BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 160021-EI

PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY.
_______________________________/

DOCKET NO. 160061-EI

PETITION FOR APPROVAL OF 2016-2018 STORM HARDENING PLAN BY FLORIDA POWER & LIGHT COMPANY
_______________________________/

DOCKET NO. 160062-EI

2016 DEPRECIATION AND DISMANTLEMENT STUDY BY, FLORIDA POWER & LIGHT COMPANY.
_______________________________/

DOCKET NO. 160088-EI

PETITION FOR LIMITED PROCEEDING TO MODIFY AND CONTINUE INCENTIVE MECHANISM, BY FLORIDA POWER & LIGHT COMPANY.
_______________________________/

VOLUME 27
PAGES 3671 - 3977

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN JULIE I. BROWN
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER ART GRAHAM
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER JIMMY PATRONIS

DATE: Monday, August 29, 2016

TIME: Commenced at 7:45 p.m.
Concluded at 10:10 p.m.

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

REPORTED BY: LISA GAINEY
Court Reporter
(850) 894-0828

APPEARANCES: (As heretofore noted.)

* * * * *

I N D E X

WITNESSES

* * * * *

EXHIBITS

NUMBER:	ID	ADMTD
227 - Previously identified		3974
228 - Previously identified		3974
229 - Previously identified		3974
230 - Previously identified		3974
718 - Previously identified	3809	3816
719 - Previously identified	3809	
720 - Previously identified	3918	3930
721 - Previously identified	3925	3930

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P R O C E E D I N G S

(Transcript follows in sequence from Volume 26.)

* * * * *

CHAIRMAN BROWN: Good evening. Welcome back. I hope everybody had a great dinner, albeit short. Just a few housekeeping items or one really, notably. I'm going to turn the staff who had an opportunity to talk about some of the exhibits on the break, and staff would like to make a statement.

MS. BROWNLESS: Yes, ma'am. With regard to the exhibits that Mr. Moyle has raised an objection to, the errata sheet, 716, being one of them -- and I think there are a few others as well -- in order to make sure everybody has an opportunity to look at those exhibits and confirm to themselves, verify that the changes that have been made are related to the withdrawal of Mr. Pous' testimony, my suggestion is that everybody be given until Thursday morning at 9:00 a.m. I think it's Monday today.

That will allow you an opportunity to verify that that is, in fact, true as has been represented by OPC.

CHAIRMAN BROWN: Thank you, Ms. Brownless. I think that's a good suggestion. So, we will hold off on moving in any of those exhibits as they relate to Pous until Thursday.

Anything else?

MR. MOYLE: Just one. I wanted to make sure. I heard two different things. If the only thing that's happening is stuff is coming out like it's being stricken and stuff is coming out, I think I'm pretty good. If stuff is being changed or added, that's where I'm going to need the time.

So, I just want to make sure the record is clear on that.

CHAIRMAN BROWN: All right. FPL?

MR. BUTLER: We're fine with that, thank you.

CHAIRMAN BROWN: Mr. Rehwinkel?

MR. REHWINKEL: So, do I understand that all of the errata 715, 716 and we're going to have -- Mr. Smith is going to have an errata, too. Those will be in a group. And as a whole we will address those Thursday morning?

CHAIRMAN BROWN: Yes, we want to give Mr. Moyle an opportunity to review the updated information.

MR. REHWINKEL: Okay.

CHAIRMAN BROWN: But Mr. Moyle made a comment just now. His understanding is that the information is being stricken. There's nothing new being added. He just wanted clarification on that because he said -- not to put words in your mouth, but I will -- that that was fine if it was just stricken.

MR. MOYLE: I mean, I want to look at it, but it's a lot easier to just know consistent with what's happening with Pous' testimony that it's coming out and it's not changing or other stuff going in.

MR. REHWINKEL: We would like, if there is going to be a bifurcation in Shultz's 715 with respect to Slattery, we would like to provide argument to you at that time. And if you're inclined to make a ruling on that tonight, we would like to proffer, but we would prefer to make argument on everything at one time.

CHAIRMAN BROWN: Uh-huh. I would prefer you to make an argument at one time.

MR. REHWINKEL: Thank you.

CHAIRMAN BROWN: Okay. Any other comments on this?

MR. LaVIA: Madam Chair, one quick question. That's 711, 714 and 716 that we have until Thursday morning to raise any concerns.

CHAIRMAN BROWN: And there may be more.

MR. LaVIA: And there may be more, but at this point --

CHAIRMAN BROWN: Right. In fact, as they are presented, I encourage the parties to lodge a notification so that we are on notice that that is one of the items that they'd like to review.

MR. LaVIA: Thank you.

CHAIRMAN BROWN: Any other comments?

MR. MOYLE: I'm sorry, the numbers went by very fast.

CHAIRMAN BROWN: 711, 714, 715 and 716. And we will be having more. Thank you. Sounds like a fair process? Yes? I'm looking at Moyle, Mr. Moyle.

MR. MOYLE: Yes. Sounds like a fair process. I don't understand. To the extent I look at one and all of a sudden, I go wait, what is this, I need to ask this witness a question, and maybe he's flown back to Texas.

I'm not sure how fair that is, but I'm just prejudging. I don't know what I'm going to see when I look at the documents.

CHAIRMAN BROWN: Staff, any other comment?

MS. BROWNLESS: No, ma'am. Thank you.

CHAIRMAN BROWN: We are on Mr. Smith. Thank you for joining us from -- Michigan?

MR. SMITH: Yes.

CHAIRMAN BROWN: Where in Michigan?

MR. SMITH: Livonia.

CHAIRMAN BROWN: No idea. You have not been sworn in, have you?

MR. SMITH: No.

CHAIRMAN BROWN: Commissioner Edgar is from Michigan.

COMMISSIONER EDGAR: Kalamazoo.

THE WITNESS: I know where that is.

CHAIRMAN BROWN: Will you please stand and raise your right hand.

* * * * *

RALPH A. SMITH

was called as a witness, having been first duly sworn, was examined and testified as follows:

CHAIRMAN BROWN: Thank you. Please be seated.

MS. CHRISTENSEN: Thank you. Good evening. We do have an errata sheet for Mr. Smith that I would ask to have passed out. I think as previously described, this exhibit identifies the adjustments that are fallout from the removal of Mr. Pous' testimony as well as fallouts from the adjustments of Mr. Shultz' testimony which were previously sponsored by Mr. Shultz when he was on the stand.

CHAIRMAN BROWN: Okay. We'll be marking that as 717. We're going to title it errata to Smith testimony.

Ms. Christensen, whenever you're ready.

MS. CHRISTENSEN: Thank you.

DIRECT EXAMINATION

BY MS. CHRISTENSEN:

Q Can you please state your name and business address for the record, please.

A My name is Ralph C. Smith. My business address is Larkin & Associates, PLOC, 15728 Farmington Road, Livonia, Michigan.

Q And did you cause to be filed prefiled direct testimony on July 7th in this docket?

A Yes.

Q And do you have any corrections to your testimony?

A Yes.

Q Now, have you reviewed the errata sheet that was passed out regarding the changes to your testimony?

A Yes.

Q And have you reviewed that errata sheet? Do you have any corrections to make to the errata?

A No.

Q Do you have any additional corrections to make to your direct prefiled testimony?

A Yes. I noticed that three numbers appearing on Page 3, Lines 15, 16 and 17, at my direct were slightly off in the as-filed version of the testimony.

Q Can you please make the corrections.

A Yes. On Line 15, the number should be 866 million. On Line 16, the number should be 263 million. On Line 17, the number should be 209 million.

Q Thank you. And I wanted to ask some further clarification regarding the errata sheet that was previously passed out. Is that errata sheet to reflect the fallout adjustments from having stricken Mr. Pous' testimony as well as the adjustments Mr. Shultz testified to earlier today?

A Yes, it is. As a result of deleting Mr. Pous' testimony, certain adjustments were eliminated. Mr. Shultz updated certain of his adjustment dollar amount recommendations, and it's basically those two things that have been flowed through the revenue requirement schedules.

Q And to the best of your knowledge, are there any substantive adjustments that you testified to made in the errata to your testimony?

A It's basically all numbers that were passed to me either by Mr. Pous or by Mr. Shultz.

MS. CHRISTENSEN: I would ask if Mr. Smith's prefiled direct testimony as corrected here today be entered into the record as though read.

CHAIRMAN BROWN: We will insert Mr. Smith's prefiled direct testimony as corrected here today into the record.

(Prefiled direct testimony inserted into the record as though read.)

ERRATA SHEET

WITNESS: **RALPH SMITH – DIRECT TESTIMONY AND EXHIBITS**

Testimony Errata

PAGE #	LINE #	CHANGE
i	Section VI.	Delete heading "Depreciation Expense – New Depreciation Rates…..37"
3	3-4	Delete "Jacob Pous addresses FPL's request for new depreciation and amortization rates."
4	16-17	Delete "and the new depreciation rates recommended by OPC witness Pous"
5	14	Change \$807.2 to \$327.5; and \$1.674 to \$1.194
5	26	Delete "Pous,"
37	10-25	Strike
38-41		Strike entire pages
42	7	Change \$604 to \$147
42	10	Change \$604 to \$147
42	11	Change \$1.737 to \$1.281
43	1	Change \$807 to \$327; and \$812 to \$329
43	2	Change \$604 to \$147

Exhibits Errata

SCHEDULE	LINE #	CHANGE
RCS-2 2017 Rate Change		
Schedule A-1	Header	Add: Revised 8/26/2016
	1	Change 32,725,587 to 32,492,235
	3	Change 1,652,216 to 1,640,435
	4	Change 2,147,370 to 1,841,305
	5	Change (495,154) to (200,870)
	6	Change 6.56% to 5.67%
	8	Change (807,225) to (327,469)

Schedule B-1, page 1

Header	Add: Revised 8/26/2016
2	Change 233,827 to 475; and (12,829,352) to (13,062,704)
3	Change 202,281 to (31,071); and 30,261,399 to 30,028,047
7	Change 188,053 to (45,299); and 31,858,549 to 31,625,197
10	Change 183,744 to (49,608); and 32,725,587 to 32,492,235

Schedule B-1, page 2

Header	Add: Revised 8/26/2016
7	Delete: "[1/2 Depr'n Exp. Adj.]"
7	Change (146,314) to 0; and (130,489) to 0
8	Delete: "[1/2 of first year amort]"
8	Change (115,391) to 0; and (102,910) to 0
9	Change "Exhibit HWS-9" to "Exhibit HWS-9 Revised"
9	Change (428) to (475); and (428) to (475)
10	Change (262,133) to (475); and (233,827) to (475)
19	Delete "Exhibit HWS-11" and "Various"

Schedule C-1, page 1

Header	Add: Revised 8/26/2016
4	Change (58,534) to (63,634); and 1,267,955 to 1,262,855
8	Change (502,157) to (950); and 1,140,564 to 1,641,771
9	Change (2,887) to (3,228); and 575,304 to 574,963
10	Change 255,373 to 65,672; and 978,542 to 788,841
12	Change (308,205) to (2,140); and 3,981,071 to 4,287,136
13	Change 509,801 to 203,736; and 2,147,370 to 1,841,305

Schedule C-1, page 2

Header	Add: Revised 8/26/2016
7	Change (17,743) to (15,899); and (17,166) to (15,382)
8	Change (28,216) to (35,616); and (27,298) to (34,458)
9	Change (2,681) to (2,395); and (2,595) to (2,319)
16	Change (60,338) to (65,608); and (58,534) to (63,634)
20	Change (211,362) to 0; and (200,920) to 0
21	Change (16,064) to 0; and (14,406) to 0
22	Change (62,689) to 0; and (62,689) to 0
23	Change (2,513) to 0; and (2,432) to 0
25	Change (93,970) to 0; and (84,266) to 0
26	Change (129,924) to 0; and (129,924) to 0
27	Change (6,889) to 0; and (6,664) to 0
29	Change (856) to (950); and (856) to (950)
31	Change (524,266) to (950); and (502,157) to (950)
34	Change (1,152) to (1,032); and (1,136) to (1,018)
35	Change (1,775) to (2,240); and (1,751) to (2,210)

	36	Change (2,887) to (3,228)
	39	Change 297,058 to 105,816
	40	Change (41,685) to (40,144)
	41	Change 255,373 to 65,672
Schedule C-4		
	Header	Add: Revised 8/26/2016
	2	Change (58,534) to (63,634)
	3	Change (502,157) to (950)
	4	Change (2,887) to (3,228)
	5	Change (563,578) to (67,812)
	6	Change 770,078 to 274,312
	8	Change 297,058 to 105,816
Schedule C-5		
	Header	Add: Revised 8/26/2016
	3	Change 560,110 to 556,116
	5	Change 108,062 to 104,068
	7	Change (41,685) to (40,144)
Schedule C-7	Withdrawn	
Schedule D		
	Header	Add: Revised 8/26/2016
	9	Change 67,371 to (15,604); and 11,636,598 to 11,553,623
	10	Change 4,413 to (1,022); and 762,151 to 756,716
	12	Change 71,784 to (16,626); and 12,398,749 to 12,310,339
	13	Change 2,372 to (549); and 409,700 to 406,779
	14	Change 42,910 to (9,938); and 7,411,492 to 7,358,644
	15	Change 619 to (143); and 106,894 to 106,132
	16	Change 189,469 to (43,883); and 32,725,584 to 32,492,232
	Note Column (D)	Change 183,744 to (49,608); and 189,469 to (43,883)

SCHEDULE	**LINE #**	**CHANGE**
RCS-3 2018 Rate Change		
Schedule A-1	Header	Add: Revised 8/26/2016
	1	Change 34,269,536 to 33,830,719
	3	Change 1,772,069 to 1,749,378
	4	Change 2,142,473 to 1,839,721
	5	Change (370,404) to (90,343)
	6	Change 6.25% to 5.44%

	8	Change (603,852) to (147,282)
	9	Change (811,834) to (329,339)
Schedule B-1, page 1		
	Header	Add: Revised 8/26/2016
	2	Change 439,500 to 683; and (13,752,362) to (14,191,179)
	3	Change 394,165 to (44,652); and 31,713,711 to 31,274,894
	7	Change 379,930 to (58,887); and 33,356,850 to 32,918,033
	10	Change 376,852 to (61,965); and 34,269,536 to 33,830,719
Schedule B-1, page 2		
	Header	Add: Revised 8/26/2016
	6	Delete: "Exh. RCS-2, Sch. C-7"
	7	Delete: "One-half Depr'n Exp."
	7	Change (143,093) to 0; and (128,358) to 0
	8	Delete: "Annual Amort. full year"
	8	Change (230,782) to 0; and (207,018) to 0
	9	Delete: "[1/2 of annual amort]"
	9	Change (115,391) to 0; and (103,509) to 0
	10	Change "Exhibit HWS-9" to "Exhibit HWS-9 Revised"
	10	Change (615) to (683); and (615) to (683)
	11	Change (489,881) to (683); and (439,500) to (683)
	23	Delete "Exhibit HWS-11" and "Various"
Schedule C-1, page 1		
	Header	Add: Revised 8/26/2016
	4	Change (64,881) to (71,719); and 1,310,440 to 1,303,602
	8	Change (496,463) to (1,365); and 1,216,914 to 1,712,012
	9	Change (2,809) to (3,260); and 612,664 to 612,213
	10	Change 269,153 to 84,096; and 925,124 to 740,067
	12	Change (295,000) to 7,752; and 4,078,645 to 4,381,397
	13	Change 549,008 to 246,256; and 2,142,473 to 1,839,721
Schedule C-1, page 2		
	Header	Add: Revised 8/26/2016
	7	Change "Exh. HWS-10, p.1" to "Exh. HWS-2 Revised"
	7	Change (16,530) to (14,887); and (15,938) to (14,354)
	8	Change "Exh. HWS-10, p.2" to "Exh. HWS-3 Revised"
	8	Change (28,216) to (37,189); and (27,298) to (35,979)
	9	Change "Exh. HWS-10, p.4" to "Exh. HWS-4 Revised"
	9	Change (2,513) to (2,246); and (2,435) to (2,177)
	12	Change (1,370) to (1,369);
	16	Change (66,966) to (74,029); and (64,881) to (71,719)
	19-27	Delete References and Jurisdictional Separation Factors
	20	Change (211,342) to 0; and (201,046) to 0

	21	Change (16,063) to 0; and (14,436) to 0
	22	Change (56,282) to 0; and (56,282) to 0
	23	Change (2,500) to 0; and (2,420) to 0
	25	Change (93,970) to 0; and (84,454) to 0
	26	Change (129,924) to 0; and (129,924) to 0
	27	Change (6,889) to 0; and (6,670) to 0
	29	Change “Exh. HWS-9” to “Exh. HWS-9 Revised”
	29	Change (1,231) to (1,365); and (1,231) to (1,365)
	30	Change (518,199) to (1,365); and (496,463) to (1,365)
	33	Change “Exh. HWS-10, p.3” to “Exh. HWS-5 Revised”
	33	Change (1,073) to (966); and (1,058) to (953)
	34	Change “Exh. HWS-10, p.3” to “Exh. HWS-5 Revised”
	34	Change (1,775) to (2,339); and (1,751) to (2,307)
	35	Change (2,848) to (3,305); and (2,809) to (3,260)
	38	Change 317,724 to 129,552
	39	Change (48,571) to (45,456)
	40	Change 269,153 to 84,096
Schedule C-4		
	Header	Add: Revised 8/26/2016
	2	Change (64,881) to (71,719)
	3	Change (496,463) to (1,365)
	4	Change (2,809) to (3,260)
	5	Change (564,153) to (76,344)
	6	Change 823,653 to 335,844
	8	Change 317,724 to 129,552
Schedule C-5		
	Header	Add: Revised 8/26/2016
	1	Change 34,269,536 to 33,830,719
	3	Change 630,589 to 622,514
	5	Change 125,914 to 117,839
	7	Change (48,571) to (45,456)
Schedule C-7	Withdrawn	
Schedule D		
	Header	Add: Revised 8/26/2016
	9	Change 146,137 to (14,729); and 12,562,882 to 12,402,015
	10	Change 4,689 to (473); and 403,064 to 397,903
	12	Change 150,826 to (15,201); and 12,965,946 to 12,799,919
	13	Change 4,547 to (458); and 390,907 to 385,902
	14	Change 91,257 to (9,197); and 7,844,995 to 7,744,541

	15	Change 1,184 to (119); and 101,743 to 100,440
	16	Change 398,639 to (40,178); and 34,269,536 to 33,830,719
	Note Column (D)	Change 376,852 to (61,965); and 398,639 to (40,178)

RCS-4 Okeechobee LSA 2019

SCHEDULE	**LINE #**	**CHANGE**
Contents Page	Title	Add: Revised 8/26/2016
	Table	Add: "Revised" column
	Table	Add "Yes" in "Revised" column for Schedule D
Schedule D	Header	Add: Revised 8/26/2016
	9	Change 146,137 to (14,729); and 12,562,882 to 12,402,015
	10	Change 4,689 to (473); and 403,064 to 397,903
	12	Change 150,826 to (15,201); and 12,965,946 to 12,799,919
	13	Change 4,547 to (458); and 390,907 to 385,902
	14	Change 91,257 to (9,197); and 7,844,995 to 7,744,541
	15	Change 1,184 to (119); and 101,743 to 100,440
	16	Change 398,639 to (40,178); and 34,269,536 to 33,830,719
	Notes and Source	Add: "FPL Weighted Cost of Debt for Interest Synchronization 1.93% Col. H, lines 1, 2 and 5" Add: "OPC Weighted Cost of Debt for Interest Synchronization 1.84% Col. H, lines 9, 10 and 13"

DIRECT TESTIMONY

OF

RALPH SMITH

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 160021-EI, et al (consolidated)

I. INTRODUCTION

Q. WHAT ARE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS?

A. My name is Ralph Smith. I am a Certified Public Accountant licensed in the State of Michigan and a senior regulatory consultant at the firm Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan, 48154.

Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES, PLLC.

A. Larkin & Associates, PLLC, ("Larkin") is a Certified Public Accounting and Regulatory Consulting Firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings, including numerous electric, water and wastewater, gas and telephone utility cases.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION?

A. Yes, I have testified before the Florida Public Service Commission ("FPSC" or "Commission") previously. I have also testified before several other state regulatory commissions.

Q. HAVE YOU PREPARED AN EXHIBIT DESCRIBING YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. I have attached Exhibit RCS-1, which is a summary of my regulatory experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. Larkin & Associates, PLLC, was retained by the Florida Office of Public Counsel ("OPC") to review the rate request of Florida Power & Light Company ("FPL" or "Company"). Accordingly, I am appearing on behalf of the Citizens of the State of Florida ("Citizens").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am presenting OPC's overall recommended revenue requirement in this case. I also sponsor some of the OPC's recommended adjustments to the Company's proposed rate base and operating income.

Q. ARE ANY ADDITIONAL WITNESSES APPEARING ON BEHALF OF THE FLORIDA OFFICE OF PUBLIC COUNSEL IN THIS CASE?

A. Yes. Helmuth W. Schultz, III, also of Larkin & Associates, PLLC ("Larkin"), is presenting testimony on storm hardening, payroll and several other issues, which impact the revenue requirement. Dr. David Dismukes is presenting testimony addressing FPL's sales forecasts for 2017 and 2018, which impact the revenue requirement in this case. Dr. Dismukes also presents information on forecasted inflation rates. Jacob Pous addresses FPL's request for new depreciation and amortization rates. Kevin O'Donnell's testimony addresses the appropriate capital structure for purposes of determining the revenue requirement of FPL in this case. Dr. Randall Woolridge presents Citizens' recommended rate of return on equity in this case using the recommended capital structure, as well as the appropriate rate of return on equity if the Commission adopts FPL's proposed capital structure. Daniel Lawton addresses FPL's request for an additional return on equity and financial ratios.

II. <u>FPL REQUESTED REVENUE INCREASES</u>

Q. WHAT ARE THE REVENUE ADJUSTMENTS THAT THE COMPANY IS PROPOSING?

A. The Company is proposing revenue adjustments over a four-year period. The Company is requesting a general base revenue adjustment of approximately $860 million effective in January 2017; a subsequent year adjustment of approximately $265 million effective in January 2018; and an adjustment of approximately $200 million effective in mid-2019 when the new Okeechobee Clean Energy Center enters service. There would be no base rate increase in 2020.

Q. FPL IS REQUESTING BOTH A BASE RATE INCREASE TO BE EFFECTIVE JANUARY 2, 2017, AND A SUBSEQUENT YEAR INCREASE FOR JANUARY 1, 2018, AND A LIMITED SCOPE ADJUSTMENT ON JUNE 1, 2019, CONCURRENT WITH THE COMMERCIAL IN-SERVICE DATES OF ITS OKEECHOBEE

CLEAN ENERGY CENTER. WILL YOU BE ADDRESSING EACH OF FPL'S THREE REQUESTED INCREASES TO BASE RATES?

A. Yes. In this testimony, I first address the base rate increase that FPL has proposed to be effective January 2, 2017 ("January 2017 Base Rates"). I then also address the proposed base rate adjustment for the Company's requested January 2018 Subsequent Year Increase and for the Company's requested Mid-2019 Limited Scope Adjustment (LSA) Increase for the Okeechobee Clean Energy Center.

III. <u>ORGANIZATION OF TESTIMONY</u>

Q. HOW WILL YOUR TESTIMONY BE ORGANIZED?

A. In Section IV, I present the overall financial summary for the base rate change to be effective January 2, 2017, showing the revenue requirement excess for the 2017 test year recommended by Citizens. In Section V, I discuss certain corrections that FPL has identified to its filing that affect the revenue requirement. In Section VI, I then discuss my proposed adjustments which impact the January 2017 Base Rates, and how the recommended sales forecast adjustment sponsored by OPC witness Dismukes and the new depreciation rates recommended by OPC witness Pous have been reflected. Where an adjustment affects both 2017 and 2018, I discuss the impact on both projected test years in Section VI. Exhibit RCS-2 presents the schedules and calculations in support of the 2017 revenue requirement and Exhibit RCS-3 presents the 2018 revenue requirement.

In Section VII, I address the January 2018 Subsequent Year Increase. Within this section, I present the OPC revenue requirement recommendation associated with the 2018 increase requested by FPL. The January 2018 revenue requirement calculations and adjustments impacting these calculations are presented in Exhibit RCS-3.

Finally, in Section VIII, I present the adjusted revenue requirement for FPL's requested Okeechobee Limited Scope Base Rate Change for the projected year ending May 31, 2020. Although an adjusted revenue requirement for the Okeechobee limited scope increase is presented on Exhibit RCS-4, I recommend that no increase for 2019 or 2020 be approved at this time.

IV. OVERALL FINANCIAL SUMMARY – JANUARY 2017 BASE RATE CHANGE

Q. WHAT IS THE JANUARY 2017 BASE RATE REVENUE REQUIREMENT DEFICIENCY OR EXCESS FOR FLORIDA POWER & LIGHT COMPANY?

A. As shown on Exhibit RCS-2, Schedule A-1, the OPC's recommended adjustments in this case result in a recommended revenue reduction for FPL in January 2017 of approximately $807.2 million. This is $1.674 billion less than the base rate revenue increase of $866.4 million requested by FPL in its filing.

Q. PLEASE DISCUSS THE EXHIBIT YOU PREPARED IN SUPPORT OF YOUR TESTIMONY AS IT PERTAINS TO THE JANUARY 2017 BASE RATE CHANGE.

A. Exhibit RCS-2, totaling 21 pages, consists of Schedules A-1, B-1 through B-2, C-1 through C-7, D, E, and F.

Q. WHAT IS SHOWN ON SCHEDULE A-1?

A. Schedule A-1 presents the revenue requirement calculation for the January 2017 Base Rate change, giving effect to all of the adjustments I am recommending in this testimony, along with the impacts of the recommendations made by Citizens' witnesses Schultz, Dismukes, Pous, O'Donnell, Lawton, and Woolridge.

Q. WHAT IS SHOWN ON SCHEDULE B-1 AND B-2?

A. Schedule B-1 presents OPC's adjusted rate base and identifies each of the adjustments impacting rate base that are recommended by Citizens' witnesses in this case. Schedule B-2 provides supporting calculations for the rate base adjustment for Plant Held for Future Use that I am sponsoring.

Q. WHAT IS SHOWN ON SCHEDULE C-1?

A. OPC's adjusted net operating income is shown on Schedule C-1, page 1. OPC's adjustments to net operating income are listed on Schedule C-1, page 2. Schedules C-2 through C-7 provide supporting calculations for the OPC adjustments to net operating income, which are presented on Schedule C-1.

Q. WOULD YOU PLEASE DISCUSS SCHEDULE D?

A. Schedule D presents Citizens' recommended capital structure and overall rate of return, based on the revisions to FPL's proposed debt-to-equity ratio recommended by Kevin O'Donnell and the rate of return on equity recommended by Dr. Randall Woolridge. The capital structure ratios for debt and common equity are based on the ratios recommended by Mr. O'Donnell. On Schedule D, I have applied the adjustments to the capital structure necessary to synchronize Citizens' recommended capital structure to the adjusted jurisdictional rate base. On Schedule D, I applied Dr. Woolridge's recommended return on equity, resulting in OPC's overall recommended rate of return of 5.05%.

Q. WHAT IS SHOWN ON SCHEDULES E AND F?

A. Schedules E and F show the incorporation of FPL's corrections to its application that affect the revenue requirement. In filings made on May 3, 2016 and June 16, 2016, FPL identified corrections and adjustments to its filing.[1]

V. INCORPORATION OF FPL IDENTIFIED ADJUSTMENTS AND CORRECTIONS

Q. AFTER FILING ITS MFRS, HAS FPL IDENTIFIED ANY ERRORS OR CORRECTIONS TO ITS FILING?

A. Yes. FPL so far has filed three notices of Identified Adjustments that impact the requested revenue requirement as detailed below. While I have included FPL's Identified Adjustments in my testimony, I have not had sufficient time to evaluate and form an opinion on the reasonableness of these adjustments.

Q. ON MAY 3, 2016, FPL FILED A NOTICE OF IDENTIFIED ADJUSTMENTS. WHAT DID THAT CONTAIN?

A. FPL's May 3, 2016 Notice of Identified Adjustments provided descriptions and estimated revenue requirement impacts for the corrections and adjustments that FPL had identified up to that point. FPL explained in its May 3, 2016 Notice that: "The Adjustments Affecting Revenue Requirements, if made, would net to an approximate net $9 million decrease in FPL's overall 2017 test year revenue requirements and a decrease of approximately $7 million for FPL's overall 2018 Subsequent Year revenue requirements." FPL stated further in its Notice that it would include all adjustments identified on Attachment 1 to its Notice in an exhibit of adjustments that it will file with rebuttal

[1] FPL made a third correction filing on June 30, 2016, which has not been incorporated at this time.

testimony, along with any other adjustments that may be identified between now and then. FPL indicates further that it had included similar exhibits with the rebuttal testimony of FPL witnesses in its 2009 and 2012 rate cases.

Q. WHAT ADJUSTMENTS WERE IDENTIFIED IN FPL'S MAY 3, 2016 NOTICE?

A. FPL's May 3, 2016 Notice in Attachment 1 identified 14 items that impact the revenue requirement, which are briefly summarized below[2] using FPL's descriptions:

> 1) **Deferred Pension Debit**. Deferred pension debit in FERC Account 186 was forecasted inconsistently with forecasted pension expense amounts reflected on MFR C-17. As such, rate base is overstated by approximately \$3.6M and \$8.9M for 2017 and 2018, respectively.
>
> 2) **West County Water Reclamation**. O&M expense for the servicing of the water reclamation bonds was double counted, resulting in an overstatement to O&M of \$4.2M for both 2017 and 2018.
>
> 3) **Outdoor Lighting Revenues**. An incorrect present rate was used for the "OL-1 Underground conductors excluding trenching (rate per foot)" in the 2018 revenue forecast. As shown on MFR E-13d page 13 of 21, line 19, column 5, the rate entered was "1.078" and the correct rate is "0.078." Adjusting this rate to reflect the correct value decreases 2018 revenues under present rates by approximately \$3.8M.
>
> 4) **Retail Base Revenues**. The long-term price of electricity for both 2017 and 2018 was calculated incorrectly as it included higher fuel expense than should have been forecasted. This underestimated the amount of usage by customers and results in less than 0.1% increase in the amount of megawatt hours sold for 2017 and less than 0.2% for 2018. This results in \$4.9M of additional retail base revenues for 2017 and \$9.3M for 2018.

[2] FPL's May 3, 2016 Notice also identified three additional adjustments/corrections without revenue requirement impact.

5) **Changes related to Forecast Revenues** including:

a) **Late Payment Charges**. Incorrect Late payment charges for 2017 and 2018 result in an understatement of revenues in 2017 and overstatement of revenues in 2018.

b) **Returned Checks**. Incorrect returned check charges for 2017 and 2018 result in an understatement of revenues in 2017 and overstatement of revenues in 2018.

c) **Uncollectible Accounts Expense**. Incorrect uncollectible accounts expense for 2017 and 2018 result in an understatement of O&M expense in 2017 and overstatement of O&M expense in 2018.

d) **NOI Multiplier - Bad Debt Rate**. Incorrect bad debt rate reflected on MFR C-44 for all periods should be 0.066% and the resulting NOI multiplier should be 1.63025.

6) **Demand Side Management (DSM) Peaking Adjustment**. FPL includes adjustments to Net Energy for Load (NEL) in its forecast for incremental DSM to account for DSM impacts not reflected in historical data; however, did not include comparable adjustments in its peak forecasts. Including the incremental DSM impact to its peak forecasts lowers the retail share of the system monthly coincident peak demand resulting in a reduction in production demand-based separation factors of 0.014% in 2017 and 0.018% in 2018. There is no impact on the allocation between the rate classes as a result of this adjustment.

7) **Amortization of Gains - Aviation**. Gain amortization related to the sale of aviation assets ceased in 2016 and should not have been included in 2017 or 2018. This results in an overstatement of the credit to FERC Account 407 by approximately $1.2M for both 2017 and 2018. FPL did not forecast any activity in the related regulatory liability (FERC Account 254); therefore, no adjustment to rate base is required.

8) **Amortization of Gains - Mitigation Bank - Phase II**. FPL included $25.1M as the estimated phase II mitigation bank gain on MFR C-29 and related amortization in 2018 in error. This benefit cannot be recognized until beyond 2020. This results in an overstatement of the credit to FERC Account 407 by approximately $5.0M for 2018.

9) **Company Adjustment - Fukushima**. Accumulated depreciation reserve for the Fukushima Company adjustment for 2018 contained a formula error for January 2018. The accumulated depreciation reserve adjustment was understated by $0.1M for 2018, with a resulting $7K impact on revenue requirements.

10) **Company Adjustment - Depreciation**. Company adjustment for base depreciation expense was not reflected in the correct distribution plant accounts. The majority of distribution plant accounts have a separation factor of 1; however, plant account 370 has a factor lower than 1. The retail jurisdictional amount for the credit to depreciation expense for the distribution function for both 2017 and 2018 was understated.

11) **Company Adjustment - Dismantlement**. Company adjustment dismantlement calculations for both 2017 and 2018 are as follows: (1) Useful life of the Okeechobee plant (currently 52 years, should be 40 years); (2) Alignment of forecasted dismantlement costs for Turkey Point and gas turbines with the study assumptions; and (3) Certain formula errors in the 2016 Dismantlement Study prepared by Burns & McDonnell. The impact of these adjustments results in an overstatement of FPL's dismantlement expense Company adjustment for 2017 and 2018 of $1.4M. Corrections to the 2016 Dismantlement Study will be filed in Docket No. 160062-EI.

Cost of Capital Impacts. FPL identified the following three adjustments as impacting on its proposed Cost of Capital:

12) **Company Adjustment - ADIT Proration**. ADIT proration company adjustment for 2017 and 2018 did not include the impact of bonus depreciation associated with FPL's Gas Reserves investment. In addition, 2018 was calculated incorrectly due to a formula error. The beginning balance for the 2018 13-month average company adjustment should have been zero, not the ending balance of the ADIT company adjustment for 2017. As such, the weighted average cost of capital for 2017 and 2018 should be 6.6080% and 6.7032%, respectively.

13) **Customer Deposits**. Amount of customer deposits for 2017 and 2018 was not updated for the final forecasted retail revenues from the sales of electricity. In addition, the amount of forecasted refunds for excess deposits on master accounts was input incorrectly. As such, the amount of total company per book customer deposits should increase $1.2M and $1.8M for 2017 and 2018, respectively, and all other classes of capital should be adjusted in order for rate base to reconcile to capital structure. The weighted average cost of capital for 2017 and 2018 should be 6.6071% and 6.7048%, respectively. Because the amounts of long term debt and common equity have changed based on these adjustments, the amount of long term debt and

common equity used in the calculation of the incremental cost of capital for the 2019 Okeechobee LSA requires an adjustment. Adjusting for these changes decreases the incremental cost of capital for the OK LSA by 0.000098%.

14) **Incremental Cost of Capital**. The calculation of the incremental cost of capital for the 2019 Okeechobee LSA was based on the jurisdictional adjusted capital structure amounts from 2018, which included an ADIT proration adjustment specific to 2018 forecasted activity. The ADIT proration adjustment for the 2019 Okeechobee LSA was already reflected in the calculation of deferred income taxes, which is a reduction to rate base. As such, incremental cost of capital should be based on the jurisdictional adjusted 2018 capital structure, less the 2018 ADIT proration adjustment. Adjusting for these changes decreases incremental cost of capital by 0.000002%.

Q. HOW HAVE YOU INCORPORATED THOSE ADJUSTMENTS IDENTIFIED BY FPL IN ITS MAY 3, 2016 NOTICE INTO THE CALCULATION OF THE REVENUE REQUIREMENT?

A. As noted above, the Notice filed by FPL on May 3, 2016 provided estimated revenue requirement impacts of its identified corrections and adjustments, but did not include detail on rate base or net operating income impacts. In Excel workpapers, FPL provided additional details showing the impacts on key rate base and net operating income components of its Identified Adjustments. I have utilized the information provided by FPL in response to that discovery to incorporate many FPL-identified adjustments to FPL's originally filed rate base and net operating income.

Q. PLEASE EXPLAIN HOW YOU HAVE REFLECTED THE FPL MAY 3, 2016 CORRECTIONS AFFECTING THE 2017 RATE BASE AND NET OPERATING INCOME.

A. On Exhibit RCS-2, Schedule B-1, page 1 of 2, which shows 2017 forecasted rate base, I have reflected the adjustments to rate base identified in FPL's May 3, 2016 Notice in column B.

Similarly, on Exhibit RCS-2, Schedule C-1, page 1 of 2, which shows 2017 forecasted net operating income, I have reflected the adjustments to net operating income that were identified in FPL's May 3, 2016 Notice in column B.

On Exhibit RCS-2, Schedule E, page 3, I have reproduced the FPL identified adjustment detail that was provided by the Company in its workpapers for impacts on the 2017 forecasted test year rate base and net operating income. Exhibit RCS-2, Schedule E, page 1, shows the reflection of FPL's May 3, 2016 adjustments on 2017 test year rate base. Exhibit RCS-2, Schedule E, page 2, shows the adjustments to 2017 test year net operating income components.

Q. HOW HAVE YOU INCORPORATED FPL'S CHANGES TO THE CAPITAL STRUCTURE AT THIS TIME?

A. As shown on Exhibit RCS-2, Schedule D, the reconciliation of the capital structure to the adjusted rate base includes the OPC rate base adjustments and the FPL identified rate base correction amounts. As described elsewhere in my testimony, OPC witness O'Donnell is recommending a different capital structure than FPL has proposed. The capital structure, cost rates, and overall cost of capital used to compute the revenue requirement for the 2017 forecasted test year is shown on Exhibit RCS-2, Schedule D.

Q. HAVE YOU INCORPORATED THE IMPACTS OF FPL'S MAY 3, 2016 NOTICE ON 2018 SUBSEQUENT YEAR RATE BASE AND NET OPERATING INCOME IN A SIMILAR MANNER?

A. Yes. I have reflected the impacts on the 2018 subsequent test year in a similar manner. Specifically, on Exhibit RCS-3, Schedule B-1, page 1 of 2, which shows 2018 forecasted rate base, I have reflected the adjustments to rate base identified in FPL's May 3, 2016 Notice in column B. On Exhibit RCS-3, Schedule C-1, page 1 of 2, which shows 2018 forecasted net operating income, I have reflected the adjustments to net operating income that were identified in FPL's May 3, 2016 Notice in column B.

On Exhibit RCS-3, Schedule E, page 3, I have reproduced the FPL identified adjustment detail that was provided by the Company in its Excel workpapers for impacts on the 2018 subsequent test year rate base and net operating income, which are shown on Schedule E, pages 1 and 2, respectively.

Q. HAS FPL FILED A SECOND NOTICE OF IDENTIFIED ADJUSTMENTS?

A. Yes. On June 16, 2016, FPL filed a Second Notice of Identified Adjustments. Similar to its May 3, 2016 Notice, in its June 16, 2016 Second Notice, FPL states they will include the adjustments identified on Attachment 1 to its Second Notice in an exhibit of adjustments that it will file with rebuttal testimony, along with any other adjustments that may be identified between now and then.

Q. WHAT ADJUSTMENTS WERE INCLUDED IN THAT SECOND NOTICE?

A. FPL's Second Notice identified the following three adjustments, along with FPL's explanations:

1) **Supplement to 2016 Depreciation Study**. As filed, FPL's 2016 depreciation study developed service lives and net salvage characteristics based on historical data through year-end 2014. Those parameters were then applied to estimated plant and reserve balances brought forward to year-end 2017. Because the primary test year in FPL's base rate case is 2017, FPL considered year-end 2017 estimated plant and reserve balances as best representing FPL's depreciable plant during the test year. Discovery to date from Staff and others has raised questions about whether using year-end 2016 balances would be more appropriate and consistent with past Commission practice. FPL continues to believe that the use of year-end 2017 balances would provide a good match with FPL's 2017 Test Year and 2018 Subsequent Year, but has no objection to using results for year-end 2016 balances for the purpose of setting depreciation rates and determining FPL's base rates in this proceeding and accordingly is proposing the adjustment described. ... [in its Second Notice].

2) **Economic Development Rider**. In responding to discovery, FPL determined that its projection of test period revenues for customers taking service under the Economic Development Rider and the Existing Facility Economic Development Rider did not take into account the base rate discounts provided under those riders and thus test period revenues were overstated by the amount of the discounts. At the same time, FPL determined that it needed to correct the five percent of economic development expenses (i.e., rate reductions and O&M expenses) from test period revenue requirements that is contemplated by Rule 25-6.0426, Florida Administrative Code. These two corrections partially offset and result in increases in revenue requirements of approximately $700,000 in 2017 and $800,000 in 2018, as shown on Attachment 1.

3) **SJRPP Dismantlement Costs**. In responding to discovery, FPL determined that it had not correctly forecast the dismantlement costs that are to be accrued for the 30% of SJRPP output that FPL purchases from JEA under a PPA. As shown on Attachment 1, this correction results in decreases in revenue requirements of approximately $70,000 in 2017 and $85,000 in 2018.

Q. HOW HAVE YOU INCORPORATED THE ADJUSTMENTS AND CORRECTIONS NOTED BY FPL IN ITS JUNE 16, 2016 SECOND NOTICE OF IDENTIFIED ADJUSTMENTS IN THE REVENUE REQUIREMENT DETERMINATION?

A. I have incorporated those June 16, 2016 FPL adjustments in a similar manner to FPL's May 3, 2016 adjustments. An Excel file containing detail of the additional FPL-identified adjustments was obtained and reproduced on Exhibit RCS-2, Schedule F, page 3, for 2017, and on Exhibit RCS-3, Schedule F, page 3, for 2018. That FPL-provided information was used to incorporate the rate base and net operating impact of those adjustments into the revenue requirement determination in the following manner.

On Exhibit RCS-2, Schedule B-1, page 1 of 2, which shows 2017 forecasted rate base, I have reflected the adjustments to rate base identified in FPL's June 16, 2016 Second Notice in column C. Similarly, on Exhibit RCS-2, Schedule C-1, page 1 of 2, which shows 2017 forecasted net operating income, I have reflected the adjustments to net operating income that were identified in FPL's June 16, 2016 Second Notice in column C.

On Exhibit RCS-2, Schedule F, page 3, I have reproduced the FPL identified adjustment detail that was provided by the Company in an Excel file that was provided to OPC after FPL filed its Second Notice. Schedule F, pages 1 and 2 summarizes the impacts on the 2017 forecasted test year rate base and net operating income, respectively, of the additional adjustments FPL identified in its Second Notice.

Q. HAVE YOU REFLECTED THE IMPACTS OF FPL'S JUNE 16, 2016 SECOND NOTICE OF ADJUSTMENTS ON THE 2018 SUBSEQUENT TEST YEAR IN A SIMILAR MANNER?

A. Yes. I have reflected the impacts on the 2018 subsequent test year in a similar manner. Specifically, on Exhibit RCS-3, Schedule B-1, page 1 of 2, which shows 2018 forecasted rate base, I have reflected the adjustments to rate base identified in FPL's June 16, 2016

Notice in column C. Similarly, on Exhibit RCS-3, Schedule C-1, page 1 of 2, which shows 2018 forecasted net operating income, I have reflected the adjustments to net operating income that were identified in FPL's June 16, 2016 Second Notice in column C.

On Exhibit RCS-3, Schedule F, page 3, I have reproduced the FPL identified adjustment detail that was provided by the Company in an Excel file for impacts of adjustments described in FPL's Second Notice on the 2018 subsequent test year rate base and net operating income. Exhibit RCS-3, Schedule F, pages 1 and 2, shows the incorporation of those FPL adjustments to 2018 rate base and net operating income, respectively.

Q. DID FPL FILE A THIRD NOTICE OF IDENTIFIED ADJUSTMENTS?

A. Yes, on June 30, 2016, FPL filed a Third Notice of Identified Adjustments.

Q. WHAT WAS CONTAINED IN FPL'S THIRD NOTICE?

A. FPL's June 30, 2016 Notice provided the following explanation, describing how it was implementing the Florida Supreme Court's May 19, 2016 Citizens v. Graham decision that reversed the Commission's orders approving cost recovery for the Woodford gas reserves project. In its filing, FPL stated:

> In January 2015, the Commission issued Order No. PSC-15-0038-FOF-EI approving Fuel Clause recovery for the costs associated with FPL's owning and operating the Woodford gas reserves project. In July 2015, the Commission issued Order No. PSC-15-0284-FOF-EJ approving guidelines for FPL investments in future gas reserves projects. Based on those orders, FPL included both the Woodford project and estimates of additional gas reserves projects in developing its Total Company financial forecast underlying the rate case filing in this docket. Because the costs for gas reserves projects were to be recovered through the Fuel Clause, FPL then made Commission adjustments to remove the costs of those projects from the test period base rate revenue requirements calculations, consistent with the Commission's Earnings Surveillance Report ("ESR") and MFR practice for clause-recoverable activities.

On May 19, 2016, the Florida Supreme Court reversed Order No. PSC-15-0038-FOF-EI and two companion orders, finding that the Commission does not have authority to allow FPL to recover costs associated with the Woodford gas reserves project from customers. While the Court's May 19 order directly addressed only the Woodford project, its rationale would apply to future gas reserves projects as well. On June 15, 2016, the Commission and all parties to the appeal of Order No. PSC-15-0284-FOF-EI filed a joint motion for the Court to relinquish jurisdiction over that order so that the Commission may vacate it. The Court granted the joint motion on June 28, 2016.

In light of the May 19 order, Staff held an informal meeting with FPL and parties to discuss removing the impact of gas reserves projects from the Fuel Clause and rate case filings. Following that meeting, FPL has rerun its financial forecasts for the 2017 Test Year, 2018 Subsequent Year and the 2019 Okeechobee LSA as if (1) there had been no Woodford investments historically and thus no sale of Woodford gas production to FPL and (2) no additional gas reserves investments would be made in the rate effective years.[3] As noted above, FPL had already made a Commission adjustment to remove gas reserves costs from base rate revenue requirements consistent with the Commission's ESR and MFR practice for clause-recoverable activities. However, for the reasons discussed in Attachment 1 to this Notice, there are some minor differences in the revenue requirements calculation when the financial forecasts assume no gas reserves projects rather than assuming that there will be gas reserves projects with a Commission adjustment to treat them as clause-recoverable. The net effect of those differences is a modest reduction in revenue requirements for the 2017 Test Year and 2018 Subsequent Year, with a negligible impact on the 2019 Okeechobee LSA.

Q. DID FPL'S THIRD NOTICE IDENTIFY ESTIMATED REVENUE REQUIREMENT IMPACTS?

A. Yes. FPL's June 30, 2016 Third Notice identified a $7.3 million decrease in its 2017 revenue deficiency, a $1.6 million increase to its 2018 revenue deficiency, and a negligible $65,000 increase in its claimed Okeechobee revenue requirement.

[3] In its actual/estimated true-up filing in Docket No. 160001-EI on August 4, 2016, FPL will include a refund calculation for the difference between the amounts it is collecting for the Woodford project in the Fuel Clause, versus the market price of the gas produced from that project.

Q. HAVE YOU INCORPORATED FPL'S THIRD NOTICE INTO THE OPC'S REVENUE REQUIREMENT COLUMN?

A. No. Due to the timing of when it was received, I have not incorporated impacts from FPL's Third Notice. I will reserve the option to amend my testimony and schedules to incorporate these impacts.

VI. RECOMMENDED ADJUSTMENTS TO RATE BASE AND NET OPERATING INCOME

Q. WOULD YOU PLEASE DISCUSS EACH OF YOUR SPONSORED ADJUSTMENTS TO FPL'S FILING?

A. Yes, I will address each adjustment I am sponsoring below.

Plant Held For Future Use

Q. PLEASE EXPLAIN THE LEVEL OF PLANT HELD FOR FUTURE USE THAT FPL HAS REFLECTED IN ITS 13-MONTH AVERAGE RATE BASE.

A. As shown on MFR Schedule B-1, FPL shows Plant Held For Future Use ("PHFFU") of $247,614,000 on a total Company 13-month average basis. FPL provided a breakout of this amount by category in MFR Schedule B-15, which is reproduced in the table below:

Description	13 Month Avg. 2017 Test Year Amount	2017 Test Year Jurisdictional Amount
Gas Reserves Future Use	$ 1,369,000	$ 1,297,000
Other Production Future Use	$ 95,089,000	$ 90,391,000
Transmission Future Use	$ 72,952,000	$ 65,820,000
Distribution Future Use	$ 44,398,000	$ 44,398,000
General Plant Future Use	$ 33,806,000	$ 32,706,000
Total PHFFU	$ 247,614,000	$ 234,612,000

Q. HAS FPL REMOVED ANY PHFFU FROM RATE BASE?

A. Yes. FPL removed the $1.369 million for Gas Reserves (jurisdictional amount of $1.297 million) from rate base. Per a footnote on MFR Schedule B-15, FPL had intended to seek recovery of that amount through the Fuel and Purchased Power Recovery Clause.

Q. DID YOU REVIEW THE DETAIL OF FPL'S REQUEST FOR RATE BASE INCLUSION OF PHFFU?

A. Yes. In OPC's Second Set Interrogatory No. 105, OPC requested that the Company provide the following information for each item of PHFFU included in the $247.614 million: (a) a description of the property; (b) purchase dates and related amounts; (c) the date originally recorded in account 105; (d) the current anticipated in-service date; and (e) documentation for system planning supporting the expected in-service dates. In response to OPC's 2nd Set of Interrogatories, Interrogatory No. 105, FPL provided a detailed listing of each item included in PHFFU.

Q. DO YOU AGREE THAT EVERY PROPERTY INCLUDED IN FPL'S 2017 TEST YEAR PHFFU BALANCE SHOULD BE INCLUDED IN RATE BASE IN THIS PROCEEDING?

A. No, I do not. Upon reviewing the detail associated with the Company's requested level of PHFFU provided in response to OPC's 2nd Set of Interrogatories, Interrogatory No. 105, I have determined that several items should be removed and not included in rate base at this time. Sites with a projected in-service date of more than ten years beyond the test year planning horizon should be excluded from rate base, resulting in an overall PHFFU reduction of $14.681 million on a total Company basis, or $14.238 million after jurisdictional allocation.

Q. **WHY DO YOU RECOMMEND THAT PHFFU WITH EXPECTED IN-SERVICE DATES OF BEYOND 2026 BE REMOVED FROM FPL'S RATE BASE?**

A. Ratepayers should not be required to pay a return to FPL's shareholders for the costs of sites that have an expected in-service date that is beyond the 10-year planning horizon because it is not used and useful to current customer and will not be used within a reasonable timeframe in future. The statute states: "The commission shall investigate and determine the actual legitimate costs of the property of each utility company, <u>actually used and useful in the public service</u>, and shall keep a current record of the net investment of each public utility company in such property which value, as determined by the commission, shall be used for ratemaking purposes and shall be the money honestly and prudently invested by the public utility company in such property <u>used and useful in serving the public</u>, ..." Section 366.06, Florida Statutes. (Emphasis added.) Property held for future use that is beyond the ten-year planning horizon is not used and useful in providing service to ratepayers. Thus, it is not reasonable to expect ratepayers to pay a return on the costs of that property held for future use on an annual recurring basis. The detail that was provided in the response to OPC Interrogatory No. 105 listed several properties under the Transmission and Distribution Future Use categories, where the expected in-service dates are beyond 2026. Additionally, eight of the sites have been on FPL's books for many years prior to 2000, ranging from 1967 to 1994, and 11 sites were added between 2000 and 2010. Exhibit RCS-2, Schedule B-2, pages 2 and 3, lists those PHFFU sites with expected in-service dates of beyond 2026, i.e., beyond the next ten years. I recommend that the cost of these sites be removed from the 2017 test year PHFFU balance that is included in rate base.

Q. DOES THE COMMISSION HAVE A STANDARD THAT IT HAS APPLIED TO DETERMINE WHETHER SPECIFIC FUTURE USE PROPERTIES SHOULD BE INCLUDED IN RATE BASE?

A. FPL offered a standard in the 2012 rate case that is useful and can be followed since they agreed to it. As addressed in his rebuttal testimony in FPL's last rate case, former PSC Commissioner Terry Deason offered the following as a standard (at page 14, lines 1 to 11):

> The Commission's standard is one of reasonableness or what amount of PHFU is reasonably needed to cost-effectively provide reliable service to existing and future customers. Applying this standard requires a review of specific properties to determine whether their acquisition and retention are reasonable to provide service over an adequate planning horizon. The Commission's reasonableness standard cannot be determined by arbitrary and rigid time limitations on the properties' ultimate use. To do so would be contrary to Commission policy and ultimately work to the disadvantage of utilities' customers.

Q. HAS FPL IN THIS DOCKET MADE ANY SHOWING THAT THE SPECIFIC PROPERTIES ARE REASONABLY NEEDED TO COST-EFFECTIVELY PROVIDE RELIABLE SERVICE TO EXISTING AND FUTURE CUSTOMERS OR WHAT TIMEFRAME IS AN ADEQUATE PLANNING HORIZON?

A. No, it has not. FPL has made no showing why the projects that have been in rate base for more than 10, and some more than 40 years, which are not expected to provide service for more than 10 years after the test year, are reasonably needed to provide reliable service to existing and future customers. Customers should not be required to continue to provide FPL with a rate base return, including shareholder profits, on these projects when FPL has failed to show why these properties were needed. Further, it has failed to explain why a 40 to 50-year planning horizon is reasonable for identifying assets to be included in rate base as used and useful plant.

Q. WHAT COSTS DID FPL ASSIGN TO PHFFU SITES WITH EXPECTED IN-SERVICE DATES BEYOND 2026?

A. A description of the PHFFU sites and their associated costs, which total $14.681 million on a 13-month average basis (per OPC Interrogatory No. 105), are summarized on Exhibit RCS-2, Schedule B-2.

Q. PLEASE SUMMARIZE YOUR OVERALL ADJUSTMENT TO PHFFU FOR THE 2017 FUTURE TEST YEAR RATE BASE.

A. As shown on Exhibit RCS-2, Schedule B-2, my adjustment removes the PHFFU in the 2017 future test year in the amount of $14.681 million total ($14.228 million jurisdictional) for sites with estimated in-service dates beyond 2026.

Q. IS THERE A SIMILAR ADJUSTMENT TO THE 2018 FUTURE TEST YEAR RATE BASE?

A. Yes. As shown on Exhibit RCS-3, Schedule B-2, for the 2018 future test year, the jurisdictional adjustment decreases average 2018 jurisdictional rate base by $14.234 million.

<u>Construction Work in Progress</u>

Q. HAS FPL INCLUDED CONSTRUCTION WORK IN PROGRESS ("CWIP") IN ITS RATE BASE REQUEST?

A. Yes. For the 2017 test year, MFR Schedule B-1 shows that $747,987,000 has been included in rate base for CWIP.

Q. SHOULD THE COMMISSION ALLOW THE NON-INTEREST-BEARING CWIP TO BE INCLUDED IN RATE BASE AS PROPOSED BY FPL?

A. No. It is my opinion that CWIP should not be afforded rate base treatment. CWIP, by its very nature, is plant that is not completed and is not providing service to customers. More specifically, and in reference to this proceeding, CWIP is not used or useful in delivering electricity to FPL's customers. Under the ratemaking process, utilities are permitted to earn a return on the assets that are used and useful in providing service to a utility's customers. Assets that are still undergoing construction clearly are not used in providing service to customers during the construction period. Because of this, the ratemaking process in some jurisdictions excludes CWIP from rate base, requiring that assets be classified as used and useful in serving customers prior to earning a return on those assets being recovered from ratepayers. Therefore, as a general regulatory principle, CWIP should be excluded from rate base and from costs being charged to customers until such time as it is providing service to those customers.

However, it is my understanding that the Commission has consistently allowed the inclusion of non-interest-bearing CWIP projects for electric utilities in rate base. This understanding was affirmed in the Commission's Order No. PSC-12-0179-FOF-EI, issued April 3, 2012, in Docket No. 110138-EI in a Gulf Power Company general rate case proceeding. In that order, at page 20, the Commission reaffirmed that: "the inclusion of CWIP (not eligible for AFUDC) in rate base is consistent with our practice." In acknowledgement of the Commission's practice and its recent affirmation thereof, I have not removed the non-interest-bearing CWIP from rate base for purposes of determining OPC's recommended revenue requirement in this case. However, the fact that the removal has not been reflected in OPC's revenue requirement calculations in this case should not be interpreted to mean that OPC's position on this issue has changed, or that OPC will not pursue this important policy issue in this rate case or future proceedings.

Rate Case Expense

Q. PLEASE EXPLAIN THE COMPANY'S ADJUSTMENT TO RATE CASE EXPENSE.

A. As discussed in the direct testimony of Company witness Kim Ousdahl, FPL has estimated rate case expenses totaling $4,925,000, which it proposes to amortize over a four-year period beginning in 2017. In its response to SFHHA Fourth Set of Interrogatories, Interrogatory No. 106, Attachment 1, FPL provided the breakdown of its projected $4.925 million of rate case expense for this case. In response to OPC Production of Documents No. 1, FPL provided detail for C-10, its rate case budget. That detail is included in the table below, which provides a breakdown of the estimated cost into categories:

Summary Table - FPL Requested Rate Case Expense	
Component	Totals
INCREMENTAL FPL Labor - Non-Exempt OT	$82,100
INCREMENTAL FPL Labor - Related Overhead	$19,992
Employee Related Travel Total	$505,800
Outside Services - Security	$24,000
Outside Services - Legal Fees Subtotal	$750,000
Outside Services - IM & Accounting Subtotal	$8,500
Outside Services - Temporary Labor Subtotal	$832,400
Outside Services - Professional Subtotal	$2,363,400
Outside Services - Other Subtotal	$86,000
Office & Facilities Administration Total	$181,808
Office & Facilities Administration Total	$71,000
Total	$4,925,000

As shown on MFR Schedule C-10, using the four-year amortization period, FPL proposes to include $1,231,250 for test year rate case expense amortization. In addition, as shown on MFR Schedule B-2, page 3 of 8, at line 23, FPL proposes to include the 13-month average unamortized balance of rate case expense associated with this proceeding of $4.309 million in the working capital component of its proposed 2017 test year rate base.

Q. DO YOU AGREE THAT THE COMPANY'S PROJECTED RATE CASE EXPENSE OF $4.925 MILLION IS REASONABLE?

A. No. The Company's projected rate case expense appears significantly overstated and should be reduced. The FPL labor costs should be removed. The $505,800 in employee related travel should be reduced, as should the amounts for temporary labor and professional.

Q. WHY SHOULD THE FPL LABOR COST BE REMOVED?

A. As indicated previously, FPL has included $82,100 for "Labor Non-Exempt OT" and $19,982 in "FPL Labor-Related Overhead". This category includes current fiscal year costs such as overtime. Because FPL's labor costs are already included in current base rates, these are labor expenses that FPL is incurring in 2016. FPL is proposing to add these 2016 labor costs to rate case expense that will be amortized in 2017 even if FPL's earnings in 2016 are adequate. The Commission has previously found that it is inappropriate for FPL to include additional pay or labor costs as part of the rate case expense to be recovered from ratepayers in future periods. In Order No. PSC-10-0153-FOF-EI, issued March 17, 2010, Docket No. 080677-EI, at page 163, in the 2008 FPL rate case, the Commission stated the following with respect to FPL including overtime labor in its projected rate case expense:

> FPL included $450,000 for overtime and or bonuses for salaried employees in its original total rate case expense filing. We have historically disallowed recovery of additional pay or bonuses as part of rate case expense. In Order No. PSC-08-0327-FOF-EI, we stated "Salaried Overtime Pay for Extraordinary Work Load" shall be disallowed because these employees and managers are paid a salary, not an hourly wage. Salaried employees are

usually expected to work the hours required to complete their job duties without extra compensation. (Footnote omitted)

Q. WHAT IS INCLUDED IN THE "EMPLOYEE RELATED TRAVEL" AMOUNT?

A. For the "Employee Related Travel" category, FPL's workpaper provides a breakdown of the total costs of $505,800, as follows:

Employee Related Travel	Amount
Hotel and Lodging	$244,300
Business Meals	$148,200
Airline Travel	$42,000
Vehicle - Car Rental	$33,800
Travel Expense	$16,700
Vehicle - Occasional	$20,800
Employee Related Travel Total	$505,800

FPL projects that $421,500 of this would be incurred in September 2016 alone:

Monthly Employee Travel Expense Components	JAN 2016	FEB 2016	MAR 2016	APR 2016	MAY 2016	JUN 2016	JUL 2016	AUG 2016	SEP 2016	OCT 2016	NOV 2016	DEC 2016	TOTAL
Hotel and Lodging	$300	$1,000	$3,000	$5,000	$2,000	$2,000	$2,000	$5,000	$215,000	$5,000	$3,000	$1,000	$244,300
Business Meals	$200	$500	$2,000	$3,000	$1,500	$1,500	$1,500	$3,000	$130,000	$3,000	$1,500	$500	$148,200
Airline Travel	$0	$0	$0	$0	$0	$3,000	$3,000	$3,000	$20,000	$10,000	$2,000	$1,000	$42,000
Vehicle - Car Rental	$100	$200	$400	$600	$600	$600	$600	$2,000	$25,000	$3,000	$500	$200	$33,800
Travel Expense	$50	$100	$200	$200	$200	$200	$200	$1,000	$14,000	$300	$200	$50	$16,700
Vehicle - Occasional	$100	$100	$200	$250	$250	$250	$250	$1,200	$17,500	$400	$200	$100	$20,800
TOTALS	$750	$1,900	$5,800	$9,050	$4,550	$7,550	$7,550	$15,200	$421,500	$21,700	$7,400	$2,850	$505,800

The hearings for this proceeding are scheduled for August 22 to September 2, 2016, with the post-hearing briefs due to be filed by the parties on September 16, 2016. Even with a two-week hearing, $421,500 of cost in September 2016 appears excessive. For example, if you take the hotel and lodging amounts for September of $215,000 and divide it by 12 days for the 10-day hearing, it equates to almost $18,000 per day. If you assume a $150 per night hotel group rate, which we could assume FPL could easily secure, that relates to over 120 employees staying in Tallahassee each night. Similarly, the amount for business meals over the same 12-day period equates to almost $11,000 per day or almost $100 a day per employee. Based on these estimates, clearly the lodging and meal estimates are excessive.

I would point out that these are the travel costs for employees and do not include the travel costs for the outside professional consultants that will attend the hearing.

Q. ARE THERE OTHER CATEGORIES OF COSTS THAT APPEAR TO BE OVERPROJECTED OR UNSUPPORTED?

A. Yes. Several of the cost estimates included in the Professional Services category appear to be either excessive or questionable. For example, $400,000 was included for "Concentric Energy, Advisors, Inc., Reed", yet only $58,190 is shown as paid through March 2016. The Company also included $40,000 for "William Feaster," yet no direct testimony was filed by Mr. Feaster. An amount of $250,000 is shown for "Sussex Consulting, Hevert" of which $73,295 is shown as paid through March 2016. That appears excessive for a return on equity witness, especially in comparison to OPC's rate of return and capital structure witnesses of less than $100,000 in total. In addition, the Company has included costs for additional potential rebuttal witnesses totaling $993,400.

Q. IS THE COMPLEXITY OF FPL'S FILING RESULTING IN INCREASED RATE CASE EXPENSE, AND WHO SHOULD BEAR THAT?

A. It appears that the complexity of FPL's filing, with two forecasted test years and an additional 2019 step increase, has increased rate case expense. These costs are not reasonable and should not be borne by ratepayers.

Q. WHAT IS YOUR RECOMMENDED AMOUNT TO BE ALLOWED FOR RATE CASE EXPENSE IN THIS CASE?

A. My recommended adjustment is presented on Exhibit RCS-2, Schedule C-2. Because several of the projected costs are inappropriate for inclusion in rate case expense, and other costs appear excessive, I recommend that the costs in this case be limited to the amount of rate case expense allowed by the Commission in FPL's 2008 rate case, adjusted for inflation. In FPL's prior 2008 rate case, Order No. PSC-10-0153-FOF-EI, the Commission authorized a rate case expense recovery of \$3,207,000[4]. I escalated the allowed level from the prior docket using the O&M multiplier for CPI[5] of 1.072066 to 2013 and by 1.05300 for 2014 to the 2017[6] test year to determine the recommended amount of rate case expense. As shown on Exhibit DR-2, Schedule C-2, this adjustment results in an overall rate case expense of \$3.620 million, or \$1.305 million less than the Company's requested amount of \$4,925,000. The annual amortization of these costs, using FPL's proposed four-year amortization period, is approximately \$905,000, or \$326,000 less than the amount proposed by FPL. Thus, the test year amortization expense requested by FPL should be reduced by approximately \$326,000.

<u>Unamortized Rate Case Expense</u>

Q. HAS THE COMPANY INCLUDED THE PROJECTED TEST YEAR BALANCE OF UNAMORTIZED RATE CASE EXPENSE IN ITS WORKING CAPITAL REQUEST IN THIS CASE?

A. Yes. As noted above, the working capital component of rate base for the 2017 test year includes \$4.309 million for FPL's projected unamortized rate case expense associated with this case. As noted in FPL's response to Staff First Set of Interrogatories, No. 52, FPL also reflected a \$1.9 million deferred tax liability:

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[4] The Final Order in FPL's 2008 rate case in Docket No. 080677-EI was issued March 17, 2010.
[5] See MFR Schedule C-40 from FPL's filing in Docket No. 120015-EI.
[6] As shown on Exhibit RCS-2, Schedule C-2, this incorporates the recommendation of OPC witness Dismukes to use an inflation rate for 2016 of 1.44% instead of 2.00% and an inflation rate for 2017 of 2.0% instead of the 2.5% for 2017 listed on FPL's MFR Schedule C-40.

> FPL has included a $1.9 million deferred tax liability on line 6, column 2 on MFR D-1a in its Company per book forecast related to the total amount of deferred rate case expenses for this proceeding of $4.9 million (refer to MFR C-10). The Company adjustment associated with the amortization of deferred rate case expenses is removed from capital structure pro rata over all sources of capital, which is consistent with the treatment of Company adjustments in prior FPL base rate proceedings.

Q. SHOULD FPL BE PERMITTED TO INCREASE RATE BASE FOR THE UNAMORTIZED RATE CASE EXPENSE BALANCE?

A. No, it should not. The Commission has disallowed the inclusion of unamortized rate case expense in working capital in several prior decisions. This long-standing Commission policy was reaffirmed in Order No. PSC-10-0131-FOF-EI, issued March 5, 2010, involving Progress Energy Florida. At pages 71 to 72 of that Order, the Commission stated the following with regard to unamortized rate case expense:

> We have a long-standing policy in electric and gas rate cases of excluding unamortized rate expense from working capital, as demonstrated in a number of prior cases. The rationale for this position was that ratepayers and shareholders should share the cost of a rate case: i.e., the cost of the rate case would be included in the O&M expenses, but the unamortized portion would be removed from working capital. It espouses the belief that customers should not be required to pay a return on funds expended to increase their rates.
>
> While this is the approach that has been used in electric and gas cases, water and wastewater cases have included unamortized rate case expense in working capital. The difference stems from a statutory requirement that water and wastewater rates be reduced at the end of the amortization period (Section 367.0816, F.S.). While unamortized rate case expense is not allowed to earn a return in working capital for electric and gas companies, it is offset by the fact that rates are not reduced after the amortization period ends.
>
> We agree with the long-standing policy that the cost of the rate case should be shared, and therefore find that the unamortized rate case expense amount of $2,787,000 shall be removed from working capital. (Footnote omitted)

In a footnote on page 71 of the Order, the Commission identified the following cases that confirm and validate its long-standing policy of excluding the unamortized rate case expense from working capital in electric and gas cases:

> Order No. 23573, issued October 3, 1990, in Docket No. 891345-EI, In re: Application of Gulf Power Company for a rate increase; Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company; Order No. PSC-09-0375-PAA-GU, issued May 27, 2009, in Docket No. PSC-09-0375-PAA-GU [080366-GU], In re: Petition for rate increase by Florida Public Utilities Company.

In addition, in Order No. PSC-10-0153-FOF-EI, which was issued pursuant to FPL's last litigated rate case in Docket No. 080677-EI, at page 164, the Commission stated in part:

> We do not agree with the Company that the unamortized balance of rate case expense should be included in rate base. Historically, the unamortized balance of rate case expense has been excluded from rate base to reflect a sharing of the rate case cost between the ratepayers and the shareholders. Rate case expenses are recovered from ratepayers through the amortization process as a cost of doing business in a regulated environment. However, the unamortized balance of rate case expense has been excluded from rate base to reflect that an increase in rates is a benefit to the shareholders. (Footnote omitted)

This policy was also affirmed in Commission Order No. PSC-12-0179-FOF-EI, issued April 3, 2012, in Docket No. 110138-EI, involving Gulf Power Company, where the Commission stated at pages 30 and 31:

> [W]e have a long-standing practice in electric and gas rate cases of excluding unamortized rate case expense from working capital, as demonstrated in a number of prior cases. The rationale for this position is that ratepayers and shareholders should share the cost of a rate case; i.e., the cost of the rate case would be included in O&M expense, but the unamortized portion would be removed from working capital. This practice underscores the belief that customers should not be required to pay a return on funds spent to increase their rates.
>
> * * *
>
> For the foregoing reasons, we find that the unamortized rate case expense of $2,450,000 shall be removed from working capital consistent with our long standing practice.

In a footnote on page 30 of the Gulf Power Order, the Commission identified the same cases referenced in the footnote of the Progress Energy Florida Order discussed above.

Q. HAS FPL CITED ANY CASES IN WHICH A PORTION OF A UTILITY RATE CASE EXPENSE WAS ALLOWED TO BE INCLUDED IN RATE BASE?

A. Yes. In response to FIPUG's First Set of Interrogatories, Interrogatory No. 32(b), FPL states that:

> Rate case expenses are a necessary cost for any regulated public utility, just like any other cost included in FPL's revenue requirement calculation. Because the rate case expenses are recovered over a period of years, the unamortized rate case balance must be included in rate base in the Test Year in order to avoid an implicit disallowance of these deferred costs. Commission Order No. **PSC-08-0327-FOF-EI, issued on May 19, 2008,** allowed Florida Public Utilities Company [FPUC] to include one half of their unamortized rate case expense balance in working capital. Additionally, FPL requested to include unamortized rate case expenses in rate base in its last rate case (Docket No. 120015-EI) and is currently applying this treatment pursuant to Order No. PSC-13-0023-S-EI. (Emphasis added)

Similarly, in response to SFHHA's Fourth Set of Interrogatories, Interrogatory No. 107, FPL stated that:

> Rate case expenses are legitimate expenses incurred by the Company to prepare and present a case before the Commission in order to obtain rate relief. FPL requested a four year amortization of rate case expenses and the inclusion of unamortized rate case expenses in rate base beginning in its 2013 Test Year in Docket No. 120015-EI. The Commission approved a stipulation and settlement agreement in this docket **in Order No. PSC-13-0023-S-EI,** which authorized this recovery. (Emphasis added)

However, the Commission specifically stated in Order No. PSC-09-0375-PAA-GU, issued May 27, 2009, in Docket No. 080366-GU, at pages 21-22, in the FPUC rate case that "[t]he inclusion of unamortized rate case expense in working capital in FPUC's case is an exception to our long-standing policy." FPUC has had this exception since 1993. Id. at

22. In this order, the Commission explained that "[w]hile unamortized rate case expense is not allowed to earn a return in working capital for electric and gas companies, it is offset by the fact that rates are not reduced after the amortization period ends." Id. at p. 21. The other order FPL refers to in its discovery response is the order approving its non-unanimous settlement in its last rate case proceeding. The Settlement specifically states that "[n]o party will assert in any proceeding before the Commission that this Agreement or any of the terms in the Agreement shall have any precedential value." Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 120015-EI, at page 26. Neither order supports a change in the Commission's long-standing policy of disallowing rate case expense in rate base.

Q. DO YOU RECOMMEND THAT THE UNAMORTIZED RATE CASE EXPENSE BE EXCLUDED FROM RATE BASE IN THIS CASE?

A. Yes, I recommend that the Commission follow its long-standing policy in electric cases of not allowing inclusion of the unamortized rate case expense in rate base. Consistent with the Commission's findings in the most recent Progress Energy Florida base rate cases, and the Gulf Power Company base rate case cited above, and FPL's 2010 rate case, it would be unfair for customers to pay a return on the costs incurred by the Company in this case when these are being used to increase customer rates. On Exhibit RCS-2, Schedule B-1, page 2, I have removed the full amount of the unamortized balance of rate case expense from working capital in this case, thus reducing rate base by $4.309 million.

Q. DO YOU AGREE THAT ADIT IN THE CAPITAL STRUCTURE SHOULD BE ADJUSTED TO SYNCHRONIZE WITH THE RATE BASE ADJUSTMENT?

A. Yes. A related adjustment to remove the related $1.9 million ADIT from the ADIT that is reflected in the capital structure should also be made. The reconciliation of the rate base with the capital structure is shown on Exhibit RCS-2, Schedule D.

Q. IS THERE A RATE BASE ADJUSTMENT FOR THE 2018 FUTURE TEST YEAR?

A. Yes. As shown on Exhibit RCS-3, Schedule B-1, line 24, FPL's requested amount of $3.078 million is removed from the 2018 future test year rate base. It would also be appropriate to adjust the 2018 capital structure for related ADIT.

<u>Generation Overhaul Expense</u>

Q. ARE YOU AWARE OF ANY COST PROJECTIONS INCORPORATED IN THE TEST YEAR THAT ARE NOT REPRESENTATIVE OF A NORMAL ANNUAL COST LEVEL?

A. Yes. FPL is projecting a significant increase in generation overhaul expense in the 2017 test year. Generation facilities are not overhauled on an annual basis. Additionally, the amount of overhaul expense incurred varies depending on the type of overhaul and the type of work needed during the overhaul. Test year generation overhaul expenses are significantly higher than a normalized cost level. The changes to base rates resulting from this case will likely be in effect longer than a one-year period. Thus, in setting rates, the costs should be based on a normalized cost level.

Q. HOW DO YOU RECOMMEND A NORMALIZED COST LEVEL BE DETERMINED?

A. I recommend that the normalized costs to be included in rates be based on a four-year average cost level. I recommend the four-year average be based on the actual costs for 2014 and 2015 and FPL's projected costs for 2016 and 2017.

Q. WHAT ADJUSTMENT DO YOU RECOMMEND TO NORMALIZE TEST YEAR OVERHAUL EXPENSE?

A. My recommended adjustment is presented on Exhibit RCS-2, Schedule C-3. As shown on the schedule, the adjustment is based on the average of the actual 2014 and 2015 as well as the projected 2016 and 2017 generation overhaul expenses. I inflated the costs to 2017 levels based on the inflation rates recommended by OPC witness Dismukes. As shown on Exhibit RCS-2, Schedule C-3, FPL's projected 2017 test year jurisdictional generation overhaul expenses should be reduced by $3.603 million. This allows for the non-unit specific costs incorporated in FPL's filing (i.e., the "Central Maintenance" expenses) on a four-year average basis, as well as a normalized cost level for the unit specific costs.

Q. IS THERE A SIMILAR ADJUSTMENT FOR 2018?

A. Yes. The similar adjustment for 2018 is shown on Exhibit RCS-3, Schedule C-3, and reduces jurisdictional O&M expense by $8.562 million. Five-year normalized overhaul expense (based upon 2014 – 2018) is also presented on Exhibit RCS-3, Schedule C-3, and would produce an adjustment to reduce jurisdictional 2018 O&M expense by $9.082 million. For purposes of reflecting this adjustment, the $8.562 million has been used by carrying that amount to the OPC net operating income adjustments on Exhibit RCS-3, Schedule C-1, page 2.

<u>Income Tax Expense</u>

Q. HAVE YOU ADJUSTED 2017 TEST YEAR INCOME TAX EXPENSE TO REFLECT THE IMPACT OF THE ADJUSTMENTS SPONSORED BY CITIZENS' WITNESSES TO NET OPERATING INCOME?

A. Yes. On Exhibit RCS-2, Schedule C-4, I calculate the impact of federal and state income tax expenses resulting from the recommended adjustments to operating expenses. The result is carried forward to the Net Operating Income Summary on Exhibit RCS-2, Schedule C-1, page 2.

Q. IS THERE A SIMILAR ADJUSTMENT FOR 2018?

A. Yes. The similar adjustment for 2018 is shown on Exhibit RCS-3, Schedule C-4.

<u>Interest Synchronization</u>

Q. WHAT IS THE PURPOSE OF YOUR 2017 TEST YEAR INTEREST SYNCHRONIZATION ADJUSTMENT ON EXHIBIT RCS-2, SCHEDULE C-5?

A. The interest synchronization adjustment allows the adjusted rate base and cost of debt to coincide with the income tax calculation. Since interest expense is deductible for income tax purposes, any revisions to the rate base or to the weighted cost of debt will impact the test year income tax expense. OPC's proposed rate base and weighted cost of debt differ from the Company's proposed amounts. Thus, OPC's recommended interest deduction for determining the 2017 test year income tax expense will differ from the interest deduction used by FPL in its filing. Consequently, OPC's recommended debt ratio increase in this case will lead to a greater interest deduction in the income tax calculation, which will in turn result in a reduction to income tax expense.

Q. IS THERE A SIMILAR INTEREST SYNCHRONIZATION ADJUSTMENT FOR THE 2018 FUTURE TEST YEAR?

A. Yes. The similar interest synchronization adjustment for the 2018 test year is shown on Exhibit RCS-3, Schedule C-5.

Q. IS THERE AN INTEREST SYNCHRONIZATION ADJUSTMENT FOR THE OKEECHOBEE STEP INCREASE?

A. Yes. The interest synchronization adjustment for the Okeechobee step increase is shown on Exhibit RCS-4, Schedule C-2.

Revenue At Current Rates - Sales Forecast

Q. PLEASE EXPLAIN THE ADJUSTMENT FOR REVENUE AT CURRENT RATES - SALES FORECAST.

A. OPC witness David Dismukes has reviewed FPL's sales forecast for the 2017 and 2018 projected future test years. Dr. Dismukes has determined that FPL's sales forecasts understate the level of metered retail sales (MWh). Accordingly, Dr. Dismukes is recommending a revision to the FPL sales forecasts. Dr. Dismukes provided me with the additional amounts of Revenue at Current Rates of $206.5 million for 2017 and $259.5 million for 2018. I have reflected the corresponding adjustments on Exhibit RCS-2, Schedule C-6 for 2017 and on Exhibit RCS-3, Schedule C-6 for 2018. Those schedules also show the related increase to Uncollectibles Expense, using FPL's corrected uncollectibles factor of 0.00066 (or 0.066%) from FPL's May 3, 2016 Notice of Identified Adjustments item 5, "NOI Multiplier - Bad Debt Rate."

The amount of adjustment for Revenue at Current Rates shown on Exhibit RCS-2, Schedule C-6 for 2017 and on Exhibit RCS-3, Schedule C-6 for 2018 has been netted against the revenue related to sales associated with the net operating income adjustment amounts of $4.9 million for 2017 and $9.338 million that FPL identified in its May 3, 2016 Notice of Identified Adjustments item 4, which have already been incorporated into OPC's revenue requirement calculation. OPC's incorporation of the adjustments that were identified by FPL in the Company's May 3, 2016 Notice of Identified Adjustments are discussed in a previous section of my testimony.

Depreciation Expense - New Depreciation Rates

Q. PLEASE EXPLAIN THE ADJUSTMENT TO DEPRECIATION EXPENSE FOR NEW DEPRECIATION RATES.

A. In the current rate case, FPL has proposed new depreciation rates for 2017. In its application, at Exhibit NWA-1, page 7 of 762 (FPL's 2017 Depreciation Study) the Company shows that on its projected December 31, 2017 Plant, at current depreciation rates, annual depreciation accruals would total to approximately $1.433 billion. At FPL's proposed depreciation rates, the annual depreciation accruals would total to approximately $1.654 billion, for an annual increase in depreciation accruals of approximately $221.3 million. In its application, at MFR Schedule C-2 for Projected Test Year Ended 12/31/17, page 3 of 3, line 15, FPL reflected an adjustment to increase 2017 projected test year jurisdictional Depreciation Expense by approximately $195.1 million.

OPC witness Jacob Pous is recommending new depreciation rates that differ from those proposed by FPL. As shown on Exhibit RCS-2, Schedule C-7, column 2, applying the new depreciation rates recommended by OPC witness Pous to FPL's December 31, 2017 Plant produces annual depreciation accruals of approximately $1.351 billion. As shown on Schedule C-7 in column 3, that is approximately $302.8 million less than the annual depreciation accruals computed by FPL in its Exhibit NWA-1, at page 7 of 762. OPC witness Pous also recommends amortizing a $923 million depreciation reserve excess over 4 years, for an annual reduction to depreciation expense of $230.8 million annually, as shown on Schedule C-7 in columns 4 and 5.

Q. HOW DID YOU ADJUST THE DEPRECIATION EXPENSE IN FPL'S 2017 TEST YEAR FOR THE IMPACT OF OPC WITNESS POUS' RECOMMENDED NEW DEPRECIATION RATES?

A. As shown on Exhibit RCS-2, Schedule C-7, OPC witness Pous' recommendation for new depreciation rates had two impacts. The first was a reduction to depreciation expense of approximately $303 million (calculated based on December 31, 2017 plant), as shown on Schedule C-7 in column 3. The second is the ratable flow-back over a four-year period of a depreciation reserve excess of approximately $923.1 million, as shown on Schedule C-7 in column 4. The annual impact of that flow back further reduces depreciation expense by approximately $230.8 million per year, as shown on Schedule C-7, in columns 5 and 10.

Q. WHAT IS SHOWN ON EXHIBIT RCS-2, SCHEDULE C-7, IN COLUMNS G THROUGH K?

A. Exhibit RCS-2, Schedule C-7, in column G shows FPL's total 2017 depreciation expense adjustment of $221.3 million by plant function that relates to the new depreciation rates being proposed by FPL. Column H shows FPL's exclusion of depreciation expense for amounts that are included in adjustment Clauses, and not in base rates. Column I shows FPL's depreciation expense amount for base rates that relates to the new depreciation rates being proposed by FPL of approximately $206 million. Column J shows the jurisdictional factors FPL applied for 2017 for its depreciation rates adjustment, and column K shows FPL's jurisdictional adjustment to depreciation expense in base rates for its new proposed depreciation rates of $195.1 million.

Q. HOW DID YOU UTILIZE THAT INFORMATION TO DERIVE THE OPC'S ADJUSTMENT TO DEPRECIATION EXPENSE FOR NEW DEPRECIATION RATES THAT IS REFLECTED IN OPERATING EXPENSES FOR THE 2017 TEST YEAR?

A. As shown on Exhibit RCS-2, Schedule C-7, in columns 3 and 7, the depreciation rates part of OPC witness Pous' recommendation (exclusive of the excess depreciation reserve flow-back) decreases FPL's depreciation expense by approximately $303 million. Column 8 shows the percentages of base rate to total FPL depreciation expense adjustment, based on the ratio of the FPL amounts in columns I (base rates) and G (total FPL new depreciation rates expense adjustment). Exhibit RCS-2, Schedule C-7, column 9, shows that after excluding the depreciation expense identified by FPL for Clauses (i.e., the amounts not sought by the Company to be recovered in base rates), the adjustment to depreciation expense for new depreciation rates is approximately $292.6 million. Column 10 shows the first year of the four-year amortization of the excess depreciation reserve recommended by OPC witness Pous, which reduces annual depreciation expense by approximately $230.8 million. Column 11 shows the sum of the two components, the $292.6 million and the $230.8 million, which total $523.4 million, before applying FPL's 2017 jurisdictional factors. After applying the jurisdictional factors, the adjustment shown on Exhibit RCS-2, Schedule C-7, in column 13 reduces FPL's requested 2017 depreciation expense in base rates by approximately $501.3 million. The amounts shown on Exhibit RCS-2, Schedule

C-7, column 13, are carried forward to Exhibit RCS-2, Schedule C-1, page 2, and reflected in the derivation of OPC's adjusted net operating income.

Q. IS THERE A RELATED ADJUSTMENT TO RATE BASE?

A. Yes. As shown on Exhibit RCS-2, Schedule B-1, page 2, there are related adjustments which decrease accumulated depreciation (and increase rate base). The impacts on 2017 rate base were derived by taking one-half of the annual depreciation expense adjustment.

Q. DID YOU COMPUTE THE ADJUSTMENT TO DEPRECIATION EXPENSE FOR THE 2018 FUTURE TEST YEAR IN A SIMILAR MANNER?

A. Yes. The adjustment to depreciation expense for the 2018 future test year in a similar manner on Exhibit RCS-3, Schedule C-7. As shown there, FPL's requested 2018 depreciation expense for base rate inclusion is reduced by approximately $495.2 million.

Q. IS THERE A RELATED IMPACT ON 2018 RATE BASE?

A. Yes. As shown on Exhibit RCS-3, Schedule B-1, page 2, the related impact on 2018 rate base is comprised of three components: (1) one-half of the 2018 depreciation rates expense adjustment, (2) a full year of the flow back in 2017 of the depreciation reserve excess, and (3) a half year (i.e., average) impact of the flow back in 2018 of the depreciation reserve excess.

Q. WERE YOU ABLE TO FULLY INTEGRATE THE OPC'S NEW DEPRECIATION RATES RECOMMENDATION WITH THE COMPANY'S ANNOUNCED FILING ADJUSTMENTS?

A. No. One of FPL's June 16, 2016 Second Notice adjustments was an adjustment to depreciation expense. FPL provided an Excel file showing an Updated Exhibit KF-2 (4 pages) showing its filing correction adjustments to 2017 and 2018 depreciation expense and accumulated depreciation. Those FPL filing corrections reduced the Company's proposed 2017 depreciation expense by $22.794 million (from FPL's as-filed amount of $206.023 million to its updated amount of $183.229 million) and reduced its proposed 2018 depreciation expense by $24.564 million (from the as-filed $208.865 million amount to the corrected amount of $184.302 million), along with related adjustments to accumulated depreciation. FPL's explanation of that adjustment described it as an update to its 2016 Depreciation Study, stating, among other things that:

> Because the primary test year in FPL's base rate case is 2017, FPL considered year-end 2017 estimated plant and reserve balances as best representing FPL's depreciable plant during the test year. Discovery to date from Staff and others has raised questions about whether using year-end 2016 balances would be more appropriate and consistent with past Commission practice. FPL continues to believe that the use of year-end 2017 balances would provide a good match with FPL's 2017 Test Year and 2018 Subsequent Year, but has no objection to using results for year-end 2016 balances for the purpose of setting depreciation rates and determining FPL's base rates in this proceeding and accordingly is proposing the adjustment described...

I am unclear as to how to integrate Mr. Pous' new depreciation rate recommendations with this FPL update adjustment. If the Commission should decide to use year-end 2016 balances for the purpose of setting FPL's depreciation rates and determining FPL's base rates in this proceeding, this FPL update would need to be integrated with the OPC's depreciation rate recommendations. If the Commission should decide not to use year-end 2016 balances for such purposes, the impact of this FPL filing update may need to be reversed.

VII. OVERALL FINANCIAL SUMMARY – JANUARY 2018 SUBSEQUENT YEAR RATE CHANGE

Q. WHAT IS THE JANUARY 2018 BASE RATE REVENUE REQUIREMENT DEFICIENCY OR EXCESS FOR FLORIDA POWER & LIGHT COMPANY?

A. As shown on Exhibit RCS-3, Schedule A-1, the OPC's recommended adjustments in this case result in a recommended revenue reduction for FPL in January 2018 of approximately $604 million. The $1.134 billion revenue increase requested by FPL for the 2018 projected future test year is presented in the Company's filing as an additional $262.3 million after the additional 2017 rate increase revenues of $871.3 million that FPL has requested. The OPC's recommendation of a revenue excess of approximately $604 million for the 2018 future test year is $1.737 billion lower than FPL's request of $1.134 billion.

Q: DO YOU BELIEVE THAT THE 2018 SUBSEQUENT TEST YEAR REQUEST IS NECESSARY OR GOOD POLICY.

A. No, I do not think that a subsequent test year is necessary or good policy. The test year is supposed to be representative of rates on a going-forward basis. If the test year is chosen appropriately, there should be no reason for another rate adjustment so shortly after original test year. As the Commission noted in Order No. PSC-10-0153-FOF-EI, at page 9, "[i]f the test year is truly representative of the future, then the utility should earn a return within the allowed range for at least the first 12 months of new rates." As the Commission noted, these types of back-to-back rate cases deprive the Commission and ratepayers of twelve months of actual economic data and operating history of the Company. Id. The Commission further stated that "[w]e believe that back-to-back rate increases should be allowed only in extraordinary circumstances." Id. The Company has shown no extraordinary need for the subsequent test year. In fact, OPC recommendation is for a reduction of approximately $807 million based on 2017 ($812 million with growth in 2018) and an overall revenue reduction of approximately $604 million for 2018.

Q. ARE YOUR SCHEDULES IN EXHIBIT RCS-3 FOR THE 2018 SUBSEQUENT TEST YEAR ORGANIZED IN A SIMILAR MANNER TO YOUR ABOVE-DESCRIBED PRESENTATION FOR 2017?

A. Yes.

VIII. <u>OKEECHOBEE LIMITED SCOPE ADJUSTMENT (LSA OR STEP INCREASE) – JUNE 1, 2019</u>

Q. COULD YOU PLEASE BRIEFLY DESCRIBE FPL'S REQUEST AS IT PERTAINS TO THE OKEECHOBEE LIMITED SCOPE STEP INCREASE?

A. FPL projects that the Okeechobee Clean Energy Center will be completed and placed into service in mid-2019. FPL is requesting that the project be included in a Step Increase that would go into effect on June 1, 2019, when the project is projected to be placed into service and begins serving customers. FPL's stated purpose of treating this as a step increase in base rates is so that base rates will reflect an annual level of the Okeechobee Project costs, beginning with the date the project is used to serve FPL customers. Thus, the costs associated with the Okeechobee Project under FPL's request would be treated as a base rate step increase after project completion based on an annualized cost level.

FPL provided the calculation of the requested Okeechobee Project LSA in a separate set of MFRs that are specific to the project. These MFRs show a projected annualized rate base of $1.063 billion, a requested 8.87% overall rate of return applied to the rate base, and a projected net operating income (loss) associated with the project of $33,868,000.

Altogether, these amounts result in FPL's projected first year annualized revenue requirement for the Okeechobee Project of $209,024,000.

Q. DO YOU HAVE A PRIMARY RECOMMENDATION AS TO WHETHER THE COMMISSION SHOULD APPROVE FPL'S REQUESTED LSA INCREASE?

A. Yes. I recommend that the Okeechobee June 1, 2019 LSA increase request by FPL not be approved at this time. This is primarily because of my previous recommendations addressed in my testimony reflecting substantial revenue excesses for both 2017 and 2018. I am also skeptical of the accuracy and reasonableness of FPL's 2019-2020 projections, given that they are three years out in the future.

Q. IF THE COMMISSION WERE TO APPROVE THE LSA, ARE YOU RECOMMENDING ANY REVISIONS TO THE AMOUNT OF THE REVENUE INCREASE ASSOCIATE WITH THE OKEECHOBEE PROJECT REQUESTED BY FPL?

A. Yes. If the step increase is to be considered, the following contingent adjustments to FPL's request should be made. First, I recommend that the rate of return the Commission will apply to the projected rate base should be based on OPC's overall recommended 2018 rate of return. Next, I recommend that the projected amount of rate base and operating costs associated with the project be updated based on more recent forecasts, which should be presented by FPL in 2019 prior to approval of the project. Additionally, I recommend that the start-up costs included in FPL's projections be removed so that base rates established at the time of the proposed step increase are based on normalized costs and exclude one-time non-recurring charges.

Q. HAVE YOU PREPARED AN EXHIBIT PRESENTING OPC'S RECOMMENDED REVENUE REQUIREMENT AS IT PERTAINS TO THE OKEECHOBEE PROJECT STEP INCREASE TO BASE RATES?

A. Yes. I have prepared Exhibit RCS-4, consisting of Schedules A-1, B-1, C-1, C-2, and D. Each of these schedules is specific to the calculation of OPC's revenue requirement calculation for the June 1, 2019 Step Increase.

Q. IN CALCULATING THE CONTINGENT REVENUE REQUIREMENT FOR THE OKEECHOBEE STEP INCREASE, DID YOU USE THE COMPANY'S PROPOSED RATE OF RETURN?

A. No, I did not. In calculating the contingent revenue requirement for the June 1, 2019 Step Increase, the Company based its calculation of the increase on an overall rate of return of 8.87%. As reproduced on Exhibit RCS-4, Schedule D, the determination of this 8.87% overall rate of return was based on the following hypothetical capital ratio for the Okeechobee Project: 39.61% for long-term debt, 60.39% for equity, a 4.87% rate for long-term debt, and an 11.50% rate of return on equity. FPL did not include any deferred income taxes in its cost of capital for the LSA, nor did it include customer deposits or investment tax credits. In my opinion, it is not appropriate to use a different capital structure and overall rate of return to calculate the revenue requirement associated with FPL's requested step increase. I would note that FPL did not provide the projected amounts for the total cost of capital as of June 2019 in its MFRs for the Okeechobee LSA. As such, I do not have a reasonable basis to determine or project the amounts necessary to calculate the overall cost of capital to use. In lieu of a reasonably projected cost of capital for 2019, I believe that it is appropriate to use the OPC's adjusted 2018 cost of capital as a proxy rate of return. The resultant overall cost of capital is 5.17%, as shown on Exhibit RCS-4, Schedule D. This is the same cost of capital I have reflected on Exhibit RCS-3, Schedule D.

Q. DID FPL EXPLAIN WHY IT USED A DIFFERENT CAPITAL STRUCTURE AND OVERALL RATE OF RETURN FOR THE OKEECHOBEE STEP INCREASE CALCULATIONS?

A. A footnote at the bottom of MFR Schedule D-1a – June 2019 Step Increase states that "The capital structure reflects incremental sources of capital consistent with the analysis submitted in connection with its need determination proceeding."

Q. DOES THIS EXPLANATION SUPPORT THE USE OF A RATE OF RETURN THAT DIFFERS FROM THE RATE OF RETURN TO BE USED FOR CALCULATING THE JANUARY 2018 BASE RATE CHANGE?

A. No, it does not. Additionally, it is my understanding that the Commission has based prior approved step increases associated with certain major capital projects on the authorized overall rate of return found to be appropriate for determining the change to base rates in a rate case proceeding. An example of this can be found in Order No. PSC-12-0179-FOF-EI, issued April 3, 2012. That decision, at page 143, shows that the Commission applied its authorized overall rate of return that it found appropriate for purposes of determining the base rate increase for Gulf Power Company in its calculation of the January 2013 step increase associated with the annualization of the Crist Units 6 & 7 turbine upgrade projects.

Similarly, in Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, the Commission applied its authorized overall rate of return it found appropriate for determining the base rate increase for Tampa Electric Company in its calculation of the January 1, 2010 step increase associated with five combustion turbine units being placed into service. This is demonstrated at pages 138 and 139 of the Order, on Schedules 5 and 6.

Q. COULD FPL'S REQUESTED OKEECHOBEE LSA TREATMENT OF ACCUMULATED DEFERRED INCOME TAXES POTENTIALLY VIOLATE THE INTERNAL REVENUE CODE NORMALIZATION REQUIREMENTS?

A. Yes. In Staff's Interrogatory No. 233, Staff asked FPL to explain why FPL chose to include the Deferred Income Taxes-Net in Operating Expenses rather than include the amount in the capital structure or use the amount to reduce the rate base for the Okeechobee Clean Energy Center Limited Scope Adjustment. In its response, while not answering the question asked, FPL stated:

> FPL has included jurisdictional deferred income tax expenses as a component of Net Operating Income of $124,436,000 and $4,758,000 on Lines 23 and 24, respectively, on Page 2 of 2 on Schedule C-4 for the 2019 Okeechobee Limited Scope Adjustment. In addition, FPL has reflected the jurisdictional 13-month average of accumulated deferred income taxes associated with the first year of operations of the Okeechobee plant of ($81,359,000) on Line 27, Page 1 of 1 on Schedule B-6 for the 2019 Okeechobee Limited Scope Adjustment as a reduction to rate base. Both sides of the accounting entry must be considered when determining revenue requirements in order to properly reflect deferred income taxes for ratemaking purposes.

By reflecting one year's deferred tax expense in operating expenses and the 13-month average balance of the accumulated deferred income taxes (ADIT) as a reduction to rate base and excluding the total Company balance of deferred income taxes in the capital structure for determining a rate increase could violate normalization requirements. By not including the balance of deferred income taxes, the utility has not only overstated the rate of return but has also removed the benefits to ratepayers for the Company's use of tax timing differences in its income tax expense charged to ratepayers. Making an incremental reduction for ADITs for this project in rate base and removing the ADITs from the cost of capital does not cure this problem. If the Commission were to accept FPL's argument that its adjusted rate base and cost of capital would not violate normalization requirements, FPL should be required to provide detailed supporting calculations that no violation will occur. These calculations should include a showing that using an incremental cost of capital, with an incremental reduction to rate base for deferred income taxes results in a revenue neutral method of calculating the revenue requirement compared to setting rates using the Commission practice of including all deferred income taxes in the overall costs of capital.

Q. DO YOU HAVE AN ESTIMATE OF THE REVENUE IMPACT OF USING AN INCREMENTAL COST OF CAPITAL COMPARED TO USING THE FULL COST OF CAPITAL?

A. Yes. For illustration purposes, if I add back the Company's $81.359 million reduction to rate base for the ADITs equals an adjusted rate base of 1.144 billion. Multiplying that rate base times FPL's requested 2018 rate of return of 6.71% (using an 11.50% ROE and 60% equity ratio) results in jurisdictional income required of $76.807 million. As I have reflected on Exhibit No. RCS-4, Schedule A-1, FPL's requested jurisdictional income required for the LSA is $94.348 million. That alone is an increase of $17.541 million and that is before taxes. After taxes, the increase for using an incremental capital structure is $28.596 million. Based on this, FPL's own numbers show that its incremental cost of capital impact is certainly not revenue neutral and results in a substantial increase in the revenue requirement.

Q. YOU STATED THAT THE PROJECTED AMOUNT OF RATE BASE AND OPERATING COSTS ASSOCIATED WITH THE OKEECHOBEE PROJECT SHOULD BE UPDATED BASED ON MORE RECENT FORECASTS. PLEASE EXPLAIN.

A. In 2019, prior to approval of any limited purpose step increase, updated estimates should be presented by FPL. This would apply only if the Commission determines that a mid-2019 step increase is needed. OPC's primary recommendation, as noted above, is that the Commission reject the 2019 step increase because OPC shows significant revenue excesses for 2017 and 2018 and FPL has not demonstrated that a mid-2019 increase would be necessary to keep FPL from falling below the low point of its authorized ROE range. Approval of a projected mid-2019 step increase would be premature.

Q. PREVIOUSLY, YOU INDICATED THAT YOU WOULD RECOMMEND REMOVAL OF THE PROJECTED START-UP COSTS. WOULD YOU PLEASE ELABORATE?

A. Yes. Start-up costs that FPL projects to expense in the twelve-month period ending May 31, 2020 are one-time, non-recurring expenses that should not be incorporated in the June 2019 Step Increase.

Q. ARE THERE ANY ADDITIONAL ADJUSTMENTS THAT NEED TO BE MADE FOR PURPOSES OF CALCULATING THE REVENUE REQUIREMENT ASSOCIATED WITH FPL'S REQUESTED OKEECHOBEE STEP INCREASE?

A. Yes. As addressed previously in this testimony, OPC's recommended revision to the capital structure results in the weighted cost of debt being different than the amount incorporated in the Company's filing. This difference in the weighted cost of debt impacts the calculation of the interest deduction in the income tax calculations (i.e., the interest synchronization adjustment). On Exhibit RCS-4, Schedule C-2, I provide the calculation of the adjustment that needs to be made to FPL's updated income tax expense amount to reflect the impact of the interest synchronization adjustment, which increases the income tax expense by $360,000.

Q. WHAT IS THE RESULTING REVENUE REQUIREMENT ASSOCIATED WITH FPL'S REQUESTED OKEECHOBEE STEP INCREASE RECOMMENDED BY THE OPC IN THIS CASE?

A. As noted above, OPC is recommending that no mid-2019 step increase be granted. As shown on OPC Exhibit RCS-4, Schedule A-1, OPC's recommended adjustments discussed above, should the Commission consider this step increase, result in a June 2019 Step Increase for FPL of $145 million, which is $64 million less than the $209 million June 2019 Step Increase requested by FPL in its original filing. As I addressed earlier, this calculation is based on OPC's adjusted overall cost of capital of 5.17%.

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, it does.

MR. MOYLE: Just so the record is clear, when you say as corrected here today, the errata is not correcting the testimony --

CHAIRMAN BROWN: No. No. The number is reflected on Page 3, correct?

MS. CHRISTENSEN: Correct. As well as the information included on the errata sheet which are line and number changes subject to whatever further discussion the Chair has regarding the errata.

CHAIRMAN BROWN: Okay.

MS. BROWNLESS: Excuse me. I'm sorry. I want to make sure I understand what is being done. You are requesting what to be inserted into the record?

MS. CHRISTENSEN: Mr. Smith has prefiled his testimony. His testimony -- he's made some corrections here today to some of the numbers on Page 3, which I think there is no objection to that.

Included also on the errata sheet are some of the numbers that were contained in his testimony which have been changed as a result of correcting fallout numbers for removal of Mr. Pous' testimony within the testimony. And I think that's indicated on the errata sheet under the header: Testimony Errata.

CHAIRMAN BROWN: We are not moving 717 into the record, if that is your question.

MS. BROWNLESS: And I can explain my confusion here, and it's with regard to the instructions that the court reporter and our clerk will follow. If we are going to allow Mr. Moyle and other parties to review this 717 errata sheet, then we should not be instructing our clerk to insert the changed record, only the few oral modifications that he made.

CHAIRMAN BROWN: Add Ms. Brownless, that's what I was inserting was just Page 3 modifications that were changed during --

MS. CHRISTENSEN: Well, I think given the clarification that we're having in this discussion, I would just at this time move his prefiled direct testimony with the oral modifications made here today and then reserve, of course, the right to have his prefiled testimony corrected when the errata sheet or Exhibit 717 is moved into the record.

CHAIRMAN BROWN: Okay. So, we will --

MS. BROWNLESS: Thank you.

CHAIRMAN BROWN: -- for clarification purposes only, since that was my intent originally, we will move into the record Mr. Smith's direct prepared testimony with the modifications that were delineated on Page 3 into the record as though read.

Ms. Christensen, please continue.

MS. CHRISTENSEN: Thank you.

BY MS. CHRISTENSEN:

Q Did you file prefiled exhibits labeled RCS-1 through RCS-4 into your prefiled testimony?

A Yes, I did.

Q And do you have corrections to those exhibits?

A Yes. There were corrections on Exhibits RCS-2, RCS-3 and RCS-4.

Q And are those corrections noted on Exhibit 717 which is the errata sheet that was passed out earlier?

A Yes, they are.

Q And have you had a chance to review that errata sheet?

A Yes.

Q And do you have any corrections to that errata sheet?

A No.

CHAIRMAN BROWN: Staff, do you have any question, authentication.

MS. BROWNLESS: Yes, ma'am.

EXAMINATION

BY MS. BROWNLESS:

Q Have you had an opportunity to review Exhibit 579, the staff composite exhibit list?

A I think so. It doesn't have a number on it.

Q That's the one?

A I think I have. At least my piece of it.

Q And there it indicates that you sponsored what's been identified as Staff Exhibit 530. Do you see that, a portion of it, a portion of 530?

A Yes, I see that.

Q All right. Did you prepare the portion of 530 that's associated with your name on this list?

A I prepared the responses to No. 44 and No. 45. I did not prepare the response to No. 43.

Q And with regard to 44 and 45, is the information contained therein true and correct to the best of your knowledge and belief?

A Yes, it is.

Q And would your answers be the same today if you were asked the same discovery responses?

A It would be the same for 45. I think we modified our thinking slightly on 44 which was this issue of whether a normalization violation would occur under the Okeechobee step increase treatment.

Q And how would you modify your response to No. 44?

A I think the citations of relevant guidance are still accurate. Having reviewed all those and reviewed some company discovery, we're withdrawing our assertion that there would be a normalization violation. I think the main issue is the consistent use of the capital structure. And that's an issue with or without this normalization violation issue.

Q Thank you. Are any portions of the responses that you prepared confidential?

A No, they're not.

MS. BROWNLESS: Thank You.

CHAIRMAN BROWN: Thank You.

Ms. Christensen.

MS. CHRISTENSEN: Thank you. I would ask at this time that the witness be allowed to provide a summary.

CHAIRMAN BROWN: Absolutely. Welcome.

MR. SMITH: Larkin & Associates was retained by the Florida Office of Public Counsel to review the rate request of Florida Power & Light Company. Accordingly, I am appearing on behalf of the citizens of the State of Florida.

The purpose of my testimony in this proceeding is to present the OPC's overall revenue requirement in this case. I also sponsor some of the OPC's recommended adjustments to the companies proposed rate base and operating income.

In developing the OPC's overall recommended revenue requirement in this case, I reflected the recommendations of a number of other OPC witnesses, including Mr. Helmuth Shultz, Dr. David Dismukes, Kevin O'Donnell, Dr. Randall Woolridge and Dan Lawton.

The OPC's adjusted results are presented in terms of adjustments to the company's filing. They're shown on Exhibit RCS-2, Schedule A-1 Revised.

For the 2017 test year, OPC shows that the company has a revenue excess of 327.5 million. That is 1.194 billion lower than the company's requested increase of approximately 866 million.

For the 2018 subsequent year as shown on Exhibit RCS-3, Schedule A-1, Revised, on Line 8, OPC shows that the company has revenue excess of approximately 147 million. That is approximately 1.281 billion lower than the company's requested revenue deficiency of 1.134 billion.

For the Okeechobee limited step increase as shown on Exhibit RCS-4, Schedule A-1, OPC's adjusted results show revenue deficiency of approximately 145 million which is approximately 64 million lower than the company's requested increase of 209 million.

However, as I describe in my testimony, OPC's primary recommendation is that the Commission reject the 2019 step increase because OPC showed significant revenue excesses for 2017 and '18, and FPL has not demonstrated that a mid-2019 increase would be necessary to keep FPL from falling below the low point of its authorized ROE range. Approval of projected mid-2019 step increase at this time would be premature.

In terms of adjustments, I recommend that several items of planned and future use should not be included in rate base at this time. Those are shown on Exhibit RCS-2, Schedule B-2, and I recommend that 14.681 million on a total company basis and 14.238 million after jurisdictional allocation be removed.

I recommend certain adjustments to rate case expense. The company's requested 4.925 million which it proposes to amortize over a four-year period beginning in 2017. The company's projected rate case expense appears significantly overstated and should be reduced.

As shown on Exhibit RCS-2, Schedule C-2, I am recommending an overall rate case expense allowance of 3.62 million which is 1.305 million less than the company's requested amount. The annual amortization of this cost using FPL's proposed four-year amortization period is 905,000 or 326,000 less than the amount proposed by FPL.

FPL is proposing significant increase in fossil generation overall expense in the 2017 test year. Generation facilities are not overhauled on an annual basis. Additionally, the amount of overhaul expense incurred varies depending on the type of overhaul and the type of work needed during the overhaul.

Temperature generation overhaul expenses are significantly higher than a normalized cost level. The changes to base rates from this case will likely be in effect longer than a one-year period. Thus in setting rates, the cost should be based on a normalized cost level.

That concludes my summary.

MS. CHRISTENSEN: We tender the witness for cross.

CHAIRMAN BROWN: Thank you. Mr. Moyle.

MR. MOYLE: Thank you. I do not have any questions.

CHAIRMAN BROWN: Hospital's.

MR. SIQVELAND: Also no questions. Thank you.

CHAIRMAN BROWN: Retail?

MR. LaVIA: No questions. Thank you.

CHAIRMAN BROWN: Thank you. FEA.

MR. JERNIGAN: No questions.

CHAIRMAN BROWN: Sierra Club is excused. AARP.

MR. LaVIA: I've been deputized by AARP. They do not have any questions. Thank you.

CHAIRMAN BROWN: Florida Power & Light.

MR. BUTLER: Just a very few.

EXAMINATION

BY MR. BUTLER:

Q Good evening, Mr. Smith. Would you identify, please, on what changed your overall revenue requirement recommendation results from the withdrawal

of Mr. Pous' testimony?

A Sure.

MR. MOYLE: I'm going to object to this question because I think it's consistent with my overarching objection which is we're not doing this case live. One witness goes and now he's changing stuff. Now, Mr. Butler is going to tell me about all these changes.

That's not how we do things here. It's not consistent with the prehearing order, so I don't want to waive my objection on these exhibits by not objecting to this question on the same grounds.

MR. BUTLER: I'm really just looking to confirm. Mr. Smith has quite a few changes that are reflected in the errata sheet, and I'm just wanting to hone in on what is kind of the bottom line of the impact of the withdrawal of Mr. Pous' testimony.

CHAIRMAN BROWN: And for the record, public counsel.

MS. CHRISTENSEN: Yes, and I would -- I'm going to agree with FPL. Now the witness is here live. It is the opportunity for him to explain the changes that we are proposing to explain how these are fallout numbers from the withdrawal of Mr. Pous' testimony.

This would be the appropriate time to ask those clarifying question while the witness is here live. So, I think it would be the appropriate time to ask these questions.

MR. MOYLE: Well, I need direction. You just said Thursday we have time to review. We've been in trial all day. It's 8:15. We keep going on, and we're getting new information. So, you know, we'd need the time.

CHAIRMAN BROWN: My understanding is that it's not new information, Mr. Moyle. Staff?

MR. HETRICK: Madam Chair, this is not new information. Counsel for FPL raised a good point. Let's move on with the questioning.

CHAIRMAN BROWN: Any further? Okay. Objection overruled.

A Probably the easiest way to follow it would be to walk through Exhibit RCS-2 which was the 2017 Revenue Procurement Calculation. The first page out of the 21 pages is a table of contents. And we've indicated there which specific schedules have been revised.

Schedule A-1 presents the overall revenue requirement calculation. You can see that by looking at Line 8. Our new number is a revenue excess of 327 million. The next page, Page 3 of 21, presents adjusted rate base.

Page 4 of 21 presents the adjustments to rate base. And in particular, if you look at Page 4 of 21, on Lines 6 and 7, those numbers are now zero. Previously, there were fairly large dollar amounts on those line items. The storm hardening amount which is on Line 9 -- that reflects a reference of Exhibit HWS-9 Revised. That number slightly changed. I think those were basically all the rate base changes.

If we'll flip forward to Page 8 of 21 which summarizes the operating income and statement adjustments. You'll notice between Line 18 and Line 28 there's a bunch of blanks there now. That is previously where OPC Witness Pous' depreciation recommendations had been reflected.

And in terms of Mr. Shultz's adjustments, if you'll look at Lines 7, 8 and 9, the numbers on those lines changed slightly as was explained by Mr. Shultz earlier. The number on Line 29 which was for storm hardening -- that number changed. That's reference to his Exhibit HWS-9, Revised.

There were some payroll tax fallout numbers.

Those appear on Lines 34 and 35. Those were also changed slightly as explained by Mr. Shultz earlier.

If you'll refer to Page 14 of 21, there's a fairly complicated schedule there that had been Schedule C-7. You'll now see designated there it says OPC testimony on new depreciation rates is withdrawn. So, that was probably the major change that impacted the updated exhibits.

Then if you'll turn to Page 15 of 21, which is the capital structure, if you'll look in Column D, as in dog, on Lines 9 through 16, there were certain adjustments reflected there that had reconciled OPC's rate base to the resulting capital structure.

Those dollar amounts in that column on those particular lines have all changed. However, that was all done proportionately, so it did not impact the overall recommended rate of return.

The remaining pages, Pages 16 through 21 of 21, were basically reflecting two of the three steps of company corrections. Those should not have changed at all.

So, that basically runs through the changes that were made to the 2017 revenue requirement which are shown in Exhibit RCS-2. Exhibit RCS-3, which is the 2018 similar calculation of the revenue requirement, similar changes were made there. I don't think we need to necessarily walk through all of them because they are highly similar.

And then in RCS-4, which is the Okeechobee Clean Energy Center Limited Scope Adjustment, the only thing that basically changed there was schedule D, which was the capital structure and cost rates.

On Schedule D of Exhibit RCS-4, which is Page 6 of 6 of that exhibit, we had basically utilized the same capital structure and cost rates that we had used in Exhibit RCS-3 on Schedule D for the 2018 subsequent test here.

So, Schedule D changed, but the overall rate of return shown on Schedule D did not change. It remained at the same 5.17 percent. That was basically the only change that impacted Exhibit RCS-4 for the Okeechobee step increase.

Q So, going back to a much higher level way of looking at this, if I understand correctly, you've changed from a position of roughly an $807 million revenue requirement reduction in your calculation to $327 million revenue requirements reduction, is that right, for 2017?

A For 2017, it changed from an approximately $807 million revenue reduction to approximately a

$327 million revenue reduction.

Q And the $327 million revenue reduction you're currently calculating -- does that reflect only the results of, you know, withdrawing Mr. Pous' testimony or does that also reflect the adjustments that Mr. Shultz discussed earlier with respect to corrections related to Ms. Slattery's testimony?

A It reflects both of those impacts, the withdrawal of the Pous' depreciation recommendation and the corrected amounts that were presented by Mr. Shultz earlier today.

Q Do you have a figure to offer to the Commission on what that revenue requirements figure would be for 2017 if you were only adjusting for the withdrawal of the Pous testimony?

MR. MOYLE: Let me make my objection that I've made about new information inconsistent with the prehearing order. We're turning into a live trial.

CHAIRMAN BROWN: Noted. Overruled.

A I don't have that number with me.

Q Same answer with respect to the change from $812 million revenue reduction to $329 million revenue reduction for 2018. That, again, reflects also the adjustments that Mr. Shultz made related to

Ms. Slattery's testimony; is that correct?

A It does reflect Mr. Shultz's corrections as well as the withdrawal of Mr. Pous' depreciation recommendation.

Q One other question for you. You had in a discussion with Ms. Brownless earlier mentioned changing a position, as I understood it, with respect to whether there was a normalization violation for the Okeechobee Limited Scope Adjustment.

Did I understand that correctly?

A Yes. We believe there's an issue with the capital structure and the overall rate of return. We are no longer asserting that there's an alleged normalization violation.

Q Does that impact your calculation of adjustments to revenue requirements for the Okeechobee Limited Scope Adjustment, that change of position?

A No, it does not.

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

CHAIRMAN BROWN: Thank you. Staff.

EXAMINATION

BY MS. JANJIC:

Q Good evening, Mr. Smith. Can you please

refer to the testimony, Page 34, and review Lines 5 through 23 for me.

A Page 34?

Q Correct. And I believe there's no changes in that page, so we shouldn't have any issues.

A I have it.

Q Can you explain why you opted to use the four-year average for overhaul expense for year 2017 but a five-year average for overhaul expense for year 2018?

A Basically, we had an extra year of information available for 2018, and we thought that that should be considered as well.

MS. JANJIC: All right. Thank you. No further questions from staff.

CHAIRMAN BROWN: Thank you. Commissioners.

MS. BROWNLESS: Excuse me. I do have a few questions.

CHAIRMAN BROWN: Sure.

EXAMINATION

BY MS. BROWNLESS:

Q Were you provided the responses to staff's interrogatories and POD's request associated with your subject area as they became available?

A Yes, I think so.

Q And were you also provided the responses associated with your subject area of FIPUG's, FEA's South Florida's, AARP's discovery requests as they became available?

MR. MOYLE: I object on relevancy grounds.

CHAIRMAN BROWN: Ms. Brownless.

MS. BROWNLESS: We are entitled to ask these questions. They are relevant to discovering whether the witness had access to the materials provided on what's been identified as Exhibit 579.

CHAIRMAN BROWN: Objection overruled.

BY MS. BROWNLESS:

Q Do you want me to ask the question again?

A I think your question was did we have access to it?

Q Were you provided the responses to the discovery in your subject area that was propounded by FIPUG, FEA, South Florida and AARP?

A To a limited extent. We basically received from OPC a log indicating all the discovery in the subject matters. Somebody in our office was assigned to downloading every last response, but I definitely did not review, you know, every single response that was filed in the case.

Q But you had the --

A I tried to focus in on the ones that were relevant to the subject matter that I was addressing. The ones I did rely on, I tried to make specific reference to those in the testimony or exhibits.

Q But you had access to those documents; is that correct?

A Had access, but not -- didn't necessarily look at every last item.

Q Great. And did you in the course of your engagement request that OPC propound discovery to the other parties in the docket?

A Yes, we did suggest some discovery questions to OPC.

Q And were you provided responses to the discovery that you requested?

A Yes.

MS. BROWNLESS: Thank you so much.

CHAIRMAN BROWN: Thank you. Commissioners again? Redirect.

REDIRECT EXAMINATION

BY MS. CHRISTENSEN:

Q I just have I think one quick follow-up to the question that you were asked regarding a generation overhaul. You said that you used a four-year average for 2017. Could you explain why you used the four-year

average for generation overhaul for 2017?

A Yes, the overhaul costs vary significantly from year to year. And if rates are going to be in effect for longer than a one-year period, a normalized amount of that type of expense is preferrable.

We've, in particular, noted that in 2017, there were some units that FPL was conducting maintenance expense on a 6- and 12-year cycle with the 12-year cycle being where the extremely heavy spending occurs. I believe that was occurring at at least two plants that were placed into service in the 2005 and 2006 timeframe.

So, the 2017 amount appeared to us to be abnormally high and not representative of normal on-going cost levels. We also noted that in the 2018 amount, the company included approximately $9.8 million of overhaul expense at Plant Scherer, Unite 4.

Now, Plant Scherer, Unit 4, is located near Macon, Georgia, and is operated by Georgia Power Company. They typically do the maintenance overhaul on that unit on a two-year cycle.

So, if you take one particular year that has the extremely high maintenance amount, which 2018 has 9.8 million, that's not representative of the multi-year period for maintenance on that particular unit. And we have been involved in pretty much continuously monitoring costs at Georgia Power Company, so we have some insights as to what's going on there.

One of the things in particular that came to our attention was that they were supposed to have a rate case filed in July of 2016, and that rate case has now been deferred to --

CHAIRMAN BROWN: Mr. Smith, this is getting to be a little bit narrative. Your answer is getting a little bit narrative. If you could wrap up your answer a little bit more succinctly.

THE WITNESS: Sure. So, anyway, we questioned whether the 2018 overhaul expense for that particular unit, Plant Scherer, Unit 4 -- it appears to us that that's not representative of an annual on-going amount that would recur every year.

BY MS. CHRISTENSEN:

Q And I think you said you added a fifth year for 2018. Can you explain why you added a fifth year of information?

A The fifth year of information was available, and we thought it should not be ignored.

Q Okay.

MS. CHRISTENSEN: I have no further

questions for this witness. Thank you.

CHAIRMAN BROWN: Okay. Exhibits 189 through 192.

MS. CHRISTENSEN: Yes, OPC would move Mr. Smith's prefiled exhibits into the record.

CHAIRMAN BROWN: 189 through -- any objections?

MR. DONALDSON: No objection.

CHAIRMAN BROWN: No objection. We will move in 189 through 192 into the record. You also have 717 which I believe we will deal with on Thursday. Sound good? Okay.

Would you like this witness excused?

MS. CHRISTENSEN: Yes, we would. Thank you.

CHAIRMAN BROWN: Mr. Smith, thanks for coming down. Hope you have a good night. Safe travels.

Okay. FEA. That conclude's OPC's direct case. We're on to FEA's.

MR. JERNIGAN: Yes, ma'am. At this time, FEA calls Ms. Amanda Alderson to the stand, please.

CHAIRMAN BROWN: All right. Ms. Alderson. I don't believe you've been sworn in. Oh, you have. Okay.

MR. JERNIGAN: I believe all of our witnesses were here this morning for the group swearing in.

CHAIRMAN BROWN: You may proceed.

* * * * *

AMANDA ALDERSON

was called as a witness, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. JERNIGAN:

Q Could you explain your name for the record.

A My name is Amanda Alderson.

Q And by whom are you employed?

A Brubaker & Associates, Inc.

Q Could you state the address for Brubaker?

A Yes, it's 16690 Swingley Ridge Road, Suite 140, in Chesterfield, Missouri.

Q And who do you represent in this case?

A The FEA.

Q And are you the same Amanda Alderson who caused testimony to be filed in this case on July 27th?

A Yes.

Q And I believe you had four -- you also had Exhibits AMA-1 through 4 and Appendix A; is that correct?

A That's correct.

Q Are there any corrections you would like to make to any of those?

A No.

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

A They would.

MR. JERNIGAN: At this time, we would request that her testimony be entered into the record as read as well as all of her exhibits.

CHAIRMAN BROWN: We will insert Ms. Alderson's direct prefiled testimony in the record as though read.

(Prefiled direct testimony inserted into the record as though read.)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	)))))	**DOCKET NO. 160021-EI**

Direct Testimony of Amanda M. Alderson

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Amanda M. Alderson. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a Consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A This testimony is presented on behalf of Federal Executive Agencies ("FEA"). FEA consists of certain agencies of the United States Government which have offices, facilities, and/or installations in the service area of Florida Power & Light Company ("FPL" or "Company") and purchase electric utility service from FPL.

Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A I will address the filed retail cost of service studies ("COSS") of FPL, the resulting spread of the required revenue increase, and proposed rate design for the Commercial Industrial Load Control ("CILC") class.

My silence in regard to any issue should not be construed as an endorsement of FPL's position.

I. Summary of Findings and Recommendations

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS CONCERNING THE 2017 TEST YEAR AND 2018 SUBSEQUENT YEAR COSS.

A. My cost of service findings and recommendations are summarized as follows:

1. I find the Company's proposal to use the 12 coincident peak ("CP") 100% demand allocation method to allocate transmission plant costs to be consistent with cost-causation principles, and recommend the Florida Public Service Commission ("Commission") approve the Company's proposal.
2. The Company's proposed change to the production demand allocator from the (1) 12 CP demand and 1/13th energy method to the (2) 12 CP demand and 25% energy method should be rejected.
3. The Company's proposal to use the 12 CP demand and 25% energy allocation method to allocate production plant costs is not reasonable, because it does not reflect demand cost incurrence, illustrated by its inconsistency with the following:
   a. FPL's recently installed generation assets, and planned installations over the next ten years,
   b. FPL's resource planning principles stated in its annual integrated resource plans,

c. FPL's system load characteristics.

I recommend the Commission reject the Company's proposal to significantly increase the energy component of the production cost allocator from 7.7% (1/13th) to 25%.

4. I find the most accurate production demand allocator is a 4 CP Summer or 4 CP/1 CP Summer/Winter allocator for production plant costs. If a change is made, I recommend the Commission adopt a 100% 4 CP production demand allocator.
5. I recommend the Commission direct FPL to conduct a Minimum Distribution Study before its next base rate filing, in an effort to follow the National Association of Regulatory Utility Commissioners ("NARUC") Manual recommendation of customer and demand classification of distribution costs.

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS CONCERNING THE COMPANY'S PROPOSED REVENUE SPREAD.

A I find the Company's proposed revenue spread gradualism constraints to be reasonable in theory, but flawed in application. I recommend the 1.5 times the system average increase gradualism constraint be applied to the total class revenues including all surcharges with the exception of the fuel surcharge, which will produce gradualistic movement toward cost of service for non-fuel rates.

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS CONCERNING THE COMPANY'S PROPOSED CILC CLASS RATE DESIGN.

A My rate design findings and recommendations are summarized as follows:

1. I find the Company's proposal in the instant proceeding to be illogical and not reflective of the Company's own COSS. It should be rejected in favor of a CILC rate design that aligns with the present CILC rate design and follows FPL's own proposed rate structure from its last base rate case.
2. I find the Company's proposal to reduce the CILC and Commercial Demand Rider ("CDR") rate credits in this case unsupported and not cost justified. I recommend the Commission reject the Company's proposal to reduce these interruptible credits and order the Company to prepare a study to estimate the value of these interruptible credits to the FPL system based on avoided peaking resources.

II. FPL's Proposed Cost of Service Study

Q HAVE YOU REVIEWED THE COMPANY'S COST OF SERVICE FILING IN THIS PROCEEDING?

A Yes. I have reviewed the testimony of FPL witness Ms. Renae Deaton and the COSS she has presented therein. The Company has filed two versions of its COSS for the 2017 Test Year and 2018 Subsequent Year. The first version uses the same cost of service allocation methods that the Company filed in its 2012 base rate case, which follow long-standing precedent for Florida investor-owned utilities ("IOU"). The second version uses the Company's proposed production and transmission allocation methods. The Company proposes designing customer rates based off the second COSS version, using new production and transmission allocation methods.[1]

[1]Direct Testimony of FPL witness Deaton, page 7, lines 5-7.

Q PLEASE DESCRIBE THE COMPANY'S PROPOSED PRODUCTION AND TRANSMISSION PLANT ALLOCATION METHODS.

A FPL proposes to increase the amount of demand-related production plant costs allocated on an energy basis by switching to a 12 coincident peak ("12 CP") and 25% allocation method from the 12 CP and 1/13th allocation method widely used by Florida IOUs over the last few decades. In addition, FPL proposes to use a 12 CP 100% demand method for transmission plant allocation, except for transmission pull-offs, as opposed to the 12 CP and 1/13th method, which aligned transmission plant and production plant allocation both on the 12 CP and 1/13th allocation method.

II.A. Transmission Plant Allocation

Q TURNING FIRST TO TRANSMISSION PLANT ALLOCATION, DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO USE THE 12 CP 100% DEMAND ALLOCATION METHOD?

A Yes. High voltage transmission plant investment is sized and planned to meet the system's coincident peak demands. Transmission plant should not be considered merely an extension of the production and generation asset investment, and therefore, the allocation methods for production plant and transmission plant need not align in all cases. Further, any classification on energy for the transmission plant is not based on cost-causation principles.

The Federal Energy Regulatory Commission ("FERC") has long held that allocation of high voltage bulk transmission plant costs should be accomplished using the 12 CP 100% demand method. I support the Company's proposal to use this method in its retail COSS.

Q DOES THE COMPANY PROPOSE ALLOCATING ALL RETAIL TRANSMISSION PLANT ON THE 12 CP 100% DEMAND BASIS?

A No. The Company's Schedule E-4a Minimum Filing Requirement ("MFR") details the functionalization of transmission plant, and shows approximately 8% of the transmission plant in-service is proposed by FPL to be functionalized in alignment with the production plant class cost functionalization, that is, the 12 CP and 25% method. This 8% subset of transmission plant is labeled GSU, Generator Step-Up assets. I agree that the transmission generator step-up plant should be allocated with production plant costs. These costs reflect the transformation to step up power at the generator for delivery to the high voltage bulk transmission system.

Q HOW DOES THE COMPANY PROPOSE TO ALLOCATE TRANSMISSION PULL-OFFS?

A Transmission pull-offs are radial lines, the conductors and equipment that connect high voltage customers directly to the transmission system. FPL proposes to continue its practice of assigning the cost of these assets to the transmission level customers, and then allocating these costs within the assigned classes on a customer basis.

Q IS THE COMPANY'S PROPOSAL FOR TRANSMISSION PULL-OFF COST ALLOCATION REASONABLE?

A Yes. These are costs related to connecting transmission customers to the FPL system. Allocating the costs on a customer basis is reasonable.

II.B. Production Cost Allocation

Q PLEASE DESCRIBE THE PRODUCTION COST ALLOCATION THAT FPL HAS HISTORICALLY USED.

A FPL specifically, and Florida IOUs generally, have historically relied upon the 12 CP and 1/13th method to allocate demand-related production plant costs. This method classifies 1/13th of the production costs as energy-related, and allocates those costs on energy requirements. The remaining 12/13^{ths} are classified as demand-related and allocated to classes on the average of the classes' 12 coincident peaks.

Q PLEASE DESCRIBE MS. DEATON'S PROPOSAL TO CHANGE THE PRODUCTION PLANT COST ALLOCATOR TO USE THE 12 CP AND 25% METHOD?

A Ms. Deaton proposes to switch to the 12 CP and 25% method from the 12 CP and 1/13th method. The result of this change is that a greater percentage of the demand-related production plant costs would be allocated on an energy basis. Ms. Deaton's proposed change increases the amount of demand-related costs allocated on an energy basis from approximately 7.7% (1/13th) to 25%. Ms. Deaton's proposal would continue to allocate the remaining demand-related production charges on a 12 CP basis.

Increasing the amount of demand-related production charges allocated on an energy basis is not supported by cost-causation principles. Generation assets are sized to meet the utility's planned system peaks, and as such, are demand-related costs.

Ms. Deaton's contention that changes in FPL's generation fleet support **any** energy classification of production demand costs, let alone an increased amount, is not supported in this proceeding by either the Company's actual installed and planned generation asset fleet, its system planning principles, or the Company's system characteristics of load use across classes.

Q HOW DOES MS DEATON SUPPORT HER PROPOSAL TO ALLOCATE A GREATER PERCENTAGE OF DEMAND-RELATED PRODUCTION COSTS ON AN ENERGY BASIS?

A At page 21 of her direct testimony, Ms Deaton explains:

> FPL has installed a significant amount of base and intermediate load generation that costs more to construct but is less costly to operate over time than peaking generation. Investment in these generating units that improve system heat rates and lower fuel costs drives the need to use a greater energy allocation (e.g., 25%) for production plant.

In this passage, Ms. Deaton alludes to the theory of "capital substitution" suggesting that when a utility chooses to install a baseload generating unit with a higher upfront capital cost but lower fuel costs over time, as opposed to a peaking unit with a lower fixed capital cost but higher fuel cost, it can be argued that the utility is substituting demand-related capital costs to obtain fuel savings. The thinking is that, therefore, the capital expenditure that generates these fuel savings could be allocated like a fuel expense, on an energy basis.

Q PLEASE COMMENT ON THIS THEORY OF CAPITAL SUBSTITUTION.

A This theory is referenced in the NARUC Manual at page 21 in the paragraph summarizing the classification process for production related costs. The NARUC Manual reads:

> Costs that are based on the generating capacity of the plant, such as depreciation, debt service and return on investment, are demand related costs. Other costs, such as cost of fuel and certain operation

> and maintenance expenses, are directly related to the quantity of energy produced. **In addition, capital costs that reduce fuel costs may be classified as energy related rather than demand related**. (emphasis added)

But the NARUC Manual, last updated in 1992, was predicated on a set of market factors and system resource planning economics that have changed. The differences in fuel costs and capital costs between various generating unit types today are vastly different from the comparative costs of generating units in the 1980s and 1990s, when the Commission last approved the 12 CP and 1/13th method in a fully litigated case.[2] As I explain below, FPL's recently installed and planned future generation capacity additions suggest that a move away from the theory of capital substitution is appropriate, not a move to more fully rely on the theory, as proposed by Ms. Deaton.

II.B.1. FPL's Recent and Planned Generation Capacity Additions

Q DOES FPL'S RECENT AND PLANNED GENERATION CAPACITY ADDITIONS SUPPORT THE APPLICATION OF THE CAPITAL SUBSTITUTION THEORY, AS MS. DEATON CLAIMS?

A No. Ms. Deaton suggests that FPL has installed a considerable amount of baseload and intermediate generating units presumably since FPL's 2012 case when the Company proposed continuation of the 12 CP and 1/13th method. But a review of the generating capacity added over the last five years, and FPL's planned additions included in its 2016 10-year Integrated Resource Plan ("2016 IRP"),[3] shows that gas-fired generation, not coal-fired generation, is the most economical baseload capacity addition.

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[2]For FPL, this was in the 1989 case, Docket No. 890319-EI.
[3]FPL's 2016 IRP, filed April 1, 2016, is titled "2016 Ten Year Power Plant Site Plan."

Q WHY DOESN'T THE ADDITION OF A SIGNIFICANT AMOUNT OF GAS-FIRED BASELOAD GENERATION CAPACITY SUPPORT USING THE THEORY OF CAPITAL SUBSTITUTION TO ALLOCATE PRODUCTION COSTS?

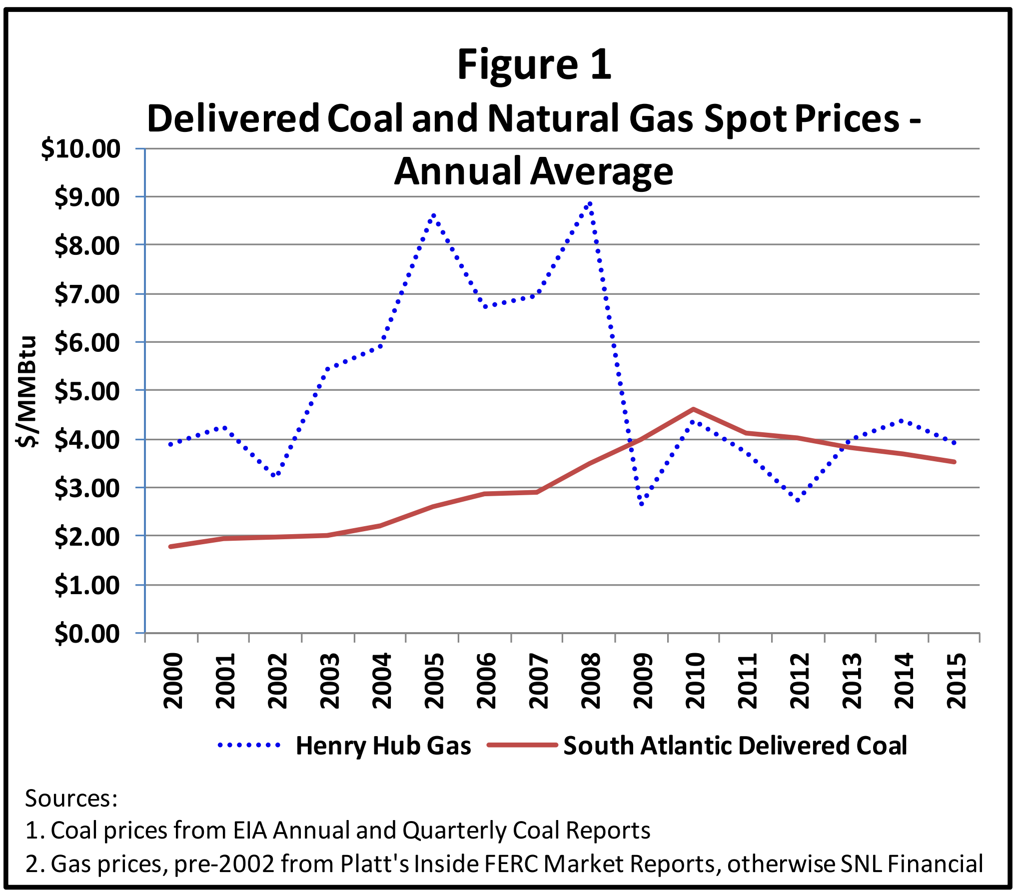
A Capital substitution was historically predicated on the relative capital and fuel cost differential between baseload coal-fired or nuclear units and peaking gas-fired or oil-fired units. Specifically, the theory posits that a high capital cost baseload coal-fired unit can be the least cost generating addition, versus a lower capital cost gas-fired peaking unit, because of the coal unit lower fuel operating cost.

But two factors contradict Ms. Deaton's claim that this theory of capital substitution applies to FPL's generation additions and supports an increase in the energy allocation. First, the fuel cost differential between coal-fired and gas-fired units has contracted, due to market factors, so the fuel savings for which capital may be substituted has reduced dramatically. Second, FPL is no longer installing coal-fired units, instead relying on gas-fired generation as baseload, which has a much lower capital cost than baseload coal units, therefore less capital is incurred for reduced fuel savings. The theory of capital substitution does not fit FPL's actual generation resource mix.

This shift in market economics, and the relative capital costs of the generating units actually installed by FPL suggest that a **smaller percentage** of demand-related production costs should be allocated on energy compared to historical allocation methods. Again, this shows that the Company's proposal to increase the energy allocation percentage is not cost based.

Q PLEASE EXPLAIN HOW THE CURRENT FUEL COST DIFFERENTIAL BETWEEN UNIT TYPES AFFECTS PRODUCTION COST OF SERVICE.

A Figure 1 below illustrates the historical price of natural gas and coal delivered to Southeast electric utilities, according to U.S. Department of Energy, Energy Information Administration ("EIA"), Platts, and SNL Financial publications. Historically, the high capital cost of a baseload coal unit might be cost justified given the fuel savings versus a gas-fired peaking unit with lower capital costs. But since the shale gas boon in the U.S., gas costs have fallen dramatically while coal prices have increased. The capital substitution theory is weakened when the fuel savings decreases.



FPL itself has indicated its understanding of the new market economics as it explains why it does not anticipate installing any coal-fired units in the foreseeable future. FPL writes:

> [There are] [s]everal other considerations currently unfavorable to new coal units compared to new natural gas-fired CC units. The first of these is a **significant reduction in the fuel cost difference between coal and natural gas** when compared to the fuel cost difference projected in 2007 which then favored coal; i.e., the projected fuel cost advantage of coal versus natural gas has been significantly reduced. Second is the continuation of **significantly higher capital costs for coal units compared to capital costs for CC units**. Third is the increased fuel efficiency of new CC units compared to projected CC unit efficiencies in 2007. Fourth are existing and proposed environmental regulations, including those that address greenhouse gas emissions, which are unfavorable to new coal units when compared to new CC units. **Consequently, FPL does not believe that new advanced technology coal units are currently economically, politically, or environmentally viable fuel diversity enhancement options in Florida at this time**. (FPL 2016 IRP, page 57, emphasis added.)

Q PLEASE SUPPORT YOUR CLAIM THAT FPL IS HEAVILY RELYING ON GAS-FIRED GENERATION.

A The cited quote above from FPL's 2016 IRP shows that it no longer considers coal-fired generation a viable asset choice. FPL's recently installed and planned generation additions prove that this is the case.

Table 1 below shows FPL's installed capacity by size and type since 2005, and the planned capacity additions explained in FPL's 2016 IRP. The table also shows the relative capacity construction and fuel costs for these units. Note that 94% of the capacity additions are either combined cycle ("CC") or combustion turbines ("CT"), which are both primarily gas-fired units.

Table 1

FPL Planned and Recently Added Capacity

Power Plant Name	Capacity (MW)	Unit Type	Year in Service	Construction Cost (2015 $/kW)		Fuel Cost (2015 $/MWh)
Recent Additions[1]						
West County Energy Center	4,019	CC	2009	$	496	$31.67
Cape Canaveral Next Gen	1,355	CC	2013	$	682	$29.72
Riviera Beach Next Gen	1,344	CC	2014	$	863	$29.85
Port Everglades Next Gen	1,250	CC	2016	$	960	$0.00
Turkey Point CC	1,178	CC	2007	$	428	$31.50
Nuclear Uprates	520	Nuclear	2012	$	5,700	$6.90
DeSoto Next Gen Solar	25	PV	2009	$	5,878	$0.00
Space Coast Next Gen	10	PV	2010	$	6,198	$0.00
FPL Solar Circuit (Daytona Rising)	2	PV	2016	$	3,333	$0.00
Florida Intl University Solar	2	PV	2016	$	4,375	$0.00
Planned Additions[2]						
Okeechobee Unit 1	1,633	CC	2019	$	832	
Unsited 3x1 CC	1,622	CC	2024	$	1,022	
Fort Myers CT	231	CT	2016	$	514	
Lauderdale CT	231	CT	2016	$	482	
New Solar	156	PV	2020	$	1,896	
Babcock Ranch Solar Energy Center	39	PV	2016	$	1,881	
Citrus Solar Energy Center	39	PV	2016	$	1,881	
Manatee Solar (Parrish Facility)	39	PV	2016	$	1,881	

Sources:
[1]SNL Financial and 2015 FERC Form 1
[2]2016 FPL IRP pp. 96-103

Q PLEASE EXPLAIN HOW FPL'S RELIANCE ON GAS-FIRED GENERATION IMPACTS THE COST-BASED APPLICATION OF THE CAPITAL SUBSTITUTION THEORY.

A The most economical system resource available to FPL currently is gas-fired generation, as evidenced in Table 1 where the vast majority (94%) of capacity additions are either CCs or CTs. Gas-fired generation can be installed in a CT or CC configuration.[4] Table 2 below shows that the installed cost of a CT is approximately $700 per kW, versus approximately $1,000 per kW for a CC. It is true that FPL has elected to incur the slightly higher upfront capital cost for CC units instead of less expensive CT units in order to obtain lower fuel costs due to the higher fuel efficiencies (lower heat rate) of the CC units. But the trade-off between higher capacity costs and lower fuel costs is far more muted than the historical trade-off between coal-fired baseload and gas-fired peaking units.

The historical capital cost differential between coal-fired baseload units and peaking units is about four times,[5] but the current differential between CC units (like the ones FPL has installed) and CTs is only approximately two times.

Table 2

EIA Estimates for Power Plant Capital Costs

Unit Type	Fuel Type	Construction Cost (2012 $/kW)
Advanced Combustion Turbine	Natural Gas	$676
Advanced Combined Cycle	Coal/Gas	$1,023
Solar Photovoltaic	Solar	$3,873
Nuclear	Uranium	$5,530

Source: EIA April 2013 Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, page 6, Table 1.

[4] A CC is essentially a CT unit, with an additional heat recovery steam generator, which increases capacity and improves the heat rate efficiency of the unit. The heat rate of a CT is approximately 10,000 BTUs per kWh. The heat rate for a CC is around 6,500 BTUs per kWh.

[5] 1990 overnight cost was approximately $2,500/kW. Source: Power Plants: Characteristics and Costs; Federation of American Scientists report, November 13, 2008.

Q PLEASE SUMMARIZE YOUR CONCLUSION CONCERNING THE APPLICATION OF THE CAPITAL SUBSTITUTION THEORY TO FPL'S PRODUCTION COST ALLOCATION.

A The concept of capital substitution suggests that a utility would choose to install a high capital cost baseload unit instead of a lower capital cost peaking unit if fuel operating costs are materially lower because this will ensure lower overall total costs over the projected operating life of the resource. But FPL's own resource mix shows that it is relying significantly on gas-fired CC units, and the capital cost differential between CC units and peaking CTs is half the historical capital cost differential between a coal unit and peaking unit, upon which the capital substitution theory is predicated. Therefore, FPL's recent capacity additions suggest that at a minimum the percentage of demand-related production costs allocated on energy should remain the same, and could even be reduced, but should not increase as proposed by FPL.

II.B.2. FPL's Resource Planning Principles

Q IS THERE FURTHER SUPPORT FROM FPL'S PRODUCTION PLANNING PRINCIPLES SUGGESTING THAT AN INCREASE IN THE PERCENTAGE OF DEMAND-RELATED COSTS ALLOCATED ON ENERGY IS UNREASONABLE?

A Yes. FPL's 2016 IRP explains that the Company has added a third reliability criterion related to system peak demands for determining the appropriate capacity additions it should install over the next 10 years. Historically, up until 2014, FPL used two criteria to determine the amount of generating capacity needed to operate the system safely and reliably. The first criterion relies on a minimum 20% peak period reserve margin for the summer (August) and winter (January) peak hour, the second relies on a maximum loss of load probability ("LOLP") of 0.1 day per year.[6]

FPL's 2016 IRP indicates that beginning in 2014, FPL added a third reliability criterion to the two previously used. The third criterion is a 10% generation-only reserve margin, which places a greater emphasis on the reserve margin at the summer and winter peaks.

FPL has grown concerned about relying too heavily on demand-side management resources during peak periods, and wishes to place a greater emphasis on having adequate installed generation at the time of the system peaks, hence the development of the third reliability criterion using a generation-only reserve margin metric.[7]

Q PLEASE DEFINE RESERVE MARGIN.

A A utility's reserve margin is the excess capacity above expected demand at the hours of the annual system peaks of the system. A minimum reserve margin threshold is used by system planners to ensure that the generating capacity is available when demands on the system are at the highest levels taking into account forecasting error and weather fluctuations, in order to greatly reduce the likelihood of brownouts or blackouts.

Q PLEASE EXPLAIN THE LOLP.

A LOLP is a metric that determines the probability of load being unavailable to meet resources over the full planning year, calculating the probability of system overload at each daily peak hour.

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[6]FPL 2016 IRP, pp. 35 and 52.
[7]*Id*., p. 53.

Q DO FPL'S PRODUCTION SYSTEM PLANNING PRINCIPLES SUPPORT AN INCREASE IN THE AMOUNT OF DEMAND-RELATED PRODUCTION COSTS ALLOCATED ON ENERGY COMPARED TO APPROVED HISTORICAL PRACTICES IN FLORIDA?

A No. FPL's IRP indicates that the Company is placing a greater emphasis on planning to meet the peak period reserve margin through its addition of a third reliability criterion of a 10% generation-only reserve margin metric. This change in FPL's production system planning principles does not support an increased allocation of demand-related production costs on an energy basis, and instead supports a reduction. FPL is strengthening its reserve margin criteria, placing a greater emphasis on meeting its peak period demands than it has historically.

II.B.3. FPL's System Load Characteristics

Q DO THE FPL SYSTEM LOAD CHARACTERISTICS SUPPORT AN INCREASE IN THE AMOUNT OF DEMAND-RELATED PRODUCTION COSTS ALLOCATED ON ENERGY COMPARED TO HISTORICAL METHODS, AS PROPOSED BY MS. DEATON?

A No. A review of the Company's load characteristics indicates that allocating production demand-related costs on the 12 CPs is unreasonable. Continuing to allocate costs on the 12 CPs while simultaneously increasing the energy allocation moves even further from cost causation. My Exhibit AMA-1 shows a clear pattern of four monthly summer peaks over the past 10 years, and over the projected period from 2016 through 2018. The projected system peaks were provided by FPL in its MFRs and corroborates the fact that FPL expects its system to continue under this

4 CP pattern. The utility was once a winter peaking system before the early 2000s, but the system load characteristics have shifted over time.

There is evidence that supports a winter peak component in the production allocation method. The 2010 system peak for FPL occurred in January, which was the only year over the last 10 that FPL peaked in a non-summer month. Further, FPL's IRP indicates that its system planning principles take into account a minimum reserve margin threshold in the winter peak month of January.[8]

In any case, a greater emphasis on the summer peak months is supported by FPL's load characteristics and system planning, more so than use of the 12 CP which considers peaks throughout the entire calendar year. Especially in the case of Ms. Deaton's proposal to increase the amount of demand-related production cost on an energy basis, it would be of even greater import to reduce the number of coincident peaks included in the demand allocation. Inclusion of an energy component in the production cost allocator is to take into account load use over the full calendar year. It is not necessary to use the 12 CPs across the full calendar year as well for the demand component when the system shows only four clear peaks.

II.B.4. Alternative 100% Demand Production Allocation Method

Q HAVE YOU CALCULATED ALTERNATIVE CLASS ALLOCATION FACTORS USING METHODS BESIDES THE 12 CP AND 1/13TH, AND 12 CP AND 25%?

A Yes. My Exhibit AMA-2 provides a comparison of the Company's present and proposed production allocation factors as well as 100% demand allocation factors eliminating the practice of allocating demand-related costs on an energy allocator. I have prepared two possible 100% demand allocation method calculations, one using

[8] *Id*.

the four summer CPs (June-September), the other using and a summer/winter peak method that equally weights both the four summer CPs and the one winter peak in the month of January, which is the forecasted peak winter month according to Florida's IRP[9] and the load forecasting model presented by FPL witness Morley.[10]

It is clear from FPL's system planning principles, its recently installed and planned assets, and its load characteristics that shifting to a greater percentage of the production allocation method on an energy basis is not supported at this time. In fact, these factors support a reduction in the amount of demand-related production costs that are allocated on an energy basis. Further, reliance on the 12 CP metric for the demand-related component of any production cost allocation factor is not justified, and instead either a summer 4 CP or a summer/winter 4 CP / 1 CP is more cost based.

Q WHAT IS YOUR RECOMMENDED PRODUCTION COST ALLOCATION METHOD?

A I believe it is justified based on the evidence presented in this proceeding to move to a 100% demand-related cost allocation method using either the four summer peaks or the four summer peaks and one winter peak. The Company's proposed 12 CP and 25% allocation method should be rejected. Continuation of the 12 CP and 1/13th method could be considered a compromised approach.

If the Commission approves a change, it should approve a 100% 4 CP method and reject FPL's proposed 12 CP and 25% method.

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[9] *Id.*
[10] Direct Testimony of FPL witness Ms. Morley at 42.

II.C. Distribution Cost Allocation

Q HOW THE DOES THE COMPANY PROPOSE TO ALLOCATE DISTRIBUTION COSTS IN THE COSS?

A Ms. Deaton describes at page 24 of her Direct Testimony that FPL proposes classifying 100% of distribution-related equipment, aside from meters, as demand-related, and using only demand-based allocators to allocate these costs.

Q WHAT IS YOUR CONCERN WITH THE COMPANY'S 100% DEMAND-RELATED DISTRIBUTION COST ALLOCATION METHOD?

A Allocating these costs, in FERC Accounts 364-368, which are the costs of poles and towers, underground and overhead lines, and transformers, on a pure demand basis: (1) is not supported by the NARUC Manual; and (2) does not reflect the fact that there is a customer-related component to the cost of the distribution system that is associated with the need to "cover the system."

Q WHY DO YOU SAY THE NARUC MANUAL DOES NOT SUPPORT THESE DISTRIBUTION-RELATED COSTS BEING CLASSIFIED AS 100% DEMAND-RELATED?

A Table 6-1 in the NARUC Manual on page 87, replicated below as Table 3, shows clearly that distribution assets in FERC Accounts 360, 361, and 364 through 368 are properly allocated on both a customer- and demand-related allocator.

TABLE 3

Table 6-1 of NARUC Manual – January 1992 Edition
Classification of Distribution Plant

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems	-	-

Footnote 2 to the NARUC Manual table explains:

> The amounts between [demand and customer] classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

In other words, the NARUC Manual leaves open the opportunity for a utility company to determine nearly none (zero) of these costs should be classified as customer-related, but only after completing the appropriate study of its distribution system.

Q IS THE COMPANY'S PROPOSAL REASONABLE, TO ASSUME 100% OF THESE DISTRIBUTION ASSET COSTS ARE DEMAND RELATED, ABSENT A STUDY OF ITS DISTRIBUTION SYSTEM?

A No. The distribution system is sized not only to accommodate demand requirements but also to simply connect each customer to the system. This minimum customer connection cost is irrespective of size. The connection equipment necessary is above and beyond the service drop to a customer's premises because there must be an infrastructure to which the service drop can be connected.

Consequently, while a customer's demand requirements will influence the particular size of the distribution facilities installed, the fact that some facilities of at least a minimum size must be constructed relates to the existence and location of customers within the service territory, the distance of conductor, and the number of transformers. Unless these factors are taken into consideration, the COSS will depart from cost-causation.

The central idea behind the minimum system concept is that there is a cost incurred by any utility when it extends its primary or secondary distribution system, replaces a component on those systems, or connects an additional customer to them. By definition, the minimum system comprises every distribution component necessary to provide service, i.e., meters, services, secondary and primary conductors and cables, poles, substations, etc. The cost of the minimum system, however, is only that portion of the total distribution cost the utility must incur to render service to customers. It does not include costs specifically incurred to meet the peak demand of the customers. Therefore, the minimum system cost is rightfully classified as customer-related, and should be allocated on a customer basis, separate and apart from the distribution costs classified as demand-related.

Q IF IT IS UNREASONABLE TO CONSIDER THESE DISTRIBUTION ASSET COSTS AS 100% DEMAND RELATED, WHAT PERCENTAGE OF THE ALLOCATION SHOULD BE DEMAND RELATED?

A In order to determine the best estimate of the percentage of total distribution asset costs that are demand related, a utility company would complete a study of its installed distribution assets, typically termed a Minimum Distribution Study.

A Minimum Distribution Study consists of a review of the distribution assets installed on the Company system that would meet the minimum required to serve a customer. For example, the smallest size pole and smallest size cable, conductor, etc. is determined, and the total book cost for that minimum system is established. This total minimum system cost for each distribution asset, separated by FERC Account number, is then allocated on a customer basis. The remainder of distribution asset costs in those FERC Accounts is allocated on a demand basis.

Alternately, the utility company could follow the Zero-Intercept Method, which is similar to the Minimum Distribution Method, but seeks instead to identify the portion of distribution plant costs related to a hypothetical no-load situation. The Zero-Intercept method often requires considerably more data, and the resulting customer/demand split is usually very similar to the results of the Minimum Distribution Study.

In this proceeding, in the absence of an analytical study to determine proper cost classification, I would support any modest movement toward a customer classification if ordered by the Commission.

Q HAS THE COMMISSION HISTORICALLY APPROVED USE OF A MINIMUM DISTRIBUTION STUDY FOR FLORIDA IOUS?

A To my knowledge, the Commission has not embraced a Minimum Distribution Study for allocation of Florida IOU distribution costs. The general acceptance of a Minimum Distribution Study in numerous jurisdictions across the country, and the NARUC Manual, suggest efficient distribution system planning does consider number and location of customers served, and the Commission should reconsider its decades-long rejection of the theory.

Q WHAT IS YOUR RECOMMENDATION CONCERNING THE MINIMUM DISTRIBUTION STUDY?

A I recommend the Commission order FPL to conduct a Minimum Distribution Study of its system, survey the use of the Minimum Distribution Study in other similarly-situated utilities across the country, with similar customer load characteristics and geographical make-up, and present the findings of these studies to Staff and other interested parties prior to FPL's next base rate case filing.

III. Revenue Spread - Gradualism

Q HAS FPL USED GRADUALISM IN ITS DETERMINATION OF THE APPROPRIATE SPREAD OF THE REVENUE INCREASE ACROSS CUSTOMER CLASSES?

A Yes. FPL witness Ms. Tiffany Cohen indicates in her direct testimony that the Company is proposing to limit any class revenue increase on a total bill basis by 1.5 times the system average increase, and has also set a floor so that all classes get at least 0.5 times the system average increase. The concept of gradualism is appropriate and necessary in this proceeding, but the Company's proposed application is flawed.

FPL recovers a considerable amount of revenue through its fuel rider, which is not a part of base rates, not included in the Company's cost of service studies, and should be excluded from the class revenues when determining the appropriate revenue increase under the gradualism constraints.

Q WHY SHOULD FUEL REVENUES BE EXCLUDED FROM THE CLASS REVENUE INCREASE GRADUALISM CALCULATIONS?

A Fuel revenues are not collected through base rates, are highly volatile and largely outside of the Company's control. On the other hand, many of the other surcharges and riders in addition to FPL's base rates do relate to costs that are generally a component of base rates in other jurisdictions, such as purchased power contract capacity costs, interruptible load credits, and certain environmental controls costs. Because the Company is proposing in this case to roll a considerable amount of these surcharge revenues into base rates, it would be inaccurate to calculate a class revenue increase spread under the gradualism constraints on only base rate revenues. The proposed base rate revenues in this proceeding are significantly higher than the present base rate revenues for reasons that include the roll in of surcharge revenue into base rates.

However, fuel revenues recovered outside of base rates make up approximately 70% or more of the total surcharge revenue recovered from FPL customers. As well, total proposed base rate revenues in this proceeding are $6.8 billion, the total clause revenue including fuel for the 2017 Test Year is $4.6 billion, making total surcharge revenue collected by the utility approximately 40% of the total

Company revenue, and fuel surcharge revenue 30% of the Company total. With fuel being a significant component of the total class revenue, it is unreasonable to include these fuel revenues in the class total revenue amount when determining the appropriate spread of the requested revenue increase across classes under the gradualism constraints.

FPL does not propose in this case to roll any fuel surcharge revenue into base rates, unlike other surcharge revenue. If fuel revenues are included when apportioning the revenue spread to classes, the movement closer to cost of service for each class is muted.

Q WHAT IS YOUR RECOMMENDATION CONCERNING THE GRADUALISM CONSTRAINTS AND THE SPREAD OF THE APPROVED REVENUE INCREASE ACROSS CUSTOMER CLASSES?

A I agree with the Company's proposed gradualism constraints, that is, limiting the revenue increase for all classes to 1.5 times the system average increase, and ensuring each class gets at least a 0.5 times system average increase. However, I believe these gradualism constraints should be applied to the total class revenues excluding fuel revenues. In addition, I recommend all classes should receive an equal percentage reduction in their total revenue excluding fuel charges if any reduction in revenue requirement is approved by the Commission. My proposals for revenue spread apply equally to any rate change approved by the Commission whether in 2017, 2018, or 2019.

Q HAVE YOU CALCULATED A PROPOSED REVENUE SPREAD THAT FOLLOWS THE ADJUSTED GRADUALISM CONSTRAINT YOU HAVE PROPOSED ABOVE?

A Yes. My Exhibit AMA-3 shows an example of my proposed revenue spread removing the estimated fuel surcharge revenue.[11] Exhibit AMA-3 calculates a sample corrected revenue spread using the Company's 12 CP and 1/13th COSS results. However, I maintain that the appropriate transmission cost allocation method is 100% demand 12 CP, and the appropriate production cost allocation method is 100% demand 4 CP summer or 4 CP/1 CP summer/winter. I view the continuation of the 12 CP and 1/13th production demand allocation method a compromise between the Company's and my proposal laid out in this testimony.

Exhibit AMA-3 shows all classes receiving between a 0.5 times and 1.5 times system average increase. It is based off of present electric revenues including the full value of CILC and CDR credits, which I will describe below.

IV. Rate Design

Q HOW HAS THE COMPANY PROPOSED TO CHANGE THE CILC AND CDR CREDITS TO INTERRUPTIBLE CUSTOMERS?

A The Company in this proceeding proposes to reduce by $23 million (37%) the value of CILC and CDR customers' interruptibility. These customers are given a rate credit for the load that they have offered to the Company as non-firm through the CDR Rider, or through the differential between the CILC base rate charges and the

[11]The Company did not provide in its filed testimony or exhibits any detail concerning the total surcharge revenue it estimates for the test year periods for each class. I have used current tariff rates in effect to estimate the class revenue that is recovered through the fuel charge, but the values for the total surcharge revenue included in the test year periods by FPL would be a function of FPL's projections of these various charge rates in the future test year. I have issued a data request seeking the workpapers supporting the calculated class surcharge revenue that the Company included in its revenue spread proposals. When and if the Company provides the fuel surcharge revenue by class, I can update my proposed revenue spread calculations.

otherwise applicable General Service rate charges for firm service. Ms. Cohen indicates very briefly beginning at page 18 that the:

> Credits provided under the 2012 rate settlement for Commercial Industrial Load Control (CILC) and Commercial Demand Rider (CDR) customers are reset to pre-settlement levels (adjusted for generation base rate adjustments) as shown in MFR E-14, Attachment 5.

Ms. Cohen does not elaborate on the Company's proposed credit levels, nor whether this proposal is cost justified. Lacking any further information on the reasonableness of the Company's proposal, I recommend the Commission reject the Company's proposal to reduce the interruptible credits offered to the CILC and CDR customers. Therefore, as shown on my Exhibit AMA-3, I have developed my target revenue requirements for the CILC and CDR customer classes to include the full level of interruptible credits that are present in the Company's existing rates and were included in the COSS provided by the Company.

Q IS THE LEVEL OF INTERRUPTIBLE CREDITS INCLUDED IN THE COMPANY'S EXISTING RATES REASONABLE?

A No, the interruptible credits on a per kW-month basis are less than the estimated cost of a new CT peaking unit. My Table 2 above indicates that the average cost of a new CT peaking unit is approximately $675 per kW-year. Using a 15% fixed cost recovery factor yields an interruptible credit of approximately $8.45 per kW-month. This is the value to FPL of avoiding the construction of an additional peaking generation resource. When the CILC and CDR customers offer their interruptible load to FPL, the Company is able to reduce its system peak demand forecast levels and thereby reduce the amount of peak demand capacity resource cost needed to meet system peak demands.

A review of the Company's MFR E-5 shows the total interruptible credit level the Company includes in its current base rates for CILC customers. The total CILC interruptible credit in the Company's present rates is $41.7 million. Dividing this interruptible credit level by the interruptible billing determinants for the CILC classes results in an actual CILC interruptible credit of only $6.17 per kW-month. This exercise shows that the level of interruptible credits included in the Company's present rates, which are well above the CILC and CDR interruptible credit levels the Company is proposing in this case, are still far below the true value to FPL of these customers' interruptibility.

Q WHAT IS YOUR PROPOSAL CONCERNING THE APPROPRIATE LEVEL OF INTERRUPTIBLE CREDITS?

A I propose that the Commission reject the Company's proposal to reduce the interruptible credits in this case. I recommend as well that the Company conduct a study to evaluate the appropriateness of the level of interruptible credits in the present rates in comparison to the true value to the FPL system. FPL should be required to provide the results of this study to Staff and other interested parties prior to filing its next base rate case.

Q DO YOU HAVE OTHER CONCERNS WITH THE COMPANY'S PROPOSED BASE RATE DESIGN FOR THE CILC CLASS IN THIS PROCEEDING?

A Yes. The Company's proposed base rate charges for the three CILC rate sub-classes for the 2017 Test Year and 2018 Subsequent Year are economically illogical, do not provide appropriate efficient price signals, and are not reflective of the

Company's own COSS results. Therefore, FPL's proposed changes to the CILC rate should be rejected.

Q PLEASE EXPLAIN.

A Table 4 below provides a comparison of the Company's present rate design for the CILC class and its proposed 2017 base rate charges.

TABLE 4

Present and Proposed CILC Base Rate Charges
(Demand Charges $/kW, Energy Charges ¢/kWh)

	Present Rates			Company's 2017 Proposed Rates		
	CILC-1G	CILC-1D	CILC-1T	CILC-1G	CILC-1D	CILC-1T
	below 69 kV		>69 kV	below 69 kV		>69 kV
	200-499 kW	500 kW+		200-499 kW	500 kW+	
Load Control Dmd	$1.97	$1.97	$1.97	$3.30	$4.00	$4.40
Firm Demand	$8.73	$8.51	$8.65	$12.00	$14.20	$16.40
Max (Dist.) Dmd	$3.82	$3.49	n/a	$4.90	$5.50	n/a
Energy	1.425	0.822	0.731	1.828	1.272	1.307

This comparison illustrates the economically illogical results of the Company's proposed rate design even compared to the Company's present rates. I will elaborate below.

Q PLEASE EXPLAIN WHY THE COMPANY'S CILC BASE RATE PROPOSAL IS ECONOMICALLY ILLOGICAL.

A As shown in Table 4 above, the existing CILC rate design reflects a declining charge for generation and transmission service, and for energy consumption, for CILC customers that take service at a higher delivery voltage level. This is economically logical because there are fewer losses serving the customer at transmission level than at the primary and secondary voltage levels. The existing rate structure reflects the reduction in losses through declining rates based on delivery voltage service. In significant contrast, the proposed charges reflect a higher charge for transmission voltage level service than they do for primary and secondary voltage customers. This is economically illogical because the Company holds less generation capacity per unit of demand to serve a transmission voltage level customer than it would need for primary and secondary voltage customers.

For example, due to energy losses during voltage transformation, the Company would need 1.0218 MW to produce 1 MW at a customer's transmission voltage level meter. The difference between generation and meter level energy is a result of the losses that take place through the conductors, and through the transformation process. In comparison, the Company's demand loss study states that it would need 1.0348 MW and 1.0644 MW to put 1 MW through a primary and secondary meter, respectively. The greater amount of production and transmission capacity at the generation level, relative to the meter level, again reflects a greater level of losses incurred by FPL to serve a customer at primary and secondary voltage relative to transmission voltage.

The existing CILC rate design reflects these differences in losses. FPL's proposed rate design distorts this economically logical structure and creates inaccurate and false price signals to customers that take service under the CILC tariff.

Q PLEASE EXPLAIN WHY YOU BELIEVE THE COMPANY'S PROPOSED REVISIONS TO THE CILC RATE DESIGN DOES NOT FOLLOW ITS OWN COST OF SERVICE.

A The Company's rate design for higher energy and demand charges for transmission level customers, relative to primary and secondary level customers, is inconsistent with its own class COSS. As shown in Table 5 below, the Company's allocated costs at transmission voltage level on a per-unit basis are lower than the Company's per-unit costs allocated to primary and secondary voltage level customers.

TABLE 5

Results of Company's 12CP and 1/13th COSS
Functionalized Unit Charges
Including CILC Credit Offset

Description	CILC-1G	CILC-1D	CILC-1T
Customer ($/Mo.)	$ 120	$ 254	$ 3,201
Production ($/kW)	$ 6.75	$ 6.32	$ 6.29
Transmission ($/kW)	$ 1.28	$ 1.20	$ 1.20
Distribution ($/kW)	$ 5.25	$ 4.94	$ -
Energy ($/kWh)	$ 0.00740	$ 0.00734	$ 0.00718

Source:

1. MFR No. E-6b, Attachment No. 2 (12 CP and 1/13th) and E-5 includes CILC credit offset

Again, FPL's existing rate structure for CILC reflects this cost differential and loss differential, but FPL's proposed pricing structure does not.

Q PLEASE EXPLAIN WHY THE COMPANY'S PRESENT RATE DESIGN FOR THE CILC CLASS IS MORE REASONABLE THAN ITS PROPOSED AND REVISED RATE DESIGN

A My support is twofold. First, the Company's COSS support the Company's present rate design more so than the Company's proposed rate design. Table 5 above shows the resultant unit costs classified by demand related production, transmission, energy, distribution and customer charges from the Company's 12 CP and 1/13th COSS. These unit costs present a rate design that tracks proper cost-causation principles. Specifically, the transmission, production, and energy per-unit costs are all lower for higher voltage level customers than they are for the lower voltage level customers.

Second, the Company's own direct testimony in its last base rate case, Docket No. 120015-EI, provides a description of how the present CILC rates were designed. This design follows cost causation, relies on the results of the COSS and its principles therein, and is superior to the CILC rate design presented in the Company's testimony in this instant proceeding. In the 2012 docket, Ms. Deaton's Exhibit RBD-6, page 13 of 22, describes beginning at line 18 that the interruptible demand charge for each of the three CILC sub-classes is identical, and is "based on the class's average transmission demand unit cost." The firm demand charges for the three classes are "based on the class's average production and transmission demand unit cost." The maximum kW charge, or distribution recovery charge for the CILC-1G and CILC-1D classes are "based on the distribution demand revenue requirements divided by the billing demands." Lastly, the energy charges are, as well, based on the rate classes' energy unit costs developed in the Company's COSS.

In contrast, Ms. Cohen describes in the instant proceeding in Exhibit TCC-6, page 16 of 27, at line 22 that "The proposed demand and energy charges were calculated by applying the rate class increase percentage to current rates." This revised proposal ignores the cost-causation principles used in the Company's COSS and the production cost allocation and energy cost allocation to the various rate classes. Ms. Cohen's proposals in the instant proceeding produce a rate design for the three CILC sub-classes that is illogical, do not follow cost-causation principles, nor produce appropriate pricing incentives.

Q WHAT IS YOUR RECOMMENDED RATE DESIGN IN THIS CASE?

A I propose that the Company revert to a rate design that is more in line with that which it presented in its last base rate case and used to develop its present base rate charges. Following the rate design description offered by FPL in its 2012 base rate case, I recommend an equal interruptible demand charge for each sub-class set at the classes' average transmission demand unit cost from the approved COSS. I recommend the firm demand charges for the various sub-classes reflect the average production and transmission demand unit costs developed in the approved. Further, I propose the distribution demand charge for the CILC-1G and CILC-1D sub-classes be based on the distribution demand revenue requirements included in the approved COSS, also following the same rate differential between sub-classes as exists in the present rates. Lastly, I propose the energy charges be adjusted to achieve the rate class target revenues I have proposed in my testimony.[12] Each of these rate charge proposals follows the Company's proposal in its 2012 case.

[12] In 2012, the Company proposed an on-peak and off-peak time-differentiated energy rate, but that is not reflected in current or proposed rates in the instant proceeding. Further, the COSS does not allocate energy costs in a time-differentiated manner, and therefore does not provide a cost basis for designing a time-differentiated energy charge.

Q HAVE YOU DEVELOPED PROPOSED CILC BASE RATES?

A Yes. My Exhibit AMA-4 illustrates the development of my proposed rates for the CILC sub-classes following the procedure I have outlined above. Page 1 of Exhibit AMA-4 provides the COSS results from the Company's 12 CP and 1/13th model, taking into account the full value of the CILC credits. I then calculate proposed CILC base rate charges based on the functionalized COSS unit costs. Page 2 of Exhibit AMA-4 compares the Company's proposed revenue targets to my total revenue targets for each sub-class and shows how my proposed rates produce the target revenue requirements.

Table 6 below shows a comparison of the Company's present CILC base rates and my proposed CILC base rates. This comparison shows that the appropriate rate design principles following cost causation of the relative voltage level customers and price signal principles are followed under my proposal.

These proposed rates are offered at FPL's proposed cost of service for illustration purposes only. A reduction to FPL's revenue requirement should be taken into account in designing the CILC rates.

TABLE 6

Present and FEA Proposed CILC Base Rate Charges
(Demand Charges $/kW, Energy Charges ¢/kWh)

	Present Rates			FEA 2017 Proposed Rates		
	CILC-1G	CILC-1D	CILC-1T	CILC-1G	CILC-1D	CILC-1T
	below 69 kV		>69 kV	below 69 kV		>69 kV
	200-499 kW	500 kW+		200-499 kW	500 kW+	
Load Control Dmd	$1.97	$1.97	$1.97	$1.20	$1.20	$1.20
Firm Demand	$8.73	$8.51	$8.65	$7.96	$7.52	$7.50
Max (Dist.) Dmd	$3.82	$3.49	n/a	$4.54	$4.21	n/a
Energy	1.425	0.822	0.731	1.813	1.476	1.311

Q DO YOUR ABOVE PROPOSED BASE RATES REFLECT YOUR RECOMMENDED CHANGES TO THE PRODUCTION COST ALLOCATOR YOU HAVE MADE IN THIS TESTIMONY?

A No. The Company's workpapers filed in this case did not provide a working cost of service model from which I could make any adjustments to develop my recommended cost of service results. Therefore, I have designed rates to follow the Company's 12 CP and 1/13th production and transmission cost allocation method, with changes to the rate design to include the full CILC interruptible credit amount, and to follow a 1.5 times system average gradualism constraint on the non-fuel revenue. However, I maintain that the appropriate transmission cost allocation method is 100% demand 12 CP, and the appropriate production cost allocation method is 100% demand 4 CP summer or 4 CP/1 CP summer/winter method. I view the continuation of the 12 CP and 1/13th production demand allocation method a compromise between the Company's proposal and mine laid out in this testimony.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

MR. JERNIGAN: Thank you. And does staff have questions?

MS. BROWNLESS: Are you going to identify your exhibits or does she have any?

MR. JERNIGAN: I'm sorry. I thought I did.

CHAIRMAN BROWN: He did.

MS. BROWNLESS: Okay.

EXAMINATION

BY MS. BROWNLESS:

Q Hi, Ms. Alderson, how are you?

A Good, thanks.

Q Have you had an opportunity to review what's been marked as Staff Exhibit No. 579?

A I have it listed as 539. Is that the pages --

Q It's the composite exhibit list.

A The comprehensive exhibit list?

Q Yes, ma'am, Exhibit 539 --

A Yes, 539.

Q -- identified on the comprehensive exhibit list?

A 539, yes.

Q Yes, ma'am. The comprehensive exhibit list itself is 579. I'm sorry if I confused you.

A No problem.

Q And with regard to the exhibit that's identified there with you, which is Exhibit 539, did you prepare these exhibits?

A Yes.

Q And are they true and correct to the best of your knowledge and belief?

A Yes.

Q And would your answers be the same today if I were to ask them again?

A Yes.

Q And are any portions of your listed exhibits confidential?

A No.

MS. BROWNLESS: Thank you so much.

FURTHER DIRECT EXAMINATION

BY MR. JERNIGAN:

Q Ms. Alderson, do you have a summary that you would like to present on your testimony, please?

A I do. Good evening. In this proceeding, I support the FEA's position concerning jurisdictional cost of service methodologies, the appropriate spread of the approved revenue increase across rate classes and the CILC class rate design.

The company asks the Commission to approve the 12 CP and 25 percent production allocation method which differs from the 12 CP and 1/13th methodology that has been traditionally approved by the Florida Commission in the past.

The company's proposal increases the amount of fixed production investment costs allocated on an energy basis which is unreasonable in this case for at least three reasons which I detail in my direct testimony.

First, the company argues that it has recently installed a significant amount of base and intermediate load generation which has brought considerable fuel savings meriting a higher energy weighting in the allocation method. But the theory of capital substitution predicating the company's arguments have actually weakened in recent years as fuel prices and generation costs have changed.

In addition, FPL's reliance on natural gas to fuel its base load and intermediate units as well as its peaking units mutes the fuel cost differential between asset types. This weakening should result in a decrease in the energy allocation percentage, not an increase as the company has proposed.

As well, tracking the production cost allocation method with the company's current level of fuel costs begs the question of whether the company would in the future support a reduction in the energy weighting allocation if fuel costs rose.

The second reason I oppose the company's production cost allocator is because in its 2014 IRP, the company added a third reliability criterion for production planning, a 10 percent generation-only reserve margin applied to the one summer coincident peak hour and one winter coincident peak hour.

FPL, therefore, has increased its emphasis on planning to meet its peak demand needs, not its energy needs in every hour which further supports my opposition to the company's proposed increase in the energy weighting of the allocation factor.

Third and finally, FPL system load characteristics show that the company has a four coincident peak pattern, not a 12 CP pattern. Allocating the demand related production costs on a 12 CP basis which the company does when a 4 CP is more appropriate exacerbates the problem of allocating costs in a way that is not reflective of cost incurrence when coupled with the company's proposal to increase the energy weighting factor when a decrease is merited.

I further advocate for 100 percent demand based production allocation method based on either the four summer coincident peaks or four summer and one winter coincident peak. Continuation of the 12 CP and 1/13th method could be considered a compromised approach between mine and the company's proposals.

I also support a minimum distribution study to classify some portion of the company's distribution investment costs as customer related because such a classification reflects cost incurrence, and the minimum distribution study is common in the industry.

For revenues spread across classes, I agree with the 1.5 times gradualism constraint that the company has proposed but recommend that the highly variable fuel costs that are estimated for the test years in this proceeding for 2017 and beyond that are included in the gradualism calculations be excluded.

In addition, I do not believe the company has justified its proposal to reduce customer's interruptible rate credits and recommend the credit levels be left unchanged in this proceeding.

Finally, the company's proposed base rate charges for the CILC class do not follow its own cost of service results and presents a potential for rate migration between the customer subgroups. The company has changed its methods for designing rates for the CILC class in this proceeding which can be seen by comparing the testimonies from the prior FPL rate cases to this one.

The methods used by the company in its prior cases does yield logical results for the class. And therefore, I have developed CILC rates in concurrence with the company's previous rate methodology.

Thank you.

CHAIRMAN BROWN: Thank you.

MR. JERNIGAN: At this time, we present Ms. Alderson for cross examination.

CHAIRMAN BROWN: Thank you. And welcome, Ms. Alderson. I hope your travel from Missouri to Tallahassee, Florida, was uneventful.

MS. ALDERSON: They were. Smooth.

CHAIRMAN BROWN: Good. All right. Public counsel.

MS. CHRISTENSEN: No questions.

CHAIRMAN BROWN: FIPUG.

MR. MOYLE: Our interests are aligned with the FEA and the military on the MDS issue and the credit issue. We have the 12 CP 1/13th issue. We have a little bit of a different view on that. So, I'd like to ask her a couple of questions about that.

CHAIRMAN BROWN: And I appreciate the preface, yes.

MR. MOYLE: You gave me ample warning by asking about friendly cross.

EXAMINATION

BY MR. MOYLE:

Q Good evening.

A Good evening.

Q You had said that your recommendation is a 12 CP. What is your recommendation with respect to the allocation of costs?

A Production-related costs?

Q Yes, ma'am.

A Yes. I believe 100 percent demand-related allocation is cost reflective, and I recommend that those demand-related costs be allocated either on a 4 CP summer basis or a 4 CP summer and 1 CP winter basis.

Q What's the difference between what FIPUG has recommended, 12 CP and 1/13th and what you're recommending?

A The 12 CP and 1/13th methodology would allocate 1/13th of the total production demand-related costs on an energy basis and the remaining 12/13th costs on a 12 CP demand-related basis. My recommendation is that a full 100 percent of the costs should be allocated on a demand-related basis, and that a 4 CP summer, a 4 CP summer and 1 CP winter method be used.

Q And why do you think yours is better than what's recommended by FIPUG and Mr. Pollock?

A My direct testimony goes into that at length. There are a number of reasons why I feel that increasing the portion of the demand related -- the portion of all production costs that are allocated on a energy basis as the company is proposing to do in this case. It's proposing to increase the weighting from 1/13th to actually 25 percent.

I find that to be unreasonable and believe that actually a reduction in the amount of production-related costs that are allocated on an energy basis is merited. I listed off three reasons in my summary, and I can go over them again now if you'd like.

MR. MOYLE: I don't think you need to if you hit them in your summary. Thank you. That's all the questions I have.

CHAIRMAN BROWN: Thank you, Mr. Moyle. Hospitals.

MR. SIQVELAND: No questions from the hospitals.

CHAIRMAN BROWN: Retail Federation?

MR. LaVIA: No questions. Thank you.

CHAIRMAN BROWN: AARP.

MR. COFFMAN: No questions.
CHAIRMAN BROWN: Thank you. Florida Power & Light.
MS. CLARK: Madam Chairman, I have two exhibits I'd like to pass out.
CHAIRMAN BROWN: Staff will assist you. Would you like to label them now as --
MS. CLARK: I would like numbers, yes.
CHAIRMAN BROWN: We're going to be starting at 718, but let's just wait until they're disseminated.
MS. CLARK: I can tell you that I'm not sure I need them in the record, but I may.
CHAIRMAN BROWN: Okay. So, what would you like marked as 718?
MS. CLARK: If we can do FEA's Response to FPL's First Set of Interrogatories, No. 2, as 718.
CHAIRMAN BROWN: We will mark it as such.
(Exhibit 718 marked.)
MS. CLARK: And the next one would be the excerpt from PSC Order 10-0153-FOF-E1.
CHAIRMAN BROWN: And obviously, the Commission takes official recognition of its own orders, but we'll mark it anyway for identification purposes as 719. And that is PSC

Order 10-0153-FOF-E1.

(Exhibit 719 marked.)

MS. CLARK: Yes, thank you.

CHAIRMAN BROWN: Thank you. You may proceed whenever you'd like.

EXAMINATION

BY MS. CLARK:

Q Ms. Alderson, I'd like just like to follow up on a question that Mr. Moyle had about your method of allocating production plan.

A Sure.

Q I understand that you are recommending the 4 CP?

A In part, yes.

Q 4 CP or 1 CP; is that correct?

A That's correct.

Q And isn't it true under either one of these proposed methods that there will be some customer classes that will receive no production costs allocated to them?

A To the extent a customer class doesn't use firm demand service at the time of the four or five coincident peak hours, then that's true.

Q Looking at your Exhibit AMA-2, if I look at Line 11 which is OL-1 -- and I believe that's outdoor

lighting. And then further down on Line 14, I believe that's street lighting. Under your methodology, the 4 CP, they are not being allocated any production plan, correct?

A Under 4 CP methodology only, not the 4 CP summer/1 CP winter, it's correct that these two rate classes would not be allocated any of the fixed production costs.

Q Okay. I'd like to ask you about an answer you gave to an interrogatory. If you will look at Exhibit 718.

A Uh-huh. I have it here.

Q This question relates to the gradualism calculation. The interrogatory asks, "Please list any and all orders of State utility commission or boards that support Ms. Alderson's recommendation that the system average increase gradualism constraint be applied to total revenues including all surcharges with the exception of a fuel surcharge."

And could you read your answer?

A The response is: Ms. Alderson has not performed the research needed to develop the requested list.

Q To your knowledge, is there any order of a State Commission or Board that supports excluding fuel

charges from the gradualism calculation?

A Not any that I can recall off the top of my head here today.

Q Isn't it true that in Florida the Commission does include fuel clause revenues in the calculation of the gradualism?

MR. JERNIGAN: Objection. The witness has already stated she's not aware.

CHAIRMAN BROWN: I don't know if she has. I'll allow her to answer it.

A Can you restate the question, please.

Q Yes. Are you aware of whether or not there is a Florida Commission order that excludes fuel clause revenues from the calculation of the gradualism limitation?

A Similar to my last response, I do not know if there are any orders that do such a thing.

Q Would you look at Exhibit 719?

A (Examining document.)

Q On the second page, which is Page 179 of the order, there's a highlighted portion there.

A I see it.

Q Would you read that into the record, please.

MR. JERNIGAN: Objection. The witness has stated that she's not aware of any such orders.

To start using her to enter in such orders is inappropriate.

MS. CLARK: I'm fine with that.

CHAIRMAN BROWN: Okay. I was going to sustain it.

BY MS. CLARK:

Q Ms. Alderson, are you aware that Patrick Air Force Base is in Florida Power & Light's territory?

A Yes, I believe it is.

Q And are you familiar with McDill Air Force Base?

A McGill?

Q McDill.

A No, I'm sorry, I'm not.

Q Are you familiar with Eglin Air Force Base which is in the Panhandle in Gulf Power's service territory?

A I have heard of that air force base, yes.

Q Do you know if the rates paid for electric service at Patrick Air Force Base are lower than those paid at Eglin Air Force Base?

MR. JERNIGAN: Objection to relevancy.

A I have not done a study.

CHAIRMAN BROWN: She answered it.

Q What about Travis Air Force Base in California?

MR. JERNIGAN: Same objection. Relevancy.

CHAIRMAN BROWN: Ms. Clark?

MS. CLARK: I'll move on.

BY MS. CLARK:

Q Let me ask you this question. Would you agree that to the extent that FPL's rates are lower than the rates at other air force bases, that means more money can be put into training and operations at Patrick Air Force Base?

MR. JERNIGAN: Objection. Calls for speculation.

CHAIRMAN BROWN: I'll allow it. If she knows, she knows.

A I do not know about the operating costs of the relative air force bases, no.

MS. CLARK: Thank you, Madam Chairman. That's all I have.

CHAIRMAN BROWN: You're welcome. Staff.

EXAMINATION

BY MS. BROWNLESS:

Q Good evening. Were you provided the responses to staff's interrogatories and POD requests associated with your subject area as they became

available?

A They were made available to me, yes.

Q And were you also provided responses associated with your subject area of FIPUG's, South Florida's, AARP's and the Office of Public Counsel?

A They were made available to me, yes.

Q And in the course of your engagement, did you prepare discovery questions for FEA to propound in your subject area?

A Yes, I did.

Q And did you receive and review the responses to this discovery?

A Yes, I did.

MS. BROWNLESS: Thank you so much.

CHAIRMAN BROWN: Thank you. Commissioners?

MS. LEATHERS: I'm sorry, Madam Chairman. We did have one more question.

CHAIRMAN BROWN: Go ahead.

EXAMINATION

BY MS. LEATHERS:

Q Ms. Alderson, could you please turn to Exhibit AMA-2?

A Yes.

Q And this exhibit shows a comparison of production allocation factors to rate classes under

four different allocation methods. Could you please tell me under which rate schedules FEA members take service?

A Of the FEA bases that I'm aware and that we analyzed in this proceeding in detail, the majority of the service classes fall under the CILC-1T rate. I believe there was a few other accounts that were under the GSLDT-3 and GSLDT-2 rates, subject to check.

MS. LEATHERS: Thank you. And we have no further questions.

CHAIRMAN BROWN: Thank you. Commissioners? Redirect?

MR. JERNIGAN: A little bit.

REDIRECT EXAMINATION

BY MR. JERNIGAN:

Q Following up on the last question, Ms. Alderson, are you aware of the -- let me make sure I get this right. The Federal executive agencies consist more than the Department of Defense, correct?

A Yes, I believe so.

Q And they fall into -- we represent -- are they solely in the classes that you just mentioned?

A I do not know. I know there are multiple accounts, nearing dozens if not more, that take service from FPL of the FEA. We probably did not get detail about every single one of those accounts in the process of our preparation of testimony here.

Q So, would it be fair to say that there are multiple accounts not included in your answer to staff that might have an FEA customer involved?

A There could have been, yes.

MR. JERNIGAN: Thank you. No further questions.

CHAIRMAN BROWN: Okay. Exhibits. This witnesses has 231 through 235.

MR. JERNIGAN: Yes, ma'am, we would move to have those entered into the record.

CHAIRMAN BROWN: Any objections on 231 to 235 into the record? Seeing none, we will move 231 through 235 into the record.

(Exhibits 231 - 235 admitted.)

CHAIRMAN BROWN: FPL, you have 718.

MS. CLARK: We would move that into the record.

CHAIRMAN BROWN: Any objections? We will move 718 into the record.

(Exhibit 718 admitted.)

CHAIRMAN BROWN: Would you like your witness excused for the evening?

MR. JERNIGAN: Please, ma'am.

CHAIRMAN BROWN: Thank you. Have a good night, Ms. Alderson. You're excused.

MS. ALDERSON: Thank you.

CHAIRMAN BROWN: You are excused. FEA, would you call your next witness.

MR. JERNIGAN: FEA calls Mr. Michael Gorman to the stand.

MS. CHRISTENSEN: Madam Chair, before we move on to the next witness, I just wanted to make sure on Witness Dismukes did we move in Exhibits 712 and 713.

CHAIRMAN BROWN: Yes, we did.

MS. CHRISTENSEN: I just wanted to make sure because we had questions regarding erratas.

CHAIRMAN BROWN: 713 got in. Good evening, sir. How are you?

MR. GORMAN: I'm doing good. And you.

CHAIRMAN BROWN: Okay. Are you ready.

MR. JERNIGAN: Yes.

* * * * *

MICHAEL GORMAN

was called as a witness, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. JERNIGAN:

Q Could you please state your name for the record.

A My name is Michael Gorman.

Q And for whom are you employed?

A I'm employed by Brubaker & Associates.

Q And could you state their address for the record, please.

A My address is Swingley Ridge Road, Chesterfield, Missouri.

Q And who do you represent in this field?

A Federal Executive Agency.

Q Are you the same Michael Gorman who caused testimony which has been previously marked on the comprehensive list as Exhibits 204 through 225 to be filed in this case?

A Yes.

Q Do you have any corrections you would like to make either to your testimony or to the attached exhibits?

A I do have a few corrections. On Page 5 of the direct testimony in Footnote 1, at the end of the footnote the number 151.1 million should be corrected. It should be 120 million.

One other correction at Page 61 on Line 8.

The sentence reads: Equity issuances from the parent. The word "issuances" should be struck and the word "infusion" should be inserted. That sentence should read: Equity infusions from the parent company may include.

That completes my corrections.

Q Thank you. If I were to ask you the same questions that appear in your testimony and your exhibits today, including the corrections that you have made, would your answers be the same?

A They would.

MR. JERNIGAN: I request that Mr. Gorman's testimony and exhibits be entered into the record as if read.

CHAIRMAN BROWN: We will insert Mr. Gorman's prefiled direct testimony in the record as though read.

(Prefiled direct testimony inserted into the record as though read.)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	)	**DOCKET NO. 160021-EI**

Direct Testimony of Michael P. Gorman

I. INTRODUCTION AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Managing Principal of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A This testimony is presented on behalf of Federal Executive Agencies ("FEA"). FEA consists of certain agencies of the United States Government which have offices, facilities, and/or installations in the service area of Florida Power & Light Company ("FPL" or "Company") and purchase electric utility service from FPL.

Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A My testimony will address the current market cost of equity, and resulting overall rate of return, for FPL. In my analyses, I consider the results of several market models, the current economic environment and outlook for the electric utility industry, as well as the financial integrity of FPL given my recommended return on equity. I will also respond to FPL witness Mr. Robert Hevert's recommended return on equity of 11.00%.

My silence in regard to any issue should not be construed as an endorsement of FPL's position.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND CONCLUSIONS ON RATE OF RETURN.

A I recommend the Florida Public Service Commission ("Commission") award a return on common equity of 9.25%, which is at the midpoint of my recommended range of 8.90% to 9.60%. My recommended return on equity will fairly compensate FPL for its current market cost of common equity, and it will mitigate the claimed revenue deficiency in this proceeding by fairly balancing the interests of all stakeholders.

Based on my recommended return on equity and the Company's capital structure and embedded cost of debt, I recommend an overall rate of return of 5.56% as developed on my Exhibit MPG-1.

Finally, I will also comment on the unreasonableness of the return on equity recommendations and supporting studies offered by FPL witness Mr. Robert Hevert.

II. RATE OF RETURN

Q PLEASE DESCRIBE THIS SECTION OF YOUR TESTIMONY.

A In this section of my testimony, I will explain the analysis I performed to determine the reasonable rate of return in this proceeding and present the results of my analysis. I begin my estimate of a fair return on equity by reviewing regulatory authorized returns on equity, the market's assessment of the regulated utility industry investment risk, credit standing, and stock price performance. I used this information to get a sense of the market's perception of the risk characteristics of regulated utility investments in general, which is then used to produce a refined estimate of the market's return requirement for assuming investment risk similar to FPL's utility operations.

As described below, I find the credit rating outlook of the industry to be strong, supportive of the industry's financial integrity and access to capital. Further, regulated utilities' stocks have exhibited strong price performance over the last several years, which is evidence of utility access to capital.

Based on this review of credit outlooks and stock price performance, I conclude that the market continues to embrace the regulated utility industry as a safe-haven investment, and views utility equity and debt investments as low-risk securities.

Q DO YOU HAVE ANY COMMENTS FOR FPL WITNESS MORAY DEWHURST'S PROPOSAL FOR A 50 BASIS POINTS RETURN ON EQUITY PERFORMANCE ADDER?

A Yes. At pages 27-31 of his testimony, Mr. Dewhurst outlines his rationale for adding 50 basis points to FPL's authorized return on equity as a performance adder. The justification largely reflects his belief that FPL is a low-cost provider of high quality, reliable service. He also outlines that FPL has been compliant with environmental regulations on generation emissions, and has been recognized for customer satisfaction.

Q IS FPL'S PROPOSED 50 BASIS POINT RETURN ON EQUITY PERFORMANCE ADDER REASONABLE?

A No. The Company's proposal for a 50 basis points return on equity adder for these factors simply is not justified. FPL has been provided the privilege of providing a monopolistic or franchise service territory to retail customers in Florida. This obligation requires FPL to provide high quality, reliable service at competitive rates. Providing FPL an opportunity to earn a market-based return on equity capital will provide fair compensation to its investors, will maintain its financial integrity, and allow it access to capital to fund necessary plant investments to modernize its infrastructure and maintain its service reliability and quality. It is expected that FPL will meet these obligations to its customers based on just and reasonable rates.

Mr. Dewhurst simply has not provided any justifications for receiving a significant reward of 50 basis points for simply providing the service expected for a monopolistic or franchise provider in Florida. Mr. Dewhurst's proposal for a 50 basis point return on equity adder should be rejected.

I would also note that a 50 basis point adder is significant. The increase in the 2017 revenue requirement through a 50 basis point return on equity adder is about $120 million per year based on the Company's $32.5 billion jurisdictional 2017 rate base, as listed on its Schedule A-1. The revenue requirement impact of a 50 basis point return on equity adder reflects both the increase in the operating income, and the related income tax expense. The Company's proposal for a performance adder to the return on equity is excessive, and should be denied.[1]

II.A. Electric Industry Authorized Returns on Equity, Credit Strength, and Access to Capital

Q PLEASE DESCRIBE RECENT EVIDENCE ON AUTHORIZED RETURNS ON EQUITY FOR ELECTRIC UTILITIES, ELECTRIC UTILITIES' CREDIT STANDING, AND ELECTRIC UTILITIES' ACCESS TO CAPITAL TO FUND INFRASTRUCTURE INVESTMENT.

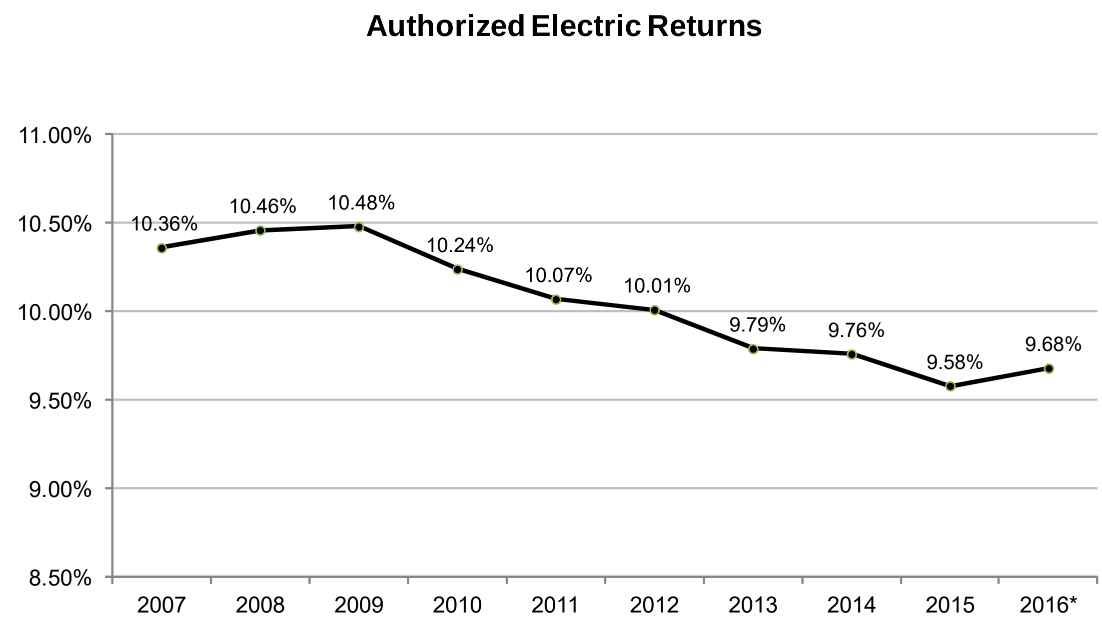
A Authorized returns on equity for electric utilities have been steadily declining over the last 10 years as illustrated in the graph below. More recent authorized returns on equity for electric utilities have declined down to about the 9.6% to 9.7% area, which approaches the high-end of my recommended range in this proceeding. Specifically, Regulatory Research Associates ("RRA") summarizes its review of recent authorized returns on equity for regulated utility companies in its April 15, 2016 publication "Major Rate Case Decisions – January-March 2016". RRA stated as follows:

> The average ROE authorized electric utilities was 10.26% in the first quarter of 2016, compared to 9.85% in 2015. There were 8 electric ROE determinations in the first three months of 2016, versus 30 in all of 2015. We note that the data includes several surcharge/rider generation cases in Virginia that incorporate plant-specific ROE premiums. Virginia statutes authorize the State Corporation Commission to approve ROE premiums of up to 200 basis points for certain generation projects (see the Virginia Commission Profile). Excluding from the data these Virginia surcharge/rider generation cases that utilize an ROE premium, the average authorized electric ROE was 9.68% for the first quarter of 2016 compared to 9.58% for full year 2015. The average ROE authorized gas utilities was 9.48% in the first quarter of 2016 versus 9.6% in all of 2015. There were 6 gas

[1] $32.5 billion rate base, change in pretax rate of return of 0.37% increases the revenue requirement by $151.1 million.

cases that included an ROE determination in the first three months of 2016, compared to 16 in 2015.[2]

Figure 1



Source and Note:
Regulatory Research Associates, Inc., Regulatory Focus, Major Rate Case Decisions, multiple publication dates. In 2010 forward, the Virginia cases, which are subject to an adjustment for certain generation assets up to 200 basis points, are excluded.
* Through March 31, 2016.

As illustrated on Figure 1 above, excluding these Virginia rider decisions, the authorized electric return on equity in 2013 and 2014 was approximately 9.8%, and dropped to 9.6% to 9.7% in 2015 and 2016.

This decline in authorized returns on equity for utilities follows the decline in capital market costs. Importantly, with the declines in capital market costs and authorized equity returns, utilities are maintaining strong investment grade credit

[2] Regulatory Research Associates *Regulatory Focus*, "Major Rate Case Decisions – January-March 2016," April 15, 2016, emphasis added indicated by double underlining.

standing, and have been able to attract large amounts of capital at low costs to fund very large capital programs.

Q HOW ARE THE RECENTLY AUTHORIZED RETURNS PERCEIVED BY THE CREDIT RATING AGENCIES?

A Credit rating agencies recognize the declining trend in authorized returns and the expectation that regulators will continue lowering the returns for U.S. utilities while maintaining a stable credit profile. Specifically, Moody's states:

> **Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles**
>
> <u>The credit profiles of US regulated utilities will remain intact over the next few years despite our expectation that regulators will continue to trim the sector's profitability by lowering its authorized returns on equity (ROE).</u> Persistently low interest rates and a comprehensive suite of cost recovery mechanisms ensure a low business risk profile for utilities, prompting regulators to scrutinize [sic] their profitability, which is defined as the ratio of net income to book equity. We view cash flow measures as a more important rating driver than authorized ROEs, and we note that regulators can lower authorized ROEs without hurting cash flow, for instance by targeting depreciation, or through special rate structures. <u>Regulators can also adjust a utility's equity capitalization in its rate base</u>. All else being equal, we think most utilities would prefer a thicker equity base and a lower authorized ROE over a small equity layer and a high authorized ROE.
>
> * * *
>
> » **Utilities' actual financial performance remains stable**. <u>Earned ROEs, which typically lag authorized ROEs, have not fallen as much as authorized returns in recent years.</u> Since 2007, vertically integrated utilities, transmission and distribution only utilities, and natural gas local distribution companies have maintained steady earned ROE's in the 9% - 10% range. Holding companies with primarily regulated businesses also earned ROEs of around 9% - 10%, while returns for holding companies with diversified operations, namely unregulated generation, have fallen from 11% (over the past seven year average) to around 9% today.[3]

[3]*Moody's Investors Service*, "US Regulated Utilities: Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," March 10, 2015, emphasis added.

Similarly, in a more recent report, S&P asserts that steady authorized returns in the mid 9.0% range are in line with earned returns. Specifically, S&P states:

> **2. Earned returns will remain in line with authorized returns**
>
> <u>Authorized returns on equity granted by U.S. utility regulators in rate cases this year have been steady at about 9.5%</u>. Utilities have been adept at earning at or very near those authorized returns in today's economic and fiscal environment. A slowly recovering economy, natural gas and electric prices coming down and then stabilizing at fairly low levels, and the same experience with interest rates have led to a perfect "non-storm" for utility ratepayers and regulators, with utilities benefitting alongside those important constituencies. Utilities have largely used this protracted period of favorable circumstances to consolidate and institutionalize the regulatory practices that support earnings and cash flow stability. We have observed and we project continued use of credit-supportive policies such as short lags between rate filings and final decisions, up-to-date test years, flexible and dynamic tariff clauses for major expense items, and alternative ratemaking approaches that allow faster rate recognition for some new investments.[4]

Q PLEASE DESCRIBE THE TREND IN CREDIT RATINGS IN THE ELECTRIC UTILITY INDUSTRY OVER THE LAST FIVE YEARS.

A Credit analysts are fully aware of regulatory decisions including authorized returns on equity. Hence, changing credit standing fully reflects regulatory decisions including the authorized returns on equity. With this as a backdrop, it is significant to recognize that electric utility credit standing has been improving over the last five to six years.

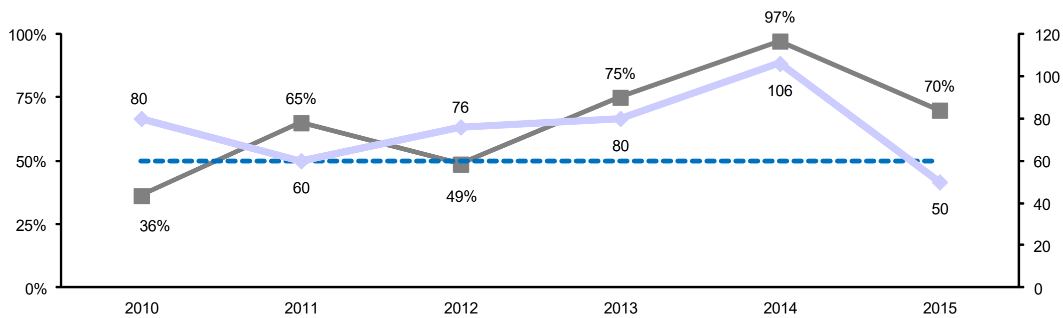
As shown below in Table 1, over the period 2010-2015, the electric utility industry has experienced a significant number of upgrades in credit ratings by all of the major credit rating agencies (Fitch Ratings, Moody's, and Standard & Poor's).

[4]*Standard & Poor's Ratings Services*: "Corporate Industry Credit Research: Industry Top Trends 2016, Utilities," December 9, 2015, at 23, emphasis added.

TABLE 1

Credit Rating Changes
(U.S. Shareholder-Owned Electric Utility Industry)

	2010	**2011**	**2012**	**2013**	**2014**	**YTD 2015**
Upgrades	29	39	37	60	103	35
Downgrades	51	21	39	20	3	15
% Upgrades	36%	65%	49%	75%	97%	70%
Total Rating Activity	**80**	**60**	**76**	**80**	**106**	**50**



Source: EEI Q4 2015 Credit Ratings, Tab IV Direction of Rating Action.

As noted above in Table 1, the upgrades in utility credit ratings started outpacing downgrades in 2011, and more recently, the number of upgrades substantially exceeds the amount of downgrades. For example, in 2014, there are 103 upgrades and only three downgrades. In 2015, the number of upgrades were more than twice the number of downgrades (at 35 upgrades and 15 downgrades).

Moody's comments on this improved credit standing of regulated utility companies in its publication, "Regulation Remains a Credit Supportive Ratings Driver Two Years After Sector-Wide Upgrades." Moody's stated as follows:

> **Summary**
>
> In January and February 2014, we upgraded the ratings of 147 US regulated electric and gas utility debt issuers as part of a sector-wide rating action that reflected our more <u>favorable view of the relative credit supportiveness of US utility regulation</u>. Factors supporting this view include better cost-recovery provisions, reduced regulatory lag,

> and generally fair and open relationships between utilities and their state regulators.[5]

Q WITH DECLINING AUTHORIZED RETURNS ON EQUITY AND STABLE CREDIT, HAVE UTILITIES BEEN ABLE TO SUPPORT LARGE CAPITAL PROGRAMS?

A Yes. While cost of capital and authorized returns on equity were declining, the utility industry has been able to fund substantial increases in capital investments needed for infrastructure modernization and expansion. The Edison Electric Institute ("EEI") reported in a 2015 financial review of the electric industry financial performance, that in 2011 electric "industry-wide capex has more than doubled since 2005."[6]

EEI also observed that despite this nearly tripling of capital expenditures during the period 2005-2015, a majority of the funding for utilities' capital expenditures has been provided by internal funds. EEI reports that approximately 25% of funding needed to meet these increasing capital expenditures has been derived from external sources, and 75% of these capital expenditures have been funded by internal cash. Further, despite nearly tripling capital expenditures, the electric utility industry debt interest expense has declined by approximately 1.9%, despite increases in the amount of outstanding debt,[7] clear proof that capital market costs have declined.

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[5]Moody's Investor Service: "U.S. Regulated Utilities: Regulation Remains a Credit Supportive Ratings Driver Two Years After Sector-Wide Upgrades," November 6, 2015, emphasis added.

[6]Edison Electric Institute, *2015 Financial Review, Annual Report of the U.S. Investor-Owned Electric Utility Industry*, page 17.

[7]*Id*., pages 8 and 11.

Q WHY DO YOU BELIEVE THE VALUATION OF ELECTRIC UTILITY SECURITIES IS ROBUST?

A This robust valuation is an indication that utilities can sell securities at high prices, which is a strong indication that they can access capital under reasonable terms and conditions, and at relatively low cost. As shown on my Exhibit MPG-2, the historical valuation of the electric utilities included in Mr. Hevert's proxy group based on a price-to-earnings ratio, price-to-cash flow ratio, and market-to-book ratio, indicate that utility security valuations today are very strong and quite robust relative to the last 15 years. Again, the strong valuations of utility stocks indicate that utilities have access to equity capital under reasonable terms, and the strong valuation is an indication that the cost of equity capital is very low.

II.B. Regulated Utility Industry Market Outlook

Q PLEASE DESCRIBE THE CREDIT RATING OUTLOOK FOR REGULATED UTILITIES.

A Regulated utilities' credit ratings have improved over the last few years and the outlook has been labeled "Stable" by credit rating agencies. Credit analysts have also observed that utilities have strong access to capital at attractive pricing (i.e., low capital costs), which has supported very large capital programs.

Standard & Poor's ("S&P") recently published a report titled "Corporate Industry Credit Research: Industry Top Trends 2016, Utilities." In that report, S&P noted the following:

> **Ratings Outlook.** Stable with a slight bias toward the negative. Utilities in the U.S. continue to enjoy a confluence of financial, economic, and regulatory environments that are tailor-made for supporting credit quality. Low interest rates, modest economic growth, and relatively stable commodity costs make for little pressure on rates and therefore on the sunny disposition of regulators.

> • **Credit Metrics.** We see credit metrics remaining within historic norms for the industry as a whole and do not project overall financial performance that would affect the industry's creditworthiness.
>
> • **Industry Trends.** Taking advantage of the favorable market conditions, utilities have been maintaining aggressive capital spending programs to bolster system safety and reliability, as well as technological advances to make the systems "smarter." The elevated spending has not led to large rate increases, but if macro conditions reverse and lead to rising costs that command higher rates, we would expect utilities to throttle back on spending to manage regulatory risk.[8]

Similarly, Fitch states:

> **Stable Financial Performance:** The stable financial performance of Utilities, Power & Gas (UPG) issuers continues to support a sound credit profile for the sector, with 93% of the UPG portfolio carrying investment-grade ratings as of June 30, 2015, including 65% in the 'BBB' rating category. Second-quarter 2015 LTM [Long-Term Maturity] leverage metrics remained relatively unchanged year over year (YOY) while interest coverage metrics modestly improved. Fitch Ratings expects this trend to broadly sustain for the remainder of 2015, driven by positive recurring factors.
>
> **Low Debt-Funded Costs:** The sustained low interest rate environment has allowed UPG companies to refinance high-coupon legacy debt with lower coupon new debt. Gross interest expense on an absolute value represented approximately 4.6% of total adjusted debt as of June 30, 2015, a decline of about 150 bps from the 6.1% recorded in the midst of the recession. Fitch believes a rise in interest rates would largely be neutral to credit quality, as issuers have generally built enough headroom in coverage metrics to withstand higher financing costs.
>
> **Capex Moderately Declining:** Fitch expects the capex/depreciation ratio to be at the lower end of its five-year historical range of 2.0x–2.5x in the near term, reflecting a moderate decline in projected capex from the 2011–2014 highs. The capex depreciation ratio was relatively flat YOY at about 2.4x. Capex targets investments toward base infrastructure upgrades, utility-scale renewables and transmission investments.
>
> * * *
>
> Key credit metrics for IUCs [investor-owned utility companies] remained relatively stable YOY and continue to support the sound credit profiles and <u>Stable Outlooks</u> characteristic of the sector. EBITDAR [Earnings Before Interest, Taxes, Depreciation, Amortization

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[8] *Standard & Poor's Ratings Services*: "Corporate Industry Credit Research: Industry Top Trends 2016, Utilities," December 9, 2015, at 22, emphasis added.

> and Rent] and FFO [Funds From Operations] coverage ratios were 5.6x and 5.9x, respectively, for the LTM ended second-quarter 2015, while adjusted debt/EDITDAR and FFO-adjusted leverage were 3.5x and 3.4x, respectively.[9]

Moody's recent comments on the U.S. Utility Sector state as follows:

> Our outlook for the US regulated utilities industry is stable. This outlook reflects our expectations for fundamental business conditions in the industry over the next 12 to 18 months.
>
> » **The credit-supportive regulatory environment is the main reason for our stable outlook.** We expect that the relationship between regulators and utilities in 2016 will remain credit-supportive, enabling utilities to recover costs in a timely manner and maintain stable cash flows.
>
> » **We estimate that the ratio of cash flow from operations (CFO) to debt will hold steady at about 21%, on average for the industry, over the next 12 to 18 months.** The use of timely cost-recovery mechanisms and continued expense management will help utilities offset a lack of growth in electricity demand and lower allowed returns on equity, enabling financial metrics to remain stable. Tax benefits tied to the expected extension of bonus depreciation will also support CFO-to-debt ratios.
>
> * * *
>
> » **Utilities are increasingly using holding company leverage to drive returns, a credit negative.** Although not a driver of our outlook, utilities are using leverage at the holding company level to invest in other businesses, make acquisitions and earn higher returns on equity, which could have negative implications across the whole family. [10]

Q PLEASE DESCRIBE UTILITY STOCK PRICE PERFORMANCE OVER THE LAST SEVERAL YEARS.

A As shown in the graph below, SNL Financial has recorded utility stock price performance compared to the market. The industry's stock performance data from 2004 through March 2016 shows that the SNL Electric Company Index has

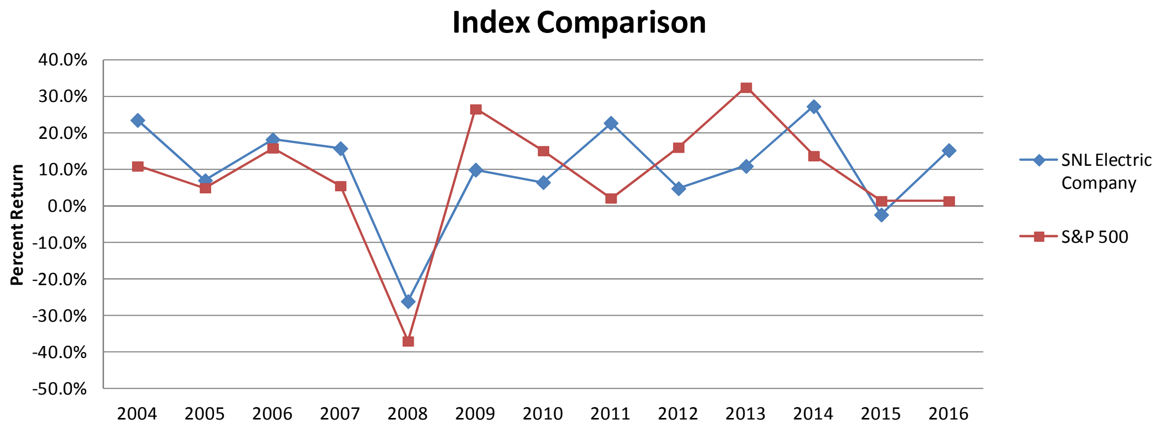
---

[9] *Fitch Ratings*: "U.S. Utilities, Power & Gas Data comparator," September 21, 2015, at 1 and 7, emphasis added.

[10] *Moody's Investors Service*: "2016 Outlook – US Regulated Utilities: Credit-Supportive Regulatory Environment Drives Stable Outlook," November 6, 2015, at 1, emphasis added.

outperformed the market in downturns and trailed the market during recovery. This relatively stable price performance for utilities supports my conclusion that utility stock investments are regarded by market participants as a moderate- to low-risk investment.

FIGURE 2



Source: SNL Financial, data through March 31, 2016.

Q HAVE ELECTRIC UTILITY INDUSTRY TRADE ORGANIZATIONS COMMENTED ON ELECTRIC UTILITY STOCK PRICE PERFORMANCE?

A Yes. In its 4th Quarter 2015 Financial Update, The Edison Electric Institute ("EEI") stated the following concerning the EEI Electric Utility Stock Index ("EEI Index"):

> EEI Index returns during 2015 embodied the larger pattern seen in Table I since the 2008/2009 financial crisis, as industry business models have migrated to an increasingly regulated emphasis. The industry has generated consistent positive returns but has lagged the broader markets when markets post strong gains, which in turn have been sparked both by slow but steady U.S. economic growth and corporate profit gains and by the willingness of the Federal Reserve to bolster markets with historically unprecedented monetary support in the form of three rounds of quantitative easing and near-zero short-term interest rates. <u>While the Fed did raise short-term rates in December 2015 for the first time since 2006</u> (from zero to a range of 0.25% to 0.50%), <u>this hardly effects longer-term yields, which remain at historically low levels and are influenced more by the level of</u>

> inflation and economic strength than by the Fed's short-term rate policy.
>
> * * *
>
> **Regulated Fundamentals Remain Stable**
>
> The rate stability offered by state regulation and the ability to recover rising capital spending in rate base shield regulated utilities from the volatility in the competitive power arena and turn the growth of renewable generation (and the resulting need for new and upgraded transmission lines) into a rate base growth opportunity for many industry players.
>
> * * *
>
> In the shorter-term, analysts continue to see opportunity for 4-6% earnings growth for regulated utilities in general along with prospects for slightly rising dividends (with a dividend yield now at about 4% for the industry overall). That formula has served utility investors quite well in recent years, delivering long-term returns equivalent to those of the broad markets but with much lower volatility. Provided state regulation remains fair and constructive in an effort to address the interests of ratepayers and investors, it would appear that the industry can continue to deliver success for all stakeholders, even in an environment of flat demand and considerable technological change.[11]

II.C. FPL Investment Risk

Q PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF THE INVESTMENT RISK OF FPL.

A The market's assessment of FPL's investment risk is described by credit rating analysts' reports. FPL's current corporate bond ratings from S&P and Moody's are A- and A1, respectively. FPL's outlook from both credit rating agencies is "Stable." Specifically, S&P states:

> **Outlook: Stable**
>
> The outlook on Florida Power & Light Co. (FPL) is stable and is based on the outlook of its parent, NextEra Energy Inc. (NEE). The stable rating outlook on NextEra and its subsidiaries, Florida Power & Light

[11] *EEI Q4 2015 Financial Update*: "Stock Performance" at 4 and 6, emphasis added.

> Co. and NextEra Energy Capital Holdings Inc., reflects our expectation that the company will preserve its "strong" business risk profile while ensuring that its financial risk profile remains well within the "intermediate" category at all times, albeit toward the lower end of the category. The stable outlook is also predicated on the company effectively managing its growth and capital spending so that regulated operations continue to contribute about 60% of operating income. Finally, the stable outlook anticipates that NextEra will fund the proposed merger with Hawaiian Electric Industries in a credit-neutral manner, while receiving approval to close the merger without any restrictive regulatory provisions or requirements.
>
> * * *
>
> **Business Risk: Excellent**
>
> We assess FPL's business risk profile as "excellent," accounting for the company's regulated utility operations that benefit from a <u>constructive regulatory framework</u>, which provides for timely investment and fuel cost recovery. FPL has historically managed its regulatory risk effectively, resulting in <u>earned returns that are consistently close to or at the authorized levels.</u> The service territory is large and lacks geographic and regulatory diversity. FPL's customer base is large, with no meaningful industrial exposure and above-average growth. The company has material exposure to natural gas-fired generation, which, in combination with low natural gas prices and the company's efficient operations, contributes to overall competitive rates for its customers.
>
> **Financial Risk: Intermediate**
>
> We assess FPL's financial risk profile as being in the "intermediate" category using the medial volatility financial ration benchmarks. Under our base-case scenario we expect that FPL's financial profile will benefit largely from recovery of invested capital and load/customer growth, with FFO to debt that averages about 33% over the next few years and debt to EBITDA that remains consistently below 2.5x.[12]

Similarly, Moody's states:

> **Summary Rating Rationale**
>
> FPL is one of the strongest regulated electric utilities in the US. The political and regulatory environment for Florida utilities is <u>stable</u>, allaying some of the uncertainties that this year's rate case will entail. FPL has good cost recovery mechanisms that produce consistently above-average financial performance. Its large, mainly residential service territory is growing, and the economic recovery will result in

[12] *Standard & Poor's RatingsDirect:* "Summary: Florida Power & Light Co.," June 12, 2015, at 3-4, emphasis added.

> organic growth in sales and a need for new infrastructure. To meet those needs, FPL continues to make substantial capital investments in its rate base, which will increase earnings as they are completed.
>
> * * *
>
> **Rating Outlook**
>
> The stable rating outlook reflects the our expectation that the current rate case will result in a constructive outcome that will maintain its existing credit-supportive ratemaking features. The ratings assume its timely cost recovery mechanisms and regular capital contributions from NextEra will maintain FPL's strong credit metrics, including CFO Pre-WC-to-debt in the low to mid 30% range.[13]

Fitch also opines as follows:

> Fitch Ratings has affirmed the Issuer Default Rating (IDR) for Florida Power & Light Company (FPL) at 'A' with a <u>Stable Rating Outlook</u>.
>
> FPL's ratings reflect the predictable nature of cash flows from regulated electric operations, a favorable outcome to the 2012 base rate case that provides for four years of regulatory certainty, recovering electric sales in its service territory after a prolonged trough, management focus on O&M cost containment that is expected to drive returns close to the upper end of the authorized return on equity (ROE) range, and a strong balance sheet and liquidity profile. The ratings also reflect high-capex investments over 2015-18 as the utility spends on new generation and other infrastructure improvements.[14]

III. FPL'S PROPOSED CAPITAL STRUCTURE

Q WHAT IS FPL'S PROPOSED CAPITAL STRUCTURE?

A FPL's proposed capital structure is shown below in Table 2. This capital structure ending the test year period December 31, 2017 is sponsored by FPL witnesses Mr. Dewhurst and Mr. Hevert. Mr. Dewhurst proposes using an investor-supplied capital structure consisting of 59.6% equity component as approved in FPL's adjusted capital

[13] *Moody's Investors Service*: "Credit Opinion: Florida Power & Light Company," March 31, 2016 at 1-2, provided by FPL in response to OPC's 1st POD No. 12, emphasis added.

[14] *Fitch Ratings*: "Fitch Affirms Florida Power & Light Co. at 'A'; Outlook Stable," December 3, 2015 at 1, provided by FPL in response to OPC's 1st POD No. 9, emphasis added.

in a manner similar to the adjustments applied in prior regulatory proceedings. (Dewhurst Direct at 24).

TABLE 2

Reasonable Capital Structure
(2017 Test Year)

Description	Regulatory Weight (1)	Investor Weight (2)
Long-Term Debt	28.76%	37.96%
Customer Deposits	1.25%	
Common Equity	45.13%	59.55%
Short-Term Debt	1.88%	2.49%
Deferred Income Tax	22.65%	
Investment Tax Credit	0.33%	
Total	100.00%	100.00%

Source: Schedule D-1a.

Q IS FPL'S PROPOSED CAPITAL STRUCTURE REASONABLE?

A No. FPL's proposed capital structure has a very large component of common equity relative to total investor capital. As shown in Table 2 above, FPL's total common equity ratio of total investor capital is 59.55%. For industry averages, the capital structures used to set rates generally include common equity to total investor capital of closer to 50%.[15] FPL's equity-rich capital structure substantially increases its cost of service with very little benefit to retail customers. Specifically, its bond ratings of A-

[15]Regulatory Research Associates *Regulatory Focus*, "Major Rate Case Decisions – January-March 2016," April 15, 2016, common equity ratio for electric utilities 2002-2016.

and A1 are approximately at the high-end of the range of most bond ratings for electric utility companies.[16]

Q WHY WOULD A CAPITAL STRUCTURE TOO HEAVILY WEIGHTED WITH COMMON EQUITY UNNECESSARILY INCREASE FPL'S COST OF SERVICE IN THIS PROCEEDING?

A A capital structure too heavily weighted with common equity unnecessarily increases FPL's claimed revenue deficiency because common equity is the most expensive form of capital and is subject to income tax expense. For example, if FPL's authorized return on equity is set at 9.0%, the revenue requirement cost to customers would be approximately 14.4%, or 9.0% adjusted by a tax revenue conversion factor of approximately 1.6x. In contrast, the cost of debt capital is not subject to an income tax expense. FPL's current marginal cost of debt is around 5.50%. Common equity is more than twice as expensive, on a revenue requirement basis, than is debt capital.

A reasonable mix of debt and equity is necessary in order to balance FPL's financial risk, support an investment grade credit rating, and permit FPL access to capital under reasonable terms and prices. However, a capital structure too heavily weighted with common equity will unnecessarily increase its cost of capital and revenue requirement for ratepayers.

For a utility managing its capital structure, it is important to balance its obligations to minimize its cost of capital, while at the same time support its financial

[16]Edison Electric Institute ("EEI") in a fourth quarter 2015 publication on electric utility credit ratings, listed the bond ratings for its universe of electric utility companies based on EEI's assessment of them being "Regulated," (above 80% of total assets) "Mostly Regulated" (50%-80% of total assets) or "Diversified" (below 50% of total assets). For "Regulated" and "Mostly Regulated" utilities, 85-90% of all electric utilities had bond ratings in the range of A- to BBB. While FPL's bond rating falls at the high end of this range, it nevertheless is not distinctively different than the electric utility industry.

integrity and access to capital. This balance requires a utility to manage its capital structure to maintain a reasonable balance of common equity and debt such that cost of capital is minimized and its credit rating is preserved.

Q ARE YOU PROPOSING ANY ADJUSTMENTS TO MODIFY FPL'S EXCESSIVE COMMON EQUITY RATIO?

A No. However, FPL's capital structure is not reasonable and unnecessarily inflates the claimed revenue deficiency in this proceeding because its common equity component of total capital is unreasonably high.

The Commission should carefully weigh the balance of a fair return on equity between the Company and its retail customers. Because FPL's capital structure has an excessive weight of common equity, the Commission should award a return on equity that is lower to reflect this reduction in financial risk, and the need for a lower rate of return to produce more balance between customers and shareholders.

For these reasons, I will consider FPL's excessive common equity weighted capital structure in recommending a fair risk-adjusted rate of return on equity for FPL in this proceeding.

Q DID THE COMPANY PROPOSE TO USE ITS CAPITAL STRUCTURE FOR SETTING THE REVENUE REQUIREMENT IN 2019 FOR ITS OKEECHOBEE LSA FACILITY ("OKEECHOBEE")?

A No. The Company proposes to set the overall rate of return for Okeechobee based on its investor capital weights only.[17] The Company is proposing to ignore all customer-supplied capital including customer deposits, and zero-cost capital

[17] Okeechobee Clean Energy Center Limited Scope, Vol. 1, Schedule D-1a.

components related to deferred income taxes and investment tax credits. This has the effect of increasing the rate of return that would be applied to the $1.06 billion investment projected at May 31, 2020.[18]

Q DO YOU BELIEVE THE COMPANY'S PROPOSAL TO SET THE REVENUE REQUIREMENT OF THE OKEECHOBEE INVESTMENT ON ONLY INVESTOR CAPITAL WOULD BE REASONABLE?

A No. The Company proposes to adjust rates to reflect this new investment in 2019. Initial rates in this case will go into effect in 2017. Over this time period, the Company's invested capital will change dramatically based on the rates set in 2017 and modified in 2018. As such, the incremental change in rates in 2019 for this investment should be based on the same capital structure used to develop the revenue requirement for all other plant investment. This is appropriate because the Company is not reflecting changes in invested capital for other rate base items that could offset the need for an increase for the Okeechobee investment as it comes in service in 2019.

Q WHAT IS THE REVENUE REQUIREMENT IMPACT IF THE COMPANY'S REGULATORY CAPITAL STRUCTURE IS USED TO DEVELOP THE 2019 REVENUE REQUIREMENT FOR THE OKEECHOBEE INVESTMENT?

A Using the Company's proposed capital structure for 2018 will reduce the revenue requirement for the Okeechobee investment by approximately $34.8 million.

[18] *Id*. at A-1.

III.A. Embedded Cost of Debt

Q WHAT IS THE COMPANY'S EMBEDDED COST OF DEBT?

A Mr. Dewhurst is proposing an embedded cost of debt of 4.62% as shown on Schedule D-1a. However, on his Schedule D-4a, the cost of debt is 4.57%.

Q DID FPL INCLUDE PROJECTED NEW BOND ISSUANCES IN ITS EMBEDDED COST OF DEBT ESTIMATE?

A Yes. Company witness Dewhurst includes the following projected debt issuances for the test year period:

- 4.75% $300 million 30-year debt with issuance, March 2016;
- 6.16% $500 million 30-year debt with issuance, March 2017; and
- 6.16% $800 million 30-year debt with issuance, November, 2017.

Q IS FPL'S PROJECTED PRICING FOR THESE BOND ISSUES REASONABLE?

A The Company should update its filing to reflect actual debt issuance costs (interest rate and expenses) after the new debt issuance occurs. Based on FPL's filing the most recent debt issuances are:

- 3.85% $600 million 10-year First Mortgage Bonds as of November 2015, and
- 4.05% $500 million 30-year First Mortgage Bonds as of September 2014.

The Company's projected debt issuances of 6.16% are significantly above the current market cost of debt.

Q ARE YOU PROPOSING TO ADJUST FPL'S EMBEDDED DEBT COST ESTIMATE?

A Yes. I revised the Company's projected debt issuances of 6.16% to reflect the current market cost of debt. My adjusted debt cost is developed on my Exhibit MPG-3.

The first panel of this exhibit shows the Company's embedded cost of debt as developed on Schedule D-4a. I used the most recent 13-week average "A" rated utility yield of 3.96% and the Company's proposed issuance expense adder of 0.875% as developed on Schedule F-8. This produced an updated new debt cost of 4.835%. Revising the coupon rate of the two projected debt issuances from 6.16% down to 4.835% reduces the embedded debt cost from 4.62% to 4.51% as shown on the second panel of Exhibit MPG-3.

Q DO YOU HAVE ANY ADDITIONAL COMMENTS RELATED TO FPL COSTS OF CAPITAL?

A Yes. FPL incorrectly calculated the cost of the investment tax credit ("ITC") included in its regulatory capital structure. The Company did not include the short-term debt in the cost of ITC. I recommend setting the ITC cost at the weighted average cost of all investor capital, including short-term debt.

IV. RETURN ON EQUITY

Q PLEASE DESCRIBE WHAT IS MEANT BY A "UTILITY'S COST OF COMMON EQUITY."

A A utility's cost of common equity is the expected return that investors require on an investment in the utility. Investors expect to earn their required return from receiving dividends and through stock price appreciation.

Q PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED UTILITY'S COST OF COMMON EQUITY.

A In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court: Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944).

These decisions identify the general financial and economic standards to be considered in establishing the cost of common equity for a public utility. Those general standards provide that the authorized return should: (1) be sufficient to maintain financial integrity; (2) attract capital under reasonable terms; and (3) be commensurate with returns investors could earn by investing in other enterprises of comparable risk.

Q PLEASE DESCRIBE THE METHODS YOU HAVE USED TO ESTIMATE FPL'S COST OF COMMON EQUITY.

A I have used several models based on financial theory to estimate FPL's cost of common equity. These models are: (1) a constant growth Discounted Cash Flow ("DCF") model using consensus analysts' growth rate projections; (2) a constant growth DCF using sustainable growth rate estimates; (3) a multi-stage growth DCF model; (4) a Risk Premium model; and (5) a Capital Asset Pricing Model ("CAPM"). I have applied these models to a group of publicly traded utilities that have investment risk similar to FPL.

IV.A. Risk Proxy Group

Q PLEASE DESCRIBE HOW YOU IDENTIFIED A PROXY UTILITY GROUP THAT COULD BE USED TO REASONABLY REFLECT THE INVESTMENT RISK OF FPL AND USED TO ESTIMATE ITS CURRENT MARKET COST OF EQUITY.

A I relied on the same proxy group developed by FPL witness Mr. Hevert, but updated it to review companies with selection criteria. Based on a review of updated information, I excluded Otter Tail because it did not have analysts' growth rates from Zacks, SNL Financial or Reuters at the time I developed my studies. Two companies began involvement in mergers and acquisitions ("M&A") activity. Dominion Resources was removed because in February 2016 it announced its intent to purchase Questar Corp. Also, Westar Energy was excluded because on May 31, 2016, it announced the intent to be acquired by Great Plains Energy.

Q WHY IS IT IMPORTANT TO EXCLUDE COMPANIES FROM THE PROXY GROUP IF THEY DO NOT HAVE CONSENSUS ANALYSTS' GROWTH RATES PUBLISHED BY ZACKS, SNL FINANCIAL OR REUTERS?

A Selecting companies that have consensus analysts' growth rate projections from at least one of these three sources is an indication that market participants are following the security, and there is adequate liquidity and market demand for the security to support the assumption that the market valuation of the security is based on fundamental valuation principles. A stock that is thinly traded, or is not widely followed by the market, may have an observable market price which is inconsistent with fundamental valuation principles.

Q WHY IS IT APPROPRIATE TO EXCLUDE COMPANIES WHICH ARE INVOLVED IN M&A ACTIVITY FROM THE PROXY GROUP?

A M&A activity can distort the market factors used in DCF and risk premium studies. M&A activity can have impacts on stock prices, growth outlooks, and relative volatility in historical stock prices if the market was anticipating or expecting the M&A activity prior to it actually being announced. This distortion in the market data thus impacts the reliability of the DCF and risk premium estimates for a company involved in M&A.

Moreover, companies generally enter into M&A in order to produce greater shareholder value by combining companies. The enhanced shareholder value normally could not be realized had the two companies not combined.

When companies announce an M&A, the public assesses the proposed merger and develops outlooks on the value of the two companies after the combination based on expected synergies or other value adds created by the M&A.

As a result, the stock value before the merger is completed may not reflect the forward-looking earnings and dividend payments for the company absent the merger or on a stand-alone basis. Therefore, an accurate DCF return estimate on companies involved in M&A activities cannot be produced because their stock prices do not reflect the stand-alone investment characteristics of the companies. Rather, the stock price more likely reflects the shareholder enhancement produced by the proposed transaction. For these reasons, it is appropriate to remove companies involved in M&A activity from a proxy group used to estimate a fair return on equity for a utility.

Q PLEASE DESCRIBE WHY YOU BELIEVE YOUR PROXY GROUP IS REASONABLY COMPARABLE IN INVESTMENT RISK TO FPL.

A The proxy group is shown in Exhibit MPG-4. The proxy group has an average corporate credit rating from S&P of BBB+, which is one notch lower than S&P's corporate credit rating for FPL of A-. The proxy group has an average corporate credit rating from Moody's of Baa1, which is three notches lower than FPL's corporate credit rating from Moody's of A1. Based on this information, I believe my proxy group will produce a conservative return on equity for FPL.

The proxy group has an average common equity ratio of 46.9% (including short-term debt) from SNL Financial ("SNL") and 49.5% (excluding short-term debt) from *The Value Line Investment Survey* ("*Value Line*") in 2015.

The Company's proposed common equity ratio of 59.6% is significantly higher than the proxy group common equity ratio, which means that my proxy group has higher financial risk than FPL and will produce a conservative return on equity for FPL. Based on these risk factors, I conclude the proxy group reasonably approximates the investment risk of FPL, and it will produce a conservative return on equity for FPL.

IV.B. Discounted Cash Flow Model

Q PLEASE DESCRIBE THE DCF MODEL.

A The DCF model posits that a stock price is valued by summing the present value of expected future cash flows discounted at the investor's required rate of return or cost of capital. This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \; .\,.\,.\,. \; \frac{D_\infty}{(1+K)^\infty} \qquad \text{(Equation 1)}$$

P_0 = Current stock price

D = Dividends in periods 1 - ∞

K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor-required return, "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

K = Investor's required return

D_1 = Dividend in first year

P_0 = Current stock price

G = Expected constant dividend growth rate

Equation 2 is referred to as the annual "constant growth" DCF model.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.

A As shown in Equation 2 above, the DCF model requires a current stock price, expected dividend, and expected growth rate in dividends.

Q WHAT STOCK PRICE HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH DCF MODEL?

A I relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on June 10, 2016. An average stock price is less susceptible to market price variations than a spot price. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not reflect the stock's long-term value.

A 13-week average stock price reflects a period that is still short enough to contain data that reasonably reflects current market expectations, but the period is not so short as to be susceptible to market price variations that may not reflect the stock's long-term value. In my judgment, a 13-week average stock price is a reasonable balance between the need to reflect current market expectations and the need to capture sufficient data to smooth out aberrant market movements.

Q WHAT DIVIDEND DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?

A I used the most recently paid quarterly dividend, as reported in *Value Line*.[19] This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D_1 factor for use in Equation 2 above.

Q WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A There are several methods that can be used to estimate the expected growth in dividends. However, regardless of the method, for purposes of determining the market-required return on common equity, one must attempt to estimate investors' consensus about what the dividend or earnings growth rate will be, and not what an individual investor or analyst may use to make individual investment decisions.

[19]*The Value Line Investment Survey*, April 29, May 20, and June 17, 2016.

As predictors of future returns, security analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data.[20] That is, assuming the market generally makes rational investment decisions, analysts' growth projections are more likely to influence investors' decisions which are captured in observable stock prices than growth rates derived only from historical data.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for investor consensus dividend growth rate expectations. I used the average of analysts' growth rate estimates from three sources: Zacks, SNL, and Reuters. All such projections were available on June 10, 2016, and all were reported online.

Each consensus growth rate projection is based on a survey of security analysts. There is no clear evidence whether a particular analyst is most influential on general market investors. Therefore, a single analyst's projection does not as reliably predict consensus investor outlooks as does a consensus of market analysts' projections. The consensus estimate is a simple arithmetic average, or mean, of surveyed analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. Therefore, a simple average, or arithmetic mean, of analyst forecasts is a good proxy for market consensus expectations.

Q WHAT ARE THE GROWTH RATES YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A The growth rates I used in my DCF analysis are shown in Exhibit MPG-5. The average growth rate for my proxy group is 5.38%.

[20] *See, e.g.,* David Gordon, Myron Gordon, and Lawrence Gould, "Choice Among Methods of Estimating Share Yield," *The Journal of Portfolio Management*, Spring 1989.

Q WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?

A As shown in Exhibit MPG-6, the average and median constant growth DCF returns for my proxy group for the 13-week analysis are 8.83% and 8.89%, respectively.

Q DO YOU HAVE ANY COMMENTS ON THE RESULTS OF YOUR CONSTANT GROWTH DCF ANALYSIS?

A Yes. The constant growth DCF analysis for my proxy group is based on a group average long-term sustainable growth rate of 5.40%. The three- to five-year growth rates are higher than my estimate of a maximum long-term sustainable growth rate of 4.35%, which I discuss later in this testimony. I believe the constant growth DCF analysis produces a reasonable high-end return estimate.

Q HOW DID YOU ESTIMATE A MAXIMUM LONG-TERM SUSTAINABLE GROWTH RATE?

A A long-term sustainable growth rate for a utility stock cannot exceed the growth rate of the economy in which it sells its goods and services. Hence, the long-term maximum sustainable growth rate for a utility investment is best proxied by the projected long-term Gross Domestic Product ("GDP"). *Blue Chip Financial Forecasts* projects that over the next 5 and 10 years, the U.S. nominal GDP will grow approximately 4.35%. These GDP growth projections reflect a real growth outlook of around 2.2% and an inflation outlook of around 2.1% going forward. As such, the average growth rate over the next 10 years is around 4.35%, which I believe is a reasonable proxy of long-term sustainable growth.[21]

---

[21] *Blue Chip Financial Forecasts*, June 1, 2016, at 14.

In my multi-stage growth DCF analysis, I discuss academic and investment practitioner support for using the projected long-term GDP growth outlook as a maximum sustainable growth rate projection. Hence, recognizing the long-term GDP growth rate as a maximum sustainable growth is logical, and is generally consistent with academic and economic practitioner accepted practices.

IV.C. Sustainable Growth DCF

Q PLEASE DESCRIBE HOW YOU ESTIMATED A SUSTAINABLE LONG-TERM GROWTH RATE FOR YOUR SUSTAINABLE GROWTH DCF MODEL.

A A sustainable growth rate is based on the percentage of the utility's earnings that is retained and reinvested in utility plant and equipment. These reinvested earnings increase the earnings base (rate base). Earnings grow when plant funded by reinvested earnings is put into service, and the utility is allowed to earn its authorized return on such additional rate base investment.

The internal growth methodology is tied to the percentage of earnings retained in the company and not paid out as dividends. The earnings retention ratio is 1 minus the dividend payout ratio. As the payout ratio declines, the earnings retention ratio increases. An increased earnings retention ratio will fuel stronger growth because the business funds more investments with retained earnings.

The payout ratios of the proxy group are shown in my Exhibit MPG-7. These dividend payout ratios and earnings retention ratios then can be used to develop a sustainable long-term earnings retention growth rate. A sustainable long-term earnings retention ratio will help gauge whether analysts' current three- to five-year growth rate projections can be sustained over an indefinite period of time.

The data used to estimate the long-term sustainable growth rate is based on the Company's current market-to-book ratio and on *Value Line*'s three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances.

As shown in Exhibit MPG-8, the average sustainable growth rate for the proxy group using this internal growth rate model is 4.26%.

Q WHAT IS THE DCF ESTIMATE USING THESE SUSTAINABLE LONG-TERM GROWTH RATES?

A A DCF estimate based on these sustainable growth rates is developed in Exhibit MPG-9. As shown there, a sustainable growth DCF analysis produces proxy group average and median DCF results for the 13-week period of 7.67% and 7.34%, respectively.

IV.D. Multi-Stage Growth DCF Model

Q HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?

A Yes. My first constant growth DCF is based on consensus analysts' growth rate projections, so it is a reasonable reflection of rational investment expectations over the next three to five years. The limitation on this constant growth DCF model is that it cannot reflect a rational expectation that a period of high/low short-term growth can be followed by a change in growth to a rate that is more reflective of long-term sustainable growth. Hence, I performed a multi-stage growth DCF analysis to reflect this outlook of changing growth expectations.

Q WHY DO YOU BELIEVE GROWTH RATES CAN CHANGE OVER TIME?

A Analyst-projected growth rates over the next three to five years will change as utility earnings growth outlooks change. Utility companies go through cycles in making investments in their systems. When utility companies are making large investments, their rate base grows rapidly, which in turn accelerates earnings growth. Once a major construction cycle is completed or levels off, growth in the utility rate base slows, and its earnings growth slows from an abnormally high three- to five-year rate to a lower sustainable growth rate.

As major construction cycles extend over longer periods of time, even with an accelerated construction program, the growth rate of the utility will slow simply because rate base growth will slow, and the utility has limited human and capital resources available to expand its construction program. Therefore, the three- to five-year growth rate projection should be used as a long-term sustainable growth rate but not without making a reasonable informed judgment to determine whether it considers the current market environment, the industry, and whether the three- to five-year growth outlook is sustainable.

Q PLEASE DESCRIBE YOUR MULTI-STAGE GROWTH DCF MODEL.

A The multi-stage growth DCF model reflects the possibility of non-constant growth for a company over time. The multi-stage growth DCF model reflects three growth periods: (1) a short-term growth period, which consists of the first five years; (2) a transition period, which consists of the next five years (6 through 10); and (3) a long-term growth period, starting in year 11 through perpetuity.

For the short-term growth period, I relied on the consensus analysts' growth projections described above in relationship to my constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor, which reflects the difference between the analysts' growth rates and the long-term sustainable growth rate. For the long-term growth period, I assumed each company's growth would converge to the maximum sustainable long-term growth rate.

Q WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?

A Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. Utilities' earnings/dividend growth is created by increased utility investment or rate base. Such investment, in turn, is driven by service area economic growth and demand for utility service. In other words, utilities invest in plant to meet sales demand growth, and sales growth, in turn, is tied to economic growth in their service areas.

The U.S. Department of Energy, Energy Information Administration ("EIA") has observed that utility sales growth tracks the U.S. GDP growth, albeit at a lower level, as shown in Exhibit MPG-10. Utility sales growth has lagged behind GDP growth for more than a decade. As a result, nominal GDP growth is a very conservative proxy for utility sales growth, rate base growth, and earnings growth. Therefore, the U.S. GDP nominal growth rate is a conservative proxy for the highest sustainable long-term growth rate of a utility.

Q IS THERE RESEARCH THAT SUPPORTS YOUR POSITION THAT, OVER THE LONG TERM, A COMPANY'S EARNINGS AND DIVIDENDS CANNOT GROW AT A RATE GREATER THAN THE GROWTH OF THE U.S. GDP?

A Yes. This concept is supported in published analyst literature and academic work. Specifically, in a textbook titled "Fundamentals of Financial Management," published by Eugene Brigham and Joel F. Houston, the authors state as follows:

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but <u>dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation)</u>.[22]

The use of the economic growth rate is also supported by investment practitioners as outlined as follows:

> **Estimating Growth Rates**
>
> One of the advantages of a three-stage discounted cash flow model is that it fits with life cycle theories in regards to company growth. In these theories, companies are assumed to have a life cycle with varying growth characteristics. Typically, the potential for extraordinary growth in the near term eases over time and eventually growth slows to a more stable level.
>
> * * *
>
> Another approach to estimating long-term growth rates is to focus on estimating the overall economic growth rate. Again, this is the approach used in the *Ibbotson Cost of Capital Yearbook*. To obtain the economic growth rate, a forecast is made of the growth rate's component parts. Expected growth can be broken into two main parts: expected inflation and expected real growth. By analyzing these components separately, it is easier to see the factors that drive growth.[23]

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[22] "*Fundamentals of Financial Management*," Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298, emphasis added.

[23] *Morningstar, Inc., Ibbotson SBBI 2013 Valuation Yearbook* at 51 and 52.

Q IS THERE ANY ACTUAL INVESTMENT HISTORY THAT SUPPORTS THE NOTION THAT THE CAPITAL APPRECIATION FOR STOCK INVESTMENTS WILL NOT EXCEED THE NOMINAL GROWTH OF THE U.S. GDP?

A Yes. This is evident by a comparison of the compound annual growth of the U.S. GDP compared to the geometric growth of the U.S. stock market. Morningstar measures the historical geometric growth of the U.S. stock market over the period 1926-2015 to be approximately 5.8%. During this same time period, the U.S. nominal compound annual growth of the U.S. GDP was approximately 6.2%.[24]

As such, the compound geometric growth of the U.S. nominal GDP has been higher but comparable to the nominal growth of the U.S. stock market capital appreciation. This historical relationship indicates the U.S. GDP growth outlook is a conservative estimate of the long-term sustainable growth of U.S. stock investments.

Q HOW DID YOU DETERMINE A SUSTAINABLE LONG-TERM GROWTH RATE THAT REFLECTS THE CURRENT CONSENSUS OUTLOOK OF THE MARKET?

A I relied on the consensus analysts' projections of long-term GDP growth. *Blue Chip Financial Forecasts* publishes consensus economists' GDP growth projections twice a year. These consensus analysts' GDP growth outlooks are the best available measure of the market's assessment of long-term GDP growth. These analyst projections reflect all current outlooks for GDP and are likely the most influential on investors' expectations of future growth outlooks. The consensus economists' published GDP growth rate outlook is 4.35% over the next 10 years.[25]

Therefore, I propose to use the consensus economists' projected 5- and 10-year average GDP consensus growth rates of 4.35%, as published by *Blue Chip*

[24] *Duff & Phelps 2016 Valuation Handbook* inflation rate of 3.0% at 2-4, and U.S. Bureau of Economic Analysis, January 29, 2016.
[25] *Blue Chip Financial Forecasts*, June 1, 2016, at 14.

Financial Forecasts, as an estimate of long-term sustainable growth. *Blue Chip Financial Forecasts* projections provide real GDP growth projections of 2.2%, and GDP inflation of 2.1%,[26] over the 5-year and 10-year projection periods. These consensus GDP growth forecasts represent the most likely views of market participants because they are based on published consensus economist projections.

Q DO YOU CONSIDER OTHER SOURCES OF PROJECTED LONG-TERM GDP GROWTH?

A Yes, and these sources corroborate my consensus analysts' projections, as shown below in Table 3.

TABLE 3

GDP Forecasts

Source	Term	Real GDP	Inflation	Nominal GDP
EIA – Annual Earnings Outlook[27]	25 Yrs	2.4%	1.8%	4.2%
Congressional Budget Office[28]	10 Yrs	2.0%	2.0%	4.0%
Moody's Analytics[29]	30 Yrs	2.0%	2.0%	4.1%
Social Security Administration[30]	50 Yrs			4.5%
The Economist Intelligence Unit[31]	35 Yrs	1.9%	2.0%	3.9%
Blue Chip Financial Forecasts	5-10 Yrs	2.2%	2.1%	4.3%

The EIA in its *Annual Energy Outlook* projects real GDP out until 2040. In its 2015 Annual Report, the EIA projects real GDP through 2040 to be in the range of 1.8% to 2.9%, with a midpoint or reference case of 2.4%, and a long-term GDP price

[26]*Id.*

inflation projection of 1.8%. The EIA data supports a long-term nominal GDP growth outlook of 4.2%.[27]

Also, the Congressional Budget Office ("CBO") makes long-term economic projections. The CBO is projecting real GDP growth to be 2.0% during the next 10 years, with a GDP price inflation outlook of 2.0%.[28] The CBO 10-year outlook for nominal GDP based on this projection is 4.0%.

Moody's Analytics also makes long-term economic projections. In its recent 30-year outlook to 2045, Moody's Analytics is projecting real GDP growth of 2.0% with GDP inflation of 2.0%.[29] Based on these projections, Moody's is projecting nominal GDP growth of 4.1% over the next 30 years.

The Social Security Administration makes long-term economic projections out to 2090. The Social Security Administration's nominal GDP projection, under its intermediate cost scenario of 50 years, is 4.5%.[30] This projection is in line with the consensus economists.

The Economist Intelligence Unit, a division of *The Economist* and a third-party data provider to SNL Financial, makes a long-term economic projection out to 2050.[31] The Economist Intelligence Unit is projecting real GDP growth of 1.9% with an inflation rate of 2.0% out to 2050. The real GDP growth projection is in line with the consensus economists. The long-term nominal GDP projection based on these outlooks is approximately 3.9%.

The real GDP and nominal GDP growth projections made by these independent sources support the use of the consensus economist 5-year and 10-year

[27] DOE/EIA Annual Energy Outlook 2015 With Projections to 2040, January 2016, at 4 and A-38.

[28] *CBO: The Budget and Economic Outlook: 2016 to 2026*, January 2016, at 140.

[29] www.economy.com, *Moody's Analytics Forecast*, January 6, 2016.

[30] www.ssa.gov, "2015 OASDI Trustees Report," Table VI.G4.

[31] *SNL Financial, Economist Intelligence Unit*, downloaded on January 13, 2016.

projected GDP growth outlooks as a reasonable estimate of market participants' long-term GDP growth outlooks.

Q WHAT STOCK PRICE, DIVIDEND, AND GROWTH RATES DID YOU USE IN YOUR MULTI-STAGE GROWTH DCF ANALYSIS?

A I relied on the same 13-week average stock prices and the most recent quarterly dividend payment data discussed above. For stage one growth, I used the consensus analysts' growth rate projections discussed above in my constant growth DCF model. The first stage growth covers the first five years, consistent with the term of the analyst growth rate projections. The second stage, or transition stage, begins in year 6 and extends through year 10. The second stage growth transitions the growth rate from the first stage to the third stage using a linear trend. For the third stage, or long-term sustainable growth stage, which starts in year 11, I used a 4.35% long-term sustainable growth rate, which is based on the consensus economists' long-term projected nominal GDP growth rate.

Q WHAT ARE THE RESULTS OF YOUR MULTI-STAGE GROWTH DCF MODEL?

A As shown in Exhibit MPG-11, the average and median DCF returns on equity for my proxy group using the 13-week average stock price are 8.00% and 8.01%, respectively.

Q PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.

A The results from my DCF analyses are summarized in Table 4 below:

TABLE 4

Summary of DCF Results

Description	Proxy Group Average	Proxy Group Median
Constant Growth DCF Model (Analysts' Growth)	8.83%	8.89%
Constant Growth DCF Model (Sustainable Growth)	7.67%	7.34%
Multi-Stage Growth DCF Model	8.00%	8.01%
Average	8.17%	8.08%

I concluded that my DCF studies support a return on equity of 8.9%, which is primarily based on my proxy group median for the constant growth DCF result.

IV.E. Risk Premium Model

Q PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A This model is based on the principle that investors require a higher return to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. Therefore, common equity securities are considered to be more risky than bond securities.

This risk premium model is based on two estimates of an equity risk premium. First, I estimated the difference between the required return on utility common equity investments and U.S. Treasury bonds. The difference between the required return on common equity and the Treasury bond yield is the risk premium. I estimated the risk premium on an annual basis for each year over the period 1986 through March 2016.

The common equity required returns were based on regulatory commission-authorized returns for electric utility companies. Authorized returns are typically based on expert witnesses' estimates of the contemporary investor-required return.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields by Moody's. I selected the period 1986 through March 2016 because public utility stocks consistently traded at a premium to book value during that period. This is illustrated in Exhibit MPG-12, which shows that the market to book ratio since 1986 for the electric utility industry was consistently above a multiple of 1.0x. Over this period, regulatory authorized returns were sufficient to support market prices that at least exceeded book value. This is an indication that regulatory authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit MPG-13, the average indicated equity risk premium over U.S. Treasury bond yields has been 5.46%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity for a risk premium methodology.

I incorporated five-year and 10-year rolling average risk premiums over the study period to gauge the variability over time of risk premiums. These rolling average risk premiums mitigate the impact of anomalous market conditions and skewed risk premiums over an entire business cycle. As shown on my Exhibit

MPG-13, the five-year rolling average risk premium over Treasury bonds ranged from 4.25% to 6.71%, while the 10-year rolling average risk premium ranged from 4.38% to 6.38%.

As shown on my Exhibit MPG-14, the average indicated equity risk premium over contemporary Moody's utility bond yields was 4.08%. The five-year and 10-year rolling average risk premiums ranged from 2.88% to 5.53% and 3.20% to 5.01%, respectively.

Q DO YOU BELIEVE THAT THE TIME PERIOD USED TO DERIVE THESE EQUITY RISK PREMIUM ESTIMATES IS APPROPRIATE TO FORM ACCURATE CONCLUSIONS ABOUT CONTEMPORARY MARKET CONDITIONS?

A Yes. The time period I use in this risk premium study is a generally accepted period to develop a risk premium study using "expectational" data.

Contemporary market conditions can change dramatically during the period that rates determined in this proceeding will be in effect. A relatively long period of time where stock valuations reflect premiums to book value is an indication that the authorized returns on equity and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this time period is long enough to smooth abnormal market movement that might distort equity risk premiums. While market conditions and risk premiums do vary over time, this historical time period is a reasonable period to estimate contemporary risk premiums.

Alternatively, some studies, such as Morningstar referred to later in this testimony, have recommended that use of "actual achieved investment return data" in a risk premium study should be based on long historical time periods. The studies find that achieved returns over short time periods may not reflect investors' expected returns due to unexpected and abnormal stock price performance. Short-term abnormal actual returns would be smoothed over time and the achieved actual investment returns over long time periods would approximate investors' expected returns. Therefore, it is reasonable to assume that averages of annual achieved returns over long time periods will generally converge on the investors' expected returns.

My risk premium study is based on expectational data, not actual investment returns, and, thus, need not encompass a very long historical time period.

Q BASED ON HISTORICAL DATA, WHAT RISK PREMIUM HAVE YOU USED TO ESTIMATE FPL'S COST OF COMMON EQUITY IN THIS PROCEEDING?

A The equity risk premium should reflect the relative market perception of risk in the utility industry today. I have gauged investor perceptions in utility risk today in Exhibit MPG-15. In Exhibit MPG-15, I show the yield spread between utility bonds and Treasury bonds over the last 36 years. As shown in this exhibit, the average utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utility bonds for this historical period are 1.52% and 1.97%, respectively. The utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utilities for 2016 were 1.46% and 2.58%, respectively. The current average "A" rated utility bond yield spread over Treasury bond yields is now lower than the 36-year average spread. The current "Baa" rated utility bond yield spread over Treasury bond yields is higher than the 36-year average spread.

A current 13-week average "A" rated utility bond yield of 3.96%, when compared to the current Treasury bond yield of 2.60% as shown in Exhibit MPG-16, page 1, implies a yield spread of around 136 basis points. This current utility bond yield spread is lower than the 36-year average spread for "A" rated utility bonds of 1.52%. The current spread for the "Baa" rated utility bond yield of 2.09% is higher than the 36-year average spread of 1.97%. However, when compared to the projected Treasury bond yield of 3.40%, the current "Baa" utility spread is around 1.29%, which is lower than the 36-year average of 1.97%.

These utility bond yield spreads are evidence that the market perception of utility risk is about average relative to this historical time period and demonstrate that utilities continue to have strong access to capital in the current market.

Q HOW DO YOU DETERMINE WHERE A REASONABLE RISK PREMIUM IS IN THE CURRENT MARKET?

A I observed the spread of Treasury securities relative to public utility bonds and corporate bonds in gauging whether or not the risk premium in current market prices is relatively stable relative to the past. What this observation of market evidence provides, and quite clearly, is that the valuations in the current market place an above average risk premium on securities that have greater risk.

This market evidence is summarized below in Table 5, which shows the utility bond yield spreads over Treasury bond yields on average for the period 1980 through 2016, and the spreads for the first quarter of 2016. I also show the corporate bond yield spreads for Aaa corporates and Baa corporates.

TABLE 5

Comparison of Yield Spreads Over Treasury Bonds

Description	Utility A	Utility Baa	Corporate Aaa	Corporate Baa
Average Historical Spread	1.52%	1.97%	0.84%	1.95%
Q1, 2016 Spread	1.46%	2.58%	1.21%	2.59%

Source: Exhibit MPG-15.

The observable yield spreads shown in the table above illustrate that securities of greater risk have above average risk premiums relative to the long-term historical average risk premium. Specifically, A-rated utility bonds to Treasuries, a relatively low-risk investment, have a yield spread in 2016 that has been very comparable to that of its long-term historical yield spread. The Aaa corporate bond yield spread is above the yield spread over the last 36 years.

The higher risk Baa utility and corporate bond yields currently have an above average yield spread of approximately 60 basis points (2.58% vs. 1.97%). The higher risk Baa utility bond yields do not have the same premium valuations as their lower risk A-rated utility bond yields, and thus the yield spread for greater risk investments is wider than lower risk investments.

This illustrates that securities with greater risk such as Baa yields versus A yields are commanding above average risk premium spreads in the current marketplace. Utility equity securities are greater risk than Baa utility bonds. Because greater risk securities appear to support an above average risk premium relative to historical averages, this would support an above average risk premium in measuring a fair return on equity for a utility stock or equity security.

Q WHAT IS YOUR RECOMMENDED RETURN FOR FPL BASED ON YOUR RISK PREMIUM STUDY?

A To be conservative, I am recommending more weight to the high-end risk premium estimates than the low-end. I state this because of the relatively low level of interest rates now, but relative upward movements of utility yields more recently. Hence, I propose to provide 75% weight to my high-end risk premium estimates and 25% to the low-end. Applying these weights, the risk premium for Treasury bond yields would be approximately 6.09%,[32] which is considerably higher than the 31-year average risk premium of 5.46% and reasonably reflective of the 3.4% projected Treasury bond yield. A Treasury bond risk premium of 6.1% and projected Treasury bond yield of 3.4% produce a risk premium return estimate of 9.50%.

Applying these weights to the utility risk premium indicates a risk premium of 4.9%.[33] This risk premium is above the 31-year historical average risk premium of 4.08%. Using the weighted utility risk premium and the current Baa observable utility bond yield of 4.69% produces an estimated return on equity of approximately 9.59%, rounded to 9.60%.

Based on this methodology, my Treasury bond risk premium return is 9.50% and my utility bond risk premium indicates a return of 9.60%. Hence, this methodology produces a return on equity in the range of 9.50% to 9.60%, with a midpoint of 9.55%, rounded to 9.60%.

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[32](4.25% * 25%) + (6.71% * 75%) = 6.09%.
[33](2.88% * 25%) + (5.53% * 75%) = 4.87%.

IV.F. Capital Asset Pricing Model ("CAPM")

Q PLEASE DESCRIBE THE CAPM.

A The CAPM method of analysis is based upon the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. This relationship between risk and return can be expressed mathematically as follows:

$R_i = R_f + B_i \times (R_m - R_f)$ where:

R_i = Required return for stock i

R_f = Risk-free rate

R_m = Expected return for the market portfolio

B_i = Beta - Measure of the risk for stock

The stock-specific risk term in the above equation is beta. Beta represents the investment risk that cannot be diversified away when the security is held in a diversified portfolio. When stocks are held in a diversified portfolio, firm-specific risks can be eliminated by balancing the portfolio with securities that react in the opposite direction to firm-specific risk factors (e.g., business cycle, competition, product mix, and production limitations).

The risks that cannot be eliminated when held in a diversified portfolio are non-diversifiable risks. Non-diversifiable risks are related to the market in general and are referred to as systematic risks. Risks that can be eliminated by diversification are regarded as non-systematic risks. In a broad sense, systematic risks are market risks, and non-systematic risks are business risks. The CAPM theory suggests that the market will not compensate investors for assuming risks that can be diversified away. Therefore, the only risk that investors will be compensated for are systematic or non-diversifiable risks. The beta is a measure of the systematic or non-diversifiable risks.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

A The CAPM requires an estimate of the market risk-free rate, the Company's beta, and the market risk premium.

Q WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?

A As previously noted, *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield is 3.40%.[34] The current 30-year Treasury bond yield is 2.60%, as shown in Exhibit MPG-16. I used *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield of 3.40% for my CAPM analysis.

Q WHY DID YOU USE LONG-TERM TREASURY BOND YIELDS AS AN ESTIMATE OF THE RISK-FREE RATE?

A Treasury securities are backed by the full faith and credit of the United States government, so long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common stock required returns and long-term bond yields. Therefore, the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

[34] *Blue Chip Financial Forecasts*, June 1, 2016 at 2.

Treasury bond yields, however, do include risk premiums related to unanticipated future inflation and interest rates. A Treasury bond yield is not a risk-free rate. Risk premiums related to unanticipated inflation and interest rates are systematic or market risks. Consequently, for companies with betas less than 1.0, using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

Q WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A As shown in Exhibit MPG-17, the proxy group average *Value Line* beta estimate is 0.75.

Q HOW DID YOU DERIVE YOUR MARKET RISK PREMIUM ESTIMATE?

A I derived two market risk premium estimates, a forward-looking estimate and one based on a long-term historical average.

The forward-looking estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

Duff & Phelps' *2016 Valuation Handbook* estimates the historical arithmetic average real market return over the period 1926 to 2015 as 8.7%.[35] A current consensus analysts' inflation projection, as measured by the Consumer Price Index,

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[35] *Duff & Phelps, 2016 Valuation Handbook: Guide to Cost of Capital* at 2-4. Calculated as [(1+0.12) / (1+0.03)] – 1.

is 2.3%.[36] Using these estimates, the expected market return is 11.20%.[37] The market risk premium then is the difference between the 11.20% expected market return, and my 3.40% risk-free rate estimate, or approximately 7.8%.

My historical estimate of the market risk premium was also calculated by using data provided by Duff & Phelps in its *2016 Valuation Handbook*. Over the period 1926 through 2015, the Duff & Phelps study estimated that the arithmetic average of the achieved total return on the S&P 500 was 12.0%,[38] and the total return on long-term Treasury bonds was 6.00%.[39] The indicated market risk premium is 6.0% (12.0% - 6.0% = 6.0%).

Q HOW DOES YOUR ESTIMATED MARKET RISK PREMIUM RANGE COMPARE TO THAT ESTIMATED BY DUFF & PHELPS?

A The Duff & Phelps analysis indicates that a market risk premium falls somewhere in the range of 5.5% to 6.9%. My market risk premium falls in the range of 6.0% to 7.8%. My average market risk premium of 6.9% is approximately the same as the high-end of the Duff & Phelps range.

Q HOW DOES DUFF & PHELPS MEASURE A MARKET RISK PREMIUM?

A Duff & Phelps makes several estimates of a forward-looking market risk premium based on actual achieved data from the historical period of 1926 through 2015, as well as normalized data. Using this data, Duff & Phelps estimates a market risk premium derived from the total return on large company stocks (S&P 500), less the income return on Treasury bonds. The total return includes capital appreciation,

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[36] *Blue Chip Financial Forecasts*, June 1, 2016 at 2.
[37] $\{ [(1 + 0.087) * (1 + 0.023)] - 1 \} * 100$.
[38] *Duff & Phelps, 2016 Valuation Handbook: Guide to Cost of Capital* at 2-4.
[39] *Id.*

dividend or coupon reinvestment returns, and annual yields received from coupons and/or dividend payments. The income return, in contrast, only reflects the income return received from dividend payments or coupon yields. Duff & Phelps claims that the income return is the only true risk-free rate associated with Treasury bonds and is the best approximation of a truly risk-free rate.[40] I disagree with this assessment from Duff & Phelps, because it does not reflect a true investment option available to the marketplace and therefore does not produce a legitimate estimate of the expected premium of investing in the stock market versus that of Treasury bonds. Nevertheless, I will use Duff & Phelps' conclusion to show the reasonableness of my market risk premium estimates.

Duff & Phelps' range is based on several methodologies. First, Duff & Phelps estimates a market risk premium of 6.9% based on the difference between the total market return on common stocks (S&P 500) less the income return on Treasury bond investments over the 1926-2015 time period.

Second, Duff & Phelps updated the Ibbotson & Chen supply-side model which found that the 6.9% market risk premium based on the S&P 500 was influenced by an abnormal expansion of price-to-earnings ("P/E") ratios relative to earnings and dividend growth during the period, primarily over the last 25 years. Duff & Phelps believes this abnormal P/E expansion is not sustainable.[41] Therefore, Duff & Phelps adjusted this market risk premium estimate to normalize the growth in the P/E ratio to be more in line with the growth in dividends and earnings. Based on this alternative methodology, Duff & Phelps published a long-horizon supply-side market risk premium of 6.03%.[42]

[40] *Id.* at 3-28.
[41] *Id.* at 3-30.
[42] *Id.* at 3-31.

Finally, Duff & Phelps develops its own recommended equity, or market, risk premium by employing an analysis that takes into consideration a wide range of economic information, multiple risk premium estimation methodologies, and the current state of the economy by observing measures such as the level of stock indices and corporate spreads as indicators of perceived risk. Based on this methodology, and utilizing a "normalized" risk-free rate of 4.0%, Duff & Phelps concludes that the current expected, or forward-looking, market risk premium is 5.5%, implying an expected return on the market of 9.5%.[43]

Q WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A As shown in Exhibit MPG-18, based on my low market risk premium of 6.0% and my high market risk premium of 7.8%, a risk-free rate of 3.40%, and a beta of 0.75, my CAPM analysis produces a return of 7.90% to 9.25%. Based on my assessment of risk premiums in the current market, as discussed above, I recommend the high-end CAPM return estimate of 9.25% as the most conservative estimate of FPL's current market cost of equity.

IV.G. Return on Equity Summary

Q BASED ON THE RESULTS OF YOUR RETURN ON COMMON EQUITY ANALYSES DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND FOR FPL?

A Based on my analyses, I estimate FPL's current market cost of equity to be 9.25%.

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[43] *Id.* at 3-40.

TABLE 6

Return on Common Equity Summary

Description	Results
DCF	8.90%
Risk Premium	9.60%
CAPM	9.25%

My recommended return on common equity of 9.25% is at the approximate midpoint of my estimated range of 8.90% to 9.60%. As shown in Table 6 above, the high-end of my estimated range is based on my risk premium study. The low-end is based on my DCF studies. The CAPM results support the midpoint of my recommended range.

IV.H. Financial Integrity

Q WILL YOUR RECOMMENDED OVERALL RATE OF RETURN SUPPORT AN INVESTMENT GRADE BOND RATING FOR FPL?

A Yes. I have reached this conclusion by comparing the key credit rating financial ratios for FPL, at my proposed return on equity, and the Company's capital structure, to S&P's benchmark financial ratios using S&P's new credit metric ranges.

Q PLEASE DESCRIBE THE MOST RECENT S&P FINANCIAL RATIO CREDIT METRIC METHODOLOGY.

A S&P publishes a matrix of financial ratios that correspond to its assessment of the business risk of utility companies and related bond ratings. On May 27, 2009, S&P

expanded its matrix criteria by including additional business and financial risk categories.[44]

Based on S&P's most recent credit matrix, the business risk profile categories are "Excellent," "Strong," "Satisfactory," "Fair," "Weak," and "Vulnerable." Most utilities have a business risk profile of "Excellent" or "Strong."

The financial risk profile categories are "Minimal," "Modest," "Intermediate," "Significant," "Aggressive," and "Highly Leveraged." Most of the utilities have a financial risk profile of "Aggressive." FPL has an "Excellent" business risk profile and an "Intermediate" financial risk profile.

Q PLEASE DESCRIBE S&P'S USE OF THE FINANCIAL BENCHMARK RATIOS IN ITS CREDIT RATING REVIEW.

A S&P evaluates a utility's credit rating based on an assessment of its financial and business risks. A combination of financial and business risks equates to the overall assessment of FPL's total credit risk exposure. On November 19, 2013, S&P updated its methodology. In its update, S&P published a matrix of financial ratios that defines the level of financial risk as a function of the level of business risk.

S&P publishes ranges for three primary financial ratios that it uses as guidance in its credit review for utility companies. The two core financial ratio benchmarks it relies on in its credit rating process include: (1) Debt to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"); and (2) Funds From Operations ("FFO") to Total Debt.[45]

[44]S&P updated its 2008 credit metric guidelines in 2009, and incorporated utility metric benchmarks with the general corporate rating metrics. *Standard & Poor's RatingsDirect*: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.

[45]*Standard & Poor's RatingsDirect*: "Criteria: Corporate Methodology," November 19, 2013.

Q HOW DID YOU APPLY S&P'S FINANCIAL RATIOS TO TEST THE REASONABLENESS OF YOUR RATE OF RETURN RECOMMENDATIONS?

A I calculated each of S&P's financial ratios based on FPL's cost of service for its retail jurisdictional operations. While S&P would normally look at total consolidated FPL financial ratios in its credit review process, my investigation in this proceeding is not the same as S&P's. I am attempting to judge the reasonableness of my proposed cost of capital for rate-setting in FPL's retail regulated utility operations. Hence, I am attempting to determine whether my proposed rate of return will in turn support cash flow metrics, balance sheet strength, and earnings that will support an investment grade bond rating and FPL's financial integrity.

Q DID YOU INCLUDE ANY OFF-BALANCE SHEET DEBT EQUIVALENTS?

A Yes. I included approximately $263 million of off-balance sheet debt related to purchased power agreements and their associated depreciation and interest expenses.

Q PLEASE DESCRIBE THE RESULTS OF THIS CREDIT METRIC ANALYSIS AS IT RELATES TO FPL.

A The S&P financial metric calculations for FPL at a 9.25% return are developed on Exhibit MPG-19, page 1. The credit metrics produced below, with FPL's financial profile score from S&P of "Intermediate" and business risk score by S&P of "Excellent", will be used to assess the strength of the credit metrics based on FPL's retail operations in Florida.

FPL's adjusted total debt ratio is approximately 41%. As shown on page 2 of Exhibit MPG-19, this adjusted debt ratio is the lowest debt ratio based on the S&P's

median debt ratio of approximately 51% for A-rated utilities. Hence, I concluded this capital structure reasonably supports FPL's current investment grade bond rating. This adjusted total debt ratio will support an investment grade bond rating.

Based on an equity return of 9.25%, FPL will be provided an opportunity to produce a debt to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA") ratio of 3.0x. This is at midpoint of S&P's "Intermediate" guideline range of 2.5x to 3.5x."[46] This ratio supports an investment grade credit rating.

FPL's retail operations FFO to total debt coverage at a 9.25% equity return is 27%, which is within S&P's "Intermediate" metric guideline range of 23% to 35%. This FFO/total debt ratio will support an investment grade bond rating.

At my recommended return on equity of 9.25% and the Company's embedded debt cost and capital structure, FPL's financial credit metrics continue to support credit metrics at an investment grade utility level.

V. RESPONSE TO FPL WITNESS MR. ROBERT B. HEVERT

Q WHAT RETURN ON COMMON EQUITY IS FPL PROPOSING FOR THIS PROCEEDING?

A The Company has requested a return on equity of 11.0% based on the recommended range of 10.5% to 11.5% sponsored by its witness, Mr. Robert Hevert.[47] This does not include the 50 basis point adder for performance. Mr. Hevert concludes that his recommended return on equity range is reasonable.[48] Mr. Hevert's recommended return is based on: (1) CAPM studies, (2) a Bond Yield Plus Risk Premium

[46] *Id.*
[47] Direct Testimony of Robert Hevert at 4-5.
[48] *Id*. at 4.

methodology, (3) a constant growth DCF analysis, and (4) a multi-stage DCF analysis,.

Q ARE MR. HEVERT'S RETURN ON EQUITY ESTIMATES REASONABLE?

A No. Mr. Hevert's estimated return on equity is overstated and should be rejected. Mr. Hevert's analyses produce excessive results for various reasons, including the following: (1) his CAPM is based on inflated market risk premiums and adjusted for flotation costs; (2) his Bond Yield Plus Risk Premium is based on inflated utility equity risk premiums; (3) his risk premium studies are based on stale Treasury yields; (4) his constant growth DCF results are based on excessive, unsustainable growth rates; and (5) his multi-stage DCF is based on an unrealistic GDP growth estimate, unsustainable payout ratio assumptions and also adjusted for flotation costs.

Q PLEASE SUMMARIZE MR. HEVERT'S RETURN ON EQUITY ESTIMATES.

A Mr. Hevert's return on equity estimates are summarized in Table 7 below, excluding his 12 basis points flotation cost adjustment. In Column 2, I show the results with prudent and sound adjustments to his common equity return estimates. With such adjustments to his proxy groups' DCF, CAPM, and Risk Premium return estimates, Mr. Hevert's own studies show my recommended return on equity for FPL is reasonable.

TABLE 7

Hevert's Return on Equity Estimates

Description	Mean[1] (1)	Adjusted[2] (2)
CAPM Results (Bloomberg Beta)		
Current 30-Yr Treasury (BL – 2.96% Rev. to 2.72%)	9.45%	7.46%
Current 30-Yr Treasury (*VL* – 2.96% Rev. to 2.72%)	8.96%	7.46%
Near-Term 2017 Proj. 30-Yr Treasury (BL – 4.00% Rev. to 3.40%)	10.50%	8.14%
Near-Term 2017 Proj. 30-Yr Treasury (VL – 4.00% Rev. to 3.40%)	10.00%	8.14%
Long-Term 2020 Proj. 30-Yr Treasury (BL – 4.80%)	11.30%	Reject
Long-Term 2020 Proj. 30-Yr Treasury (VL – 4.80%)	10.80%	Reject
CAPM Results (*Value Line* Beta)		
Current 30-Yr Treasury (BL – 2.96% Rev. to 2.72%)	11.24%	8.72%
Current 30-Yr Treasury (*VL* – 2.96% Rev. to 2.72%)	10.61%	8.72%
Near-Term 2017 Proj. 30-Yr Treasury (BL – 4.00% Rev. to 3.40%)	12.29%	9.45%
Near-Term 2017 Proj. 30-Yr Treasury (VL – 4.00% Rev. to 3.40%)	11.66%	9.45%
Long-Term 2020 Proj. 30-Yr Treasury (BL – 4.80%)	13.09%	Reject
Long-Term 2020 Proj. 30-Yr Treasury (VL – 4.80%)	12.46%	Reject
Risk Premium		
Current 30-Yr Treasury (2.96% Rev. to 2.72%)	10.04%	8.81%
Near-Term 2017 Proj. 30-Yr Treasury (4.00% Rev. to 3.40%)	10.24%	9.49%
Long-Term 2020 Proj. 30-Yr Treasury (4.80%)	10.53%	Reject
Constant Growth DCF:		
30-Day Average	9.19%	9.19%
90-Day Average	9.23%	9.23%
180-Day Average	9.30%	9.30%
Average Constant Growth DCF	**9.24%**	**9.24%**
Multi-Stage Growth DCF:		
30-Day Average	9.72%	8.64%
90-Day Average	9.76%	8.67%
180-Day Average	9.84%	8.76%
Average Multi-Stage Growth DCF	**9.77%**	**8.69%**
DCF Range	9.2% to 9.8%	8.7% to 9.2%
ROE Range	10.5% to 11.5%	8.7% to 9.5%
Flotation ROE Adder	0.12%	--
Recommended Return on Equity	11.0%	9.25%

Sources:
[1]Hevert Direct Testimony at 23, 26, 31 and 36, excluding flotation costs of 12 basis points.
[2]Exhibit MPG-20.

V.A. Flotation Costs

Q PLEASE DESCRIBE MR. HEVERT'S PROPOSED FLOTATION COST ADDITION TO HIS RETURN ON EQUITY ESTIMATES.

A Mr. Hevert estimated that a 12 basis point adder represents a reasonable adjustment to account for flotation costs. He adds this flotation cost adder to the results of his DCF and CAPM studies. At page 50 of his testimony, Mr. Hevert goes over his development of a flotation cost return on equity adder.

He bases this return on equity on stock issuances of companies other than FPL.[49] As such, he uses industry data to approximate a flotation cost that has been incurred by other utility companies. Mr. Hevert did not develop a flotation cost adder based on FPL's specific cost data and he has not identified flotation cost incurred by or allocated to FPL.

Q IS MR. HEVERT'S FLOTATION COST RETURN ON EQUITY ADDER OF 12 BASIS POINTS REASONABLE?

A No. Mr. Hevert's flotation cost estimate is flawed and it should not be included in determining a fair return on equity for FPL.

Flotation costs are a legitimate cost of doing business. However, flotation costs should only be included in the development of cost of service when proven reasonable. Mr. Hevert's flotation cost adder is not reasonable for several reasons. First, FPL has to demonstrate what its actual common stock flotation costs are, and FPL has not proven the costs are reasonable. It is not appropriate to approximate flotation costs for utility companies and build those approximated costs into a utility's cost of service. Costs should be known and measurable and should be verifiable and

[49]Exhibit RBH-9.

most importantly should be shown to be reasonable before they are included in cost of service. This is not possible if a utility's flotation costs are approximated, as Mr. Hevert has done.

Second, FPL is not a publicly traded company. Rather, it is a wholly-owned subsidiary of NextEra Energy. Hence, FPL does not incur costs related to selling common stock to the market. FPL's common equity capital comes from two sources: (1) retained earnings, which incur no flotation costs, and (2) equity infusion from its parent company. Equity issuances from the parent company may include selling stock to the public. In this case, it might be appropriate for NextEra Energy to allocate part of its public stock flotation cost to FPL if the proceeds of the equity stock issuance are used to make equity contributions to FPL. However, NextEra Energy can fund equity infusions into FPL by internal sources of funds (dividend payments from utility subsidiaries such as FPL) or issuing debt securities. Neither of these two sources of funds to NextEra Energy would include flotation cost expenses related to making equity infusions into FPL. As such, even equity contributions from NextEra Energy to FPL may not include incurring the cost of selling stock to the public or flotation expenses.

Mr. Hevert's proposed 12 basis points return on equity adder for flotation costs should be rejected because it is not a known and measurable cost to FPL.

Q DO YOU AGREE WITH MR. HEVERT THAT FPL'S FOUR-YEAR RATE PROPOSAL IMPOSES MULTIPLE RISKS ON SHAREHOLDERS?

A No. The risks Mr. Hevert refers to are already accounted for in credit rating agencies' assessment.[50] Second, Mr. Hevert has not provided enough evidence that interest

[50] *Moody's Investors Service*: "Credit Opinion: Florida Power & Light Company," March 31, 2016 at 1-2, provided by FPL in response to OPC's 1st POD No. 12, emphasis added.

rates and the inputs of the various financial models he uses will increase. Those input estimates could also decline and lead to a lower return for FPL. Therefore, Mr. Hevert's assessment is one-sided and is unreasonable. The four-year plan provides certainty that the Company will be able to achieve its authorized earnings during its construction program.

V.B. Hevert CAPM

Q PLEASE DESCRIBE MR. HEVERT'S CAPM ESTIMATE.

A Mr. Hevert developed CAPM return estimates based on market risk premiums derived from DCF returns on the market, and current observable and projected returns on U.S. Treasury bond yields for 2017 and 2020.[51]

He derives two market risk premiums using DCF methodologies. First, he uses Bloomberg growth rate projections to produce a DCF return on the market of 13.63%. He subtracts from this the risk-free rate to produce the implied risk premium. Second, he relies on *Value Line* data to produce a second DCF return on the market of 12.82% from which he subtracts the risk-free rate to produce an alternative risk premium estimate.[52]

Q PLEASE DESCRIBE THE ISSUES YOU TAKE WITH MR. HEVERT'S CAPM ANALYSES.

A My major concern with Mr. Hevert's CAPM analyses is his inflated market risk premium estimates. I also take issue with Mr. Hevert's outdated projected risk-free rates based on a December 2015 *Blue Chip Financial Forecasts* document. Finally,

[51]Hevert Direct Testimony at 20.
[52]Exhibit RBH-6, pages 1 and 7.

Mr. Hevert applies his unreasonable flotation cost adder to his CAPM, which should be rejected, as discussed above.

Q PLEASE DESCRIBE MR. HEVERT'S MARKET RISK PREMIUMS.

A Mr. Hevert developed two market risk premium estimates. Both are DCF-derived market risk premiums of 10.68% (Bloomberg) and 9.87% (*Value Line*). These market risk premiums are based on projected market DCF returns of 13.63% and 12.82%, less the current 30-year Treasury bond yields of 2.96%.[53]

Q ARE MR. HEVERT'S DCF-DERIVED MARKET RISK PREMIUM ESTIMATES REASONABLE?

A No. Mr. Hevert's DCF-derived market risk premiums are based on inflated market returns of 13.63% and 12.82%. The DCF market returns are produced using growth rates of 11.24% and 10.58%, and market dividend yields of 2.41% and 2.45%.[54]

As discussed above, the DCF model requires a long-term sustainable growth rate. Mr. Hevert's sustainable market growth rates of 11.22% and 10.37% are far too high to be a rational outlook for sustainable long-term market growth. These growth rates are more than two times the consensus analysts projected long-term growth of the U.S. GDP of 4.35%.

As a result of his inflated long-term market growth rate, Mr. Hevert's market DCF returns are inflated and not reliable.

Mr. Hevert's 10.68% (Bloomberg) and 9.87% (*Value Line*) market risk premiums should be given no weight in estimating a fair return for FPL in this case.

[53]Direct Testimony of Robert Hevert, page 20, Exhibit RBH-6.
[54]Exhibit RBH-6 (13.63% = 2.41% + 11.22%) and (12.82% = 2.45% +10.37%).

Q DO HISTORICAL ACTUAL RETURNS ON THE MARKET SUPPORT MR. HEVERT'S PROJECTED MARKET RETURNS?

A No. This is significant because Mr. Hevert does rely on historical market returns to produce real returns on the market for use in developing his GDP growth forecast in his DCF study. Using the same line of logic, historical data shows just how unreasonable Mr. Hevert's projected DCF return on the market is going forward.

Q PLEASE EXPLAIN.

A Duff & Phelps estimates the actual capital appreciation for the S&P 500 over the period 1926 through 2014 to have been 5.8% to 7.7%.[55] This compares to Mr. Hevert's projected growth of the market of 11.22% to 10.37%.

Further, historically the geometric growth of the market of 5.8%[56] has reflected geometric growth of GDP over this same time period of approximately 6.2%.[57]

This review of historical data establishes two facts very clearly. First, historical actual achieved growth has been substantially less than that projected by Mr. Hevert. Second, historical growth on the market has tracked historical growth of the U.S. GDP. Projected growth of the U.S. GDP now is closer to the 4% to 5% area. All of this information strongly supports the conclusion that Mr. Hevert's projected growth on the market of 11.22% to 10.37% is substantially overstated. While I do not endorse the use of a historical growth rate to draw assessments of the market's forward-looking growth rate outlooks, this data can be used to show how the market return estimates produced by Mr. Hevert are unreasonable and inflated.

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[55]Duff & Phelps, *2016 Valuation Handbook: Guide to Cost of Capital* at 2-4.

[56]Real historical growth 3.25% (Hevert Direct Testimony at 35) and historical inflation of 2.9% (Duff & Phelps, *2016 Valuation Handbook: Guide to Cost of Capital* at 2-4).

[57]Hevert Direct Testimony at 35, line 3, and note 53. Real GDP of 3.25% and historical inflation of 2.9%.

Q WHAT ISSUES DO YOU HAVE WITH MR. HEVERT'S RISK-FREE RATES?

A Mr. Hevert's risk-free rates are based on *Blue Chip* current (2.96%), near-term 2017 projected (4.00%) and long-term 2020 projected (4.80%) 30-year Treasury yields, which are now more than 6 months old. Based on the most recent *Blue Chip* publication the current, near-term and long-term projected 30-year Treasury yields are 2.72%, 3.4% and 4.4%, respectively.[58] However, using projections for 2020 (4.4%) is highly uncertain and it will produce unreliable return estimates.

Q CAN MR. HEVERT'S CAPM ANALYSIS BE REVISED TO REFLECT A MORE REASONABLE MARKET RISK PREMIUM AND RECENT RISK-FREE RATES?

A Yes. I have revised Mr. Hevert's CAPM cost estimate by making the following adjustments to his study:

1. Rejected his 12 basis point flotation cost adder.
2. Relied on the more recent projections of risk-free rates projected through 2017.
3. Relied on Mr. Hevert's beta estimates from Bloomberg and *Value Line* for his proxy group of 0.608 and 0.776.
4. Relied on a market risk premium of 7.8% which reflects the highest market risk premium from historical data, and corresponds with very low risk-free rates.

With all these adjustments, Mr. Hevert's adjusted CAPM return would be no higher than 9.5%, as shown in Table 7 above.

[58] *Blue Chip Financial Forecasts*, June 1, 2016 at 4 and 14.

V.C. Bond Yield Plus Risk Premium

Q PLEASE DESCRIBE MR. HEVERT'S BOND YIELD PLUS RISK PREMIUM.

A As shown on Exhibit RBH-3, Mr. Hevert constructs a risk premium return on equity estimate based on the premise that equity risk premiums are inversely related to interest rates. He estimates an average electric risk premium of 4.50% over the period January 1980 through January 15, 2016. Then he applies a regression formula to the current, near-term, and long-term projected 30-year Treasury bond yields of 2.96%, 4.00%, and 4.80% to produce electric risk premiums of 7.08%, 6.24%, and 5.73%, respectively. Thus, he calculates return on equity estimates of 10.04%, 10.24%, and 10.53%, respectively.

Q IS MR. HEVERT'S BOND YIELD PLUS RISK PREMIUM METHODOLOGY REASONABLE?

A No. Mr. Hevert's contention that there is a simplistic inverse relationship between equity risk premiums and interest rates is not supported by academic research. While academic studies have shown that, in the past, there has been an inverse relationship among these variables, researchers have found that the relationship changes over time and is influenced by changes in perception of the risk of bond investments relative to equity investments, and not simply changes to interest rates.[59]

In the 1980s, equity risk premiums were inversely related to interest rates, but that was likely attributable to the interest rate volatility that existed at that time. As such, when interest rates were more volatile, the relative perception of bond

[59]"The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," Robert S. Harris and Felicia C. Marston, *Journal of Applied Finance*, Volume 11, No. 1, 2001 and "The Risk Premium Approach to Measuring a Utility's Cost of Equity," Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *Financial Management*, Spring 1985.

investment risk increased relative to the investment risk of equities. This changing investment risk perception caused changes in equity risk premiums.

In today's marketplace, interest rate volatility is not as extreme as it was during the 1980s.[60] Nevertheless, changes in the perceived risk of bond investments relative to equity investments still drive changes in equity premiums. However, a relative investment risk differential cannot be measured simply by observing nominal interest rates. Changes in nominal interest rates are heavily influenced by changes to inflation outlooks, which also change equity return expectations. As such, the relevant factor needed to explain changes in equity risk premiums is the relative changes to the risk of equity versus debt securities investments, and not simply changes in interest rates.

Importantly, Mr. Hevert's analysis simply ignores investment risk differentials. He bases his adjustment to the equity risk premium exclusively on changes in nominal interest rates. This is a flawed methodology that does not produce accurate or reliable risk premium estimates.

Q CAN MR. HEVERT'S BOND YIELD PLUS RISK PREMIUM ANALYSIS BE REVISED TO REFLECT CURRENT PROJECTIONS OF TREASURY YIELDS?

A Yes. Disregarding Mr. Hevert's simplistic and inaccurate notion of a continuing inverse relationship between interest rates and the risk premium will produce more realistic results. Adding my weighted average equity risk premium over Treasury bonds of 6.09% to his updated current (2.72%) and two-year projected (3.40%) Treasury yields will produce return on equity estimates no higher than 9.5%, as shown in Table 7 above.

[60]"The Risk Premium Approach to Measuring a Utility's Cost of Equity," Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *Financial Management*, Spring 1985, at 44.

V.D. Hevert DCF Studies

V.D.1. Constant Growth

Q PLEASE DESCRIBE MR. HEVERT'S CONSTANT GROWTH DCF RETURN ESTIMATES.

A His constant growth DCF returns are developed in Exhibit RBH-1. Mr. Hevert's constant growth DCF models are based on consensus growth rates published by Zacks and First Call, and individual growth rate projections made by *Value Line*.

He relied on dividend yield calculations based on average stock prices over three different periods ending January 15, 2016: 30-day, 90-day, and 180-day, reflecting one-half year dividend growth adjustments.

Q ARE THE DCF RESULTS PRODUCED BY MR. HEVERT REASONABLE?

A Mr. Hevert's constant growth DCF studies generally support a mean return on equity of approximately 9.1%, similar to my constant growth DCF study.

Mr. Hevert arranges his DCF return estimates for low, median and high. His high-end estimate produces a DCF return estimate of 10.08%[61] (excluding 0.12 flotation adder). However, these high-end estimates appear to be what Mr. Hevert largely relies on in forming his recommended return on equity range for FPL.

These high-end estimates are not reasonable for several reasons. First, they do not reflect DCF return estimates for his proxy group reflecting a consistent source for growth. Rather, they rely on the highest growth rate estimates produced from one of three sources. As such, the growth rates are not derived from a single source rate forecast, do not reflect a consistent application of a DCF growth rate, and do not

[61]Exhibit RBH-4, page 3 of 3.

reflect growth rates that are reasonable estimates of long-term sustainable growth as required by this model.

The latter point is the most relevant. Mr. Hevert's high-end DCF return estimate of 10.08% is based on a proxy group growth rate of 6.22%. This growth rate is nearly 200 basis points higher than the long-term growth outlook for the U.S. GDP of 4.35%, as discussed above. Mr. Hevert's mean constant growth DCF analysis, excluding the flotation cost adjustment, ranged from 9.19% to 9.30%. The midpoint of the DCF range is approximately 9.25%, which supports my recommendation in this proceeding. (See page 31 of Mr. Hevert's testimony, Table 4, excluding 12 basis point flotation cost adder).

V.D.2. Multi-Stage Growth DCF

Q DID MR. HEVERT PERFORM A MULTI-STAGE GROWTH DCF ANALYSIS?

A Yes, he did. His multi-stage DCF model is developed on Exhibit RBH-2. However, his multi-stage DCF analysis is flawed for at least two reasons. First, Mr. Hevert relied on a long-term growth rate of 5.35%. This is not a reasonable estimate of long-term growth. Mr. Hevert's long-term growth rate is considerably higher than the market GDP growth outlooks as reflected in the consensus analysts' projections.

Q HOW DID MR. HEVERT CALCULATE A LONG-TERM GROWTH RATE?

A Mr. Hevert produced a nominal projected GDP growth rate of 5.35% using a real GDP growth factor of 3.25% and a forward-looking inflation rate of 2.04%.

Mr. Hevert's real GDP growth rate was based on the actual achieved real growth in the U.S. GDP over the period 1929-2014.

He then relied on two sources to project going-forward inflation. First, he considered the inflation rate as implied by the difference in spread between nominal Treasury bond yields and Treasury Inflation Protected Securities ("TIPS") over an 180-day average period. This produced a forward-looking inflation outlook of 1.87%. Second, he considered CPI's projection for inflation over the period 2022-2026 of 2.2% as published by the *Blue Chip Financial Forecasts*. The average of these two inflation projections is 2.04%. ((2.2% + 1.87%)÷ 2).

Mr. Hevert's nominal GDP forecast of 5.55% then is the product of this real GDP of 3.25% and inflation projection of 2.04%. (1.0325 x 1.0204 - 1).

Q IS MR. HEVERT'S LONG-TERM GROWTH RATE ESTIMATE OF 5.35% REASONABLE?

A No. The methodology used by Mr. Hevert to calculate this growth rate simply is not based on market participants' outlooks for future GDP growth. Therefore, Mr. Hevert's GDP growth rate projections do not reflect market participants' outlooks of future growth, and therefore are not useful or reliable in estimating a current market-required return for FPL in this proceeding. By relying on his own GDP growth forecast, rather than one that reflects market participants, he is not accurately estimating the current market cost of equity.

Q WHY DO MR. HEVERT'S GDP GROWTH PROJECTIONS NOT REASONABLY ALIGN WITH MARKET PARTICIPANTS?

A Mr. Hevert's growth rate of 5.35% is based on a historical real GDP growth rate of 3.25%. This real GDP growth rate is considerably higher than the real GDP growth provided by consensus analysts in projections of future real GDP growth.

In order to measure the current market cost of equity demanded by investors in today's marketplace, it is necessary to reasonably capture the outlooks by investors that have formed valuations of observable stock prices used in the various time periods underlying Mr. Hevert's and my DCF studies. Mr. Hevert's long-term growth rate simply ignores current consensus analysts' outlooks for future growth, and therefore is not a reasonable estimate of what market participants have relied on in order to produce those market valuations, for example.

The consensus economists' projected GDP growth rate is much lower than the GDP growth rate used by Mr. Hevert in his DCF analysis. A comparison of Mr. Hevert's GDP growth rate and consensus economists' projected growth over the next 5 and 10 years is shown in Table 8 below. As shown in this table, Mr. Hevert's GDP rate of 5.35% reflects real GDP of 3.25% and an inflation adjusted GDP of 2.04%. However, consensus economists' projections of nominal GDP over the next 5 and 10 years are 4.35%.

As is clearly evident in Table 8, Mr. Hevert's historical GDP growth is much higher than, and not representative of, consensus market expected forward-looking GDP growth.

TABLE 8

GDP Projections

Description	GDP Inflation	Real GDP	Nominal GDP
Mr. Hevert	2.0%	$\boxed{3.3\%}$	5.35%
Consensus Economists (5-Year)	2.1%	2.2%	4.35%
Consensus Economists (10-Year)	2.1%	2.2%	4.35%

Source: *Blue Chip Financial Forecasts*, June 1, 2016 at 14.

Mr. Hevert's 5.35% nominal GDP growth rate is not reflective of consensus market expectations and should be rejected. Indeed, Mr. Hevert's 5.35% GDP growth rate outlook is inconsistent with the consensus of economists' independent projections of future long-term GDP growth, and is also inconsistent with projections made by the U.S. EIA and CBO (as referenced in my testimony above where I describe the parameters used in my own multi-stage growth DCF analyses). Those agencies also project nominal GDP much more consistent with the consensus independent economists' projections shown in Table 8 above. For all these reasons, Mr. Hevert's GDP growth outlook is simply out of line and out of touch with the consensus market outlooks.

Q PLEASE EXPLAIN HOW MR. HEVERT'S MULTI-STAGE GROWTH DCF MODEL OVERSTATED DIVIDEND CASH FLOWS BECAUSE OF HIS LONG-TERM DIVIDEND PAYOUT RATIO ASSUMPTION.

A Mr. Hevert modified analysts' three- to five-year dividend payout projections of 61.68% for his proxy group, and assumed that eventually they would converge to the historical industry average dividend payout ratio of 67.30%.[62]

Q IS MR. HEVERT'S ASSUMPTION THAT THE PROXY GROUP'S PAYOUT RATIO WILL INCREASE TOWARD THE INDUSTRY HISTORIC DIVIDEND PAYOUT RATIO REASONABLE?

A No. There is simply no reason to expect the dividend payout ratio of the proxy group will increase toward the historical utility industry average. The going forward payout

[62]Direct Testimony of Robert Hevert at 36.

ratio of the proxy group will be controlled by funding requirements and dividend growth outlook for the future.

Utilities are reducing dividend payout ratios in order to increase retained earnings as a means to increase internal cash flow. This increased internal cash flow supports the utility's ability to fund larger capital expenditure programs with internal funding. Since the capital expenditure program for the industry is expected to remain large, there is no reasonable basis to assume that the industry payout ratio will increase during Mr. Hevert's transition period growth stage.

Further, there should be a tie between the growth rate in the short-term stage and the long-term stage. Changes in the payout ratio may explain these differences in growth rates. However, Mr. Hevert's assumption for changes in the dividend payout ratio is not tied to transitioning from a short-term growth stage to a long-term growth stage. There is simply no basis for the assumption that the dividend payout ratio will increase or change between growth stages of this model.

For all these reasons, his changing payout ratio assumptions seem to only result in enhancing cash flows during the transition phase through the terminal phase, and artificially increasing his multi-stage growth DCF return estimate.

Q CAN MR. HEVERT'S MODEL BE CORRECTED TO ELIMINATE HIS UNREASONABLE INDUSTRY PAYOUT RATIO ASSUMPTIONS?

A Yes. Simply eliminating his assumption that the utility payout ratio will revert from the analysts' three- to five-year growth rate projections to the higher long-term historical growth rate will correct this problem. Maintaining the existing payout ratio is consistent with industry outlooks.

Q HOW WOULD MR. HEVERT'S MULTI-STAGE GROWTH DCF MODEL CHANGE IF THE CORRECTIONS YOU DESCRIBED ABOVE ARE MADE TO HIS RETURN ESTIMATE?

A As shown below in Table 9, revising the GDP growth rate to the consensus analysts' projection and coordinating the payout ratio assumption with the long-term earnings growth rate assumption reduces Mr. Hevert's multi-stage growth DCF return from 9.77% to 8.64% for his proxy group.

TABLE 9

Hevert Multi-Stage Growth DCF Analysis

Description	Mean[1] (1)	Adjusted[2] (2)
30-Day Average	9.72%	8.64%
90-Day Average	9.76%	8.67%
180-Day Average	9.84%	8.76%
Average	9.77%	8.69%

Sources:
[1]Hevert Direct Testimony at 36, excluding flotation costs of 0.12%.
[2]Exhibit MPG-20.

V.D.3. DCF Conclusions

Q WHAT IS A REASONABLE DCF RETURN FOR FPL BASED ON MR. HEVERT'S CONSTANT GROWTH DCF ESTIMATES AND YOUR SOUND ADJUSTMENTS TO HIS MULTI-STAGE DCF RESULTS?

A Mr. Hevert's constant growth DCF study supports a return on equity of approximately 9.25%. As shown above in Table 9, balanced and accurate adjustments to Mr. Hevert's multi-stage growth DCF study support a return on equity in the range of 8.64% to 8.76%, with a midpoint of approximately 8.7%. Based on this assessment, Mr. Hevert's DCF studies reflecting market participants' outlooks for growth, and reasonable estimates of the central tendency of the results of the DCF study, support a return on equity for FPL in the range of 8.7% to 9.25%.

V.E. Risk Factors

Q DID MR. HEVERT CONSIDER ADDITIONAL BUSINESS RISKS TO JUSTIFY HIS RECOMMENDED RETURN ON EQUITY OF 11.0%?

A Mr. Hevert believes that: (1) the Company's geographic risk; (2) the Company's need to access external capital; (3) the potential for new regulatory requirements associated with nuclear generation; (4) the need to account for flotation costs; and (5) the potential for an increase in the cost of equity over the Company's proposed four year rate period justify a return on equity above the mean of his analytical results.

Q PLEASE COMMENT.

A I disagree. Setting the return on equity within Mr. Hevert's range of 10.5% to 11.5% will place an unreasonable cost burden on FPL's ratepayers without any justified benefits.

Customers are already required to pay cost-based rates to fully compensate FPL for its cost of service within its geographic area (including storm hardening costs), support cash flow and earnings metrics that will maintain strong investment grade credit rating and support its access to external capital, reflect all operating and business risk requirements such that it can meet its obligations to operate and decommission nuclear generating stations, and to account for a legitimate and verifiable cost such as flotation expenses if the Company actually incurs such expenses. Further, the proposal for a multi-year rate plan benefits the Company to the extent it creates rate certainty, and allows for adjustments in rates to track changes in cost of service. Increasing the authorized return on equity to support the Company's request for a multi-year rate plan provides it compensation for risks that are largely transferred to customers in such a regulatory mechanism. For all these reasons, Mr. Hevert's proposal for recognizing business risk increases to support an above market return for FPL is without merit and should be denied.

Q DO YOU BELIEVE THAT FPL FACES OPERATING RISKS THAT ARE COMPARABLE TO THE PROXY GROUP FROM WHICH YOU AND MR. HEVERT HAVE MEASURED A RISK-ADJUSTED MARKET RETURN?

A Yes. As shown on my Exhibit MPG-4, the average S&P credit rating for my proxy group of BBB+ is lower than FPL's credit rating of A-. The relative risks discussed on pages 37-52 of Mr. Hevert's testimony are already incorporated in the credit ratings of the proxy group companies. S&P and other credit rating agencies go through great detail in assessing a utility's business risk and financial risk in order to evaluate their assessment of its total investment risk. Therefore, this total risk investment assessment of FPL, in comparison to a proxy group, is fully absorbed into the market's perception of FPL's risk and the proxy group fully captures the investment risk of FPL. In fact, as discussed above, the return on equity produced by the proxy group is conservative considering the lower business and financial risks of FPL relative to the proxy group.

Q HOW DOES S&P ASSIGN CORPORATE CREDIT RATINGS FOR REGULATED UTILITIES?

A In assigning corporate credit ratings the credit rating agency considers both business and financial risks. Business risks among others include company's size and competitive position, generation portfolio, capital expenditure programs as well as a consideration of the regulatory environment, current state of the industry and the economy as whole. Specifically, S&P states:

> To determine the assessment for a corporate issuer's business risk profile, the criteria combine our assessments of industry risk, country risk, and competitive position. Cash flow/leverage analysis determines a company's financial risk profile assessment. The analysis then combines the corporate issuer's business risk profile assessment and its financial risk profile assessment to determine its anchor. In general, the analysis weighs the business risk profile more heavily for investment-grade anchors, while the financial risk profile carries more weight for speculative-grade anchors.[63]

Q DID MR. HEVERT ALSO OFFER AN ASSESSMENT OF CURRENT MARKET CONDITIONS IN SUPPORT OF HIS RECOMMENDED RETURN ON EQUITY?

A Yes. Mr. Hevert describes a few factors that, he suggests, gauge investor sentiment, including the relationship between the Federal Reserve's balance sheet and market volatility, measured by the CBOE Volatility Index, known as the VIX, his contention that interest rates will increase and credit spreads have widened.[64] He concludes that these metrics indicate that current levels of instability and risk aversion are at historically low levels and that the market is disjointed.

[63]Standard & Poor's RatingsDirect: "Criteria/Corporates/General: Corporate Methodology," November 19, 2013.

[64]Direct Testimony of Robert Hevert at 52-65.

Q DO YOU BELIEVE THAT MR. HEVERT'S USE OF THESE MARKET SENTIMENTS SUPPORTS HIS FINDINGS THAT FPL'S MARKET COST OF EQUITY IS CURRENTLY 11.0%?

A No. Indeed, in many instances Mr. Hevert's analysis simply ignores market sentiments favorable toward utility companies and instead lumps utility investments in with general corporate investments. A fair analysis of utility securities shows that the market generally regards utility securities as low-risk investment instruments and supports the finding that utilities' cost of capital is very low in today's marketplace.

Q WHAT IS THE MARKET SENTIMENT FOR UTILITY INVESTMENTS?

A The market sentiment toward utility investments, rather than just general corporate investments, is that the market is placing high value on utility securities recognizing their low risk and stable characteristics.

For example, this is illustrated by my Exhibit MPG-15, under column 11, which shows the spread between "A" rated utility bond yields and "Aaa" rated corporate bond yields. Currently, the spread is approximately 0.25%. This is a relatively low spread over the 36-year time horizon. Indeed, current spreads of utility versus high-grade corporate bond yields are at the lowest level they have been in most periods over the last 36 years. This is also reflective of the spreads between "Baa" utility bond yields relative to "Baa" corporate bond yields. Currently, utility bonds are trading at a premium to corporate bonds. This has been largely the case during the significant market turbulence that has occurred over the last five to eight years. However, over longer periods of time, utility bond yields on average trade at parity to a premium to corporate "Baa" rated bond yields. The current strong utility bond valuation is an indication of the market's sentiment that utility bonds have lower risk than general corporate bonds, and are generally regarded as a safe haven by the investment industry.

Further, other measures of utility stock valuations also support a robust market for utility stocks. As shown on my Exhibit MPG-2, utility valuation measures – *e.g.*, price-to-earnings ratio, market price to cash flow ratio and market-to-book ratio, – show that stock valuation measures for the proxy groups are robust. For example, for the proxy group, the current price-to-earnings ratio is comparable to and the cash flow ratio is stronger than the 14-year average valuation metrics.

For all these reasons, direct assessments of valuation measures and market sentiment toward utility securities support the credit rating agencies' findings, as quoted above, that the utility industry is largely regarded as a low-risk, safe haven investment. All of this supports my findings that utilities' market cost of equity is very low in today's very low cost capital market environment.

Q DO YOU HAVE ANY COMMENTS CONCERNING MR. HEVERT'S CONTENTION THAT INTEREST RATES ARE GOING TO INCREASE?

A Yes. Mr. Hevert develops his risk premium studies mainly relying on near-term and long-term projected interest rates, which he believes are expected to increase (Hevert Direct at 61-63). Mr. Hevert's proposal to rely mainly on forecasted Treasury bond yields is unreasonable because he is not considering the highly likely outcome that current observable interest rates will prevail during the period rates determined in this proceeding will be in effect. This is important, because while current observable interest rates are actual market data that provides a measure of the current cost of capital, the accuracy of forecasted interest rates is at very best, problematic.

Q WHY DO YOU BELIEVE THAT THE ACCURACY OF FORECASTED INTEREST RATES IS HIGHLY PROBLEMATIC?

A Over the last several years, observable current interest rates have been a more accurate predictor of future interest rates than economists' consensus projections. Exhibit MPG-21 illustrates this point. On this exhibit, under Columns 1 and 2, I show the actual market yield at the time a projection is made for Treasury bond yields two years in the future. In Column 1, I show the actual Treasury yield and, in Column 2, I show the projected yield two years out.

As shown in Columns 1 and 2, over the last several years, Treasury yields were projected to increase relative to the actual Treasury yields at the time of the projection. In Column 4, I show what the Treasury yield actually turned out to be two years after the forecast. In Column 5, I show the actual yield change at the time of the projections relative to the projected yield change.

As shown in this exhibit, over the last several years, economists consistently have been projecting that interest rates will increase. However, as shown in Column 5, those yield projections have turned out to be overstated in almost every case. Indeed, actual Treasury yields have decreased or remained flat over the last several years, rather than increased as the economists' projections indicated. As such, current observable interest rates are just as likely to accurately predict future interest rates as are economists' projections.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

MR. JERNIGAN: And I believe staff has a couple of questions at this point.

EXAMINATION

BY MS. BROWNLESS:

Q Good evening, Mr. Gorman.

A Good evening.

Q Did you have an opportunity to look at what's been identified as Staff Exhibit 540?

A Yes.

Q And did you prepare this exhibit, the responses to these interrogatories?

A Yes, I did.

Q And are they true and correct to the best of your knowledge and belief?

A They are.

Q And if you were asked the same questions as are in these interrogatories and discovery requests today, would your answers be the same?

A They would.

Q Are any portions of your listed exhibits confidential?

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

Q Are any portions of your listed responses in this exhibit confidential?

A I do not believe so.

MS. BROWNLESS: Thank you so much.

CHAIRMAN BROWN: Thank you.

FURTHER REDIRECT EXAMINATION

BY MR. JERNIGAN:

Q Mr. Gorman, do you have a summary you would like to read into the record at this point?

A I do. Thank you. Good evening Commissioners. My name is Michael Gorman. I'm appearing on behalf of the Federal Executive Agency. And on behalf of the FEA, I've been asked to recommend a fair rate of return for Florida Power & Light in this case for the development of revenue requirement and development of retail rates.

In my review of current market capital costs for FPL based on an assessment of FPL's current investment risk, I find a fair return on equity to fall in the range of 8.9 percent to 9.6 percent. I recommend rates be set at the mid point of 9.25 percent.

In reviewing the fair return on equity for FPL, I also considered observable market evidence. In doing that, I looked at the price performance of electric utility stocks over the last five years. I looked at industry-authorized returns on equity for electric utility companies, and I reviewed credit reports and other market literature to get a sense of whether or not industry market participants were aware of regulatory decisions with respect to return on equity. They are. This is public knowledge.

After that review, I reviewed credit rating reports for electric utility companies. And with authorized returns on equity dropping down below 10 percent more recently in 2015 and most recently in 2016, they have been falling in the 9.5 to 9.6 area on average for electric utility companies.

With authorized returns on equity at that level, the electric utility industry credit rating has been strengthening. At authorized returns on equity at that level, electric utility companies are able to access external capital to fund very large capital programs, and that capital has been a very low cost under reasonable terms.

The industry information tells the market that utilities, by and large, are able to earn the authorized returns on equity that regulatory commissions award them. Again, that's less than 10 percent. More recently and specifically in 2015 and 2016, it has been close to the 9.5 or 9.7 percent area.

I then reviewed Florida Power & Light's investment risk characteristics specifically. I looked at their credit rating reports from Standard and Poor's, Moody's and Fitch. I looked at Standard and Poor's specific findings on financial risk ratings for FPL. I looked at Standard and Poor's business risk assessments of FPL.

I found that S & P rates FPL's financial risk as intermediate which is relatively strong for an electric utility company and has relatively strong or low business risk. S & P ranks their business rating as excellent which is the strongest rating or the lowest operating risk characteristics for a utility company.

S & P bond rating currently for FPL is around A-. Moody's bond rating for FPL is around A1. Two of those are amongst the stronger bond ratings for electric utility companies specifically.

Based on that assessment, I found that FPL was generally regarded by the investment community as a stable, low-risk investment vehicle.

I then reviewed FPL's proposed capital structure in this proceeding and noted that its common equity ratio is significantly higher than other utilities. They're able to maintain the same bond rating.

FPL has a common equity ratio of total

investor capital of almost 60 percent, around 59.6 percent. When looking at credit rating reports for other utilities and looking at credit metrics published by S & P for the industry, FPL's capital structure contains far more common equity than other utility companies with the same bond rating are able to maintain.

What's significant about that is a capital structure that has an excessive balance of common equity, has the effect of increasing the utility's cost to capital and their income tax expense. That is caused because common equities is the most expensive form of capital, and it is subject to income tax expense.

In contrast, debt capital is much lower cost than equity capital and is not subject to an income tax expense adjustment in developing the revenue requirement costs for debt capital. Indeed, the cost to customers of equity capital is more than three times the expense of debt capital.

In reviewing my return on equity for FPL, I looked at a discounted cash flow analysis, three versions of it, which produced a return of 8.9 percent. I looked at two versions of a risk premium model. One indicated a fair return of 9.6 percent. The other indicated a return of 9.25 percent.

I also responded to Mr. Hevert's return on equity methodologies and found that they were largely overstating FPL's current market cost of equity.

CHAIRMAN BROWN: Thank you, Mr. Gorman.

MR. JERNIGAN: Thank you. At this time, FEA presents Mr. Gorman for cross examination.

CHAIRMAN BROWN: Great. Thanks. All right. Public counsel?

MR. SAYLER: Good evening, Madam Chairman. I do have a couple of questions for the witness. They are aligned differently on the recommended ROE and also the equity ratio.

CHAIRMAN BROWN: Just a reminder, no friendly cross.

MR. SAYLER: Yes, ma'am.

CHAIRMAN BROWN: Thank you.

EXAMINATION

BY MR. SAYLER:

Q Mr. Gorman, in your testimony, isn't it true that you're not recommending a change to their equity ratio?

A That's correct. I am recommending that the Commission recognize a high-equity ratio as reflective of low financial risk and take that into consideration in awarding a fair and reasonable return on equity.

Q As an expert in capital structures, what is the concept of double leveraging?

A Double leverage is a notion that the capital starts at the parent company, and the parent company is able to capitalize the utility in a way consistent with management objectives. And in capitalizing the utility's common equity component, the parent company is able to use both parent company debt and parent company equity capital.

So, the double leverage generally recognizes that the equity component of the utility's capital structure is funded by the parent using both debt and equity capital; whereas, the debt issued on behalf of the utility is utility debt which reflects standard debt instruments.

So, a double leverage adjustment to a utility's cost of service will, at times, reconstruct the ratemaking capital structure to break down the equity component into a debt-and-equity component and price it at the parent company's cost of debt and cost of equity and then add to that the utility cost to debt.

Q Thank you for that thorough explanation. Could that be summed up as a situation where the parent

company borrows debt, takes that debt and invests it in its regulated operating company?

MR. BUTLER: I'm going to object to this. So far as I know, it's outside the scope of Mr. Gorman's testimony and also pretty clearly friendly cross.

CHAIRMAN BROWN: Mr. Sayler.

MR. SAYLER: I'm testing his expertise in this area, and I was trying to understand his concept of double leveraging. I was trying to just summarize what he just testified to to make sure that I understand it.

MR. BUTLER: And I would have objected to the earlier question if I had thought of it. I think it's all pretty much beyond Mr. Gorman's direct testimony.

MR. SAYLER: He is an expert witness, and experts have expertise in many areas in this case, Madam Chair. And this was going to be my last question to rephrase just if I was understanding it.

CHAIRMAN BROWN: Objection overruled. You can answer, sir.

A I would not agree with it explicitly, but I would with one correction. When the parent company issues debt, they would take the proceeds of that debt and they would make equity infusions in the utility company, so the utility would record it as equity capital where the parent company would record it as debt capital.

So, it would be an equity contribution to the utility affiliate that is funded by debt at the parent company level.

Q So --

CHAIRMAN BROWN: That was the last question. I'm holding you to it.

MR. SAYLER: All right. Thank you very much.

CHAIRMAN BROWN: Seriously, any further?

MR. SAYLER: No. The follow-up question was I was just trying to understand you borrow at one rate and then you earn a return at a higher rate. And that's --

MR. BUTLER: I object to Mr. Sayler testifying.

MR. SAYLER: I was trying to ask the question.

CHAIRMAN BROWN: Thank you, Mr. Sayler. Mr. Moyle.

MR. MOYLE: Thank you. I have some

questions similar to the other ROE witnesses that I have asked and maybe a couple more.

EXAMINATION

BY MR. MOYLE:

Q Sir, you believe, do you not, that decisions of other commissions with respect to ROE, particularly to the extent that they are in close proximity to time that this commission is asked to make a decision, is something that could and should be considered?

MR. BUTLER: Objection. Friendly cross.

CHAIRMAN BROWN: Mr. Moyle, I should have prefaced the discussion no friendly cross.

MR. MOYLE: I know. I've asked the other couple of witnesses this, but you know, our position is 10 percent or lower. He's at 9.25. So, we're not completely aligned.

CHAIRMAN BROWN: I understand your position.

MR. BUTLER: Wait a minute. He's not aligned because this is lower than his? How is that not aligned?

MR. MOYLE: I'm trying to get you a little more money, John.

CHAIRMAN BROWN: Objection sustained. Mr. Moyle, please move along. Again, please, no friendly cross.

BY MR. MOYLE:

Q What's income tax expense?

A Income tax expense is the cost to the utility of producing profits. In developing the revenue requirement, the utility must recover its profits plus applicable income tax from customers. So, the income tax expense is the amount of tax to Federal and State income tax authorities or local authorities that the utility has to remit taxes to based on their income.

Q Who pays for that?

A Customers.

Q So, when you're asking for 9.25 or 12 or whatever it is, the income tax is above -- on top of that?

MR. BUTLER: I'm going to object again as friendly cross.

CHAIRMAN BROWN: Mr. Moyle.

MR. MOYLE: I'm trying to clarify his answer to the previous question with respect to the income tax burden, whether it is cumulative and is added on to, in effect, looking at the effect on rates, whether the ratepayers pay for that income tax or whether they don't.

MR. BUTLER: My objection is that it's

friendly cross. The clarified answer to that is just helping your case and his, which is, I think, the definition of friendly cross.

CHAIRMAN BROWN: Objection sustained.

BY MR. MOYLE:

Q Is double leverage going on in this case?

MR. BUTLER: Going to object to that as friendly cross and outside the scope of Mr. Gorman's direct testimony.

MR. MOYLE: He answered a question on it before. He answered it and said here's what it is. So, I can't ask him to say --

CHAIRMAN BROWN: He did, and counsel didn't object at the time, so I will allow it for clarification to the previous question that was answered by the witness.

A I haven't specifically reviewed the case for that purpose, but from what I've reviewed of FPL's, their bond rating does seem to be a little weak for the amount of common equity in the utility's capital structure.

So, that certainly is a red flag that the bond rating reflects the greater debt levels at the parent company level.

Q So, just could be clear, would that suggest

that maybe they're borrowing money and taking debt and putting it in the company and earning equity rates on it?

MR. BUTLER: I'm going to object again as friendly cross.

CHAIRMAN BROWN: Mr. Moyle.

MR. MOYLE: It's the same line. I was just trying to ask about this double leverage thing and have a couple of questions about understanding what he's testified to.

MR. BUTLER: But the whole double leverage line is clearly friendly to both his and Mr. Gorman's client's positions, and it's not becoming any less friendly simply because it's cumulative.

CHAIRMAN BROWN: Just one second. Staff, a little guidance here.

MS. BROWNLESS: I think that Mr. Moyle has been allowed enough latitude in this area, and I think it is dangerously close to friendly cross, if not friendly cross.

CHAIRMAN BROWN: Okay. Objection sustained. New topic, Mr. Moyle.

MR. MOYLE: Can I have a minute to look at my notes?

CHAIRMAN BROWN: Sure. Take as much time as you need.

MR. MOYLE: Respectfully, can I make a proffer?

CHAIRMAN BROWN: You can make a proffer.

MR. MOYLE: Thank you. So, if permitted to ask the question with respect to double leveraging, you know, I would proffer that FPL's cost of debt is less than the cost of equity. This witness, based on his answer with respect to his review of the bonds, could have potentially elaborated and provided relevant information with respect to the capital structure and the costs of money that FPL uses to run its business.

And to the extent that they're borrowing money at a low rate and taking that money and characterizing it as equity when they invest it in FPL and earn the ROE on it, that that would argue and suggest that the ROE that this Commission awards be lower than would otherwise take place.

So, thank you for the proffer. No further questions.

CHAIRMAN BROWN: Okay. Hospitals.

MR. SIQVELAND: Nothing from us, thank you.

CHAIRMAN BROWN: Retail.

MR. LaVIA: No questions, thank you.

CHAIRMAN BROWN: AARP.

MR. COFFMAN: I know Mr. Gorman, so any questions I would ask would probably be friendly, so I won't.

CHAIRMAN BROWN: Thank you for that. Florida Power & Light.

MR. BUTLER: I think one question.

REDIRECT EXAMINATION

BY MR. BUTLER:

Q Mr. Gorman, do you know whether FPL's parent, Nexterra Energy, issues debt?

A Yes.

Q Your understanding is that that the parent company does?

A I believe they have lines of credit, yes.

Q Do they have first mortgage?

A I would have to check what the types of long-term debt issuance they have, if any, but they do have access to lines of credit.

Q Do you know whether they have any long-term debt?

A I would have to review. I can't say for certain as I sit here.

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

CHAIRMAN BROWN: Staff.

EXAMINATION

BY MS. BROWNLESS:

Q Good evening.

A Good evening.

Q Were you provided responses to staff's interrogatories and POD requests associated with your subject area as they became available?

A Yes.

Q Were you also provided responses associated with your subject area of FIPUG, South Florida, AARP and OPC discovery requests as they became available?

A I did have access, yes.

Q And did you prepare discovery questions for your client?

A I did.

Q And did you receive responses and review responses associated with those requests?

A Yes.

MS. BROWNLESS: Thank you so much.

CHAIRMAN BROWN: Commissioners.

MS. MAPP: Wait, Madam Chairman, we also have further questions for the witness.

EXAMINATION

BY MS. MAPP:

Q Good evening, Mr. Gorman.

A Good evening.

Q Could you please turn to Exhibit MPG-1 attached to your direct testimony.

A I'm there.

Q On this schedule you calculate your recommended weighted cost of capital for FPL; is that correct?

A It is.

Q Do you believe that your recommended weighted cost of capital of 5.56 percent for FPL located on Line 7 is sufficient to generate the necessary cash flow metrics to maintain a Standard & Poor's credit rating of A-?

A Well, that along with the other source of internal cash available to the company, I believe it will, yes.

Q Could you please turn to Exhibit MPG-19, Page 1 of 4.

A I'm there.

Q Yes. Can you look at Column 1 labeled retail cost of service amount?

A Yes.

Q Do you know if these are the exact amounts and calculations that Standard & Poor's would use to determine the debt to EBITDA metric?

A They wouldn't be the same numbers because Standard & Poor's would not be looking at retail operations. Rather, they would be looking at total FPL cash flows.

The reason I am looking at retail costs of service is because I'm testing whether or not my recommended rate of return will produce revenue for retail operations that is consistent with the objective of producing a fair return on equity. That is fair compensation, and the revenues will produce adequate cash flow strength to maintain the financial integrity of the utility in operating the business.

So, I focused on the retail cost of service rather than the total company which S & P would do because my focus here is judging whether or not the rate of return within the retail cost of service will support FPL's financial integrity relative to its financial obligations supporting retail operations.

Q Thank you. You're now being handed two exhibits. If you could turn to the second exhibit labeled FPL's responses to staff, 11 set of interrogatories, No. 239.

CHAIRMAN BROWN: We're going to label that or identify that as 720. That's No. 239?

MS. MAPP: Yes, 239.

(Exhibit 720 marked.)

BY MS. MAPP:

Q Mr. Gorman, if you could turn to Page 3 of 8 on the attachment in this exhibit.

A (Witness complying.)

Q And if you could refer to the headings Standard & Poor's base case scenario and the subheading of key metrics where there's a chart laid out.

A Page 3 of 8 of Attachment No. 2?

Q Yes.

A I'm there.

Q Now, the key metrics chart, Standard & Poor's calculates that the OCF or the operating cash flow to the debt percentage; is that correct?

A Yes.

Q In Exhibit MPG-19 which we just referred to, did you calculate the operating cash flow to debt percentage?

A The funds from operation of FFO to debt, yeah, are listed on Line 14. And under the retail cost of service, I estimated it could be about 27 percent.

Q Can you please point to the OCF on your

schedule identified on one of four of MPG-19.
A I'm sorry, can you repeat that question, please?
Q Can you please identify the OCF to debt percentage located on MPG-19, Page 1 of 4?
A OCF is operating cash flow, but the S & P table -- I'm sorry. I was referring to FFO to debt which is listed in the S & P table that's funds from operation to debt. And that aligns with Line 14 in my table, MPG-19.
Q I was referring to OCF to debt which is the third row of the key metrics identified on Page 3 of 8 in the exhibit.
A Yes, that's the operating cash flow as they note here. That's an important -- there are many cash flows that S & P considers for specific utilities. They are not included in its credit metric matrix that it publishes for the electric utility industry.
The FFO-to-debt ratio is one of the key metrics that S & P includes in its industry credit reports and actually its corporate credit report. While the OCF to debt is mentioned in that, it's not one where they have a matrix benchmark that allows you to look at prescribed ranges that S & P notes is generally consistent with certain levels of the

financial and business risk.

Q But did you specifically -- did you -- calculate the OCF-to-debt percentage ratio?

A I'm sorry, I did not because it was not one of the standard S & P metrics that is included in their industry metric publication that allows you to identify ranges of the metric that coincide with different levels of financial and business risk.

Q And Standard & Poor's rates FPL's business risk as excellent, correct?

A They do.

Q Would you agree that part of Standard & Poor's business risk rating includes regulatory risk?

A Yes.

Q Now, remaining on Page 3 of 8 on the exhibit that we just referred to, could you refer to the paragraph under the subheading downside scenario?

A I'm there.

Q If the Commission set FPL's authorized ROE at 9.25 percent, do you know if Standard & Poor's would consider that decision as an unfavorable regulatory outcome?

A I can't speak for S & P. I can tell you that the industry-authorized returns on equity are closer to the high end of my range. I know that the authorized returns on equity around 9.5 and 9.6 have not been regarded as poor regulatory treatment of the utility which has not resulted in downgrades of other utilities.

So, I can with confidence tell you that an ROE of 9.5 to 9.6 would not be regarded as poor regulatory treatment. I can also point to the results of my study that show that authorized returns on equity have been going down from year to year, albeit relatively slowly largely because of a conservative practice by utility commissions to reduce the return on equity slower than capital market costs have declined.

So, with that as the rationale, I feel very strongly that a return on equity at the high end of my range would not impact FPL's financial position because it's generally aligned with industry practices right now. But a 9.25 percent return on equity may be viewed by S & P as a continued reduction in the authorized return on equity.

Q Have you ever been employed by Standard & Poor's?

A I have not.

Q Thank you. Could you turn to Page 23 of your direct testimony. At Lines 13 through 18, you disagree with the method FPL chose to calculate the

cost rate of the investment tax credits in the capital structure.

Would you agree that FPL's method to calculate the cost rate for investment tax credits and the capital structure comports with IRS requirements?

A I believe the IRS gives them that flexibility. However, I don't believe it's consistent with their objective to recognize that as a source of capital and use it in a way to minimizes their cost of capital to retail customers.

I believe they have the flexibility to do it the way they've done it, and they have the flexibility, based on IRS rules, to do it in a way that reduces the rate of return. They chose a way that increased the rate of return, and I think that's inappropriate.

Q Within your testimony you conclude that your proxy group has a higher financial risk than FPL based, in part, on a comparison of the average corporate credit rating of the electric companies in your proxy group and that of FPL. Is this correct?

A In part, yeah. The other part was the capital structure common equity ratio.

Q The electric companies in your proxy group are holding companies, correct?

A They are. They are publicly-traded entities which is a necessity in order to do market-based models on observable stock prices and other market metrics.

Q I'm sorry, was that a yes to my question?

A Yes.

Q And is FPL a holding company?

A Pardon me?

Q Is FPL a holding company?

A FPL is a subsidiary of a holding company.

Q So, that's a no? They are not a holding company?

A They are not a holding company.

Q Would you agree that the credit rating from Standard & Poor's and Moody's rate a company's ability to pay its debt obligations?

A Yes.

Q Did you provide any analysis in your testimony to compare the business risks of FPL to the business risks of the electric companies in your proxy group?

A It was part of my comparison of the total investment risk of the proxy group relative to FPL. A business risk is a component of that determination, but it doesn't end with business risk. It's a complete assessment and total investment risk.

Q Did you provide any analysis in your

testimony to compare the regulatory risks of FPL to the operating or regulatory risks of the electric companies in your proxy group?

A No specifically. Regulatory risk, again, is a component of total business risk, so to the extent business risk was considered, that would reflect regulatory risk and other business risk factors as well as financial risk and relevant factors which I used to assess total investment risk which is a combination of the two.

Q Please turn to Page 42 of your testimony.

A (Witness complying.)

Q Here you state that your second risk premium estimate is based on the difference between regulatory Commission-authorized returns on common equity and the a contemporary A-rated utility bond yield by Moody's. Are the regulatory Commission-authorized returns on common equities the actual earned returns on common equity realized by electric companies?

A No.

Q You also disagreed with FPL's Witness Hevert's proposed 12 basis point addition to the ROE to account for flotation costs, correct?

A Correct.

Q Do you agree in general that when a company

issues stock, it incurs transaction costs which reduce the actual proceeds received by the company?

A If it issues those stock in a public offering, it does, but it doesn't always incur those costs when it issues stock. In a private placement or in a parent-subsidiary transaction, those costs are not incurred when stock is issued.

Q Now, you reviewed Mr. Hevert's direct testimony in this case, correct?

A Yes.

Q Could you please turn to the second exhibit that was handed out. That's labeled FPL's Response to Staff's Eighth Request for Production of Documents, No. 55. I believe that should now be 721.

CHAIRMAN BROWN: Yes, we'll mark that as 721 and it will be as you identified.

(Exhibit 721 marked.)

Q If you'd turn to the attachment labeled cost of capital, this article was cited in Mr. Hevert's direct testimony. Did you have an opportunity to review it while you were viewing his testimony?

A I've reviewed this. I run into Mr. Hevert in many proceedings all over the country. At one point or another, I have reviewed his textbook, yes.

Q In general practice, do you agree with

adjusting the discount rate and cost of capital models to account for flotation costs?

A I agree you can make that adjustment if it's appropriate. I don't agree that it's always appropriate.

Q Would you agree that the purpose of a flotation cost adjustment to the cost of equity estimate is to reflect a hypothetical flotation cost that would be incurred if FPL were to issue stock?

A No, I very strongly disagree with that. Flotation cost is an expense that should be properly accounted for by FPL. It should be verified, auditable, and FPL should have the obligation to show it's prudent and reasonable.

It should not be a hypothetical cost.

MS. MAPP: Thank you. I have no further questions of this witness.

CHAIRMAN BROWN: All right. Commissioners? Redirect.

MR. JERNIGAN: Thank you, ma'am. Just a moment.

CHAIRMAN BROWN: Sure.

FURTHER REDIRECT EXAMINATION

BY MR. JERNIGAN:

Q Mr. Gorman, you were asked a few questions

by OPC and FIPUG about double leverage. Do you recall those questions?

A I do.

Q Do you recall being asked if that was occurring in this case?

A Yes.

MR. BUTLER: I'm going to object to questions redirecting on double leverage because I believe that those questions were all friendly cross in the first place and essentially doubling down on the friendly cross.

CHAIRMAN BROWN: Yeah, but I allowed him. Staff?

MS. BROWNLESS: I think you did allow some questions in that area and that Mr. Jernigan should be allowed to have limited --

CHAIRMAN BROWN: I think that's fair.

MR. BUTLER: Thank you, ma'am.

BY MR. JERNIGAN:

Q You stated that -- my notes are kind of incomplete here -- something about a red flag due to the bond ratings. Could you repeat or clarify your answer in that regard?

A Double leverage generally concerns whether or not there's leverage at the parent company that is being used to make equity available to the utility subsidiary. And I didn't look at it from that specific standpoint, but one thing that did concern me is reviewing the utility's capital structure which had a lot of common equity in it, much more than other utilities with the same bond rating.

But it didn't have a much stronger bond rating than other utilities that had a more balanced capital structure; less debt and more equity. In my experience, utilities that have a credit rating that doesn't reflect the low financial risks that the utility subsidiary has, if you only look at the utility subsidiary suggests that there's a negative impact on the utility's credit rating that is caused by its affiliation with other companies.

One of the other affiliated companies can be at the parent company level. Of course, that means that a utility with a 60 percent common equity ratio you'd expect to have one of the strongest bond ratings in the industry, but FPL does not.

One reason it may not is because its affiliation risk. That affiliation risk can hold its bond rating down even though it has relatively low financial risk. So, the consequence of that is customers pay for a high common equity ratio but don't get the benefit of lower debt interest expense at the utility debt issue.

So, they get the higher cost without any benefit. So, it's a real concern in ratemaking.

Q Thank you. And you were being asked a few questions by staff with regards to flotation. Do you recall those questions?

A I do.

Q In this case, was there any evidence presented to show that there is actual flotation occurring with FPL?

A Not for FPL.

Q And I believe you stated that hypothetical flotation should not be included?

A Hypothetical cost is not a known and measurable expense, and I believe it would be inconsistent with protecting customers if that kind of cost was allowed in the utility's revenue requirement and ultimately retail rates.

Only known and measurable expenses that are shown to be prudently incurred and reasonable should be included in the utility's revenue requirement.

MR. JERNIGAN: Thank you, Mr. Gorman. I believe that's all my questions.

CHAIRMAN BROWN: All right. Mr. Gorman has a lot of exhibits, 204 through 225.

MR. JERNIGAN: Yes, ma'am, we would move those to be entered into the record.

CHAIRMAN BROWN: Any objections?

MR. BUTLER: No objection.

CHAIRMAN BROWN: We'll move in 204 through 225 into the record.

(Exhibits 204 - 225 were admitted.)

CHAIRMAN BROWN: Staff, you have two exhibits, 720 and 721.

MS. MAPP: Yes, we would move for those to be entered into the record.

CHAIRMAN BROWN: Any objections? We'll move 720 and 721.

(Exhibit 720 and 721 were admitted.)

MR. MOYLE: We would object to the --

CHAIRMAN BROWN: They're already in the record.

MR. MOYLE: -- the cost of capital exhibit. I mean, to extent that it's being moved in for the truth of the matter asserted, it's inappropriate hearsay. So, I'd register an objection on that ground.

CHAIRMAN BROWN: Your objection is --

MR. BUTLER: What number?

MR. MOYLE: It's 721, I believe, right?

CHAIRMAN BROWN: Uh-huh, 721, the article.

MR. LaVIA: And I'd join that objection and also point out that I don't believe the witness testified that he relied on it. He testified he was aware of it. It would be cumulative to Mr. Hevert's testimony.

CHAIRMAN BROWN: All noted for the record. It's in the record. All right. Let's take a five minute -- would you like your witness to be excused?

MR. JERNIGAN: Please.

CHAIRMAN BROWN: Thank you. Thank you, Mr. Gorman, for your time. Have a good night.

Let's take a five-minute break.

MR. JERNIGAN: We have one more witness?

CHAIRMAN BROWN: One more witness, but I think staff needs a five-minute break.

(Brief recess.)

CHAIRMAN BROWN: All right. Mr. Andrews, good evening. You've been sworn?

MR. ANDREWS: I have, yes.

CHAIRMAN BROWN: You are our last witness of the night.

MR. ANDREWS: You guys are lucky.

CHAIRMAN BROWN: No, we appreciate you taking the time to come out tonight.

MR. JERNIGAN: Thank you, ma'am. The fact that we chose depreciation doesn't mean anything.

* * * * *

BRIAN C. ANDREWS

was called as a witness, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. JERNIGAN:

Q Please state your name for the record.

A Brian C. Andrews.

Q And by whom are you employed?

A Brubaker & Associates, Inc.

Q Could you state your address for the record?

A 16690 Swingley Ridge Road, Suite 140, in Chesterfield, Missouri.

Q Thank you. Are you the same Brian Andrews who caused testimony to be filed in this case along with the corresponding exhibits that have been labeled on the comprehensive exhibit list as Hearing ID 226 through 230?

A I believe that's correct, yes. Let me check the list. You said 226 through 230?

Q Yes. Also, I believe you labeled them as

appendix --

A Yes, that's correct.

CHAIRMAN BROWN: You gentlemen are very, very, soft speakers. Please feel free to speak loud.

MR. JERNIGAN: I will try to speak a little louder, ma'am.

MS. BROWNLESS: And I'm sorry, I did not hear a single thing that you just said.

MR. JERNIGAN: Should I go back to his name or just the exhibits?

MS. BROWNLESS: You can skip his name, but after that --

MR. JERNIGAN: Okay.

BY MR. JERNIGAN:

Q Are you the same Brian Andrews who caused Hearing ID Exhibits 226 through 230 as listed on the comprehensive exhibit list to be filed in this hearing?

A Yes, I am.

Q Are there any corrections you would like to make to any of those exhibits?

A Yes, I'd like to make one minor correction to my direct testimony at Page 24, what I have labeled at Figure 6. The third line of text says experience, 1968 through 2014. That should read 1995 through 2014.

Q Thank you. Is that the only correction?

A Yes, it is.

Q If I were to ask you the same questions listed in your testimony, including that change that you just made, would all your other answers be correct?

A Yes, they would.

Q Or the same?

A Yes, they would.

MR. JERNIGAN: We'd request at this time that items 226 through 230 be entered into the record.

CHAIRMAN BROWN: We will not do that, but we will enter Mr. Andrews' prefiled direct testimony into the record as though read.

(Prefiled direct testimony inserted into the record as though read.)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	)))))	**DOCKET NO. 160021-EI**

Direct Testimony of Brian C. Andrews

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a Consultant in the field of public utility regulation with Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am testifying on behalf of the Federal Executive Agencies ("FEA"), consisting of certain agencies of the United States government, which have offices, facilities, and/or installations in the service area of Florida Power & Light Company ("FPL" or "Company"), from whom they purchase electricity and energy services.

Q WHAT IS THE SUBJECT MATTER OF YOUR DIRECT TESTIMONY?

A My testimony will address FPL's proposed changes to depreciation rates for certain accounts. I will propose adjustments to the survivor curves utilized for three distribution accounts. My silence in regard to any issue should not be construed as an endorsement of FPL's position.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A My conclusions and recommendations are summarized as follows:

1. FPL has overstated its depreciation rates for three distribution accounts. These rates produce an excessive amount of depreciation expense and overstate the test year revenue requirement.
2. FPL has underestimated the average service lives of three distribution accounts, Accounts 362, 365 and 369.1, due to its reliance on fitting survivor curves to a set of data containing outdated retirement history.
3. The average service lives for three distribution accounts should be based on the more recent retirement history contained in the original life tables reflecting retirement history from 1995-2014 rather than 1941-2014.
4. These adjustments to the average service lives for these three accounts result in an overstatement of the 2017 test year depreciation expense of $22.5 million, as developed on Exhibit BCA-1.

Book Depreciation Concepts

Q PLEASE EXPLAIN THE PURPOSE OF BOOK DEPRECIATION ACCOUNTING.

A Book depreciation is the recognition in a utility's income statement of the consumption or use of assets to provide utility service. Book depreciation is recorded as an expense and is included in the ratemaking formula to calculate the utility's overall revenue requirement.

Book depreciation provides for the recovery of the original cost of the utility's assets that are currently providing service. Book depreciation expense is not intended to provide for replacement of the current assets, but provides for capital recovery or return of current investment. Generally, this capital recovery occurs over the average service life of the investment or assets. As a result, it is critical that appropriate average service lives be used to develop the depreciation rates so no generation of ratepayers is disadvantaged.

In addition to capital recovery, depreciation rates also contain a provision for net salvage. Net salvage is simply the scrap or reused value less the removal cost of the asset being depreciated. Accordingly, a utility will also recover the net salvage costs over the useful life of the asset.

Q ARE THERE ANY DEFINITIONS OF DEPRECIATION ACCOUNTING THAT ARE UTILIZED FOR RATEMAKING PURPOSES?

A Yes. One of the most quoted definitions of depreciation accounting is the one contained in the Code of Federal Regulations:

> "Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption of prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities."
>
> (Electronic Code of Federal Regulations, Title 18, Chapter 1, Subchapter C, Part 101)

Effectively, depreciation accounting provides for the recovery of the original cost of an asset, adjusted for net salvage, over its useful life.

Q WHAT METHOD, PROCEDURE AND TECHNIQUE WERE USED TO CALCULATE THE PROPOSED DEPRECIATION RATES FOR FPL?

A The proposed depreciation rates were calculated using the straight line method, the average life group procedure and the remaining life technique. Under this method, procedure and technique of developing depreciation rates, the unrecovered cost of plant in service is adjusted for the cost of net salvage, and is recovered over the remaining life of the asset or group of assets. At the end of the useful life, the asset is fully depreciated.

Q IS YOUR METHOD OF CALCULATING DEPRECIATION RATES DIFFERENT THAN THE COMPANY'S?

A No, both the Company and I utilized the same method to calculate depreciation rates. FPL witness Ned Allis discusses the depreciation calculation process in his pre-filed direct testimony and the depreciation study filed as Direct Exhibit NWA-1.

Q PLEASE DESCRIBE THE ACTUARIAL LIFE ANALYSIS THAT IS PERFORMED TO EVALUATE HISTORICAL ASSET RETIREMENT EXPERIENCE.

A I will first provide the description of actuarial life analysis (retirement rate method) that is contained in the National Association of Regulatory Utility Commissioners' ("NARUC") Public Utility Depreciation Practices manual.

> "Actuarial analysis is the process of using statistics and probability to describe the retirement history of property. The process may be used as a basis for estimating the probable future life characteristics of a group of property.

> Actuarial analysis requires information in greater detail than do other life analysis models (e.g., turnover, simulation) and, as a result, may be impractical to implement for certain accounts (see Chapter VII). However, for accounts for which application of actuarial analysis is practical; **it is a powerful analytical tool and, therefore, is generally considered the preferred approach**.
>
> Actuarial analysis objectively measures how the company has retired its investment. The analyst must then judge whether this historical view depicts the future life of the property in service. The analyst takes into consideration various factors, such as changes in technology, services provided, or, capital budgets."

(NARUC Public Utility Depreciation Practices Manual, 1996, Page 111, Emphasis Added).

As explained by NARUC, when the required data exists, a database that contains the year of installation and the year of retirements for each vintage of property, actuarial life analysis is the preferred method of determining the life, and thus retirement, characteristics of a group of property. In this type of analysis, there are two major steps. The first step is to use available aged data from the company's continuing plant records to create an observed life table. The observed life table provides the percent surviving for each age interval of property. The observed life tables can be created from multiple combinations of placements and experience of the aged property data. It is important to select a combination of data that will best reflect future lives of the property. The second step is to match the actual survivor data from the observed life table to a standard set of mortality, or survivor curves. Typically, the observed life table data is matched to Iowa Curves. The fitting process is both a mathematical fitting process, which would minimize the Sum of Squared Differences ("SSD") between the actual data and the Iowa Curves, and a visual fitting process. Though the mathematically fitting process provides a curve that is theoretically possible, the visual matching process will allow the trained depreciation professional to use informed judgment in the determination of the best fitting survivor curve.

Q PLEASE PROVIDE FURTHER EXPLANATION OF THE SUM OF SQUARED DIFFERENCES STATISTICAL MEASUREMENT.

A In the Actuarial Life Analysis section of the NARUC Depreciation Manual, it describes SSD as follows:

> "Generally, the goodness of fit criterion is the least sum of squared deviations. The difference between the observed and projected data is calculated for each data point in the observed data. This difference is squared, and the resulting amounts are summed to provide a single statistic that represents the quality of the fit between the observed and projected curves.
>
> The difference between the observed and projected data points is squared for two reasons: (1) the importance of large differences is increased, and (2) the result is a positive number, hence the squared differences can be summed to generate a measure of the total absolute difference between the two curves. The curves with the least sum of squared deviations are considered the best fits."

Q PLEASE EXPLAIN SURVIVOR CURVES AND THE NOTATION USED TO REFERENCE THEM.

A A survivor curve is a visual representation of the amount of property existing at each age interval throughout the life of a group of property. From the survivor curve, parameters required to calculate depreciation rates can be determined, such as the average service life of the group of property and the composite remaining life. In this case, as well as the majority of others throughout the U.S. and Canada, the Iowa Curves are the general survivor curves utilized to describe the mortality characteristics of group property. There are four types of Iowa Curves: right-moded, left-moded, symmetrical-moded, and origin-moded. Each type describes where the greatest frequency of retirements occur relative to the average service life. Mr. Allis provides a more detailed explanation of Iowa Curves in his Direct Exhibit NWA-1.

A survivor curve consists of an average service life and Iowa Curve type combination. When describing property with a 50-year average service life that has mortality characteristics of the R2 Iowa Curve, the survivor curve would simply be notated as "50-R2."

Q IN THE ANALYSIS PERFORMED BY MR. ALLIS, DID HE RELY ON GOODNESS OF FIT STATISTICS SUCH AS THE SSD?

A Yes, however, rather than reliance on the SSD, Mr. Allis utilized a statistic called the "Residual Measure." This statistic is simply the square root of the SSD divided by the number of points that were tested for fit on the original survivor curve. As an example, if in a fitting analysis to the first 50 data points of the original curve, the SSD was determined for a certain Iowa curve to be 100. The resulting Residual Measure would be the square root of 100, which is 10, divided by 50 data points, which equals 0.2. This measurement indicates that the average deviation at each data point between the original survivor curve and the standardized Iowa Curve is 0.2.

Book Depreciation Recommendations

Q PLEASE SUMMARIZE THE PROPOSED CHANGES THAT YOU ARE RECOMMENDING TO FPL'S PROPOSED DISTRIBUTION DEPRECIATION RATES.

A The distribution book depreciation rates should be reduced by increasing the average service lives associated with the property contained in Accounts 362, 365, and 369.1

such that the survivor curves better fit the retirement data that is reflective of more recent retirement history.

Q WHAT IS THE BASIS FOR YOUR RECOMMENDATIONS?

A FPL has largely based its proposals on retirement history that spans the 74 years between 1941 and 2014. The use of such a long history of retirement data averages out any trends of increased property lives that are expected with newer and better maintenance practices. When retirement data are analyzed from more recent periods, a clear trend of increasing lives can be seen for the accounts to which I propose making changes. When recommending survivor curves for a group of property, it is important that those recommendations reflect the analyst's best forecast of the life expectations of property in the future. A more recent retirement experience will more accurately reflect the future lives of property than will the reliance on data that is older than the majority of property being studied.

It is obvious that maintenance and operational practices that occurred over 70 years ago are no longer relevant, as are maintenance and operational practices from 30 years ago. Maintenance and operational practices are a large driver of the lives of utility property; therefore, a forecast of the lives of this property should largely be based on recent retirement activity. Furthermore, construction practices and materials have significantly changed over the past 70 years, and the majority of the investments in the accounts to which I propose adjustments were constructed after 1994.

FPL recognizes this trend of increasing service lives. Mr. Allis states:

> "the trend towards longer service lives is not uncommon" and "changes in the composition of assets in the account resulted on the estimation of longer service lives than indicated by the historical data."[1]

Q DO AUTHORITATIVE TEXTS SUPPORT YOUR CLAIM THAT MORE RECENT EXPERIENCE BANDS OFFER BETTER INFORMATION?

A Yes, two authoritative texts cited by FPL witness Mr. Allis both provide support for this claim.

First, Wolf and Fitch's "Depreciation Systems," states:

> "Recent experience bands yield the most recent retirement ratios providing the forecaster with valuable information about the current retirement ratios for all ages…..The ultimate combination of bands is the overall band which combines all individual placement and experience bands into a single, overall band. The major attribute of the survivor curve obtained from this band is that it uses every available exposure and retirement. On the other hand, this grand average obscures the dynamic characteristics of the life characteristics of the property. In addition, it is difficult to define the meaning of the resulting curve. The first retirement ratio will include observations from all vintages and the second retirement ratio from all but the most recent. This pattern continues until the final point is based on observations from only one vintage. **It is difficult to figure out the exact meaning of the overall band, and, in spite of the fact it does include all the data points, it should be given limited significance**."

(Wolf and Fitch, Depreciation Systems, 1994, Pages 186-87; emphasis added)

Additionally, the NARUC manual states: "In general, historical data used to forecast future retirements should not contain events that either anomalous of unlikely to recur."

(NARUC Public Utility Depreciation Practices Manual, 1996 Page 112)

[1]Ned Allis Direct Testimony at page 44.

Both of these authoritative texts on depreciation, which are cited by Mr. Allis, support my claim that more recent experience bands offer better information to the forecaster to determine the future retirement activity that is likely to occur with this property.

BCA Depreciation Model

Q PLEASE DISCUSS THE DEPRECIATION MODEL YOU CREATED TO DETERMINE THE APPROPRIATE SURVIVOR CURVES FOR THE TRANSMISSION AND DISTRIBUTION ACCOUNTS.

A I created an Excel-based model ("BCA Model") that tests the fit of the various Iowa curves to the original life table data for the FPL accounts. The BCA Model also calculates the annual original cost accrual and composite remaining for the account being studied. In the fitting process, the model determines for each curve type, the average service life that minimizes the sum of the squared differences ("SSD") between the Iowa Curves and the actual data points that were determined to be significant.[2] This analysis provides for each dispersion, the average service life that best fits the data. Once that analysis is performed, I conducted a visual analysis of the curves that had the lowest SSD. After utilizing judgment to select the appropriate curve, the model then can calculate the annual accrual amount and the corresponding depreciation rate for the account. The annual accrual amount is calculated in the same manner as described in the FPL Depreciation Study for the Average Life Group method with the Remaining Life technique.

[2]Significant data points were determined by dividing the exposures for each vintage by the Age 0 vintage exposures. If that ratio was greater than 1%, the data point was determined to be significant.

Q HOW DOES THE BCA MODEL DEPRECIATION MODEL COMPARE TO THE FPL DEPRECIATION MODEL WHEN THE SAME INPUTS ARE UTILIZED?

A For the accounts that I am recommending changes to, the original cost annual accrual and composite remaining lives are nearly identical to what is calculated by FPL. This comparison is shown below in Table 1.

TABLE 1

Comparison of FPL and BCA Depreciation Models with FPL's Proposed Survivor Curves

	FPL Model		BCA Model		Delta	
Account	**Original Cost Annual Accrual**	**Composite Remaining Life**	**Original Cost Annual Accrual**	**Composite Remaining Life**	**Original Cost Annual Accrual**	**Composite Remaining Life**
362 – Station Equipment	$42,429,353	34.06	$42,471,825	34.03	$42,472	(0.03)
365 – Overhead Conductors and Devices	$46,465,421	39.29	$46,539,885	39.23	$74,464	(0.06)
369.1 – Services - Overhead	$11,022,092	47.09	$11,003,386	47.17	($18,706)	0.08
Total	**$99,916,866**		**$100,015,096**		**$98,230**	

Sources: Exhibits NWA-1, BCA-2, BCA-3, BCA-4

As can be seen above in Table 1, the differences between the original cost annual accrual amount between the BCA Model and FPL's are insignificant. The total expense for these three accounts only differ by $98,230 which is only a difference of 0.01% of the approximately $100 million original cost annual accrual for these three accounts.

Q WHAT CAN YOU CONCLUDE ABOUT THE RESULTS SHOWN ABOVE IN TABLE 1?

A Table 1 shows that the BCA depreciation model is sufficiently benchmarked to the calculations arrived at with the model utilized by FPL witness Mr. Allis. This benchmarking exercise confirms the accuracy of my own model and that the results calculated by the model when utilizing different Iowa Curves will be an accurate reflection of the composite remaining life resulting from those Iowa Curves.

Distribution Proposed Survivor Curves

Q WHICH DISTRIBUTION ACCOUNTS ARE YOU RECOMMENDING A SURVIVOR CURVE THAT DIFFERS FROM FPL PROPOSALS?

A I am recommending that the survivor curves used to determine the composite remaining life and thus depreciation rates for Accounts 362, 365, and 369.1 be changed to reflect dispersions and average service lives that better fit the more recent retirement data for the property in the account.

Q PLEASE SUMMARIZE THE IMPACT ON THE DEPRECIATION EXPENSE FOR THE ACCOUNTS WHICH YOU ARE RECOMMENDING SURVIVOR CURVES THAT DIFFER FROM FPL'S RECOMMENDATIONS.

A Table 2 below shows the impact on each account. The sum of these three adjustments is a reduction of $22.5 million to FPL's 2017 test year depreciation expense. This information is also shown in my Exhibit BCA-1.

TABLE 2

BCA Proposed Depreciation Adjustments

	FPL Model			BCA Model			Delta	
Account	**Survivor Curve**	**2017 Annual Accrual**	**Accrual Rate**	**Survivor Curve**	**2017 Annual Accrual**	**Accrual Rate**	**2017 Annual Accrual**	**Accrual Rate**
362	45-R1.5	$45,136,206	2.36%	51-S0.5	$38,910,129	2.04%	$(6,226,077)	-0.32%
365	48-R1	$82,040,086	3.67%	57-R1	$66,999,688	3.00%	$(15,040,398)	-0.67%
369.1	53-R1	$25,050,963	4.30%	56-R1.5	$23,802,458	4.08%	$(1,248,505)	-0.22%
Total		$152,227,255			$129,710,304		$(22,516,951)	

Account 362

Q WHAT TYPE OF PROPERTY IS CONTAINED IN ACCOUNT 362?

A This account is for Station Equipment. Per the FERC Uniform System of Accounts,

> "This account shall include the cost installed of station equipment, including transformer banks, etc., which are used for the purpose of changing the characteristics of electricity in connection with its distribution."

This includes much of the equipment located within the fence at a distribution substation, including busses, conduit, control equipment, transformers, switching equipment, insulators, general station equipment, platforms, foundations, etc.

Q WHAT SURVIVOR CURVE IS FPL RECOMMENDING FOR ACCOUNT 362?

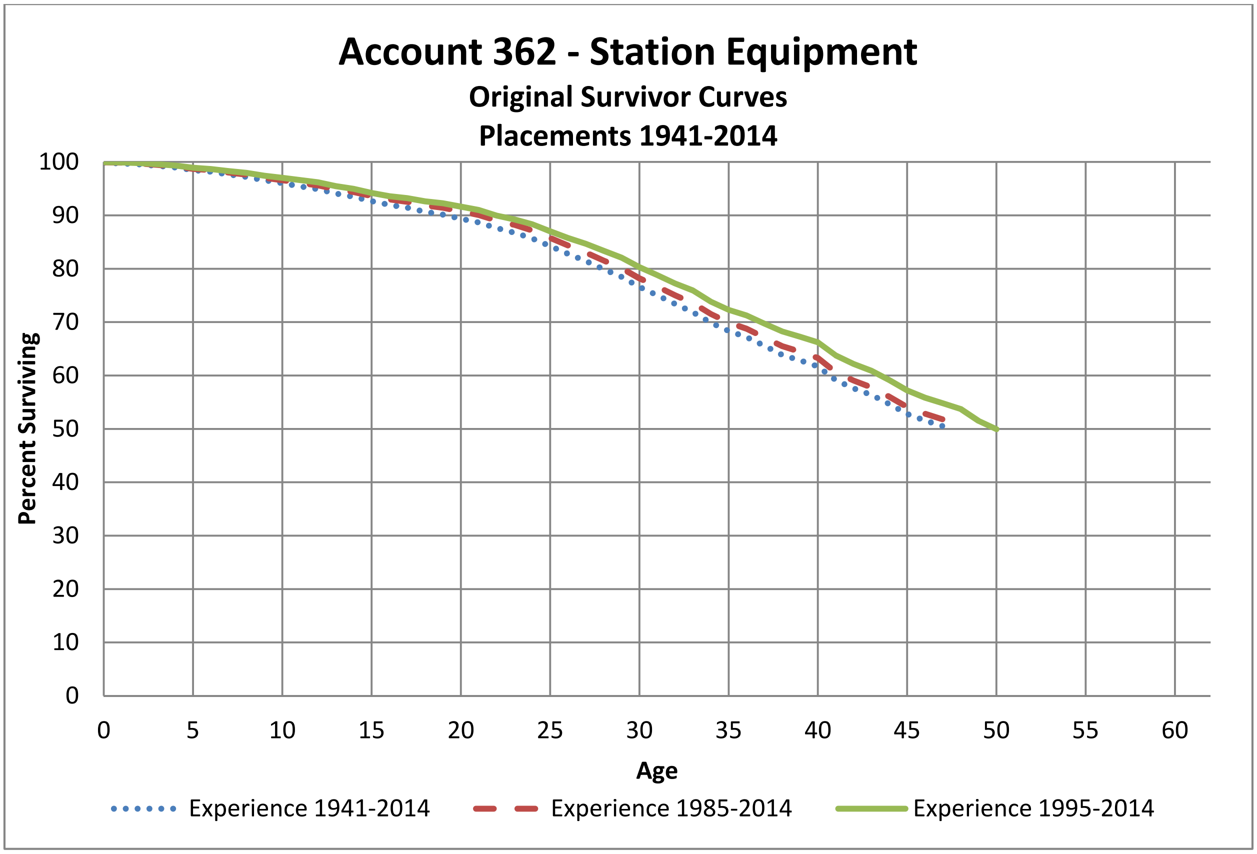
A FPL is proposing to use a 45-R1.5 survivor curve. That is the Iowa R1.5 dispersion curve with an average service life of 45 years. This proposal yields a composite remaining life for this account of 34.06 years and a depreciation rate of 2.36%.

Q DO YOU AGREE WITH FPL'S RECOMMENDATION FOR THE SURVIVOR CURVE TO UTILIZE FOR ACCOUNT 362?

A No, I do not. Mr. Allis has chosen a survivor curve that does not account for a trend of increasing lives. The survivor curve recommended by Mr. Allis is an excellent fit for the retirements experienced between 1941-2014; however, more recent retirement history indicates a longer life is appropriate. Figure 1 below shows three of the original survivor curves created by Mr. Allis for his actuarial analysis. All three curves reflect property installed between 1941 and 2014; it is the years in which retirement activity occurred that differentiates these lines. The dotted line is the overall band which contains retirement experience from 1941 through 2014, the dashed line

contains retirement experience from 1985-2014, and the solid line contains the data from 1995-2014.

Figure 1



As Figure 1 clearly shows, there is a trend of increasing lives as the older retirement history is removed from the analysis. As I stated earlier, it is the more recent retirement history that will be most indicative of the future lives of this property and while the overall band does contain all of the placement and retirement data, it should be given limited significance relative to more recent bands.

Q DOES THE ACTUARIAL ANALYSES PERFORMED BY MR. ALLIS SHOW THERE IS A TREND OF INCREASING LIVES FOR THE PROPERTY IN THIS ACCOUNT?

A Yes. My Table 3 below shows the average service lives that best fit the R1.5 Iowa Curve for each experience band analyzed by Mr. Allis for property installed between 1941 and 2014.

TABLE 3

Account 362 – Station Equipment
Average Service Life Associated with R1.5 Iowa Curve
Placements: 1941-2014

Experience Band	1941-2014	1985-2014	1995-2014
Average Service Life	45.7	47.3	49.5

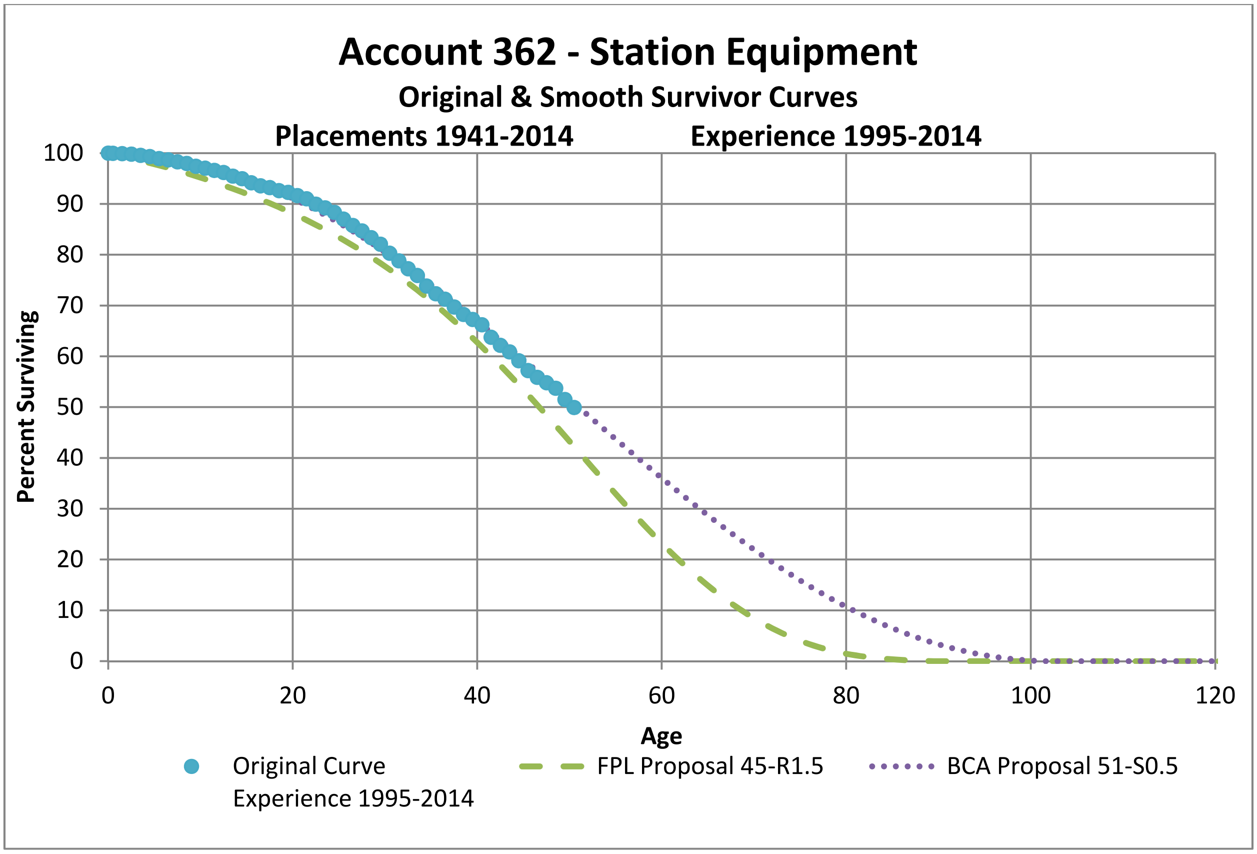
Source: "160021 - OPC's 1st POD No. 2 - FPL - 2014 - Trans, Dist and Gen Plant - OLTs and Preliminary Curve Fits.pdf"

As Table 3 shows, the average service life estimated by actuarial analysis increases as the older retirement history is removed from the analysis.

Q WHAT IS YOUR RECOMMENDED SURVIVOR CURVE FOR ACCOUNT 362?

A My recommended survivor curve for this account is the 51-S0.5 and is shown below in Figure 2. As can be seen in Figure 2, the 51-S0.5 survivor curve is a much better fit to the FPL's retirement data that was experienced between 1995 and 2014. The SSD for the 51-S0.5 is only 30 versus FPL's recommended 45-R1.5 which has an SSD of 684.

Figure 2



Q WHAT IS THE IMPACT ON THE ANNUAL ACCRUAL, ACCRUAL RATE, AND COMPOSITE REMAINING LIFE FOR ACCOUNT 362 DUE TO A CHANGE IN THE SURVIVOR CURVE?

A Changing the survivor curve for Account 362 from a 45-R1.5 to a 51-S0.5 reduces the 2017 annual accrual by $6,226,077 to $38,910,129. This also reduces the accrual rate to 2.04%, down from the FPL proposal of 2.36%. The recommendation results in a composite remaining life of 39.51 years versus FPL's proposal of 34.06 years. The calculation of composite remaining life is shown in my Exhibit BCA-2.

Account 365

Q WHAT TYPE OF PROPERTY IS CONTAINED IN ACCOUNT 365?

A This account is for Overhead Conductors and Devices. According to the FERC Uniform System of Accounts, "This account shall include the cost installed of overhead conductors and devices used for distribution purposes." The items contained within this account include circuit breakers, conductors, ground wires, insulators, lightning arresters, railroad and highway crossing guards, switches, the initial cost of tree trimming including permits, and other line devices.

Q WHAT SURVIVOR CURVE IS FPL RECOMMENDING FOR ACCOUNT 365?

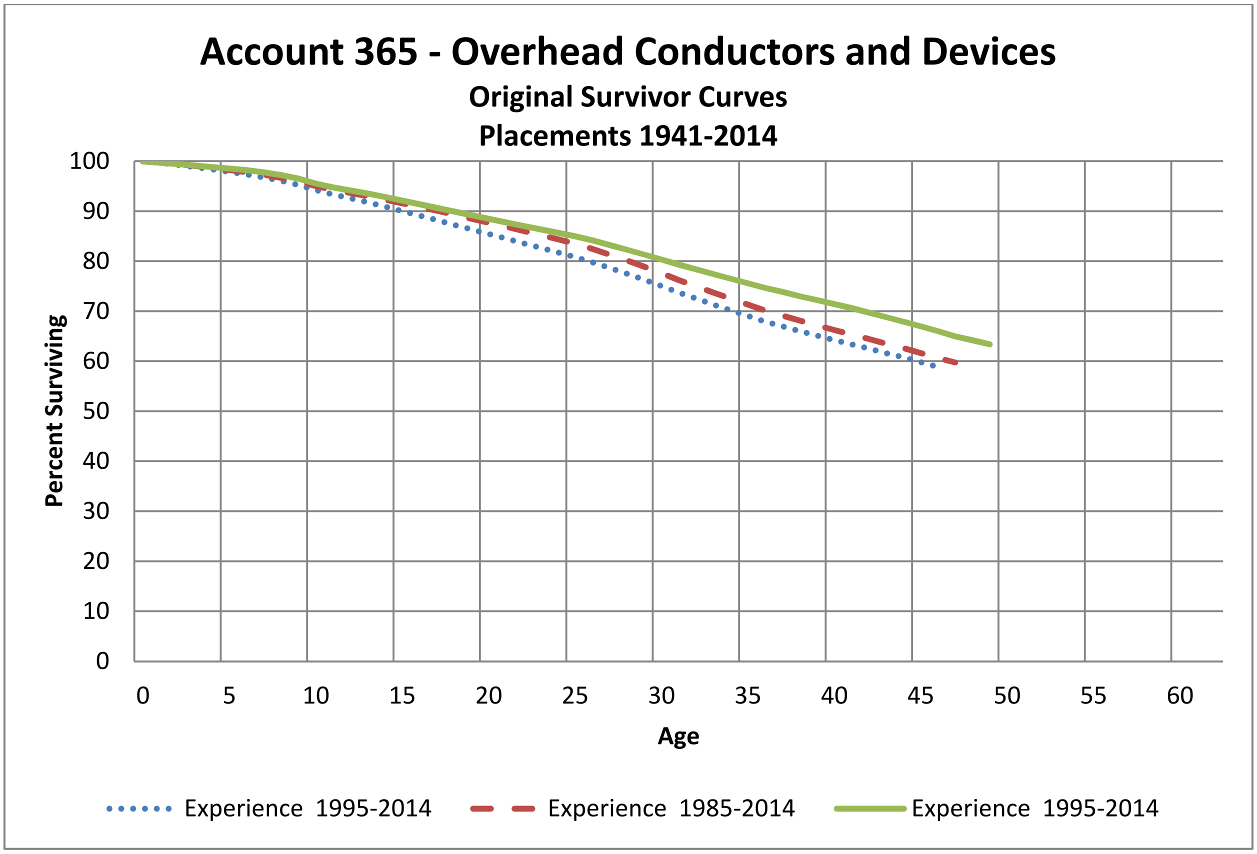
A FPL is proposing to use a 48-R1 survivor curve. That is the Iowa R1 dispersion curve with an average service life of 48 years. This proposal yields a composite remaining life for this account of 39.29 years and a depreciation rate of 3.67%.

Q DO YOU AGREE WITH FPL'S RECOMMENDATION FOR THE SURVIVOR CURVE TO UTILIZE FOR ACCOUNT 365?

A No, I do not. Mr. Allis has chosen a survivor curve that does not account for a trend of increasing lives. The survivor curve recommended by Mr. Allis is an excellent fit for the retirements experienced between 1941-2014; however more recent retirement history indicates a longer life is appropriate. Figure 3 below shows three of the original survivor curves created by Mr. Allis for his actuarial analysis. All three curves reflect property installed between 1941 and 2014; it is the years in which retirement activity occurred that differentiates these lines. The dotted line is the overall band which contains retirement experience from 1941 through 2014, the dashed line

contains retirement experience from 1985-2014, and the solid line contains the data from 1995-2014.

Figure 3



As Figure 3 clearly shows, there is a trend of increasing lives as the older retirement history is removed from the analysis. As I stated earlier, it is the more recent retirement history that will be most indicative of the future lives of this property and while the overall band does contain all of the placement and retirement data, it should be given limited significance relative to more recent bands.

Q DOES THE ACTUARIAL ANALYSES PERFORMED BY MR. ALLIS SHOW THERE IS A TREND OF INCREASING LIVES FOR THE PROPERTY IN THIS ACCOUNT?

A Yes. My Table 4 below shows the average service lives that best fit the R1 Iowa Curve for each experience band analyzed by Mr. Allis for property installed between 1941 and 2014.

TABLE 4

Account 365 – Overhead Conductors and Devices
Average Service Life Associated with R1 Iowa Curve
Placements: 1941-2014

Experience Band	1941-2014	1985-2014	1995-2014
Average Service Life	48.5	51.9	57.3

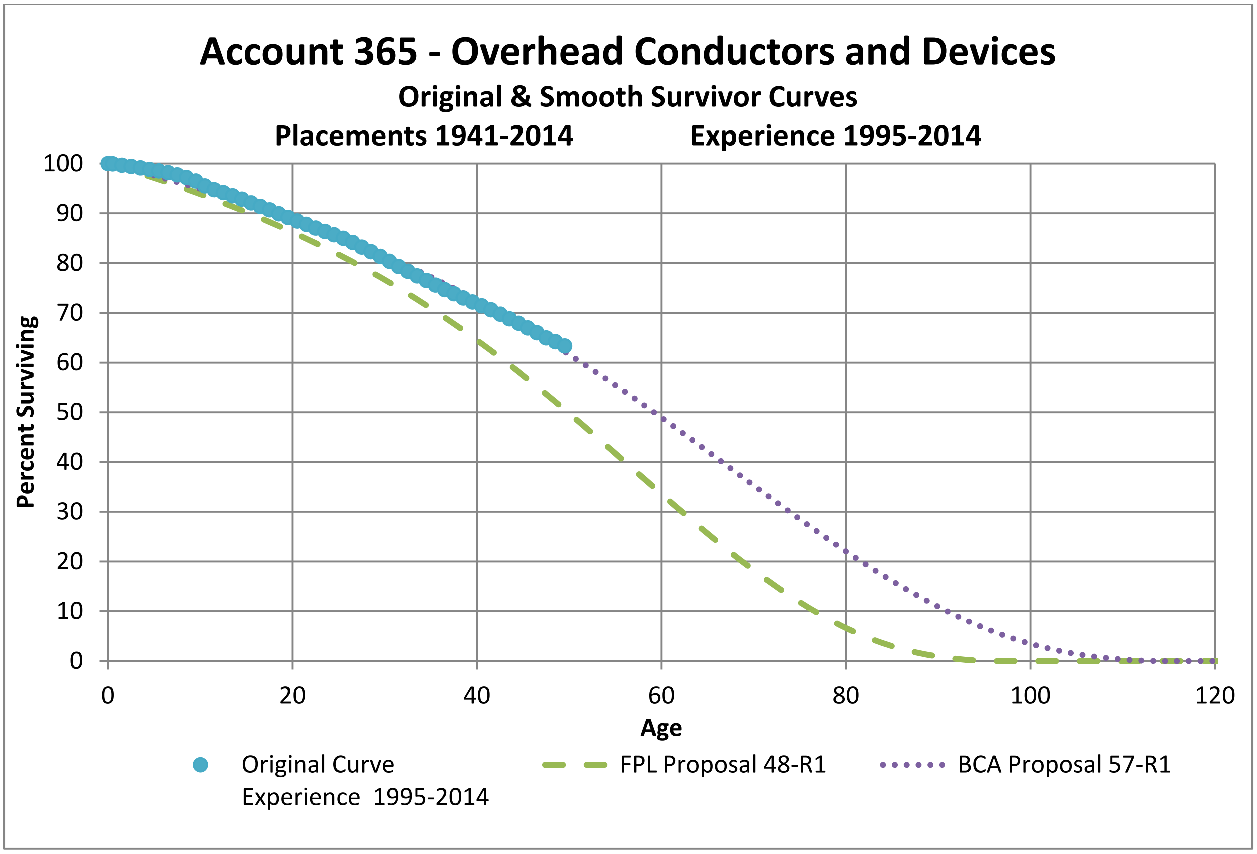
Source: "160021 - OPC's 1st POD No. 2 - FPL - 2014 - Trans, Dist and Gen Plant - OLTs and Preliminary Curve Fits.pdf"

As Table 4 shows, the average service life estimated by actuarial analysis increases as the older retirement history is removed from the analysis.

Q WHAT IS YOUR RECOMMENDED SURVIVOR CURVE FOR ACCOUNT 365?

A My recommended survivor curve for this account is the 57-R1 and is shown below in Figure 4. As can be seen in Figure 4, the 57-R1 survivor curve is a much better fit to the FPL's retirement data that was experienced between 1995 and 2014. The SSD for the 57-R1 is only 28 versus FPL's recommended 48-R1 which has an SSD of 1,527.

Figure 4



Q WHAT IS THE IMPACT ON THE ANNUAL ACCRUAL, ACCRUAL RATE, AND COMPOSITE REMAINING LIFE FOR ACCOUNT 365 DUE TO A CHANGE IN THE SURVIVOR CURVE?

A Changing the survivor curve for Account 365 from a 48-R1 to a 57-R1 reduces the 2017 annual accrual by $15,040,398 to $66,999,688. This also reduces the accrual rate to 3.00%, down from the FPL proposal of 3.67%. The recommendation results in a composite remaining life of 48.11 years versus FPL's proposal of 39.29 years. The calculation of composite remaining life is shown in my Exhibit BCA-3.

Account 369.1

Q WHAT TYPE OF PROPERTY IS CONTAINED IN ACCOUNT 369.1?

A This account is for Overhead Services. Per the FERC Uniform System of Accounts for Account 369,

> "This account shall include the cost installed of overhead conductors leading from a point where wires leave the last pole of the overhead system or the distribution box or the top of the pole of the distribution line, to the point of connection with the customer's outlet or wiring."

The items contained within this account include brackets, cables and wires, insulators, inspection, permits, suspension wire, and service switch.

Q WHAT SURVIVOR CURVE IS FPL RECOMMENDING FOR ACCOUNT 369.1?

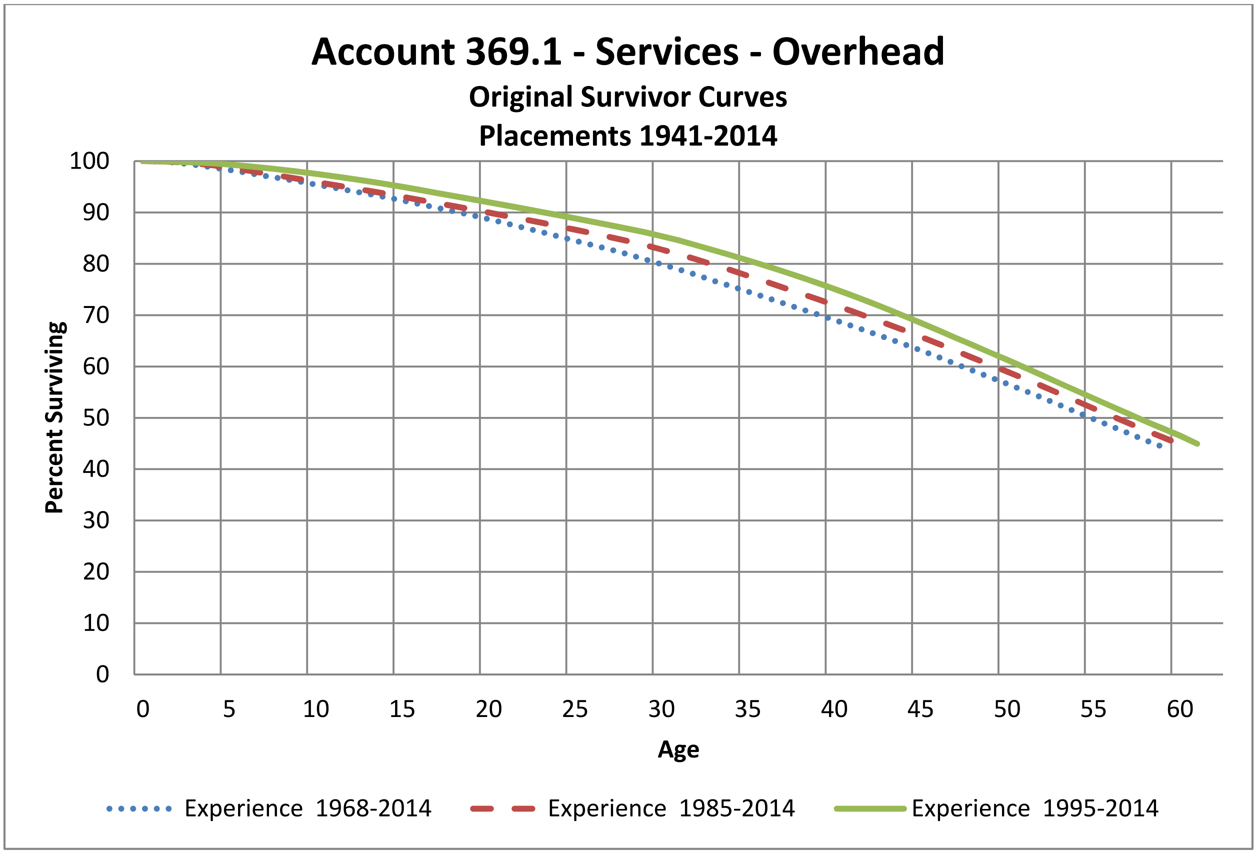
A FPL is proposing to use a 53-R1 survivor curve. That is the Iowa R1 dispersion curve with an average service life of 53 years. This proposal yields a composite remaining life for this account of 47.09 years and a depreciation rate of 4.30%.

Q DO YOU AGREE WITH FPL'S RECOMMENDATION FOR THE SURVIVOR CURVE TO UTILIZE FOR ACCOUNT 369.1?

A No, I do not. Mr. Allis has chosen a survivor curve that does not account for a trend of increasing lives. The survivor curve recommended by Mr. Allis is an excellent fit for the retirements experienced between 1941-2014; however more recent retirement history indicates a longer life is appropriate. Figure 5 below shows three of the original survivor curves created by Mr. Allis for his actuarial analysis. All three curves reflect property installed between 1941 and 2014; it is the years in which retirement activity occurred that differentiates these lines. The dotted line is the overall band which contains retirement experience from 1941 through 2014, the dashed line

contains retirement experience from 1985-2014, and the solid line contains the data from 1995-2014.

Figure 5



As Figure 5 clearly shows, there is a trend of increasing lives as the older retirement history is removed from the analysis. As I stated earlier, it is the more recent retirement history that will be most indicative of the future lives of this property and while the overall band does contain all of the placement and retirement data, it should be given limited significance relative to more recent bands.

Q DOES THE ACTUARIAL ANALYSES PERFORMED BY MR. ALLIS SHOW THERE IS A TREND OF INCREASING LIVES FOR THE PROPERTY IN THIS ACCOUNT?

A Yes. My Table 5 below shows the average service lives that best fit the R1 Iowa Curve for each experience band analyzed by Mr. Allis for property installed between 1941 and 2014.

TABLE 5

Account 369.1 – Services - Overhead
Average Service Life Associated with R1 Iowa Curve
Placements: 1941-2014

Experience Band	1941-2014	1985-2014	1995-2014
Average Service Life	54.2	57.2	61.0

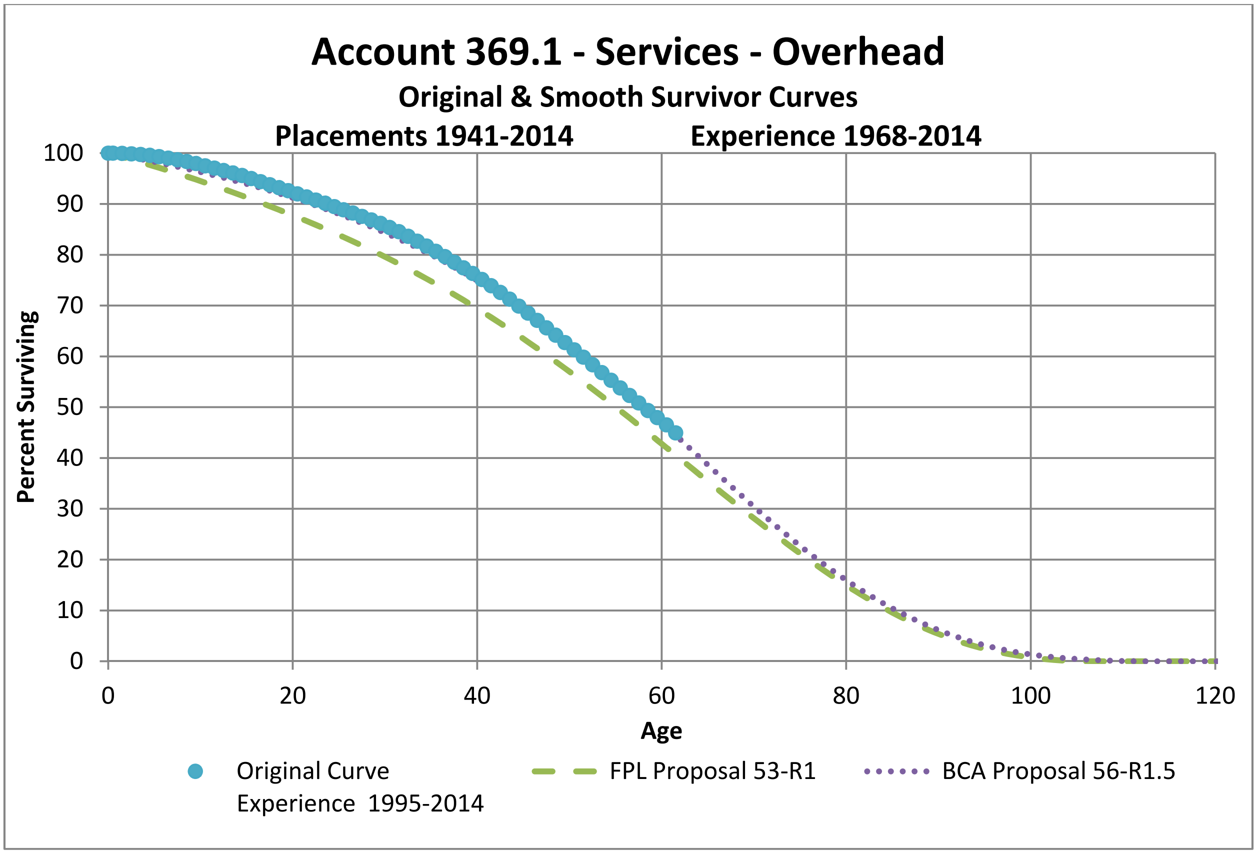
Source: "160021 - OPC's 1st POD No. 2 - FPL - 2014 - Trans, Dist and Gen Plant - OLTs and Preliminary Curve Fits.pdf"

As Table 5 shows, the average service life estimated by actuarial analysis increases as the older retirement history is removed from the analysis.

Q WHAT IS YOUR RECOMMENDED SURVIVOR CURVE FOR ACCOUNT 369.1?

A My recommended survivor curve for this account is the 56-R1.5 and is shown below in Figure 6. As can be seen in Figure 6, the 56-R1.5 survivor curve is a much better fit to the FPL's retirement data that was experienced between 1995 and 2014. The SSD for the 56-R1.5 is only 61 versus FPL's recommended 53-R1 which has an SSD of 1,422.

Figure 6



Q WHAT IS THE IMPACT ON THE ANNUAL ACCRUAL, ACCRUAL RATE, AND COMPOSITE REMAINING LIFE FOR ACCOUNT 369.1 DUE TO A CHANGE IN THE SURVIVOR CURVE?

A Changing the survivor curve for Account 369.1 from a 53-R1 to a 56-R1.5 reduces the 2017 annual accrual by $1,248,505 to $23,802,458. This also reduces the accrual rate to 4.08%, down from the FPL proposal of 4.30%. The recommendation results in a composite remaining life of 49.56 years versus FPL's proposal of 47.09 years. The calculation of composite remaining life is shown in my Exhibit BCA-4.

Q **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A Yes, it does.

CHAIRMAN BROWN: Staff?

MS. BROWNLESS: Thank you.

EXAMINATION

BY MS. BROWNLESS:

Q Mr. Andrews, when you were looking at the comprehensive exhibit list, did you look at what's been marked as Exhibit 538?

A Yes, I did.

Q And did you prepare the responses to that exhibit or were they prepared under your direction and control?

A I prepared those responses.

Q Are they true and correct, to the best of your knowledge and belief?

A Yes, they are.

Q If you were asked the same questions as contained in those responses today, would your answers be the same?

A Yes, they would.

Q And are any portions of your listed exhibit confidential?

A No, they're not.

MS. BROWNLESS: Thank you so much.

FURTHER DIRECT EXAMINATION

BY MR. JERNIGAN:

Q Did you have a summary you would like to read into the record at this time?

A I do, yes. I filed direct testimony on July 7, 2016, which addressed FPL's depreciation rates and expense. I concluded that FPL overstated its depreciation rates for certain accounts, and those overstated depreciation rates produce an excessive amount of depreciation expense.

I proposed adjustments to survivor curves utilized to determine the depreciation rates for three distribution accounts. Those three accounts are: 362, station equipment; 365, overhead conductors and devices; and 369.1, overhead services.

The fact that I did not address a particular issue should not be construed as my endorsement of FPL's position. I based my recommendations on the fact that FPL's reliance on retirement history that spans the 74 years between 1941 and 2014 has averaged out any trends of increased lives that can be seen for these three accounts.

When the older retirement history is removed from analysis, a clear trend of increasing lives can be seen. Using a more recent retirement experience will more accurately reflect the future lives of property, the annual reliance on data from the 1940s through the 1980s which occurred prior to the installation of the majority of this property.

FPL's witness, Mr. Allis, analyzed three sets of retirement history for property that was installed from 1941 through 2014; one with retirement experience between 1941 and 2014, one between 1985 and 2014 and one for 1995 through 2014.

For each account to which I have recommended adjustments, Mr. Allis' own analysis shows a clear trend towards increasing lives which he has acknowledged in his direct testimony and exhibits.

For Account 362, I've recommended that the 51-S0.5 Iowa Curve be utilized to determine the depreciation curve for this account. This represents a six-year increase in the average service life relative to Mr. Allis' recommendation.

For Account 365, I've recommended that the 57R-1 Iowa Curve being utilized to determine the depreciation rate for this account, and that represents a nine-year average service life increase relative to Mr. Allis' recommendation.

For Account 369.1, I've recommended the 56R-1.5 Iowa Curve be utilized to determine the depreciation rate for this account, and that represents a three-year accuracy relative to Mr. Allis' recommendation.

The combined impact of these three recommendations results in a reduction to the 2017 test year depreciation expense of approximately $22.5 million.

MR. JERNIGAN: At this time, I present Mr. Andrews for cross examination.

CHAIRMAN BROWN: Thank you. Welcome. Public counsel?

MR. SAYLER: No questions, Madame Chair.

CHAIRMAN BROWN: Mr. Moyle.

MR. MOYLE: Thank you, Madam Chair.

EXAMINATION

BY MR. MOYLE:

Q Sir, you're a depreciation expert and witness, right?

A That's correct.

Q So, nothing in your testimony or any of the changes you made in any way, shape or form have anything to do with Jack Pous; is that right?

A That's correct. Our analyses and conclusions are independent of one another.

MR. MOYLE: Thank you. and that's all I have.

CHAIRMAN BROWN: Thank you. Hospitals.

MR. SIQVELAND: Nothing for this witness. Thank you.

CHAIRMAN BROWN: Retail Federation.

MR. LaVIA: No questions, thank you.

CHAIRMAN BROWN: Thank you. AARP.

MR. COFFMAN: No questions.

CHAIRMAN BROWN: Thank you. Florida Power & Light.

MR. BUTLER: Just a few.

EXAMINATION

BY MR. BUTLER:

Q Good evening, Mr. Andrews.

A Good evening.

Q I'd like you to turn to Appendix A of your testimony, your qualifications, for just a minute.

A Okay.

Q Are you a certified depreciation professional?

A No, I'm not.

Q Have you ever performed a full depreciation study of the sort that Janet Fleming, Mr. Allis prepared for FPL and filed in this case?

MR. JERNIGAN: Objection. I believe we've already done one here, and that's been addressed in the prehearing. The question seems to be going in that direction at this time.

CHAIRMAN BROWN: Mr. Butler.

MR. BUTLER: I'm not -- I would concede and have not challenged the status as an expert witness of Mr. Andrews. I'm just wanting to contrast his level of experience and familiarity with FPL's system to Mr. Allis'.

CHAIRMAN BROWN: Okay. I'll allow it.

THE WITNESS: I have not conducted a complete depreciation study, no.

BY MR. BUTLER:

Q Have you visited any of FPL's distribution facilities?

A I have not.

Q Have you discussed those facilities with any FPL personnel?

A No, I have not.

Q Would you turn to your Exhibit BCA-1, please.

A (Witness complying.) I'm there.

Q You're there. And this summarize or quantifies the results of your testimony, correct, as to the adjustments to depreciation accruals?

A That's correct.

Q And to confirm, you're only proposing adjustments to three exhibits and they're all distribution accounts; is that right?

A Yes, Accounts 362, 365 and 369.1 which are all distribution accounts.

Q And the total adjustment you're proposing is a reduction in the depreciation accrual of about $22 million; is that right?

A Correct.

Q Do you know whether making such an adjustment to the depreciation accrual would have an impact on the theoretical reserve imbalance?

A It would have an impact to that theoretical reserve.

Q Do you know what the impact would be?

MR. MOYLE: Objection. Go ahead.

MR. SAYLER: I will let counsel for the witness go first.

MR. JERNIGAN: I would object to the theoretical impact is subject to the motions that already are in place. It's also outside of scope of my witness' testimony at this point.

CHAIRMAN BROWN: Okay. Other objections?

MR. SAYLER: I would join in with those objections as well as note that there is no testimony as far as I know in the record related to that theoretical whatever it is. So, thank you.

(Laughter.)

MR. BUTLER: I'll find something that says "theoretical" on it.

CHAIRMAN BROWN: Mr. Moyle.

MR. MOYLE: We would also object as beyond the direct and is not identified as any kind of issue in the case and is inappropriate.

CHAIRMAN BROWN: All right. Mr. Butler.

MR. BUTLER: I think that it is a direct mathematical calculation from the evidence that Mr. Andrews has presented in the case. It is routinely part of depreciation analyses.

It's actually part of what has to be filed under the Commission's depreciation rule in conjunction with whatever is recommended as accruals for the various depreciation or various types of plant function. So, I think it's a direct, logical connection to his testimony.

MS. BROWNLESS: Well, the hour is late, but I am persuaded by Mr. Butler.

CHAIRMAN BROWN: Okay. Objection overruled.

MR. MOYLE: Can we get this marked as well from the court reporter? Thank you.

CHAIRMAN BROWN: Marked?

MR. MOYLE: Just marked so that we can find this in the transcript.

MS. BROWNLESS: With all due respect, that's what one reads the transcript for.

(Laughter.)

MR. BUTLER: It will be part of my relatively brief cross examination of Mr. Andrews.

CHAIRMAN BROWN: It gets funnier as the night goes on. Go ahead.

BY MR. BUTLER:

Q Mr. Andrews, do you know the magnitude of the impact on the theoretical reserve imbalance that the $22 million reduction in depreciation accruals that you recommend would have?

A I did do a quick calculation because I foresaw this question coming. It's my estimation that it would be a $140 million swing or impact to the theoretical reserve. Mr. Allis' testimony showed an undercollection of $99 million.

So, the impact of my three adjustments would be an approximately $40 million overcollection to the theoretical reserve.

MR. BUTLER: Just one second. That's all

the questions I have. Thank you.

CHAIRMAN BROWN: You're welcome. Staff.

EXAMINATION

BY MS. BROWNLESS:

Q Hi, nice to see you.

A You, too.

Q This will be quick from me. Were you provided the responses to staff's interrogatories and production of documents request associated with your subject area as they became available?

A They were provided to me, yes.

Q Were you also provided the responses associated with your subject area of FIPUG's, South Florida, AARP and OPC's discovery requests as they became available?

A Yes.

Q During the course of your engagement in this proceeding, did you prepare discovery questions for your clients?

A I did.

Q And were you able to receive and review the responses to your own discovery?

A I did.

MS. BROWNLESS: Thank you so much.

EXAMINATION

BY MS. LEATHERS:

Q Mr. Andrews, please turn to your direct testimony, Page 12, Lines 4 through 18.

A You said Page 12, Lines 4 through 18?

Q Correct. Are you there?

A I am.

Q Is it correct that FPL has proposed an average service life of 45 years for Account 362 of distribution station equipment in this proceeding?

A Yes, they have.

Q And is it also correct that you alternately proposed a longer average service life for this account, specifically an average service life of 51 years?

A Yes.

Q Would you please briefly explain the reasoning behind your proposal?

A Yeah, I used -- I fit my survivor curve to data based on the retirement history from 1995 through 2014. Mr. Allis chose to use a period from 1941 through 2014. If you go to Page 14 of my testimony, we can kind of walk through the process that he did and then what I did.

So, on Page 14 what I have shown here is my Figure 1. These are what's called the original survivor curves for this account that Mr. Allis put together. They're representative of equipment that's been installed from 1941 through 2014.

The three different curves represent different periods of time under which this property was studied. The dotted blue curve is for the retirement history that occurred between 1941 through 2014, otherwise known as the overall band. The red dashed is the experience from 1985 to 2014. The green solid is from 1995 through 2014.

Mr. Allis decided to fit his survivor curve and determine the average service life of that property based on the experience that occurred from 1941 through 2014. So, he would have fit a generalized set of curves to the blue dotted line. That's how he came up with his 45R-1.5 recommendation.

My recommendation is to use a more recent retirement history, the curve that is from 1995 to 2014. When you use outdated retirement or even -- when you use the entire band, you're averaging out trends of increasing lives that can be seen with better maintenance practices and better construction practices that can be seen over time.

Furthermore, the majority of the property in this account has been installed after 1995. So, the behavior of the older equipment when it was first installed is not really relevant to the amount of dollars we're trying to collect going forward for the majority of the equipment that's been installed in the most recent 20 years.

Q Thank you. Please turn to your direct testimony, Pages 17 through 19. It's a similar question. FPL has proposed an average service life of 48 years for Account 365, distribution overhead conductors and devices in this proceeding; is that correct?

A That's correct.

Q And is it correct that you have alternately proposed a longer average service life for this account, specifically an average service life of 57 years?

A Correct.

Q And could you please briefly explain the reasoning behind your proposal?

A My reasoning is exactly the same as the previous account. It's my opinion that the more recent retirement history will provide a better indication of the lives that will be experienced by the current property in the future.

MS. LEATHERS: Thank you. I appreciate it.

No further questions.

CHAIRMAN BROWN: Commissioners? Redirect.

MR. JERNIGAN: Thank you, ma'am.

REDIRECT EXAMINATION

BY MR. JERNIGAN:

Q Mr. Andrews, do you recall the questions asked to you by FPL earlier regarding whether you had done a full depreciation study in the past.

A I do, yes.

Q In order to make the adjustments that you did in this case, would you need to have done a full depreciation study in the past?

A I would not. I had reviewed the data and the depreciation study presented by the company is and Mr. Allis.

Q Okay. They also asked if you had visited the facilities and you said no. Do you remember that?

A I do.

Q For this analysis, does that require you to have gone and seen each piece of equipment and visited them individually?

A No, it does not.

MR. JERNIGAN: I have no further questions. Thank you.

CHAIRMAN BROWN: On to exhibits, you have

226 through 230. Would you like those moved into the record?

MR. JERNIGAN: Yes, ma'am.

CHAIRMAN BROWN: Are there any objections?

MR. BUTLER: No.

CHAIRMAN BROWN: Seeing none, we will move in 226 through 230 into the record.

(Exhibit 226 - 230 admitted.)

CHAIRMAN BROWN: Would you like this witness excused for the evening?

MR. JERNIGAN: We would, ma'am.

CHAIRMAN BROWN: Mr. Andrews, thank you for coming down.

THE WITNESS: Thank you.

CHAIRMAN BROWN: Safe travels. And that will -- we will be recessing now unless there are any other housekeeping items to take up at this time. None?

MR. HETRICK: Madam Chair? It's coming from here, from your general counsel.

(Laughter.)

MR. HETRICK: Just to be clear about how we proceed tomorrow, we've got one, two, three, four witnesses up, as I understand it; Cohen, Baron, Pollock and Brosch. And then we have Wal-Mart scheduled for Wednesday.

CHAIRMAN BROWN: And staff also.

MR. HETRICK: And staff.

MS. BROWNLESS: Rhonda Hicks.

MR. HETRICK: Yes.

CHAIRMAN BROWN: When would you like staff to go?

MS. BROWNLESS: We can go tomorrow. That's fine.

CHAIRMAN BROWN: We'd like that.

MR. HETRICK: And then time permitting, I think you mentioned proceeding with rebuttal?

CHAIRMAN BROWN: I would really like that, time permitting. Okay, FPL?

MR. BUTLER: Absolutely. We'll have our witnesses here.

CHAIRMAN BROWN: I appreciate that.

MR. MOYLE: Is the order that was just read how we're going to do it or should we work amongst ourselves?

CHAIRMAN BROWN: It was your order -- whoever prepared the sheet. If you'd like -- I'm flexible to changing it. You just get together with the parties and make sure everyone agrees.

So, we have four intervenor witnesses

left -- pardon me -- five, but Wal-Mart will be on Wednesday. And then staff witness which we'll take up tomorrow, and then we'll start on rebuttal.

MR. MOYLE: Probably tomorrow?

CHAIRMAN BROWN: I'm hoping. I'm hoping.

MR. JERNIGAN: Is the order for the rebuttal witnesses the same as listed in the order?

CHAIRMAN BROWN: Yes. The order for the rebuttal witnesses is as identified in the prehearing order. That is the order unless there is a request to take folks out, but remember, Mr. Miranda had testified on Friday.

So, other than that right now, we're proceeding as delineated in the prehearing order. I would like to stop a little bit before dinner time tomorrow. So, have a great night everyone. We'll see you at 9:30 tomorrow morning. 9:30.

We are in recess.

(Proceedings concluded at 10:10 p.m.)

* * * * *

(Transcript continues in sequence in Volume 28.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, LISA GAINEY, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

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

DATED this 30th day of August, 2016.

Lisa Gainey

LISA GAINEY
NOTARY PUBLIC
COMMISSION #EE198942
EXPIRES MAY 23, 2020