to meet compliance. When we talk about compliance now, there's three or really four standards at the NERC level that really go everywhere, from single contingency to multiple contingency outages, common structure outages, all these kind of things. We sort through all of that internally first, and then we pass that off to FRCC for their look.

Q So the initial determination of what you need to build, where, how much, comes from Progress, and then you submit that up to the FRCC planning committee?

A Right.

Q And the FRCC is what exactly?

A Well, Florida Reliability Coordinating Council is an entity that's charged by NERC to be the regional authority for reliability.

Q And do Progress Energy Florida employees participate in the FRCC planning committee?

A We do.

Q Okay. So you submit a plan -- the Progress plan to the planning committee on which Progress Energy Florida people sit?

A Right, along with all of the other utilities in the state.

Q Okay. Earlier in your discussion with Mr. Moyle you mentioned 90 additional requirements --

A Actually, it's actually more than that.

Q -- over the last two years. Are you referring to the mandatory reliability standards?

A Right.

Q And those standards became effective and mandatory in June 2007?

A Right.

Q And before that, there were NERC standards, weren't there?

A There were NERC guidelines.

Q NERC guidelines. And -- that were -- that covered most of the ground as the existing standards?

A Yes.

Q And did Progress operate its system to comply with those guidelines?

A We did, and those were referred to as good utility standard.

Q Okay. And isn't it true that about 90 of the hundred standards that FERC adopted -- FERC and NERC adopted was just a restatement of the old guidelines?

A Not necessarily. They were a lot more stringent, a lot more -- I would say more specific as to what acceptable levels of -- for example, on the planning standards, what accepted levels of voltage excursion or voltage depression were, just much more specific.

Q Let's hold that thought on the excursions, but the initial pass-through from FERC was to codify the existing standards, wasn't it?

A I think you could probably say that, but it was much more -- I think it was much more extensive and much more involved than that.

Q Okay. Let's talk about excursions, because you mention that also on page 14 of your testimony where you talk about mitigating reliability excursions from the FRCC and NERC criteria.

A Uh-huh.

Q What are excursions?

A Well, I think in this case, when we're talking about planning requirements, there's certain -- when you do a planning study on a transmission line or a, what we'll say a substation bus, there are certain voltage levels, there's voltage level criteria that you don't want those limits to fall below. So I think the word "excursion" there, I'm not -- you know, there's an upper bound to it and a lower bound in there, so it really kind of tells you what your proper operating levels for what your scenario are.

Q Okay. I guess I'm trying to take sort of a vague term, *excursions*, and understand more specifically what we're talking about. Are you talking about for planning purposes ensuring that you maintain voltage, frequency, stability?

A All of those things.

Q Okay. And so --

A Within acceptable limits.

Q Within acceptable limits that are defined by the various applicable standards?

A Right.

Q Such as the balancing standards?

A Right.

Q Okay. What I'm trying to figure out is, I don't want to go beyond your scope, which is if we're talking about Progress Energy's compliance with the applicable criteria, many of the means for complying with those criteria are generation-related, are they not?

A I think there are a set of those that are generation, yes.

Q So if a frequency is dropping, a response might be to add more generation?

A Right, or shed load.

Q Or shed load. And, in fact, along those lines, if frequency was dropping and you were 50 megawatts short, you could comply either by adding 50 megawatts of supply or dropping 50 megawatts of load?

A I think you'd have to look at things from a stability standpoint on the decay rates and things like that, and it's very involved. I don't think it's just as simple as saying add 50 or take 50 away.

Q I didn't want to oversimplify, but that -- certainly ways of complying to keep the system in balance could be to drop load or to add supply?

A Right.

Q Page 13, please. On line 15, you mention specifically FERC Order 890. Do you see that?

A Yes.

Q And I've got to say this: Did you read the rule?

A Have I read FERC 890?

Q Yes.

A I have read portions of FERC 890 and understand the nine principles, but it's a fairly lengthy document.

Q Okay.

A And I think the other one that I'm more familiar with is Attachment K, which is the cost allocation and planning standards of that.

Q Now, would you agree with me that in Order 890, FERC directed responsible entities, which for your control area would be Progress, in its transmission planning process, which you're familiar with, is that -- you're responsible for, is that right?

A Right.

Q To direct them to consider using demand resources in complying with the criteria and for planning purposes, is that right?

A I'm not sure I'm that familiar with that aspect of this. I think probably Mr. Crisp may be a better witness for the demand response piece.

Q Okay. Let me ask it from a transmission planning specific. In response to Order 890, is Progress Energy Florida taking into account demand response as a resource in complying with the applicable criteria?

A I can't answer that. I think -- I think Mr. Crisp may be a better -- better witness for the demand response.

Q What I'm asking you is in terms of your transmission planning function in compliance with Order 890, are you taking demand response into account --

A I would say that we're in compliance with the standard, but as far as how it goes -- you know, how it's calculated into the planning process, that Mr. Crisp may be a better witness for that.

Q Forgive me for pressing for an answer to my question, but from a transmission planning perspective, not in terms of demand response planning, but from a transmission planning perspective, are you taking demand response into account as a resource in meeting your transmission planning objectives?

MR. BURNETT: Mr. Chair?

CHAIRMAN CARTER: Mr. Burnett.

MR. BURNETT: Thank you. I count the third time that question's asked. He has made clear that Mr. Crisp, who reports on this aspect for the transmission relation to Mr. Oliver, can answer the question. So I don't know if he can make it any clearer.

MR. BREW: Mr. Chairman, I persisted because I wasn't getting an answer. This is the only witness that testifies on transmission planning and meeting the applicable reliability criteria. The applicable FERC order deals with transmission planning and the reliability criteria. The question is whether Progress is taking that into account for transmission planning purposes, which is this witness's responsibility, so --

CHAIRMAN CARTER: I thought I heard you say demand response. That's what I thought I heard you say.

MR. BREW: Well, demand response as a resource in transmission planning is what the Commission -- FERC addressed in Order 890. What I'm asking this witness, who is responsible for transmission planning, is if the company, in doing transmission planning, takes demand resource into account. It's a transmission planning question, not a demand response question.

CHAIRMAN CARTER: Okay. Ms. Brubaker?

MS. BRUBAKER: It seems to me that if the witness is able to answer the question, then we could get the answer and just move on.

CHAIRMAN CARTER: Do you want to try again, Mr. Brew?

MR. BREW: Sure.

BY MR. BREW:

Q Mr. Oliver, do you take demand response into account in your transmission planning activities?

A I don't know.

Q Okay. A minute ago we talked about excursions, and if one such excursion was a system circumstance where a frequency was dropping, that would require a response by the company in order to restore the system to its proper balance, is that right?

A Correct.

Q And that is, in fact, what some of the applicable FRCC and NERC criteria address and require?

A Directly, yes.

Q And so would you agree with me that having resources that can allow the company to more quickly restore that balance are desirable resources to have on your system?

A I think that's hard to say. In looking, again, at whatever the disturbance is, I think it depends. I think in some instances the best response, if you will, to a frequency excursion is to shed load, because I'm just not sure that from a generation standpoint you are able to -- generators can ramp at as quick a rate to match the decay on the frequency. So -- and, you know, as far as our system is concerned, we shed load in -- under frequency blocks to meet those requirements to allow the system to catch back up with itself, so --

Q Thank you.

MR. BREW: That's all I have.

CHAIRMAN EDGAR: Questions from the Navy?

MS. VAN DYKE: No questions.

CHAIRMAN EDGAR: Mr. Wright?

MR. WRIGHT: Thank you.

/ / / / /

CROSS EXAMINATION

BY MR. WRIGHT:

Q Good afternoon, Mr. Oliver. We met earlier in the day. I'm Scheff Wright, and I represent the Florida Retail Federation in this proceeding. I just have a few questions for you that relate to some matters that were deferred to you by Mr. Dolan.

At page 11 of Mr. Dolan's testimony, which was actually Mr. Lyash's testimony -- this isn't complex, I mean, I'm happy for you to get it, but --

A I don't have his testimony in front of me.

Okay, thank you.

MR. WRIGHT: Madam Chair, I have handed the witness my copy of Mr. Dolan's testimony.

BY MR. WRIGHT:

Q The sentence there says that the company projects it will need $611 million in future annual revenue requirements for transmission and distribution?

A Right.

Q Okay. I inquired of Mr. Dolan about that, and he said he thought you might be better able to answer that with regard to transmission. I will aver to you I've had an opportunity to discuss this with your attorneys, and I think I know what's going on with this number, but let me see if you and I can walk through it on the record.

A Okay.

Q Okay. The understanding I have is that the $611 million -- and I'm going to get to a question, I promise -- the $611 million is a projected total transmission and distribution cash outlay for 2010. Is that your understanding?

A That is my understanding.

Q And of that amount, is it correct that -- and you talk about this in your testimony -- of that $611 million, 45.3 million is the -- is transmission O&M?

A That's right.

Q That is in your testimony?

A Yes, it is.

Q And 185.2 million is capital cash outlay in 2010?

A Yes.

Q This follows up on that question and also a little bit on some discussion you had with Mr. Moyle. I just want to be sure I understand how things are going on, and if I could ask you to look at your Exhibit JDO-2?

A Okay.

Q Would I be correct, or would it be correct that if a project was completed in 2010, then the total project cost for that project would be included in the 2010 test year rate base for the company?

A I think it would be projects that are completed in 2010, also any projects that have started that have future in-service where we may have to spend -- in all actuality, when you get into some of these larger 230 projects, 115 projects, you may start purchasing land and easement and going through TLSA requirements years in advance. So there would be some spending.

For example, this -- we show the Dale Mabry to Zephyrhills north 230 line, October 2014. We're in the land acquisition portion of that now.

Q Let's pursue that example.

A Okay.

Q I'm trying to understand the relationship between the cash outlay in 2010 and how it relates to what's actually in rate base or not in rate base in this case. I think the Dale Mabry to Zephyrhills north example may be useful here. You just said you have started land acquisition?

A That's right.

Q Would it be your testimony, then, that you've spent some money for land and easements, land rights, to date?

A Very preliminarily in '09. I don't know the number, I don't have that, but I would say that for a project with a 2014 in-service date, that a -- that project -- a bulk of the spending on that project would probably be in the '13 time frame, and mainly land and permitting up through that point in time. It's just hard to say how much.

Q I understand that, but the point is that -- is it your testimony that the land costs incurred in 2009 and 2010 would show up in rate base in this case?

A In '10, only the '10.

Q Well, if you spent, let's just say, a million dollars for land rights in 2009, would that be part of the company's rate base in 2010? And remember I'm talking about rate base, not --

A I'm not an expert -- to be honest with you, I'm not an expert on rate base, and so I'm not sure I can answer that question.

Q All right. Do you think that's a question I should perhaps ask Mr. Toomey?

A Mr. Toomey.

Q Thank you.

MR. WRIGHT: That's all I have, Mr. Chairman.

CHAIRMAN CARTER: Thank you, Mr. Wright.

Staff?

MR. YOUNG: Thank you. Mr. Chairman, in lieu of cross, the parties have agreed that items numbers 27 and 28 can be moved into the record in lieu of cross, and this is --

CHAIRMAN CARTER: Hang on a second. Let's everybody get on the same page here. In lieu of cross on this witness will be items 27 and 28, is that correct?

MR. YOUNG: Yes, sir.

CHAIRMAN CARTER: Let me ask the parties, is that your understanding?

MR. WRIGHT: Yes, sir.

CHAIRMAN CARTER: Without objection, show it done.

MR. YOUNG: Thank you, sir.

(Staff's Items 27 and 28 marked for identification and admitted into the record.)

CHAIRMAN CARTER: It's 27 and 28, right? That's correct?

MR. YOUNG: Yes, sir.

CHAIRMAN CARTER: No further from staff?

Commissioners?

Okay, redirect?

MR. BURNETT: No, sir, and we would move

Exhibits 62 and 63.

CHAIRMAN CARTER: Are there any objections?

MR. WRIGHT: No objection.

CHAIRMAN CARTER: Without objection, show it done.

(Exhibit Nos. 62 and 63 were admitted into the record.)

CHAIRMAN CARTER: Call your next witness.

MR. BURNETT: Yes, sir, we would call Jackie Joyner.

CHAIRMAN CARTER: Is this the sprinter?

MR. BURNETT: No, sir.

Whereupon,

JACKIE JOYNER, JR.

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

DIRECT EXAMINATION

BY MR. BURNETT:

Q Mr. Joyner, would you please introduce yourself to the Commission and provide your business address?

A Yes, my name is Jackie Joyner. I currently am employed by Progress Energy Florida, current title of Vice-President of Distribution Florida. And my business address is 299 First Avenue North, St. Petersburg, Florida.

Q Mr. Joyner, you have been sworn as a witness already, correct?

A Yes, sir, I have.

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

A Yes, sir, I have.

Q Do you have any changes to make in your prefiled direct testimony?

A No, sir.

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

A Yes, sir.

MR. BURNETT: Mr. Chair, the exhibits to Mr. Joyner's testimony have been marked 64 through 66, and we would ask at this time that his prefiled direct testimony be entered into the record as if read today.

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

PROGRESS ENERGY FLORIDA
DOCKET NO. 090079-EI

Petition for rate increase by Progress Energy Florida, Inc.

DIRECT TESTIMONY OF JACKIE JOYNER JR.

I. Introduction and Summary.

Q. Please state your name and business address.

A. My name is Jackie Joyner. 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 "the Company") in the capacity of Vice President of Distribution - Florida.

Q. What are the duties and responsibilities of your position with PEF?

A. As Vice President of Distribution - Florida, I direct and manage the development of PEF's distribution strategic programs and compliance policies within the following functional areas: distribution asset management; distribution services; distribution resource management and construction; distribution training and safety; and the distribution control center.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science degree in Electrical Engineering from the University of Tennessee in 1985. In 1994, I earned a Master of Business Administration degree from Nova Southeastern University. I also attended leadership training courses at the University of North Carolina and Duke University. Prior to assuming my current role for PEF, I was the Regional Vice President, Energy Delivery – Progress Energy Carolinas (PEC), responsible for the execution of asset management programs, construction of new electrical infrastructure, and restoration of electric service for 350,000 customers in an 18-county area of eastern North Carolina. I also served as Director – Asset Management for PEC and Supervisor – Distribution Control Center – PEC. Prior to joining Progress Energy in 2000, I held a number of supervisory and management positions for Florida Power & Light Company.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to support the reasonableness of Capital and Operations and Maintenance ("O&M") expenses in the Company's distribution area.

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. __ (JJ-1), a summary of sponsored or co-sponsored schedules of the Company's Minimum Filing Requirements ("MFRs");

- Exhibit No. __ (JJ-2), a summary of Distribution reliability results for the years 2000 through 2008; and
- Exhibit No. __ (JJ-3), a summary of PEF's Distribution Capital and O&M Expenses for key distribution enhancements and reliability and storm hardening initiatives.

These exhibits are true and correct.

Q. Do you sponsor any schedules of the Company's Minimum Filing Requirements (MFRs)?

A. Yes. Exhibit No. ___ (JJ-1) to my testimony lists the schedules of the Company's MFRs that I sponsor or co-sponsor with respect to the Company's distribution system. These are true and correct, subject to being updated during the course of this proceeding.

Q. Please summarize your testimony.

A. PEF successfully maintained the reliability improvements attained through our 2002-2004 Commitment to Excellence ("CTE") program. PEF executed seven reliability initiatives and developed the Customer Reliability Excellence Monitor ("CREM") to further drive improvements. As a result, PEF has sustained the improvements achieved through CTE and improved in other reliability metrics that matter most to our customers. We remain committed to providing superior, reliable distribution service to our customers while prudently managing our costs.

Managing our costs moving forward, however, is a challenge in this economy. Also, we face additional capital and operation and maintenance ("O&M") expenses to comply with regulatory mandates such as the Florida Public Service Commission ("PSC" or the "Commission") storm hardening initiatives. Additionally, we must continue to invest in capital improvements to our distribution system and incur O&M expenses to maintain it to preserve the reliability gains we have achieved and that our customers expect. To accomplish these objectives, the Company needs $236 million for distribution capital investments and $145 million for distribution O&M expenses in the 2010 test year. These expenditures are reasonable and necessary to continue to reliably distribute power to our customers and comply with Commission reliability initiatives in a cost-effective manner.

II. PEF's Distribution System.

Q. Please generally describe PEF's distribution system.

A. PEF's distribution system reliably delivers power to approximately 1.6 million customers across a service area in west central Florida that is 20,000 square miles and includes the densely populated areas around Orlando, St. Petersburg, and Clearwater. PEF's distribution system includes approximately 18,000 circuit miles of overhead primary voltage distribution conductors, approximately 13,000 miles of underground primary voltage distribution cable, distribution substations, and related poles, transformers, cables, wires, and other material and equipment, such as bucket trucks, to provide reliable service. To ensure that PEF reliably delivers power around-the-clock to its customers, PEF must continually invest in capital additions and replacements and incur the necessary expenses to operate and maintain the distribution system.

Q. How does PEF manage its distribution system?

A. PEF manages its distribution system through the following functional areas: distribution asset management; distribution services; distribution resource management and construction; distribution training and safety; and the distribution control center. In each of these functional areas, PEF has developed strategic programs and compliance policies to ensure the reliable delivery of power to PEF's customers at a reasonable cost.

Q. What has the Company done to ensure the reliable distribution of power to PEF's customers since 2005?

A. As a result of our 2002-2004 CTE program, PEF significantly improved the reliable distribution of power to its customers. This was an unprecedented improvement in our reliability. In 2005, PEF initiated seven reliability measures to build upon the success of our CTE program. These reliability initiatives included (1) a focused maintenance program on its underground network in several major cities, (2) a program to replace annealed conductor to reduce outages, (3) an infrared scanning and repair program to replace high current density connection points before outages occurred, (4) an underground cable replacement program, (5) a capacitor maintenance program to account for system growth, (6) an infrastructure capacity planning program to meet customer growth, and (7) an increase in vegetation management to reduce vegetation-related outages in both storm and non-storm conditions. PEF invested $104 million in capital and $42.8 million in O&M during 2006 and 2007 in these seven reliability initiatives.

Additionally, in 2006 PEF implemented the Customer Reliability Excellence Monitor. We developed this tracking key performance indicators based on surveys we conducted with customers to better understand what aspects of reliability are most important to our customers. As a result, we have been able to better link customer satisfaction to improved reliability based on certain recognized reliability metrics. CREM was developed to identify capital and O&M projects that drive balanced improvement to the reliability metrics that mattered most to customers. To ensure our focus on these improvements, the CREM metric was established as one of the ten employee incentive goals in 2006 and remains one today. Status reports on the CREM metric for both field and engineering groups are published weekly so that distribution reliability performance can be tracked in relative real time. Implementation of CREM establishes PEF as an electric utility industry leader in customer oriented reliability.

Q. What are the reliability metrics the Company uses to determine that it is providing reliable distribution service to its customers?

A. The Company uses electric utility industry standards to measure the reliability of its distribution system. These include (1) the System Average Interruption Duration Index ("SAIDI"), which captures the duration of the average customer outage measured by the total number of minutes of interruptions divided by the total number of customers served; (2) the System Average Interruption Frequency Index ("SAIFI"), which measures the frequency (number) of interruptions experienced by a typical customer; and (3) the Customer Average Interruption Duration Index ("CAIDI"), which captures the average length of each interruption for each recorded customer interruption. These reliability indices are routinely used by electric utilities and regulators as indicators of utility performance in the area of distribution reliability. Changes in magnitude and direction of these indices over time allow for the comparison of reliability performance from one period to the next.

Additionally, as a direct result of CREM, PEF measures the Customers Experiencing Multiple Interruptions greater than 4 ("$CEMI_4$"), the Momentary Average Interruption Frequency Index ("$MAIFI_e$") and Customers Experiencing Long Interruption Durations greater than 3 hours ("$CELID_3$"). CREM was created to drive balanced reliability improvements in the reliability metrics that matter most to PEF's customers. CREM gauges reliability performance by simultaneously measuring and ensuring balance among SAIDI, $CEMI_4$, $MAIFI_e$, and $CELID_3$. These metrics are regularly tracked by the Company to ensure continued focus on the reliable delivery of power to our customers.

Q. Based on these reliability metrics, is the Company still providing customers with reliable distribution services?

A. Yes. As measured by CREM, PEF has maintained the distribution reliability improvements obtained through its CTE program. The Company exceeded the SAIDI 80 goal for 2004 by 23 percent and has sustained that reliability improvement in each subsequent year, holding SAIDI below 80 minutes in 2005, 2006, 2007, and 2008. PEF's reliability metric results from 2000 through 2008 are provided in Exhibit No. __(JJ-2) to my testimony.

Q. Has the Company achieved the distribution reliability that its customers demand at a reasonable cost?

A. Yes. We take a number of steps to ensure that we aggressively manage our distribution related costs and that we are focused on the right priorities, our budgets are reasonable, and we are spending our money wisely. One step is that we benchmark our distribution costs against the distribution costs incurred by other electric utilities. We use this benchmarking data to set cost targets, allocate budget dollars, and monitor our cost performance. We use the Southern Company Distribution Benchmarking Group, which includes similarly situated electric utilities, as our benchmark. We compare very favorably against this benchmark; we have maintained first or second quartile performance since 2005 in Cost per Install, Cost per Customer, Cost per megawatt-Hour, and Cost per Customer per Line Mile. Since 2005, our Cost per Line Mile also improved from 4th quartile to 3rd quartile. This is a significant improvement because PEF has the fourth largest percentage of underground line miles among the benchmarked companies and the maintenance cost for underground line miles is greater than that for overhead line mile.

Another step we take is the continual implementation of distribution construction process improvements where available to manage our costs. One example is the formation of a specific Distribution Asset Management organization within Distribution. This organization includes Systems Engineering, Component Engineering, and Distribution Project Management. Systems Engineering focuses on system expansion planning and reliability performance for load growth improvements and storm hardening projects. Component Engineering focuses on the application, maintenance, and end-of-life replacement of specific distribution assets such as poles, underground cable, and transformers. Distribution Project Management focuses on the efficient completion of large projects generated by the systems and component engineering groups. The Distribution Asset Management organization focuses on key distribution initiatives while continually evaluating risks and making improvements in the processes for handling these initiatives. This enhanced focus ensures that we are delivering safe, reliable, high-quality power to our customers at a reasonable cost.

Another example is our emphasis on joint trench construction when more than one utility (such as electric, cable, and telephone) will share the trench. Joint trench construction is more efficient than each utility separately burying their lines or cables and it reduces the risk of damage caused by another utility separately burying their lines or cables at a later time. We are also transitioning to a "direct buried" standard method of cable installation because it is more cost effective over the life of the asset. As a further example of our continual construction process improvement, we are currently undertaking a Future State Construction Process Study in conjunction with the implementation of a new Work Management System to reduce construction costs.

Another step we have taken to manage our costs is the implementation of performance guarantees for residential subdivisions. This requires a deposit for the full cost of any facility installation beyond the initial area where homes are under construction. This deposit is returned if and when homes are built within five years beyond the initial area of home construction. This requirement encourages developers to phase in any large subdivisions to avoid the initial deposit requirement and helps us to manage our construction budgets by incurring new facility construction only when it is needed.

Finally, we established an Investment Portfolio prioritization tool to best manage the balance between cost and reliability performance. The Investment Portfolio model ties resource allocation directly to reliability metric impacts and optimizes spending on distribution programs and initiatives.

Q. What management oversight exists to ensure that PEF is efficiently managing its distribution system costs?

A. First, our Distribution Project Management group provides in-the-field guidance on our Distribution capital and maintenance projects to ensure that they are completed on time, on budget, and in the most efficient way possible under the circumstances. Next, our Business Operations group monitors our spending each month for reasonableness and compliance with our budget. Our Business Operations group also facilitates our operational analysis, the development of ideas to improve efficiency where possible, and the revision of spending projections when needed. In addition, our budget and cost and reliability performance metrics are woven into incentive compensation goals for our employees at all levels of the Distribution organization. This ensures that our employees are focused on achieving the reliability and other performance goals of our Distribution program and initiative spending at a reasonable cost to our customers.

Also, before we initiate a Distribution program or capital or maintenance initiative, the program or initiative is reviewed by the Distribution Finance Committee. The Finance Committee is comprised of management from a range of functional areas within PEF. It provides PEF's Distribution management with a "cross-check" on distribution programs, plans, and budgets.

Q. Does the Company plan to continue to provide customers with reliable electric service at a reasonable cost?

A. Yes, we currently plan to maintain our top quartile reliability performance in the industry and meet our regulatory obligations while effectively managing our costs. This requires, however, additional capital and O&M investment in our Distribution system. One reason is that our distribution system is larger today than it was in 2005. We serve more customers and we have more distribution assets on our system to maintain than we had in 2005. More customers on the system also means there are times, even under current economic conditions, when additional capacity demands placed on the system create localized capacity constraints that jeopardize efficient and reliable delivery of power. Relieving localized delivery system constraints improves efficiency, which reduces losses and fuel costs. Therefore, PEF must continue to invest in capacity expansion of the distribution system.

PEF's distribution system is also four years older since its last base rate proceeding. As the infrastructure ages, it needs to be maintained or replaced. Finally, the Commission's storm hardening policies and initiatives require us to alter our distribution engineering, construction, and maintenance practices and processes, at additional cost, and further require additional distribution capital and O&M expenditures by the Company.

III. <u>Distribution System Revenue Requirements</u>.

Q. What are the Company's distribution capital and O&M revenue requirements?

A. PEF requires Distribution capital expenditures of $236 million and Distribution O&M expenditures of $145 million. Please see Exhibit No. ___ (JJ-3) to my testimony, which highlights key initiatives of the 2010 Distribution capital and O&M expenses.

Q. Why does the Company need the distribution capital and O&M revenue requirements it requests in this proceeding?

A. The Company's overarching goal is to meet the needs and expectations of our customers for the distribution of reliable power at a reasonable cost. To do this, we must sustain a distribution system with adequate capacity reserves to meet the demands placed on it by a larger number of customers, we must minimize the number and duration of outages to this larger number of customers, and we must methodically harden the system against storm damage to comply with Commission regulatory reliability requirements. Thus, the Company has three strategic priorities for the distribution system over the next several years.

First, PEF plans to maintain its recent reliability performance improvements. PEF's outstanding reliability performance, as measured by the various electric utility industry reliability metrics, cannot be sustained without further capital and maintenance improvements to the distribution system.

Second, PEF plans to prudently invest in delivery system capacity enhancement and equipment end-of-life replacement projects to continue to ensure the efficient delivery of reliable power to customers. PEF's distribution system is larger, its assets are getting older, and it is serving more customers. PEF needs to and will implement well designed and executed system maintenance and equipment replacement programs and it will make power factor improvements to increase system efficiency.

Third, PEF plans to enhance and maintain its distribution system assets to harden the system against storm damage to comply with the Commission's storm hardening orders and rule.

Q. What are the Commission's storm hardening initiatives?

A. Following the 2004 and 2005 hurricanes, and the resulting extensive storm restoration costs to electric utility customers in Florida, the Commission took steps to explore ways to minimize future storm damage and customer outages. The Florida Legislature was equally concerned about the vulnerability of the state's electric system to the effects of hurricanes and required the Commission to review measures to potentially enhance the reliability of the electrical system during extreme weather. The Commission initiated workshops toward these goals and the Florida electric utilities, including PEF, participated in those workshops. Subsequent to the workshops, the Commission took a series of actions that established the storm preparedness initiatives that PEF must now satisfy.

In February 2006, the Commission issued Order No. PSC-06-0144-PAA-EI, requiring all Florida investor-owned utilities ("IOUs") to implement an eight-year wood pole inspection cycle. Consequently, PEF 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 Electric 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 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, which implemented processes meeting the requirements of the ten initiatives identified in the Order.

In February 2007, the Commission issued Rule 25-6.0342, F.A.C., which established various requirements for storm hardening for the Florida electric transmission and distribution systems. The Rule requires, at a minimum, that each IOU's Plan address the following:

(a) Compliance with the NESC;

(b) 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;

(c) Mitigation of damage due to flooding and storm surges;

(d) Placement of facilities to facilitate safe and efficient access for installation and maintenance;

(e) 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

(f) the inclusion of 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 is a consolidated response to the requirements of the Commission's storm hardening Orders and Rule 25-6.0342, F.A.C. As a result, PEF is meeting all storm hardening requirements for its distribution system.

Q. Have the Commission's storm hardening initiatives impacted PEF's management of its Distribution system?

A. Yes. The Commission's storm hardening initiatives developed in the Commission's storm hardening orders and rule have impacted the Company's management of its Distribution system at additional cost to the Company. To begin with, compliance with the Commission's storm hardening initiatives requires additional management and administration, including storm hardening research, the collection, measurement, and analysis of data, and reporting the results of that analysis to the Commission in the Company's Plan and required reports.

In addition, the Commission's storm hardening initiatives changed the way PEF manages its distribution system. To comply with the Commission's storm hardening initiatives, PEF developed a systematic approach to storm hardening that involved engaging an industry expert and, with that expert's assistance, developing a comprehensive prioritization model to identify potential storm hardening projects, procedures, and strategies. This Investment Portfolio strategy identifies and prioritizes pilot projects based on a number of criteria that are explained in detail in the Company's Storm Hardening Plan. All of these Distribution management models, procedures, and strategies require additional O&M expense by the Company to ensure that it is meeting the Commission's storm hardening requirements and objectives.

Q. Are there any specific storm hardening initiatives that require additional distribution capital and O&M expenditures?

A. Yes. In particular, the storm hardening initiatives require aggressive wood pole inspections and vegetation management beyond established electric utility practice and what is necessary to maintain PEF's top quartile reliability performance. For example, prior to Order No. PSC-06-0144-PAA-EI, there was no mandatory wood pole inspection cycle. With the Commission-required, eight-year inspection cycle, since 2006, PEF has completed inspections on almost 257,000 wood poles, or 34 percent of its total wood pole inventory. Of the 34 percent inspected, PEF replaced over 4,000 priority poles or 1.6% of the total inspected poles. PEF spent $8.9 million on wood pole inspection and treatment and $11.5 million on wood pole replacement from 2006 through 2008. Based on this experience, PEF expects to spend $3.2 million in 2010 to comply with the Commission's required eight-year inspection cycle. Additionally, PEF will spend $8.6 million in capital expenditures replacing wood poles based on its experience with the mandatory wood pole inspection program. These O&M and capital expenditures are incremental to PEF's Distribution capital and O&M expenses and mandated by the Commission.

Similarly, in that same time period, PEF trimmed over 11,000 miles of overhead conductor or 62 percent of its total line miles. Of the 62 percent trimmed, over 5,000 danger trees have been removed. This work was performed in accordance with the Company's Integrated Vegetation Management ("IVM") approach approved by the Commission in Order No. PSC-06-0947-PAA-EI. The Company's IVM is a modification of the Commission three-year vegetation management cycle proposed as one of the Commission's storm hardening initiatives. Based on its current experience with this vegetation management cycle, PEF will incur $34.4 million in vegetation management expenses in 2010 under the IVM, to ensure compliance with this storm hardening initiative.

Additionally, the Company will spend $4.9 million on Storm Hardening Pilot projects in 2010. These projects test and evaluate different storm hardening strategies to target optimum storm hardening applications for PEF's distribution system in compliance with the Commission's storm hardening initiatives and policy goals.

The impact of the mandated storm hardening initiatives, such as the pole inspection and vegetation management cycles, storm hardening pilot projects, storm hardening administration, and management of reliability assessments, accounts for over 29 percent of the PEF distribution O&M expenses and over 14 percent of the PEF capital expenses.

Q. How does the Company plan to achieve its other strategic priorities?

A. PEF plans to maintain its recent reliability performance improvements through the continued use of the CREM metric supported by employee incentive goals. Tying employee incentives to reliability performance is the foundation to our year-over-year improvement in the vast majority of the reliability metrics that we benchmark against and monitor. Distribution expenses tied to maintaining or improving our distribution reliability include the component integrity replacement (CIR) project and the network maintenance project, among others, identified in Exhibit No. ____ (JJ-3) to my testimony.

PEF's delivery system capacity expansion and equipment end-of-life replacement projects are also identified in Exhibit No. ____ (JJ-3) to my testimony. These include over $24 million in capital expenditures for system capacity through new and expanded transmission to distribution stepdown substations. PEF will also require $7.74 million for new distribution feeders. Other substantial capital expenditures include $12.76 million for the replacement of underground cable that has reached the end of service life. Additional distribution capital and O&M expenses for other capacity enhancement and end-of-life replacements are identified in my Exhibit No. ____ (JJ-3).

The Company will achieve these strategic priorities by employing superior prioritization, planning, and project management. PEF will utilize an annual work plan, annual resource plan, and weekly schedule to ensure that these projects stay on schedule.

Q. Have recent economic conditions impacted the Company's distribution capital and O&M expenses?

A. Yes. We are mindful of the recessionary conditions that occurred in Florida and the rest of the nation and we have taken steps to manage our costs. For example, we reduced the number of both overhead and underground contractors. We have also reorganized, stream-lined decision-making, and re-calibrated staffing levels with the construction activity in the current economy. This initiative focuses our entire organization on service delivery and restoration. Our distribution department is focused on strategic planning, system performance, and compliance with established standards. Our operation centers are focused on outage response, operations, and construction for improved customer and community relations. The resulting operational cost efficiencies yield O&M savings of approximately $6.3 million and represent a favorable variance to the Commission's O&M benchmark.

Q. Are the Company's distribution O&M revenue requirements within the FPSC O&M benchmark costs?

A. The Company's O&M expenses vary from the Commission benchmark by approximately $14.3 million. The primary reason for this variance is the O&M expenses for the aggressive vegetation management program that the Company has undertaken to comply with the Commission's storm hardening initiatives and that the Commission has approved. This variance is about $13.9 million. This is offset by the cost savings from the operational efficiencies and re-organization that I previously mentioned. There is also a smaller unfavorable variance of approximately $2.6 million that arises from the transition of the Transformer Remediation Inspection Program costs previously included in the environmental cost recovery clause to base rates. In addition, FERC reclasses from Transmission to Distribution occurred causing an unfavorable variance of $4.1 million. As a result, these cost variances are not real variances from the benchmark established based on prior base rates because they were not previously included in Distribution's base rates.

Q. Are the Company's distribution system capital and O&M revenue requirements reasonable and necessary?

A. Yes. PEF has maintained the reliability improvements achieved through CTE and made improvements in other reliability metrics important to our customers. PEF must continue to maintain its capital and O&M investments to reliably deliver power to our customers because that is what they expect. Additionally, we must enhance our distribution system to efficiently deliver power to our customers. We are serving more customers now than in our last base rate proceeding with an older distribution system. A larger, aging distribution system requires additional expense to maintain it. We must continue the capital investments and O&M expenses necessary to replace assets as they reach the end of their useful life, maintain existing distribution assets, and reliably serve our customers.

Our capital and O&M expenditures are also necessary to harden our distribution system. The Commission has directed us to conduct more pole inspections, replace more wood poles, and more aggressively manage vegetation, among other initiatives, all to achieve the Commission's storm hardening policies and requirements. We must have adequate capital and O&M funds to comply with these Commission-approved storm hardening initiatives.

We have further demonstrated by industry benchmarking that we have reasonably managed our distribution capital investments and O&M expenses, achieving first or second quartile cost per customer, cost per megawatt-hour, and cost per customer per line mile performance.

Our future distribution capital and O&M expenses are, therefore, reasonable and needed to maintain the reliability improvements we have achieved, maintain the high level of service our customers enjoy, comply with regulatory initiatives, and continue to be an industry leader in cost efficient energy delivery.

Q. Does this conclude your direct testimony?

A. Yes it does.

BY MR. BURNETT:

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

A I do.

Q Keep in mind the lights in front of you, and the color. Please give it.

A Okay. Good afternoon --

CHAIRMAN CARTER: Hang on a second.

THE WITNESS: Yes, sir.

CHAIRMAN CARTER: Move to my right just a little bit. That way you'll have both microphones.

You may proceed.

THE WITNESS: Good afternoon, sir. Good afternoon, Commissioners. I just wanted to state specifically my responsibility as I stated my position, but my department is responsible for the planning and compliance of the work plan, which involves our asset management programs, our resource management strategies, our safety governance, our technology that we utilize and also specific responsibility for our distribution dispatch center. We also have four regional operations that's held accountable for the execution of this work plan.

My testimony supports the reasonableness of distribution's capital and O&M expenses.

Progress Energy Florida successfully maintained the reliability improvements attained through our 2002-2004 Commitment to Excellence Program. PEF has also executed seven reliability initiatives and developed our Customer Reliability Excellence Monitor -- you may see it referred to as CREM, C-R-E-M, in our testimony -- to further drive improvements. As a result, we have sustained the improvements achieved through the Commitment to Excellence Initiative, and improved in other reliability metrics that matter most to our customers. We remain committed to providing superior, reliable distribution service to our customers, while prudently managing our costs.

Managing our costs moving forward without additional funding, however, is a challenge. We face additional capital and O&M expenses to comply with regulatory mandates, such as the Florida Public Service Commission's storm-hardening initiatives. Initially we must continue to invest in capital improvements to our distribution system and incur O&M expenses to maintain it to preserve those reliability gains that we have achieved and our customers expect.

To accomplish these initiatives, the company needs $236 million for distribution capital investments and $145 million for distribution O&M expenses in the

2010 test year. These expenditures are reasonable and necessary to continue to reliably distribute power to our customers and comply with Commission reliability initiatives in the most cost-effective manner. This concludes my summary, and I'm happy to answer any questions you may have. Thank you.

CHAIRMAN CARTER: Hang on for a second. You can take a moment, Mr. Rehwinkel. You tendered the witness, right, Mr. Burnett?

MR. BURNETT: Yes, sir.

CHAIRMAN CARTER: Okay, thank you.

Mr. Rehwinkel?

MR. REHWINKEL: Thank you, Mr. Chairman. I apologize for the delay.

CROSS EXAMINATION

BY MR. REHWINKEL:

Q Good afternoon, Mr. Joyner. My name is Charles Rehwinkel with the Office of Public Counsel, and I'm going to ask you a series of questions that you probably have heard --

A Okay.

Q -- before, and I've provided some information to your counsel to assist and make this go a little quicker.

A I appreciate that.

Q It's true, is it not, that in the test year, that O&M, projected O&M expense in your area of distribution is $144,926,000?

A That's correct, sir.

Q And the budgeted O&M for distribution operations and maintenance for the 2009 year is $125,843,000?

A Yes, sir.

Q And for 2008, the same number is 120,595,000?

A Yes, sir.

Q And for 2007, $125,493,000?

A Yes, sir.

Q And would you agree that for 2007, 2008 and 2009, the -- well, for 2007 and 2008 actuals and 2008 budgeted amounts, that those represent a fairly level trend line?

A When you say "budget," do you mean the actual for '08?

Q I'm talking about 2007 actual, 2008 budget -- I mean 2008 actual, and 2009 is the budgeted amount, correct?

A Right. You had said '08 budget, I believe --

Q I'm sorry. So those three years are fairly level?

A They range between 120 to 125 million.

Q And would you also agree that the increase from 2009 budgeted level to 2010 is approximately 15 percent?

A Yes, sir, it is.

Q I have asked other witnesses about the 2009 budget. For your area, is the 2009 budget amount of 125,843,000, has that number changed --

A No, sir, it has not.

Q So no belt-tightening look there?

A Well, that's the budget amount. So we have, and I think we mentioned -- or I have mentioned in my direct testimony our workforce assessment initiative where we reduced distribution personnel. So we felt it imperative to -- that I considered to be more than just belt-tightening, but we took that initiative to ensure that we could meet this budget and ongoing -- and also offset ongoing O&M expenses in the future.

Q Do you have MFR C-6 with you?

A I do, sir.

Actually, I think I may have brought my own copy instead of using this thing.

Q And I would like you to look at page 68, which is page 3 of 7 of Schedule C-6.

A Okay. It may be 69 if we're talking about distribution.

Q I'm sorry, yes, I apologize, 69.

A Yes, page 69, right. If we're referring to distribution.

Q Yes. Let me ask you to look at column E on line 37, if you would, please, and for the budget for 2008, the budget for distribution-operation was $95,897,000, is that correct?

A Yes, sir, it was.

Q Now, what was the actual?

A Actual was 71,586,000.

Q How about for 2007, what was the budget amount on that same line in column D?

A 98 million -- 98,192,000.

Q And for the actual?

A 77,462,000.

Q Okay. So my question to you is, isn't it true that when the company develops budgets that those budgeted dollar amounts do not always equal the actuals in the cost centers?

A Yes, sir. Now, specific to those issues here, those were cases where we had some reconciliation of our operational expenses to FERC accounts, so in this case, if you look at the actuals, they are more in line with the operational budget. This is more of just matching it to a FERC account.

Q But it's true, is it not, that every year the budget is looked at on a, if not continuous basis, on a periodic basis throughout the calendar year?

A Yes, sir, it is.

Q Okay, so is it your testimony here today that, for your area of responsibility and distribution area, that there has been no look at the budget along the lines that you would do in the normal course of business that would cause the number that's in the MFRs to change?

A That's correct.

Q Is that because you have not done it, or you looked at it and it looks like it's going to be exactly what you budgeted?

A No, sir, this is about -- again, going into the year, we always look at -- every month we go in and monitor our actuals to our budgets. But this is a situation where, again, coming into '09, we went through a pretty extreme streamlining effort to get to where we knew that we could go in and actually meet our '09 budget, which in itself was very aggressive, or we would not have gone through our workforce assessment exercise.

Q But the workforce assessment exercise that you are talking about occurred prior to the filing of these MFRs, correct?

A We went into the filing of -- it was in March, so we would have seen the benefits of the WFA in the '09 year.

Q But the WFA, as you put it, that assessment was done prior to this filing?

A Yes, sir, it was done in the fall of year '08, yes, sir, it was.

Q Okay, so is it your testimony that since that time there have been no further looks at cost savings or productivity improvements in your area?

A No, sir, I would not say that. This was relative to whether the budget number would have changed or our ability to make that budget was what I had stated. We continually look for opportunities to go in and challenge our activities through the year, so the areas of -- you know, all aspects of cost-cutting measures are looked at as we go through the year, so --

Q And so -- but all of those efforts have not produced any opportunities for reductions in your 2009 budget?

A The only thing I'm aware of, sir, is more of a -- is a technology initiative that we were going to train on this year that was -- I wouldn't consider that a cost-cutting measure is the reason I mentioned that, sir -- was we were going to spend approximately

1.5 million to train resources on a new technology platform rolling out. That has now been moved into 2010 because of the timing of deployment of that technology program, and we are running favorability in our meals and travel, so we are running some favorability in some areas that would go in and continue to challenge that. So the cost-cutting measures would always be in how you're doing due diligence and how you're managing your business.

But that is the only significant amount that's a deferment into 2010, and I just wanted to make mention of that. And that is also based in our 2010.

CHAIRMAN CARTER: Commissioner Skop?

COMMISSIONER SKOP: Thank you, Mr. Chairman.

Just trying to follow along with the numbers, and I was wondering if I might be able to get one quick clarification.

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: I follow Mr. Rehwinkel's line in terms of the distribution costs going up from 2009 to 2010 by approximately 15 percent, so I've got that.

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: What I'm trying to put my finger on is that on page 4 of your prefiled testimony, line 9, you speak to $145 million for distribution O&M expenses for 2010 test year.

THE WITNESS: Page 9, sir?

COMMISSIONER SKOP: Page 4 of your prefiled, line 9.

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: And I think you previously stated that the projected cost for the 2010 test year for O&M, distribution-related O&M expenses was approximately $145 million, in terms of the request?

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: Okay. And I'm trying to look at the numbers on the exhibit -- Schedule C-6, page 69, which for the operation part of that yields 78,715,000 for the 2010 budget part, and then following that on to -- I hope I have this right, but page 71, column G, which lists 66,211,000 for the maintenance part of distribution.

THE WITNESS: That's correct, sir.

COMMISSIONER SKOP: Okay. If I sum those two numbers, subject to check, I get more than $145 million. I get approximately 146, almost 147 million dollars. So am I missing something there or not calculating that correctly? I'm just trying to follow the numbers so I can --

THE WITNESS: No, I'm doing the same, because my sheet here shows those -- I came up with 144. Somebody with a calculator help me out here.

COMMISSIONER SKOP: I'm looking in Excel, but -- just so I know what I'm looking at, it's on column G on page 69. If you take line number 37, which is the distribution operation amount which is listed as, I believe, $78,715,000, and then move to page 71, column G, line 39, which is the maintenance part of the distribution budget, which shows $66,211,000, and if you sum those two numbers together, which -- okay, hold on real quick.

Got it. Okay, never mind, it was an Excel error, but I was just making sure I was following. Thank you.

CHAIRMAN CARTER: Mr. Rehwinkel?

MR. REHWINKEL: Thank you, Mr. Chairman.

BY MR. REHWINKEL:

Q Mr. Joyner, the 15 percent increase in the -- from the 2009 budget to the 2010 projected amounts that we discussed early on --

A Right.

Q -- is it your testimony that that increase is just coincidental to the fact that 2010 is a test year?

A Sir, I would say that's not -- I would say it's neither coincidental or non-coincidental. This was the amount that we need to -- several things: serve new growth, serve the peak demand and also to meet the company's hardening initiatives as dictated or mandated by the Commission. That's what drove that amount. It was irregardless of whether it was a test year, that was a 2010 request.

Q What growth and demand are you referring to?

A This is a situation, as Mr. Oliver stated earlier, in some of the capital requests that we have here embedded in our 236 number is the -- each year we have to make sure that we meet peak demands in serving load, so in this case, as Mr. Oliver also stated, customer usage, while that may be declining, the peak demand actually is increasing each year, so that's what I was referring to is installation of new equipment to meet those demands.

Q The difference between the 145 million in 2010 and the 120.595 million in 2008 that we discussed is about $24 million, is that correct?

A Versus 2008?

Q Yes, 2008 actual.

A It would be, yeah, about 24, yes, sir.

Q Okay. On page 20 of your direct testimony, is that where you initiate your discussion of -- or explanation of the difference between your 2010 projected amounts and the PSC's O&M benchmark?

A Yes, sir, it is.

Q Is the difference between 2008 and 2010 different than the benchmark difference that you're explaining beginning at that portion of your testimony?

A No, sir. That page 20, that question is my answer to why the revenue requirements -- how we come up with a 14.3 million, which was the 2010 request, versus the Commission benchmark. And it actually goes in and specifically highlights, and this is referred to, as you know, in my rebuttal testimony, that specifically highlights how we determine and calculate the 14.3 million.

MR. REHWINKEL: Okay. Mr. Chairman, I would like to pass out an interrogatory response just for purpose of questioning.

CHAIRMAN CARTER: You may do so.

MR. REHWINKEL: And this is interrogatory response 270 to Public Counsel's. I'll wait until your counsel has this.

CHAIRMAN CARTER: This gentleman looks remarkably like one of your colleagues who used to be a University of Florida supporter, but I don't really know this guy here. He's not wearing his Gator tie today.

MR. REHWINKEL: He's a former NCAA champion of the University of Florida, so --

CHAIRMAN CARTER: I need to see some ID.

MR. REHWINKEL: I actually looked him up, and it says his name in there.

CHAIRMAN CARTER: Yeah. He told me yesterday, he said the only thing I need to straighten my back out is I need a Gator tie. I'm inclined to try it. You know, I've tried everything else, so that might be my next move.

Mr. Rehwinkel, you may continue.

MR. REHWINKEL: Thank you, Mr. Chairman.

BY MR. REHWINKEL:

Q Mr. Joyner, are you familiar with interrogatory response 270?

A I am, sir.

Q Did you have a role in preparing --

A I did.

Q -- this answer?

Can you tell me -- and I have just provided this so you can refresh your recollection. Can you tell me for 2008 what the vegetation management expenses in your area of responsibility was?

A The expense as reflected on 270 here is $18,530,730.

Q Okay. Mr. Schultz, in his testimony, subject to check, states that $15.9 million, or 34.4 million minus 18.5 million of the difference between the 2008 and 2010 O&M expenses in your area is for vegetation management. Would you agree with that, based on the $34.4 million amount that you identify on page 18, line 13, of your testimony?

A Yeah, as reflected in my rebuttal testimony, I do remember that question, sir, and the 15.9 figure was the requested amount of 34 million, as you stated. Subtracting this 18.5 is how that calculation of 15.9 figure came about, yes.

Q Okay. On page 17 of your direct testimony, is it correct that you indicate that in 2010 the company anticipates spending $3.2 million on wood pole inspections?

A Yes, sir.

MR. REHWINKEL: Mr. Chairman, I'm going to pass out, with your permission, another interrogatory response --

CHAIRMAN CARTER: You may do so.

MR. REHWINKEL: -- to aid in cross-examination. And this is in response to interrogatory 269.

CHAIRMAN CARTER: I will try not to haze your colleague this time, because Commissioner Skop, he's got a Gator down here to back him up, so I'm going to leave him alone.

(Discussion off the record.)

BY MR. REHWINKEL:

Q Mr. Joyner, I have provided you with a copy of the response, the company's response to interrogatory 269. Are you familiar with this interrogatory?

A I am. It has been a while since I've seen this one, but I was involved in the preparation.

Q And I apologize, I tried -- meant to get you this before your --

A Okay, yeah, I had not seen this one prior.

Q I wasn't trying to -- can I ask you if you can tell me if this assists you in answering this question: Can you tell me what the amount expense for 2008 for wood pole inspections was?

A Yes. And you're differentiating inspection from replacement, sir?

Q Yes, sir.

A Okay. The inspection or treatment cost for the year 2008 was 3,194,640.

Q Is it correct, then, that there is essentially no difference between the 2008 pole inspection cost and the 2010 projected pole inspection cost in your area?

A Yes.

Q It appears to us that there was $15.9 million of the approximately $24 million difference between the 2008 distribution operations and maintenance expense, and the 2010 distribution operation and maintenance expense. Is that correct?

A Can you say that again?

Q It looks to us that there is about $15.9 million of the approximately $24 million difference that we discussed earlier between the 2008 distribution operations and maintenance expense and the 2010 distribution operations and maintenance expense. Is that right?

A Yes, sir, and again, going back to make sure I understand, that 15.9 of the 24 we're saying is the vegetation management acceleration as based on -- going back and basing that on an '08 actual, right?

Q Yes.

A Again, we're just going back to reference that, so we're going back a couple of years. So the other 7.7 million that may be in question here that was, again, answered in our rebuttal testimony, and I state that here, that would encompass other programs, other initiatives, other escalations that would make up that difference in a 2010 request.

Q Is there anywhere in your testimony or in the MFRs that explains that somewhere close to $8 million in difference?

A Yes, sir. If you look -- well, right now, it would be explained in these FERC accounts as broken down to the 144 million, so yes, sir, it is.

Q When you say "these FERC accounts," were you referring to --

A I'm referring to the Schedule C-6 that we went over earlier. I can reflect the amounts by each one of the FERC accounts of how we calculated the -- or came up with our request of 144.9 million for 2010.

Q So you can show me where -- and I think the difference is about 8.1 million. You said 7.7?

A In Mr. Schultz's testimony, I think it was around 7.7.

Q Okay.

A I'm almost positive it was.

Q Okay. You can show me where in the MFRs --

A Yes, sir, it would be -- it's going to be give-and-takes here, and stuff, but there's also escalations, whether it be labor or other programs, but yes, sir, I can. It would take a moment, but we could do that. And I actually will do that in our rebuttal discussion, if you would like.

Q Okay. I would appreciate it if you could tell me here on direct where those numbers are.

A Okay. If you look at the -- again, if you go in -- we would have to go back again and use --

Q What page are you referring to?

A I'm sorry, I was going back to the Schedule C-6.

Q Which of the --

A It would be page 67 -- I'm sorry, page 69. I was going back like you were earlier, I think. You would have to go back and take a look at the '08 actual, which, again, in that discussion was referring to 125, which is a total, right, which is actually going to be a total of the distribution operation expense and the distribution maintenance expense, which totals I believe to be about a $125 million figure, correct?

Q Yes, sir.

A And then you go look at the 144 request, that's a difference, again, from an '08 actual to a 2010 request, that difference is $19,083, I believe, but you may want to check me.

Q Did you say million or thousand?

A Million.

Q Okay.

A It would be easier if we were talking about thousands here, wouldn't it? We might not be having that discussion if that was the case.

Q I think not.

A But that difference was $19,000,083, if I recollect, if I looked through my math correct. And mine is worse than Excel, I guarantee you, so -- out of that amount is going to be an expense on -- so if you take a look at the 19 million, if you go to FERC 592 --

Q And that's on page 71?

A I'm on page 71.

Q Line 32?

A I went ahead and combined them together on one sheet here, that's the reason why I'm -- because I got tired of flipping pages, so --

Q Okay.

A But if you look at that 592, you will see an increase, in this case, of a $4 million figure in two thousand -- four million in '08 to a $6 million figure in 2010 request. Are you following that?

Q Yes, sir. You are talking about 4.885 million to --

A To the 6.834.

Q Okay.

A So you've got that, that's around two million, I have rounded some of this off. That's substation maintenance that's required, and this would actually be work performed by Mr. Oliver, but it's actually hitting our FERC account. But that's maintenance on substation equipment that's required through the cycle -- through a cycle need in 2010.

Q Okay.

A Then, of course, you've got the FERC number 593 -- FERC account, I should say --

Q Yes, sir.

A -- distribution maintenance of overhead lines. That actual -- in 2008, if everybody is following me, that actual is 29,818 to a 45 figure, 838. If you look at that differential, that's around 13.9 million -- I'm sorry, that's between '09 and '10. I kept going back to '09 budget, sir, on that one, but we going back to an '08 figure, aren't we?

And what that -- mainly all that's, that's the 15.9 million you talked about in vegetation management. And that FERC account handles our restoration, which is outage restoration, our corrective maintenance and vegetation management. That's the operational accounts that go back into that.

So all that said and done, it's about a -- over a $2 million delta that I have not accounted for. Specifically that would be a mixture of different things, probably up in the distribution operation expenses, in operation supervisor and engineering spaces, that's the other area where we have a slight increase. So outside of vegetation management, it's basically in other program expenditures.

Q So does that complete your explanation of the differential?

A Yes, sir, it does.

Q Okay. So would it be fair to say after that, looking at your testimony, that beginning on line 21 of page 20 of your direct, that given the benchmark explanations provided, that the use of the Commission benchmark justifies your 2010 costs?

A No, sir. Actually, this -- as I stated earlier, my request of 144 million, I'll 145 round up on this one, was based on what it's going to require us to meet those three criteria I mentioned to you earlier. It had nothing to do with what the benchmark -- this line on line 21, the explanation there was to describe what drove the variance from the benchmark to my request, and that's what is explained here.

MR. REHWINKEL: Okay. Mr. Chairman, those are all the questions I have of Mr. Joyner on direct [sic].

CHAIRMAN CARTER: Thank you, Mr. Rehwinkel.

Ms. Bradley?

MS. BRADLEY: Thank you.

CROSS EXAMINATION

BY MS. BRADLEY:

Q And you do distribution, right?

A Yes, you referred to me earlier.

Q At least I had the right witness this time.

A I hope so.

Q Did you go to any of the public service hearings?

A No, ma'am, I didn't, and can I elaborate, if I may?

Q Certainly.

A Because that is a valid question.

In my opening comments, I mentioned that I support a department that handles the planning and compliance, basically. Really the intent of me representing distribution is I come up with the request for monetary needs for 2010, which is why I'm here.

I also have four peers around the regions that are directly held accountable for handling customer issues, so they themselves and the operational leadership in each of these geographical areas, they went to each of the meetings themselves, and then I actually had dialogue and have read the outcome of those. So I wanted to let you know that there was representation by Progress Energy at each one of these hearings. But I wanted to explain exactly why I was not there.

CHAIRMAN CARTER: Ms. Bradley, before you go on, would you yield for a moment, please?

MS. BRADLEY: Certainly.

CHAIRMAN CARTER: Commissioner Skop?

COMMISSIONER SKOP: Thank you. Just wanted to go on briefly back to some points that Mr. Rehwinkel had asked you on before we get too far into this, and I had three quick questions. I apologize in trying to track the numbers, I have my distant vision glasses on, and up close it gets a little blurry.

THE WITNESS: That's fine. I'm here to answer your questions.

COMMISSIONER SKOP: Appreciate that.

What I want to do is refer you to page 4, lines 7 through 12 of your prefiled testimony, and also the respective pages on Schedule C-6 of the MFRs, which would be pages 69 and 71, respectively, that deal with the distribution O&M related expenses.

THE WITNESS: I'm with you, sir. Page 4, what lines?

COMMISSIONER SKOP: Page 4, lines 7 through 12.

THE WITNESS: I'm with you.

COMMISSIONER SKOP: Now, on page 4, lines 7 through 12 of your prefiled testimony, you identified that the -- for the requested test year of 2010, that Progress is requesting approximately $136 million for distribution capital investment expenses and then also 145 million for distribution O&M related expenses, is that correct?

THE WITNESS: And it may be what I heard, but I believe you said 136 for distribution capital investments.

COMMISSIONER SKOP: 145.

THE WITNESS: I'm sorry, it was 236 for distribution capital, I believe you may have said 136. I'm sorry.

COMMISSIONER SKOP: Okay, yes, 236 for --

THE WITNESS: And then 145 million for O&M.

Yes, sir.

COMMISSIONER SKOP: Okay, correct. So looking now at Schedule C-6 of the MFRs, page 69 and 71, which reflect the historical as well as the projected test year budgeted amounts for distribution operation and distribution maintenance costs, do you see those?

THE WITNESS: Yes, sir, I do.

COMMISSIONER SKOP: Okay. You would agree that the historical budget amounts have been greater than the historical actual amounts for most of the years presented there, is that correct?

THE WITNESS: Right, and again, my understanding in talking to the finance was from a FERC account, that was some reconciliation, it was actually -- you know, we go by the operational budget. So my understanding, and it may be good to get with Mr. Toomey to clarify that, because I asked that very question myself because I was not used to seeing those budgeted amount from a FERC perspective. But I think that's what's driving that, sir.

COMMISSIONER SKOP: Thank you. And then you would also agree that Progress has requested a 15 percent increase on a year-to-year budget basis for distribution O&M expenses for 2009 versus 2010, is that correct?

THE WITNESS: That's correct, sir.

COMMISSIONER SKOP: Okay. I guess just the question that I have that follows from that, if the projected test year request for distribution O&M -- strike that.

If the projected test year request for distribution O&M expenses were granted for the 2010 test year, what assurances would the Commission and the ratepayers have that Progress would prudently incur actual distribution O&M expenditures to the requested level?

For instance, if we're granting that amount, how do we know that investment is actually made in terms of doing O&M as opposed to after a request was granted in light of the 15 percent year-to-year basis increase, that there wouldn't be a cutback after the fact?

THE WITNESS: I understand your question. The way we would validate that is the requested amount of that 15 percent is predominantly all, if you look at that, our vegetation management acceleration, as we discussed earlier.

We are currently on a three -- per our mandate, as you know, we're on a three-year feeder, five-year lateral, a three- to five-year vegetation management cycle. This 2010 is the year five of our vegetation management cycle. So we will be reporting out, Commissioner Skop, as to our ability to adhere, to be compliant with that standard, when we file our reliability reports in 2011 that will talk about what we did in 2010. And that's what we will be -- we're held accountable for that, and that's exactly where those dollars will go to be able to meet -- to be compliant with our five-year cycle.

COMMISSIONER SKOP: And just playing devil's advocate for a second again, I mean, the Commission has set trimming requirements is a result of storm-hardening and the utilities are making progress to that, but assuming for the sake of discussion that that substantial increase is built into rates and then, for whatever reason, there is not the performance, I guess that's what I'm -- I guess it stems on trust to some degree.

THE WITNESS: Well --

COMMISSIONER SKOP: I mean, it is a substantial year-to-year increase.

THE WITNESS: Yeah. There was some discussion earlier about what is -- what are you held -- what's legal requirements or whether you have to.

The way we met our three-year commitment, we had to have a certain amount of feeders, our pole inspections each year since the storm-hardening initiatives have come out, we have met compliance. Each year we have met compliance. So I don't see why we would change our business model and our expectation that you would have of us of not doing that and it just happens to be a 2000 test year.

COMMISSIONER SKOP: I think in light of the requested percentage increase on a year-to-year basis, that was a fair question, so I just wanted to get a response. Thank you.

CHAIRMAN CARTER: Thank you.

Ms. Bradley?

MS. BRADLEY: Thank you.

CHAIRMAN CARTER: Let me give everyone a heads-up. I told the court reporter I would give her a break at 4:00.

MS. BRADLEY: I'd better be quick.

CHAIRMAN CARTER: No, no, you can have your time, we can come back, but I wanted to give the court reporter a break, because I want to keep my word to the court reporter or we're all in trouble.

MS. BRADLEY: Just let me know.

CHAIRMAN CARTER: Yes, ma'am.

BY MS. BRADLEY:

Q Sir, you said something about you reviewed something from the public service --

A Well, that was the actual service hearing report that you had referenced earlier.

Q So you have actually reviewed that?

A I have. I actually have a copy of that with me.

Q Great, that may speed things up, then.

A I assumed you would have a question or two.

Q So you're aware of the complaints that some of the customers made regarding power outages and power surges and some of the tree-trimming issues, which I guess actually are tied in to some of those others?

A I'm aware, yes, I am.

Q Okay. Would you agree that customers shouldn't have to come to a public service hearing to get their complaints addressed?

A I look at -- there's all avenues that we take. Customers can call in and talk to us personally at any time. So the fact that a customer did take it on themselves to travel and sit for hours to be able to do that, we take that serious. So, in this case, do we need for them -- there are times that we need to understand of the customer's concern, because we can't go out there and fully understand 1.6 million customers' issues at times. But no -- they should not have to, but in this case, they took it upon themselves to do that.

Q There is a complainant at page 32 of the report from Clearwater that talked about numerous power surges that he had experienced, and in response to that, your investigation revealed it was Mr. -- if I can pronounce this right, it looks like Gollinger?

A I'm with you now. You had mentioned him earlier.

Q Right. Your response was that you offered to change out a splice service drop line?

A Yes, ma'am. Just to let everybody know, too, here, our customer service associates, we also -- you know, if you think about the 1.6 million, I believe we had 300 or something that came up and actually testified, I think, if I'm correct. Out of that, we mentioned earlier, Mr. Dolan in his discussion mentioned there were 18 of those that happened to be service-related. This would be one of those.

But in discussion, our customer service associates and field personnel have went back and met with the gentleman to fully understand what his surge issues were. Two things, if I may: One is that this person had never contacted us before, because we keep a record in our customer service system of any contact that a customer has with us. So there had been no previous discussion with this gentleman. I won't try to pronounce his name, either. But in this time, we actually offered to change out his service, and he declined, because it would require an outage to do that, and he declined that.

Q Is there a charge to the customer for that?

A No, ma'am.

Q So it's just the fact that it would involve an outage?

A Yes, ma'am.

Q Okay. How long do those outages usually take to replace that?

A Well, in this case, it would require -- this would have been all of our work, so it wouldn't have required an hour, because it would not have required any electrician work. Sometimes when we do this, then the electrician has to do some work and get an inspection. In this case, it would not have -- so I personally do not know. My understanding is he did not want to take it, but I don't know for sure what his concern about the timing was, whether it was an hour or three, I can't speak to that.

Q All right. I believe there was also some tree-trimming that you all did for that customer as well?

A I'm not aware of the tree-trimming, at least in my discussion here. I do know that on every account that expressed a complaint, we actually went out and field-verified to look for trimming and any other issue, and we very well could here. I did not see that in the writeup specific to him.

Q I may have him confused with another one.

The other one -- I forget which page, whether this was on the same page or not, but Mr. McEwen?

A And what hearing was that?

Q Well, it may have been the same one, because it's on my notes right under that. I'm not sure.

A Let me look real quick, because I have them highlighted by whatever hearing.

Q He was complaining that he had had momentary interruptions that messed up his or destroyed his computer.

A Oh, okay. I don't believe that was Clearwater.

Q That may be page 21.

A Yes, when I printed this, I did it on both sides. But I do remember reading about that one, if I may just look here.

Q Okay.

A Do you remember again what hearing it was? That helps me.

Q I don't remember what hearing. Let me look real quick at the page number.

A I found it. That happened to be, just for our reference, that was in the Lake Mary area.

Q Okay. Now, your response to him, or the response that you filed on this indicated that you had installed a meter-base protection. Is there a charge for that?

A No, ma'am. In this case, there's two situations. One is -- I shouldn't say that. I do think there is a charge for having that. Actually, Ms. Morman would be the one to -- Miss Willette, as I call her, she will be the one to specifically address that. I don't know the specific details of it. We do offer that to employees.

But there was two things to that account. One is, to your point, there was some computer damage, alleged computer damage by the customer, and there's two things that we do. One is that we will actually put a, what I call more of a large-scale suppressor, surge suppressor, coming into your home that will wind up mitigating surges of a large scale.

Q And that's the meter-base protection?

A That's the MBP that's referred to there, yes, ma'am. And then at that point, you go into your home, but there still could be cases where there's very high spikes, high voltage spikes, that still get into your home through that device. And then there we have customers actually go out and put individual surge suppressors actually on their electronic equipment. So in this case, the gentleman actually had the MBP on the main home, but in this case -- what I call the first line of defense, for lack of a better term, but in this case, the individual did not have it on the individual appliance, the one I think that was damaged.

Q Do you know what the charge, or is there a charge for the -- I think you all referred to them as premium plug-in protection?

A I'm not aware of that specific charge, but we can get that for you. I think our next witness -- our next witness can address that, I believe.

Q And I assume those are just what we usually refer to as surge protectors?

A We do, yes, ma'am.

Q Okay. And you all said that because he didn't have your plug-in protections or surge protectors on this appliance, that you all refused his complaint?

A Yes, ma'am.

Q If he had had a regular surge protector that he bought in a store, would you have covered that?

A I don't know the details of that, but typically if we -- it goes back earlier if there's specific, direct standards around whether we will be held accountable for a claim or not. So all that's determinant on what the actual cause of the -- that drove the problem, or in this case, the complaint of the customer, that dictates whether we pay or not, not specifically equipment. All this is are mitigation. This attempts to mitigate the problem, but does not wind up -- by doing this, it doesn't go in and drive calls or claim expectations either way.

Q So the statement that he had failed to put in your -- he had declined your plug-in protection was not really what drove this?

A What I do -- I know that in this case a customer must have the main and the plug-in suppressors to be part of the program, the total program. What I'm not familiar with is to your point, whether that would have generated the denial of the claim or not. I'm not aware of that, I don't know that answer.

Q Do you know who would be able to answer that?

A My assumption is the next witness would, but I'm making that assumption, so --

Q Now, in Lake Mary, and I don't have a page number for that, but there was actually a Mr. and Ms. Bradley, no relation, who complained of lengthy --

A Are you sure about that? I hope it's not a claim issue you're bringing.

Q I trust not. They were complaining about lengthy power outages that they had had, and they, I think, blamed it on lack of tree-trimming.

A There were two things. If you -- and if I may just reflect, too, for the record, Mr. Bradley expressed -- well, in this case, would you want me just to read a little bit of the resolution?

Q Well, I was particularly focusing on this one on tree-trimming. There seems to be -- there were a number of customers that complained about surges or outages or something, they seemed to relate it to tree-trimming.

A Right.

Q And, in fact, you all went out and did some tree-trimming or scheduled some tree-trimming in that area?

A Right. Actually, if you look, there was cases where we had scheduled, again, based on our cyclic vegetation management program, that we were scheduled to actually be in his entire subdivision in the first half of 2010. In this case, we actually went in and let him know that one thing that you've got to be aware that a tree-trimming problem three miles away, of course, could wind up causing a concern here, right, so that's the reason why we were focused on the entire subdivision.

But I guess on his case, there's actually Redbug Road I guess is his road itself, that we actually had been performing tree-trimming along that road, and he actually expressed his appreciation with the steps taken to resolve his concern. So my understanding in looking through him, we also left him with a direct phone number of how to contact us in the event he had a problem again.

Q Do you have a regular cycle of tree-trimming?

A Yes, ma'am, we do.

Q And how frequently is that done?

A Well, as we mentioned earlier, we have a storm-hardening initiative that we typically, on our main backbone every three years, and for our laterals, every five years. So it's all according to where you're at on the cycle.

Now, you can imagine, in cases where density, the type -- the type tree and the fact that you could be between two or three years between you would go back, those grow at different patterns. So with this case, we have patrols by our line personnel and every means possible, but we have over 18,000 miles of primary wire, so it's hard to get our eyes on all of that all at one time. So there are times that customers will call in based on a concern, and we go out and there may be a limb that needs trimmed, and a lot of this is in a back lot, things like that, but there are times between these cycles that you could have sporadic issues, yes.

CHAIRMAN CARTER: Ms. Bradley, do you mind yielding at this point in time?

MS. BRADLEY: I can do that, or I can ask maybe one more question and be done, whichever you prefer.

CHAIRMAN CARTER: Let's go with the last question.

MS. BRADLEY: Okay.

BY MS. BRADLEY:

Q There seemed to be an issue with tree-trimming, and, as you indicated, sometimes it becomes more of a problem at different times than you'd expect it because of, I guess, rain and various things that can affect that. But have you made any adjustment in how you look at this or how you respond to this so that you can try to avoid these problems?

A The -- any adjustments, other than ensuring that we resolve the customer's complaint to the best of our ability, no, ma'am, and I don't mean to -- but if you think about, we serve, again, 1.7 million, and these were 18 cases where they had every right to come and see us, because they took it on themselves to do that, but there are cases that we try to, again, go in and resolve these, but there has been no specific change to programs based on this -- on this, no, ma'am.

MS. BRADLEY: Nothing further.

CHAIRMAN CARTER: Thank you, Ms. Bradley, and also, staff, I think you wanted to talk to parties at the break. So what we'll do, Commissioners, we'll come back at 4:15.

(Brief recess.)

CHAIRMAN CARTER: We're back on the record, and when we last left, there was cross-examination, and by agreement of the parties, we will go to Mr. Wright next, then we'll come back to Mr. Moyle and then Ms. Van Dyke.

Mr. Wright, you're recognized.

MR. WRIGHT: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. WRIGHT:

Q Good afternoon, Mr. Joyner.

A Good afternoon, sir.

Q We have met and, as you know, I'm Scheff Wright and I represent the Florida Retail Federation in this case. I just have a few questions for you. You may or may not know that Mr. Dolan deferred to you to answer a couple of questions regarding a certain aspect of his testimony.

At page 11 of his testimony, he referred to some $611 million of future revenue requirements for Progress's transmission and distribution systems. I was just really trying to nail down those values.

A Okay. I have been shared those values in preparation for this question. The distribution portion of that 611 that Mr. Dolan had mentioned, distribution would be the O&M request of 145 million, the capital request of 236 million, so the distribution 2010 request would be $381 million.

Q Thank you. And it's correct -- let me ask it this way: Am I correct that that's a cash outlay number, not a revenue requirement number?

A That's -- as an operations person, that's what we would need to expand for 2010 test year. I'm not for sure the financial side of that, sir.

Q Is it generally your understanding --

A That would be a cash outlay, yes, sir. How it's ties back to a revenue requirement --

Q How that ties back to a revenue requirement you don't know?

A -- would be the area -- an area that's not my expertise.

Q Thank you.

A Thank you.

Q I just wanted to ask you a couple more questions following up on some questions that were asked you from the bench. I think your testimony indicates that the company projects to spend some $34 million on vegetation management in 2010?

A Yes, sir.

Q Distribution vegetation --

A Distribution vegetation management, correct.

Q If you don't spend the whole $34 million, customers don't get any of it back, do we?

A In this case, if they did not -- ask that again, sir.

Q If the Commission were to approve $34 million, or if they weren't, you've budgeted $34 million for spending in 2010 --

A Yes, sir, I have.

Q -- for distribution vegetation management? If you don't spend the whole amount, we don't get any back, do we?

A I expect to spend the whole amount.

Q I understand that to be your testimony, but if you don't, there's no adjustment flowing back in favor of customers?

A That's my understanding. It would be redirected to some other priority O&M issue, I'm sure.

Q And if you didn't complete all of the planned vegetation management activities but did spend all the money, it would just -- what would happen then?

A As we mentioned earlier, I would be in default of meeting a storm-hardening initiative, which I don't plan to do.

Q You mentioned that 2010 is the fifth year since the implementation of the -- the Commission's approval, I should say, of the company's storm-hardening plan, is that right?

A Yes, it's the fifth year of the lateral cycle.

Q Now, did you trim approximately a fifth of your laterals in 2007?

A We basically adjust the amount of feeder -- the requirement is at the end of the fifth year to have met the lateral, so what we do is we report out on the combination of how many feeder miles and lateral miles on a yearly basis, we're meeting those, but the fifth year is where you have to actually meet the expectation of the fifth-year lateral cycle.

Q Let's talk about the primaries for a minute before we come back to laterals.

A Okay.

Q Is it correct that under the company's approved storm-hardening plan, you're required to trim your primaries -- your primary distribution lines every three years?

A And just for the benefit of terminology, the feeder is the three-year, and the lateral, that's all considered primary lines, just --

Q Thank you, I knew that and I didn't phrase my question artfully. Thanks.

A But it would drive my answer to your question. That's the reason I brought that up.

Q So you trim feeders every three years?

A We're required to trim the feeders every three years, correct, and then at the end of the fifth year for the laterals, yes, sir.

Q Do you endeavor to trim the feeders on a, basically on a one-third/one-third/one-third cycle over three years?

A That's a good question. Not necessarily. The reason why I say that is you have to go in and balance what I consider to be the storm-hardening initiative here, which is more of a proactive maintenance approach, which is beneficial for the customer. You also have to balance that with what I consider more immediate reliability issues, that if you've got an area where there's some density issues that crept up or something comes up, you have to adjust your plan accordingly to make sure we're not going to jeopardize our current state of reliability to ensure in the future a better state of reliability. We can't compromise today's standards. So it can fluctuate in that case, Mr. Wright.

Q Through 2009, if you know -- let me back up.

I think that I understood your testimony to indicate that you've got some 18,000 miles of feeder and 13,000 miles of laterals?

A Actually, if I look, it's 18,300, and that's total primary.

Q That's total primary?

A That's feeders and laterals, yes, sir. That's the -- let me make sure, that's overhead primary. If you incorporate underground, it's a higher number.

Q Thank you. What proportion of that 18,000 miles, if you know, is primary and what proportion is laterals -- I'm sorry, feeders?

A Feeders, I think there's about -- I'm not for sure, but I believe there's about -- close to 4,000 with feeders, and the remainder being laterals. Because I know we're required -- at the end of the three-year period, it all adds up to -- it's 3,600, excuse me. We will have to trim 3,600 miles of feeder at the end of that three-year period.

Q If you know, what proportion of total laterals had the company trimmed since the approval of its storm-hardening plan and the end -- or I should say projected to have completed trimming of by -- between approval of the storm-hardening plan and the end of 2009?

A I don't know that exact amount between feeders and laterals. We met the feeder compliance standard last year, so we're back already working on the feeders again. So for 05, it will be a combination of feeders miles and lateral miles, but I don't have that in front of me.

Q How many miles of laterals do you expect to trim in 2010?

A That will be determined by, again, meeting the fifth year, and the reason I answered it that way, your cost per mile, so there will be a certain amount, like, for instance, out of the 34 million request, the intent is to do that based on a certain cost per mile, and we have already looked at, going into 2010, what we think that would be.

Each year we go out and do a pre-inspection to ensure what miles are climbing miles, what -- what I mean by "climbing," there's different costs per mile, whether you can do out of an aerial device versus you have to climb the trees. And so, with that, until you go in each year and see what that amount of aerial device trimming and back lot or climbing miles, then that dictates sometimes what your mileage will be.

That's the reason why we have to look at reliability issues, proactive maintenance issues and the cost, to ensure that we look at all that to meet a three-year feeder and a five-year lateral. So it can -- it will change year to year.

Q As you sit here this afternoon --

A Yes, sir.

Q -- as of today --

A Right.

Q -- whereas of some recent reporting date like August 31st or July 31st --

A Okay.

Q -- can you tell us how many miles of lateral primary lines the company has trimmed since the approval of its storm-hardening plan and whatever date near to today you want to pick?

A I cannot in front of me, but I can get you that information. We have that down to the mile.

Q Can you tell us how many miles you expect to trim from today, or approximately today, till the end of 2010, of laterals?

A I can. It would be that remainder that we -- because we're going to meet that five-year commitment next year, so it would be that delta.

MR. WRIGHT: With your leave, Mr. Chairman, could I just -- and with the company's approval, could I be allowed to ask the witness about this when he comes back on rebuttal?

CHAIRMAN CARTER: On rebuttal? Mr. Burnett?

MR. BURNETT: No problem, sir.

CHAIRMAN CARTER: Be prepared to do that on rebuttal.

THE WITNESS: Yes, sir. Again, I just don't have that breakdown, but it's very easily obtained.

CHAIRMAN CARTER: You're keeping a list, right?

THE WITNESS: Yes.

MR. WRIGHT: Thank you, Mr. Chairman, and, thank you, Mr. Joyner, that's all the cross I have.

CHAIRMAN CARTER: Thank you.

Mr. Moyle?

MR. MOYLE: Thank you, Mr. Chairman.

CHAIRMAN CARTER: Mr. Moyle, you missed our little -- we were talking about the Gators. I was saying some very positive things. Did you hear that?

MR. MOYLE: I did, and I was going to compliment the witness, Mr. Chairman. I understand he is under oath, but he has been very, very gracious, because my first question was going to be to ask him to confirm that he got a degree from the University of

Tennessee in electrical engineering.

THE WITNESS: But I'm not the one out there playing. I can't take any credit at all.

CHAIRMAN CARTER: They probably could have used you on Saturday. That was mean; sorry about that.

CROSS EXAMINATION

BY MR. MOYLE:

Q Good afternoon.

A Good afternoon, sir.

Q I want to go back and see if I can understand a little bit more about this vegetation management and the, what I understand to be sort of an acceleration of trimming in 2010. We would agree there's an acceleration in 2010, correct?

A Yes, sir. Based on previous spends, yes, sir.

Q And that's largely so that you can meet the five-year goal, correct?

A Yes.

Q And I think we have established it's approximately $20 million from '09 to '10?

A Actually, we have -- from '09 to '10, it was 13.9 million specifically in vegetation management from an '09 budget to a 2010 request.

Q I wrote down 125 for 2009 and --

A Yes, sir, that's the total O&M spend for --

but specific to your question was in vegetation management.

Q Yes, sir.

A If you look on FERC item 593 --

Q Right.

A -- if you're there with me, the budget was 31,852 in that line item in '09.

Q Right.

A And you look at a budget of 45,838, that differential was 13.9, and out of that differential, that is vegetation management only spend.

Q So just for the purposes of our discussion, can we just call it 14 million?

A Absolutely can.

Q And you would agree that rates need to be fair when they're set by this Commission, correct?

A Yes, sir.

Q You didn't -- when these passed, you didn't take the difference, either the three-year requirement and the five-year requirement and just divide it and say we're going to do approximately one-third/one-third/ one-third or one-fifth/one-fifth/one-fifth, correct, you did not do it that way?

A Correct, we did not do it that way.

As I explained earlier, Mr. Moyle -- is there a need to go back and explain why?

Q Yes, I think there is. Go ahead, if you would.

A If you look at it based on -- if you look at the proactive maintenance aspect of this hardening plan, there's a certain amount of -- you go in and you do a cyclic look, going out, proactively trimming trees. But there is also what we call a demand aspect of this, and that is, as Ms. Bradley has said earlier, there may be a case where you have to go use vegetation management money to go here -- to take care of an individual concern. There also may be cases where a reliability of a circuit is in question for some reason that may be out of cycle.

So it's really a balance of what I consider to be more of a current state reliability prioritization versus a cyclic, proactive maintenance prioritization. And between the two of those, then you actually go in and blend and aggregate a budget or a plan, a work plan, that will wind up supporting both a storm-hardening initiative and to make sure that our reliability gains do not diminish.

Q In that answer you had talked about a demand component and then a planned or maintenance component. Can we use those terms?

A You can. Demand is just more of a reactive component, if I may.

Q Okay. And you have been in this business how many years?

A 25 years in distribution only.

Q And with respect to the general breakdown, I understand that it may vary from year to year, but I would also expect there to be some broad trends. What would be the percentage that you would expect to see for demand type activity as compared to planned or maintenance type activity?

A If you look at how we have gone in and attempted to break that 34 down, it's about 1.9 million of that 34 would be in the demand side.

Q So that's a small piece, correct?

A Yes, sir, it is.

Q And when you were asked about the one-third/ one-third/one-third or the one-fifth/one-fifth, the demand portion is the portion that you talked about that says, well, we can't just do it one-third/one-third/ one-third because we've got to be flexible to go hit something that's an acute problem, correct?

A Right. It goes in and associates where you go do the work at.

Now, the demand miles themselves, if we go out and trim an entire section, that's considered to be a mile trim. It's just we go in and we -- because we want to make sure -- to Ms. Bradley's point, we want to make sure we specifically keep up with that aspect of reactive trimming versus proactive.

Q And to the extent that the goal was six years and not five years and you had another year to do it, there wouldn't be this rush necessarily to go out and get all this done in year five, correct, this rush that's resulted in this additional spend?

A Right, we -- I've thought about that question, and there is different utilities around the nation have different ones like that. In this case, when I said 05 is largely driven by the fact that we're going to hear that, that is the case, but 06 also could, again, be driven by what reliability needs you need versus the proactive means and the cost per mile. The reason I mentioned earlier is whatever amount of miles are going to be aerial trim versus climbing miles could dictate what your 06 spend could be, even though the miles themselves could be less trim -- even though you could trim less miles.

Q Yes, sir, and that's another variable, climbing versus --

A It is, and it will generate -- but it will generate how many miles and what your expense is on a given year.

Q Just so the record is clear, when you talked about 05 and 06, you weren't referring to the years 2005, 2006, you were referring to a five-year trim plan versus a six-year trim plan, correct?

A Thanks for that clarification. Yes.

Q So with respect to the answer to my question about if we were on a six-year plan and you had to get all this done not by 2010, but by 2011, you would agree that the need to aggressively accelerate the spend in 2010 would not be present, correct, if you were on a six-year plan?

A I hesitate, Mr. Moyle, only because I have not looked to see what our 2011 spend would be because that's not -- again, this is to meet a five-year storm-hardening mandate. So I have not looked at that to be able to answer your question with confidence.

Q All right. I'm to ask you probably a question just to get your judgment on, and it's going to be about what you would consider fair.

If you assume that 14 million is being spent in 2010 to meet this five-year goal, that if the goal were six, that the 14 million would not be spent in 2010, wouldn't you agree that it wouldn't be fair to the ratepayers to charge them an extra $14 million in 2010 to meet this five-year goal? And premised kind of on that is the idea --

A I understand where you're going -- I understand your question, sir. And part of that is -- and the reason why I'm hesitant, because I'm going to answer the question if I know it, it's more about whether we know what the five-year -- when we say it's reasonable for the customer, we really have to go in there and assume what is the level of reliability, what's the expectation that our customers have of our level of service. That to me is going to generate whether this spend for vegetation management is reasonable, not really because it's a fifth year or a sixth year, because we could very easily be coming in asking for a certain level of spend next year, outside the fact that it was in 05, that is driving a specific amount of 34. But it could also be very similar to that number based on the reliability that we see of the system to sustain our current state of service level.

Q Right. But your testimony in this case is that that 14 million additional spend is driven largely by the need to meet the five-year goal, correct?

A That is correct.

Q And a hypothetical, because I think we've made the point with respect to the actual information in your testimony, but you would agree in a hypothetical, let's say there was a ten-year plan and it said you have to have all this done by ten years, and not that you would do this, but for purposes of the hypothetical, if you didn't do anything for nine years and then said, okay, year ten, we've got to meet this goal, and spent all that money in year ten, which happened to be a test year, you would agree that wouldn't be fair to ratepayers to hit them for a spend in one year to meet a ten-year goal, correct?

A Yes, with a caveat, and that is my assurance that their level of quality of service will not diminish based on that decision.

Q Thank you.

I want to direct your attention to page 20, line 7, and talk a little bit. You say in here that, quote, "We have taken steps to manage our costs," end quote. You all have not deferred any activities to try to reduce costs in 2009 or 2010, have you?

A No, sir. As I mentioned earlier, the only thing that we have deferred from a major O&M expense was this training I talked about. That's it.

Q And you talk about there was some savings, some operational cost efficiencies that yielded a

$6.3 million savings, do you see that on line 16?

A Yes, sir.

Q That represented a favorable variance to the Commission's O&M benchmark; in other words, that was a number that drove the Progress Energy spend number negative as compared to the benchmark, correct, or in the negative direction?

A Well, if you look, they were -- and it's expanded on, I believe, in my rebuttal, Mr. Moyle, that you're familiar with.

There were actually four variables that I explain from the benchmark to our request. And three of those were additions. Vegetation management we just talked about. There was an environmental, going from the environmental clause to base rates, and there was also a transmission reclass issue. When you add those up, we then took into consideration this workforce assessment where we went in, and in this case it was 150 field positions, another 150 vacant, and as I think Alex had -- Mr. Glenn had gone over some of those details in his opening comments. We took those -- that off that to come down to that variance, I think it was 14.3 million from the benchmark. So this was, actually uses a subtraction, but it wasn't the total amount.

Q So just to make sure we're clear, if you didn't have the $6.3 million savings, the benchmark would have been exceeded by approximately $20 million as compared --

A That's correct.

Q -- to 14?

A And if I may, knowing that we're going into -- well, this is to this point in my testimony. The economy, knowing that we need to make some very tough decisions, and that's also, you can imagine, when we talk about earlier cost-cutting or belt-tightening, you can imagine an organization that will have looked and unturned every stone available before you went out and started laying off craft workers. We took that very seriously. And so yes, I think that answers your question.

Q Do you have understanding about how these benchmarks are set?

A I understand that's also -- so my understanding would be I think the same as my peers in the fact that I do understand it takes an 06 base year, and at that point you multiply a multiplier to come up with that, but I'm not an expert as to the multiplier itself.

Q Do you have a view as to whether that benchmark is reasonable or not?

A No, sir, I don't.

Q Do you all, during the course of your business operations, make efforts to manage to the benchmark number?

A This -- we manage every day to what our -- our expectations internally. And I say that, but do we go back and specifically, as part of our normal dialogue, go back and refer to this benchmark that you're mentioning, which is the Commission benchmark? No, sir, not in what I do.

Q Then how is it that that became part of your testimony?

A Because that was the actual request for what the Commission benchmark -- what would that Commission benchmark 06 times the multiplier, what would that be. And then you had to explain what your request, that differential. That's why it's being brought up.

Q Okay. That's helpful. So with respect to your ongoing daily operations, the benchmark is not something that you take into consideration for the purposes of your rate filing and your rate case, it does become something that's considered, is that right?

A Let me make sure I expand on that.

For the day-to-day activities of how we manage our business within the distribution group, we look to see what our needs are that meet our customers' needs for any given year, and we base that, again, with balancing all the things that we hold important, right: safety, reliability, customer sat, and we drive what that budget should be. That's what drives the benchmark itself, and how that's used in ratemaking policy and procedures is not for me, I'm not the one to speak to about that.

Q And I had asked you about day-to-day operations. Just to make sure we're clear, presumably that the benchmark is also not factored or considered or made a part of the judgment equation that you all go through when establishing budgets when going through an annual budgeting process, correct?

A Let me clarify that, too. What we're doing as a business unit is this is the request we need for our business. Now, at that point, what our financial group or our ratemaking to come back around and say from this -- you know, there is the benchmarks used in some level of decision-making, I can't speak to that, I don't know. I know I was not familiar with this term until we were preparing for this proceeding.

Q But you're not necessarily sure whether the benchmark is or is not considered sort of a -- at other higher levels, correct?

A Right, I'm not aware of that, sir.

Q Again, just so that we try to have a clear record with respect to relative terms, that 6.3 million that's reflected on line 16, can you tell me from a percentage basis what that would represent from the O&M budget that you're seeking to have this Commission approve?

A That was an '09 best estimate. It's hard to go in and do that based on how people charge their hours, because based on the activity that they charge, they either charge a capital or an O&M component. So this was our best estimate of the O&M component of that. So that would have been what we, again, used to reflect that would have come off a 144 number.

Q Okay. So the 6.3 million would -- whatever percent of 144 that is, that would be the percentage savings?

A Yes, sir. And that represents about 7.5 percent of that workforce.

Now, there were also contractor dollars that's not a part of that. I want to make sure that -- there were several hundred contractors that are not part of that figure.

Q Right, and those contractors, they perform services, contractual services, they're not your employees?

A That's correct, but that was also, just want to make sure, as you go in and look to see that activity, I just wanted to make mention that that did not equate to those dollars.

Q Thanks.

You had a little bit of a discussion with Mr. Wright, and I want to make sure that the record is clear. On page 13, line 16, you talk about the system being larger in 2005 -- I'm sorry, the system is larger now than in 2005. And similar to a question I asked of your transmission expert, I would like to ask you how much larger the system is today as compared to 2005.

A In reference to primary lines, is that how, Mr. Moyle, you want to reference that when you say larger? Because we have added a number of substations, we have added -- but in this case, do you want to reference that just from a primary lines? Because I have that answer.

Q Yes.

A Okay. Just for clarification, if you look at Schedule -- in your C, I think it may be 34, sir.

Q Okay.

A Yes. Are you there?

Q Go ahead.

A Okay. If you look at since -- on this -- on this -- on this page, if you look at '04, we had over 40,000 miles of line. If you look at 2008, we have 48,000 lines of -- and this would be considered primary lines. So that would relate to a 4.3 percent annual growth rate over the last five years.

Q It's about a 20 percent increase?

A Yes, sir.

Q How about with respect to substations, can you give me a percentage increase?

A I don't have those exact, but during that same time you're growing the primary lines, you've got to have the capacity out in the field to serve. So there's been additional investment through those years for substation capacity.

Q Is there any rule of thumb with respect to increased costs both for -- for O&M as to how much that should increase vis-à-vis the number of line miles that are added?

A No, sir, because this would be whether it's a -- where the line is at, accessibility, the age of the line; there's a lot of factors that go into that.

Q I want to talk to you a minute about the pole inspection process. You testified about that I think as part of the storm-hardening process, correct?

A Yes, sir.

Q 17, page 17, line 13. This is the, you say aggressive wood pole inspections?

A Right.

Q And then you go down on line 19 and say that you inspected 34 percent of the poles in the system, and over 4,000 poles or 1.6 percent of the total inspected poles have been replaced, is that correct?

A Yes, sir.

Q Okay. Now, before this storm-hardening took place, presumably the number of poles replaced was less than 1.6, is that right?

A I can't speak to those numbers. I am not for sure.

Q So in terms of like a before and after type of measurement of the positive effects related to storm-hardening, we couldn't do that, because we don't necessarily know the ratio of poles being replaced in the "before" part of that analysis, correct?

A We have those numbers; I just don't know them or have them with me.

Q Okay. I had asked your transmission expert some questions about engineering and design criteria, and you're an engineer. Do you have information about design criteria of your distribution poles?

A Yes. We have a standards organization that actually are the experts within that, but I do know in relation to the storm-hardening requirements what our expectations are in regards to that.

One thing that's different, if I may, is in this case here, when the 06 discussions were going on, during the storm-hardening discussions with the Commission and staff, in the case of distribution, the infrastructure itself, there was no changes to the design standards in the storm-hardening, because flying debris and other things drive more of a distribution issues during a major event, not the line strength themselves. So there was no changes in the design specs.

Q What are the design specs, as we sit here today?

A It changes based on the size pole, the length of the line. There's a whole -- there's a book that's considerably in depth that goes in and drives those level of standards.

Q Do you know if they're designed to withstand tropical force winds?

A Yes, they are designed to meet a certain standard, and it's exactly that, yes, sir.

Q Tropical force?

A At least tropical. I don't know specifically what the mile differentiation is, but I do know that that was looked at in considerable depth during the storm-hardening discussions in 06 that I was not a part of, and it was determined. So I don't know exactly what that wind differential, or that distinction is.

Q And you would agree with me, would you not, that to the extent that the distribution system was, let's say, designed to Level 2 hurricane standards, that -- I understand the idea of debris and whatnot, but from an engineering perspective, if it's designed to withstand that kind of wind force, you would not expect damage, all other things being equal, correct?

A If it indeed is designed for that, and again, I'd have to get clarification on that for you, then, yes, the issue is going to be what external factors are driving impact to that line, whether it be flying debris and other matters that would drive, or in this case, that's the reason why there's a pole inspection process, right, to ensure the integrity of our assets.

Q Similar to the transmission question, would you mind looking for that information and maybe being prepared to talk about it on rebuttal?

A If I may, just so we capture it, specifically what are you going to be asking for there? I just want to make sure I can come back with that answer for you.

Q With respect to your distribution, your distribution system, the design criteria for the distribution system relative to wind velocity.

A Okay.

MR. BURNETT: Mr. Chairman?

CHAIRMAN CARTER: Mr. Burnett.

MR. BURNETT: With all due respect to Mr. Moyle, I think this stems from his lack of appreciation of what he's asking for, that that would accomplish probably the length of this table. We have various classes of poles, various guy wires, loadings to our poles. I don't think I could do that before the end of 2010.

We can provide the general requirements under the NSC and what standard our poles are built to, but for all of our pole types, that would be impossible.

CHAIRMAN CARTER: Mr. Moyle?

MR. MOYLE: I appreciate that. I'm just looking for information that would represent the vast majority of your poles to see -- you know, without getting into it, I think there is an interrelation between this issue and the storm accrual issue, and that's why I'm asking --

MR. BURNETT: Not a problem to provide the level of detail as we did to the Commission in the 05 and 06 materials, not a problem for that.

THE WITNESS: And that's why I was asking for that specific, because we can provide all the information that was discussed back in that time.

BY MR. MOYLE:

Q Thank your counsel for slowing me down.

A Yeah, because we both have to go back to school for a while if you need to answer that one.

Q You would agree that the vegetation management plan should have a positive impact on system reliability and reduce damages from tropical storm or hurricane events, correct?

A Yes, sir, and if I may, since the storm-hardening initiative, since we have been going down the path with the VM standard, we have not experienced a certain level of major event, but I do want to mention that we did, after Tropical Storm Fay, you know, we're not going to wait just for the next hurricane to go out and assess whether this is working or not, so we did go out and assess after Tropical Storm Fay, which is an event in last August, we had tropical force winds and we actually went out and we have a forensic team that's now part of our storm preparedness, our storm activities, that went out to those locations where we felt had the most significant winds. And it was validated that yes, we saw better hardening of the system in those locations versus prior practices.

So in that case, I think there's explicit evidence that we have seen improvement. The rest of it is the fact that you're now going through a proactive maintenance versus a reactive. Intuitively, you would say yes, it would better the customer.

Q Yes, sir, and thank you for that explanation.

When you did that evaluation looking at the damage caused by Fay, you said that you found that there was improvement made. Were you able to quantify that?

A Yes, we were.

Q Can you describe the quantification?

A There's a whole forensic technique of which we went out and -- as a matter of fact, it's mentioned in my testimony -- where we had people come in and actually watch the inspection methods, and we actually have an actual product from that, but it was basically going in and looking at what prior -- one thing, what I have always welcomed, the fact that we've now been through certain hurricanes, you actually have now data to go back and see what the impact was, based on different wind speeds. We use that to estimate well in advance of a storm coming of how many resources we need based on a model.

So we went back and looked at some of the areas where previous, in '04 and others, in this area, this typically would have been the amount of damage, and it helps us, again, for resources and equipment forecasting, right? In this case, we used that against what we actually saw. The only variable that was a little different with Fay was the amount of water, because we had areas where it was 25 to 30 inches of rain, which, again, can cause more trees outside the right of way, so that was a little bit of a variable.

So taken outside of that, we actually saw that we had a less fault rate or less outage rate on those lines where we actually had gone in and actually instituted the storm-hardening vegetation management plan. It was really a before-and-after look.

Q And with respect to damage, because I think you also mentioned damages, did you perform a similar analysis to try to ascertain the -- what I would assume to be a reduced level of damages as a result of the storm-hardening?

A In this case, an outage, assuming that would be the damage, we assumed the outage itself. Really in this case it was really the integrity of the line, did we see what the integrity -- did it wind up falling down, those kind of things. So that was really the assessment aspect of it.

Q Can you quantify it in a percentage terms, say it performed ten percent better, 20 percent better?

A I cannot. I'd have to go back, but I don't believe I -- because I was here when we went through that and took a look at that, but I don't remember a percentage improvement, no, sir.

Q Okay. One further just kind of final line --

A Because that was -- by the way, that's the first time that, using these techniques, that we had gone out and done that, so --

Q Thank you for that.

And the variable that you think was different, you think you got pretty much similar conditions, with the variable being Fay had additional rain, additional saturation, so that may have worked kind of to make Fay a more severe event than it --

A Correct.

Q -- would have otherwise been?

A That's exactly the case.

Q Okay. And if I -- to ask you a hypothetical question, if somebody in the business came to you and said, you know, we want to get some information and judgment about insurance needs of our company as it relates to anticipated hurricane damage, and previously we have been insuring at $10, and we did that in '04, '05, we had damage in '04 and '05, and we have taken these steps, spent money taking these measures to improve our system, do you believe, assuming all other things being equal, not that you're going to have more hurricanes in this year, so just take that off the table, but based on the fact with respect to your storm-hardening expenditures and your vegetation management, that if you were spending $10 for insurance in 2004-2005, that you could reduce that insurance spend or that insurance accrual for 2010?

MR. BURNETT: Mr. Chairman?

CHAIRMAN CARTER: Mr. Burnett.

MR. BURNETT: I would object on the foundation and compound and confusing and TMI, I suppose, but if Mr. Joyner can handle it, I guess I don't mind if he could.

THE WITNESS: I'll answer it this way, and this is the only way I know to answer it, is my operational experience or what I'm held accountable for is predicting the level of damage and ensure that we have the amount of resources and material to meet a customer's expectation on their length of outage, right, that's what --

BY MR. MOYLE:

Q Yes, sir.

A Now, in regards to a storm reserve, so I'm not going to be able to answer your question, only because the variables that will relate to what would be a storm expense, it's all -- each storm is its own. For instance, if this storm were to hit multiple states, or hit ours, it all depends on where you get resources from. During 2004-2005 we were having to go to California to get resources that come at a higher expense than if you had to go to Georgia. So those amount of variables that drive that decision drastically change.

Those -- to answer your -- storm-hardening and that proactive, does that have any effect of that, the answer to that would be yes. On the total storm reserve and all those other factors, I think there's a lot more of those other factors that's going to drive the answer to your question more than just the storm-hardening itself.

(Brief pause at 5:06 p.m.)

(The transcript continues in sequence with Volume 7.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)

COUNTY OF LEON)

I, CLARA C. ROTRUCK, do hereby certify that I was authorized to and did stenographically report the foregoing proceedings at the time and place herein stated.

IT IS FURTHER CERTIFIED that the foregoing transcript is a true record of my stenographic notes.

I FURTHER CERTIFY that I am not a relative, employee, attorney, or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 25th day of September, 2009, at Tallahassee, Leon County, Florida.

Clara C. Rotruck

CLARA C. ROTRUCK