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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 160021-EI
FLORIDA POWER & LIGHT COMPANY
AND SUBSIDIARIES

IN RE: PETITION FOR RATE INCREASE BY
FLORIDA POWER & LIGHT COMPANY
AND SUBSIDIARIES

DIRECT TESTIMONY & EXHIBITS OF:

KIM OUSDAHL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF KIM OUSDAHL

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Kim Ousdahl, and my business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as Vice President, Controller and Chief Accounting Officer.

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

A. I am responsible for financial accounting, as well as internal and external financial reporting for FPL. In these roles, I am responsible for ensuring that the Company's financial reporting complies with requirements of Generally Accepted Accounting Principles ("GAAP") and multi-jurisdictional regulatory accounting requirements.

Q. Please describe your educational background and professional experience.

A. I graduated from Kansas State University in 1979 with a Bachelor of Science Degree in Business Administration, majoring in Accounting. That same year, I was employed by Houston Lighting & Power Company in Houston, Texas. During my tenure there, I held various accounting and regulatory management positions. Prior to joining FPL in June 2004, I was the Vice President and Controller of Reliant Energy. I am a Certified Public Accountant ("CPA") licensed in the state of Texas and a member of the

American Institute of CPA's, the Texas Society of CPAs and the Florida Institute of CPAs.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- KO-1 MFRs and Schedules Sponsored and Co-sponsored by Kim Ousdahl
- KO-2 MFR A-1 for the 2017 Test Year
- KO-3 2017 and 2018 ROE Calculation Without Rate Relief
- KO-4 MFR A-1 for the 2018 Subsequent Year
- KO-5 Nuclear Maintenance Outage Costs Revenue Requirement
- KO-6 Fukushima Project Cost by Recovery Mechanism – Company Adjustment
- KO-7 Clause Recoverable Projects CWIP – Company Adjustment
- KO-8 Accumulated Deferred Income Tax Proration Adjustment to Capital Structure for 2017 Test Year and 2018 Subsequent Year
- KO-9 FPSC Adjustments for Cedar Bay and Woodford Project Costs
- KO-10 NextEra Energy, Inc Primary Operating Entities Structure and Affiliate Support Services
- KO-11 2016 Cost Allocation Manual
- KO-12 Direct Charges – Historical and Projected
- KO-13 Corporate Services Charges – Historical and Projected Specific Cost Drivers and Massachusetts Formula Ratios

- KO-14 Historical and Projected Corporate Services Charges - Cost Pools and Costs Billed to Affiliates

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the calculation of the rate relief and appropriateness of the ratemaking adjustments FPL proposes in this proceeding. I support accounting and ratemaking practices that affect the determination of the appropriate rate base, working capital, rate of return, capital structure and net operating income. Specifically, this includes:

1. The calculation of rate relief requested for the 2017 Base Rate Increase;
2. The calculation of the rate relief request for the 2018 Subsequent Year Adjustment ("2018 SYA");
3. The calculation of the 2019 Okeechobee Clean Energy Center ("Okeechobee Unit") Limited Scope Adjustment ("2019 Okeechobee LSA") that FPL is requesting in order to recover the non-fuel revenue requirements of the Okeechobee Unit, which is scheduled to go into commercial operation on June 1, 2019;
4. Commission and Company adjustments that FPL proposes to rate base, net operating income and capital structure in order to properly represent the 2017 Test Year and 2018 Subsequent Year results for ratemaking purposes;
5. The treatment of West County Energy Center Unit 3 ("WCEC3") revenues in the 2017 Test Year and 2018 Subsequent Year; and

6. The reasonableness of the methods employed by the Company for allocating corporate service costs to affiliates and compliance with the Florida Public Service Commission ("FPSC" or "Commission") and the Federal Energy Regulatory Commission ("FERC") requirements to ensure that no improper subsidization exists between FPL and its affiliates.

Q. Please summarize your testimony.

A. FPL has prepared its request for base rate relief in this filing in accordance with the rules and requirements of the FPSC. The Commission has a number of long standing practices for the determination of proper retail base rates, and FPL has consistently applied those practices in this filing. Those practices include items such as the use of forecasted test periods, proper synchronization of retail rate base and capital structure, specified rules directing assumptions for Construction Work in Progress ("CWIP") earning Allowance for Funds Used During Construction ("AFUDC"), and the use of capital recovery schedules for assets retired but not fully recovered.

FPL is also proposing some new practices for Commission consideration. For example, FPL proposes to recover nuclear maintenance costs on a deferred basis versus recovering those costs in advance of outages. My testimony will provide information to support that adjustment, which lowers FPL's base rate request in this proceeding. Other adjustments that I support include movement of certain project costs from base rates to clause recovery, including the Cedar Bay costs as prescribed by the settlement order approved by this Commission as well as return on investment for clause related construction projects that FPL has historically recovered as part of base rates.

I will address FPL's practices for providing shared corporate services to the NextEra Energy, Inc. ("NEE") enterprise, including regulated and unregulated affiliates. The long-standing cost charging methods approved by this Commission and by the FERC are providing corporate services at lower costs to FPL's customers while ensuring no subsidization of affiliate activities. Those practices are unchanged and remain fully consistent with Commission requirements.

Finally, I sponsor and co-sponsor many Minimum Filing Requirements ("MFRs") and provide the calculation of net operating income, working capital, rate base and revenue requirements for the 2017 Test Year, the 2018 Subsequent Year and the 2019 Okeechobee LSA.

II. SPONSORSHIP OF MINIMUM FILING REQUIREMENTS

Q. Are you sponsoring or co-sponsoring any MFRs in this case?

A. Yes. Exhibit KO-1 lists the MFRs and Schedules I sponsor and co-sponsor for the 2017 Test Year and 2018 Subsequent Year.

Q. Are you sponsoring or co-sponsoring any Schedules in support of FPL's request for the 2019 Okeechobee LSA in order to address the additional revenue requirements associated with that project?

A. Yes. Exhibit KO-1 also reflects the 2019 Okeechobee LSA Schedules that I sponsor and co-sponsor.

Q. Please explain the time periods, including test years, reflected in the MFRs and Schedules FPL has filed in this proceeding.

A. FPL is filing MFRs that include actual costs incurred through 2015 and forecasted costs for the 2017 Test Year as the basis for its jurisdictional revenue requirement calculation for 2017. FPL's MFRs include a 2015 Historic Period, 2016 Prior Year and 2017 Test Year. Additionally, FPL has prepared a complete set of MFRs for the 2018 SYA using forecasted 2018 costs. Lastly, FPL has prepared certain Schedules reflecting the first year incremental annual revenue requirement for the 2019 Okeechobee LSA. The 2019 Okeechobee LSA is projected to be effective June 1, 2019, coinciding with the projected in-service date of the power plant, and will cover the 12 months ended May 31, 2020, which represents the first full year of operation.

Q. Please describe the 2019 Okeechobee LSA Schedules that you are sponsoring or co-sponsoring in this proceeding.

A. These Schedules include the incremental revenue requirement calculation based on the net operating income and rate base impacts commencing with commercial operation of the Okeechobee Unit. Due to the implementation of this project, FPL is requesting an additional base rate increase to be effective from the date the facility goes into commercial operation. FPL witness Kennedy discusses the Okeechobee Unit in further detail; FPL witness Barrett provides the basis for the 2019 Okeechobee LSA; and FPL witness Cohen provides a summary of proposed tariff changes and the true up process related to this requested increase in base rates.

III. 2017 TEST YEAR REVENUE REQUIREMENT

Q. What is the amount of FPL's requested base rate increase for the 2017 Test Year?

A. As shown on Exhibit KO-2, MFR A-1 for 2017 Test Year, the amount of FPL's requested base revenue increase for 2017 is $866 million.

Q. Which MFRs directly support the 2017 Test Year revenue increase calculation?

A. Exhibit KO-2 lists the MFRs that directly support the overall 2017 Test Year jurisdictional revenue requirement increase of $866 million requested by FPL. Those MFRs include schedules that support jurisdictional adjusted rate base of $32.5 billion, jurisdictional adjusted net operating income of $1.6 billion and the calculation of the jurisdictional revenue expansion factor of 1.63024 used to derive the requested overall jurisdictional revenue requirement. Additionally, I sponsor the jurisdictional adjusted capital structure and the overall rate of return ("ROR") of 6.61%, which reflects FPL's requested return on equity ("ROE") of 11.5% (including a 50 basis point ROE performance adder) that is further discussed in the testimony of FPL witnesses Hevert and Dewhurst. The related Commission and Company adjustments applicable to the above schedules are also included in the MFRs filed in this case.

Q. What would be the resulting ROE for the 2017 Test Year absent the requested rate relief?

A. Exhibit KO-3 shows that absent the requested rate relief, the 2017 Test Year jurisdictional adjusted ROE is projected to be 7.88% which is well below the bottom end of the current authorized range for ROE and the proposed ROE supported by FPL witnesses Hevert and Dewhurst.

IV. 2018 SUBSEQUENT YEAR REVENUE REQUIREMENT

Q. What is the amount of FPL's requested base rate increase for the 2018 Subsequent Year?

A. As shown on Exhibit KO-4, MFR A-1 for the 2018 Subsequent Year, the amount of FPL's requested base revenue increase for 2018 is $262 million.

Q. Are all of the Company adjustments requested for the 2017 Test Year also applicable to the 2018 Subsequent Year?

A. Yes. We have consistently applied the proposed Company adjustments reflected on MFRs B-2 and C-3 for the 2017 Test Year to the 2018 Subsequent Year and reflected the amount of those adjustments applicable for the 2018 Subsequent Year.

Q. Which MFRs directly support the 2018 SYA calculation?

A. Exhibit KO-4 lists the MFRs that directly support the 2018 SYA jurisdictional revenue requirement of $262 million. Those MFRs include schedules that support FPL's jurisdictional adjusted rate base of $33.9 billion, jurisdictional adjusted net operating income of $1.6 billion and the calculation of the jurisdictional revenue expansion factor of 1.63024 to arrive at the requested overall jurisdictional revenue requirement. Additionally, I present the jurisdictional adjusted capital structure that reflects FPL's requested ROE of 11.5% and an overall ROR of 6.71%.

Q. What would be the impact on ROE for the 2018 Subsequent Year absent the requested rate relief?

A. Exhibit KO-3 shows that, absent both the 2017 Test Year and 2018 Subsequent Year requested base rate relief, the 2018 jurisdictional adjusted ROE is projected to be only 6.95%. The exhibit also shows that, with FPL's requested base relief for 2017 but absent the requested rate relief for 2018, the 2018 jurisdictional adjusted ROE is projected to be 105 basis points below the requested ROE and below the bottom end of the required cost of equity range supported by FPL witnesses Hevert and Dewhurst.

V. 2019 OKEECHOBEE LIMITED SCOPE ADJUSTMENT

Q. What is the amount of FPL's requested base rate increase for the 2019 Okeechobee LSA?

A. As shown on Schedule A-1 for the 2019 Okeechobee LSA, the amount of FPL's requested base revenue increase for the first 12 months of operation is $209 million.

Q. What is the basis for the revenue requirement calculation associated with the 2019 Okeechobee LSA?

A. The Commission approved the determination of need for the Okeechobee Unit on January 19, 2016 in Docket No. 150196-EI, Order No. PSC-16-0032-FOF-EI. The revenue requirement computation is based on the estimated capital expenditures and operating costs for the facility presented in that docket, and it reflects the impact of the recently approved bonus depreciation on the calculation of income taxes, proposed composite depreciation rate for FPL's newest and most comparable combined cycle plant based on the 2016 Depreciation Study, and incremental cost of capital reflected in FPL's 2018 Subsequent Year. FPL witnesses Kennedy, Barrett and Cohen provide additional support for the 2019 Okeechobee LSA.

VI. ADJUSTMENTS TO 2017 TEST YEAR AND 2018 SUBSEQUENT YEAR

Q. Has FPL presented Commission and Company adjustments to rate base and net operating income necessary in order to properly reflect the 2017 Test Year and 2018 Subsequent Year for ratemaking purposes?

A. Yes. These adjustments are detailed in MFRs B-2 and C-3 for their respective periods. The Commission adjustments are consistent with those currently reflected in FPL's monthly Earnings Surveillance Report ("ESR").

Q. Would you please describe the Company adjustments FPL is proposing?

A. Yes. FPL is providing support for a number of appropriate ratemaking adjustments. First, I will demonstrate the reasonableness of newly offered Company adjustments that provide customer benefits and ensure consistent ratemaking for project costs recovered in either base or clause, but not both. Second, I will present the Company adjustment to accumulated deferred income taxes ("ADIT") required under the Internal Revenue Code ("IRC") when a projected test year is used in setting rates. Lastly, I will provide support for certain Commission adjustments that are required by FPSC rules, practice and/or precedent.

Nuclear Maintenance Costs

Q. Please describe the ratemaking adjustment you propose for nuclear maintenance outage costs.

A. FPL has historically recovered the estimated costs to conduct nuclear facility outages ratably over the 18 month period in advance of the outage in accordance with Order No. PSC-96-1421-FOF-EI, issued November 21, 1996. FPL has determined that it would be beneficial to instead defer the costs at the time of the outage and amortize those deferred costs over the subsequent period prior to the next outage. This approach is consistent with GAAP; however, for regulatory accounting purposes, the proposed change can only be appropriately made in the context of a base rate proceeding

Beginning in 2013, FPL incorporated into the budget process a step that is specifically focused on generating and evaluating productivity and efficiency improvement ideas – an initiative known internally as Project Momentum. Since then, through the Project Momentum initiative, outage durations are being reduced and outage cost increases, which would normally be expected over time, have been moderated as well. These improvements are now fairly stable, so introducing this change in methodology for base rate recovery in the instant proceeding is timely. This change does not violate accounting requirements under FERC's Uniform System of Accounts ("USOA"), and FPL's strong balance sheet can support financing the deferral of these transition costs and prospective amortization over a three-year period. The effect of this change reduces FPL's 2017 and 2018 revenue requirement by $36 million and $39 million, respectively. Exhibit KO-5 summarizes the impact on revenue requirements of deferral and subsequent amortization of the transition liability created by this proposed Company adjustment over a three-year period.

<u>**Consolidating Clause-Recoverable Projects for Clause Recovery**</u>

Q. Please describe the proposed Company adjustment that moves certain costs related to clause-recoverable projects currently recovered in both base and clause, to solely clause recovery.

A. It is preferable to identify projects as either wholly base or clause recoverable at the outset in order to avoid having to bifurcate the recovery of a given project into two recovery mechanisms. FPL accountants must manually identify costs in accordance with prior orders for base and clause recovery, and this bifurcation exercise becomes even more challenging when plant is in-service and being depreciated. During the planning phase for this rate case, FPL carefully reviewed the forecast in light of its business and operational plans in order to identify all projects that are eligible for clause recovery for the entire project lifecycle, and we have excluded those project costs in their entirety from this base rate request.

Consistent with this approach, FPL is proposing an adjustment to transfer the portion of the Incremental Nuclear Regulatory Commission ("NRC")

Fukushima-related Compliance Costs ("Fukushima Project") currently recovered in FPL's base rates to FPL's Capacity Cost Recovery Clause ("CCRC"). During FPL's previous base rate filing, Docket No. 120015-EI, the Company included a preliminary level of capital expenditures of $10 million and approximately $144,000 of O&M in its 2013 Test Year for the Fukushima Project, which represented its best estimate of compliance costs at that time. Since that original estimate, the scope of work necessary to be compliant with NRC requirements has been clarified, and the incremental project costs have grown substantially. During 2013, FPL petitioned the Commission for recovery of the *incremental* costs through the CCRC (i.e., above and beyond the original $10 million of capital and $144,000 of O&M) which was approved by the Commission in Order No. PSC-13-0665-FOF-EI.

Consistent with Order No. PSC-13-0665-FOF-EI, FPL is currently recovering both incremental capital and O&M associated with the Fukushima Project through the CCRC, which amounts are reviewed annually by the FPSC. Exhibit KO-6 reflects the breakdown as of December 31, 2016 of the Fukushima capital costs delineated between base and clause recoverable. The Company adjustment FPL is proposing in this proceeding will ensure that *all* costs related to the Fukushima Project will be reflected and recovered solely through the CCRC, reducing complexity in accounting and ratemaking. The reductions in base rate revenue requirement associated with this adjustment for the 2017 Test Year and 2018 Subsequent Year are $1.6 million and $1.5 million, respectively.

Q. Please describe the Company adjustment for capital projects identified as clause recoverable CWIP and the proposed movement of those projects from base to the proper clause.

A. Presently, a handful of small, approved Environmental Cost Recovery Clause ("ECRC") and Energy Conservation Cost Recovery ("ECCR") projects remain in base rates and do not earn a clause return at FPL's weighted average cost of capital ("WACC") while classified as in-construction or CWIP. Instead, these projects earn a return as part of CWIP in base rates, while all other clause in-service and some CWIP associated with large projects earn a return at FPL's midpoint WACC in their respective cost recovery clauses. This distinction is not required by FPSC rule or precedent; clause recovery of return on investment associated with these projects while in construction was simply not proactively requested by the Company at the time original petitions were filed for recovery of these specific projects. Historically, in petitioning for approval of new, higher cost clause projects, the Company requested the project be reflected in clause for recovery of a return on construction costs through its entire life cycle; however, the Company did not make such a request for the smaller, capital clause projects and instead started clause recovery when those projects entered into service. FPL believes that consistency in recovery vehicle for the entire project lifecycle is appropriate;

therefore, we request consolidation of all clause-recoverable CWIP into the clauses.

Q. What clause capital investment projects and amounts has FPL removed from CWIP in rate base in this proceeding in order to move their recovery to clause?

A. FPL has identified all clause recoverable CWIP and has removed each item from this base rate filing as either a FPSC or a Company adjustment. The CWIP balance for each clause project that was removed from rate base will earn a return while in CWIP in its respective clause at the midpoint WACC as reflected in the May ESR, consistent with Order No. PSC-12-0425-PAA-EU. The revenue requirement reduction in the 2017 Test Year and 2018 Subsequent Year is $825,000 and $493,000, respectively. Exhibit KO-7 reflects a list of the projects and amounts comprising the basis for the FPSC and the Company adjustment. Additionally, for the FPSC adjustments, it contains the orders approving this treatment in the respective clauses.

<u>Normalization Adjustment to ADIT</u>

Q. Please explain why FPL has presented a Company adjustment to decrease the amount of ADIT included in capital structure in the 2017 Test Year and 2018 Subsequent Year.

A. In light of recent Internal Revenue Service ("IRS") Private Letter Rulings ("PLRs") and in order to comply with the IRC set forth under Treasury Regulations §1.167(1)-1(h)(6), ADIT that is treated as zero cost capital, or a component of rate base, in determining a utility's cost of service must be determined by reference to the same period as is used in determining the income tax expense utilized for ratemaking purposes. The IRC goes on to state that a utility may use either historical data or projected data in calculating these two amounts, but it must be consistent. If the amounts are computed using projected data, in whole or in part, and the rates go into effect during the projected period, then the utility must use the formula provided in Treasury Regulations §1.167(l)-1(h)(6)(ii) to calculate the amount of ADIT to be included for ratemaking purposes. Because FPL is presenting a change in base rates at the beginning of both the projected 2017 Test Year and 2018 Subsequent Year, the Company is required to comply with Treasury Regulations §1.167(l)-1(h)(6) in this proceeding.

Q. Please describe the required formula FPL must follow to adjust ADIT in the 2017 Test Year and 2018 Subsequent Year.

A. Treasury Regulations §1.167(l)-1(h)(6)(ii) contain a precise formula ("Proration Requirement") for computing the amount of depreciation-related ADIT to be treated as zero cost capital when a future test period is used. The Proration Requirement is as follows:

> The pro rata portion of any increase to be credited or decrease to be charged during a future period….shall be determined by multiplying any such increase or decrease by a fraction, the numerator of which is the number of days remaining in the period at the time such increase or decrease is to be accrued,

and the denominator of which is the total number of days in the period.

Q. Please explain the calculation of the Proration Requirement and its impact to FPL's capital structure for the 2017 Test Year and 2018 Subsequent Year.

A. As reflected on Exhibit KO-8, the calculations of the Proration Requirement for ADIT for the 2017 Test and 2018 Subsequent Year results begin with 13-month average balances of $8.3 billion and $8.5 billion, respectively. FPL then compared the balances using the Proration Requirement totals for 2017 of $8.2 billion and 2018 of $8.5 billion to the per-book 13-month average ADIT balance. The difference results in the Company adjustment of $58 million for the 2017 Test Year and $43 million for the 2018 Subsequent Year. This Company adjustment is reflected as a specific adjustment to decrease ADIT on MFR D-1a.

Q. Why has FPL not introduced this adjustment in previous base rate filings?

A. Prior to the issuance of the recent PLRs, the Company interpreted the IRC consistency requirements as potentially being compromised if this adjustment were singularly made. The recent PLRs issued by the IRS during 2015 make it clear that to ignore this adjustment in a forecasted test year base rate setting will violate normalization requirements.

Q. Has FPL also reflected the Proration Requirement in the calculation of the 2019 Okeechobee LSA?

A. Yes. FPL has included the impact of the Proration Requirement related to the projected first year of operations for the 2019 Okeechobee LSA in the calculation of ADIT, which is a component of rate base.

<u>Rate Case Expenses</u>

Q. What adjustment is FPL requesting for rate case expenses?

A. FPL is requesting a four-year amortization period for estimated, incremental rate case expenses associated with this case totaling $4.9 million. In addition, FPL is requesting that the unamortized balance be included in rate base in the 2017 Test Year and 2018 Subsequent Year in order to avoid an implicit disallowance of reasonable and necessary costs. The fact that FPL is requesting a 2018 SYA and the 2019 Okeechobee LSA as part of one proceeding reduces the amount of rate case expenses we would otherwise incur for multiple back-to-back rate cases. Full recovery of necessary rate case expenses is appropriate but will not occur unless FPL is afforded the opportunity to earn a return on the unamortized balance of those expenses.

Commission Adjustments for Woodford and Cedar Bay Projects

Q. Please describe the Commission adjustments you are making consistent with Orders in Docket No. 150001-EI - Gas Reserves Woodford Project and Docket No. 150075-EI - Cedar Bay Transaction.

A. As a result of recent transactions approved by this Commission, certain items must be removed from base rates in a different fashion from typical Commission adjustments. The Company is highlighting these items for ease of review. Exhibit KO-9 shows the components of each transaction by FERC account and its removal from rate base, net operating income, and capital structure, as applicable.

- Gas Reserves Investment – Woodford Project – Pursuant to Order No. PSC-15-0038-FOF-EI, Docket No. 150001-EI, FPL recovers the revenue requirements associated with the Woodford Project through its fuel recovery clause. As such, FPL removes the net plant-in-service, depletion and depreciation expense, O&M, and working capital associated with the gas reserves investment as an FPSC adjustment in its monthly ESRs and is doing the same for base rate setting purposes. A listing of each component of the gas reserves investment removed from the filing is reflected on Exhibit KO-9.
- Cedar Bay Transaction – Pursuant to the settlement agreement approved by the Commission in Order No. PSC-15-0401-AS-EI, Docket No. 150075-EI, FPL was authorized to recover the $520.5 million purchase price for the stock purchase of CBAS Power, Inc and $326.9 million income tax gross up

associated with the loss on the termination of the power purchase agreement. Recovery of these costs under the settlement was apportioned between FPL's CCRC and base rates as follows: $85 million of the purchase price and its associated income tax gross up of $53 million initially to be recovered through base rates and the balance to be recovered through the CCRC. This treatment was to be in place only until FPL's next Test Year for a general base rate proceeding; therefore, the remaining unamortized portion of the $85 million and related income tax gross up at the beginning of the 2017 Test Year would be removed from rate base and recovered through FPL's CCRC. The unamortized amount to be reclassified to the CCRC as of December 31, 2016 is $73 million for the purchase price and $46 million for its associated income tax gross up. Exhibit KO-9 demonstrates the removal of all Cedar Bay amounts from FPL's base rate filing.

VII. TREATMENT OF WCEC3 IN 2017 TEST YEAR AND 2018 SUBSEQUENT YEAR

Q. How are the revenues associated with WCEC3 currently treated in FPL's monthly ESR?

A. Consistent with the 2012 Rate Settlement approved in Order No. PSC-13-0023-S-EI, the revenue requirements associated with WCEC3 are currently collected through FPL's CCRC. Because the O&M expenses and return on investment for WCEC3 are base rate components, the WCEC3 revenues collected through CCRC are in turn reclassified on FPL's books and records from CCRC revenues to base revenues. Therefore, the amounts reported in FPL's monthly ESR already reflect revenues associated with WCEC3 as base revenues.

Q. How is the revenue associated with WCEC3 reflected in the 2017 Test Year and 2018 Subsequent Year?

A. Consistent with the 2012 Rate Settlement and with the treatment described above for monthly surveillance reporting, the revenues associated with WCEC3 are forecasted and reflected as base revenues.

Q. Is FPL requesting to recover WCEC3 revenue requirements in base rates as part of this filing?

A. Yes. Pursuant to the 2012 Rate Settlement, the Company is reflecting revenue requirements associated with WCEC3 in base rates.

Q. If the Commission approves FPL's proposal to recover WCEC3 revenue requirements costs through base rates, will FPL discontinue recovery of those revenue requirements through the CCRC?

A. Yes. If the Commission agrees to allow FPL to move the recovery of WCEC3 revenue requirements from the CCRC to base rates in the 2017 Test Year, then the revenue requirements associated with WCEC3 will not be included in FPL's CCRC billing factors beginning January 1, 2017. FPL witness Cohen outlines the rate effect of this request.

Q. If the Commission does not approve recovery of WCEC3 revenue requirements through base rates in this proceeding, should FPL be permitted to continue recovery through the CCRC?

A. Yes. The Commission made an affirmative determination of need for WCEC3 in Order No. PSC-08-0591-FOF-EI, finding it to be a cost-effective addition to FPL's generating system that meets the customer's demand and energy requirements with clean, fuel-efficient combined cycle generation. FPL must be permitted the opportunity to fully recover the WCEC3 revenue requirements either as a component of base rates or as a component of the CCRC.

VIII. CORPORATE SERVICES AND AFFILIATE TRANSACTIONS

Q. Please describe the NEE corporate and fleet services organizational model, FPL's role in that model, and its benefits.

A. In the years both before and since the formation of NEE, FPL has consistently performed the required corporate center activities for all entities. Over the last twenty years, FPL's sister operating affiliate, NextEra Energy Resources ("NEER"), has expanded its unregulated renewables business to become the largest renewables generator in the U.S. In addition to the remarkable growth of NEER, NEE has developed a number of new operating entities that are also served by FPL, albeit much smaller in size and scale, including an affiliate engaged in FERC competitive transmission development. The simplified organizational chart on Exhibit KO-10 reflects the primary operating entities, both regulated and unregulated, receiving services from FPL today. Despite the growth of its affiliates, FPL remains the primary NEE subsidiary by nearly any metric.

As the functioning corporate center for NEE, FPL incurs costs in order to perform all necessary shared fleet operating and corporate support functions, with the ultimate goal to efficiently and cost effectively lever talent and resources across the enterprise, which is beneficial to FPL and its customers. Exhibit KO-10 lists both the traditional corporate center functions and the fleet services activities provided by FPL across the broader NEE operating businesses.

While the shared corporate service activities embedded in FPL today continue to be necessary to support the provision of electric service to FPL's retail customers, charging a portion of these support services to its affiliates has allowed FPL to reduce its share of these necessary fixed costs for the benefit of its retail customers. This structure has proven over the years to be efficient and effective from an operating perspective. The special skills and talents of FPL's employees and contractor resources are consistently leveraged over the largest organizational reach.

Q. Have there been any material changes in affiliate transaction processes or controls since FPL's last base rate filing in Docket No. 120015-EI?

A. No. FPL's current processes and billing practices continue to ensure that affiliate transactions comply with all applicable regulatory rules and regulations.

Q. Are FPL's affiliate billing practices codified?

A. Yes. FPL uses an integrated structure of billings and allocations that are codified in the Company's Cost Allocation Manual ("CAM"). Maintaining the CAM is a requirement under Rule No. 25-6.1351, Cost Allocations and Affiliate Transactions, F.A.C. ("Affiliate Rule"). In addition, FPL's CAM largely follows the published guidelines recommended by the National Association of Regulatory Utility Commissioners ("NARUC"). FPL's 2016 CAM is included as Exhibit KO-11.

Q. Please describe the three major categories of shared support provided by FPL to its affiliates.

A. The first category is strategic and governance related support traditionally performed by the corporate center executive team. Strategic and governance support includes activities such as those associated with the Board of Directors, Legal Compliance, Investor Relations, Internal Audit and the Office of the General Counsel.

The second category is the fleet construction and operations support, provided by the Power Generation Division, Nuclear Division, Transmission, Engineering and Construction, Integrated Supply Chain, and Environmental departments. FPL has leveraged its commercial and technical practices and knowledge regarding fleet construction, compliance and operating capabilities in order to optimize results for its customers and the broader enterprise. The larger scale of the enterprise fleet has facilitated sharing expertise in complex commercial and technical operating skills, which has lowered FPL's share of costs.

The third category of shared activities is comprised of traditional corporate support services. This includes, but is not limited to, Human Resources compliance, benefits administration and payroll processing, Information Management, Treasury and Cash Management, Corporate Communications, Corporate Tax, and SEC reporting.

Q. What specific methods are utilized by FPL to charge costs to its affiliates?

A. There are three methods FPL utilizes to charge costs of shared activities to its affiliates. These methods are commonly employed by other utilities and are recommended by the FERC and NARUC:

1. <u>Direct Charges</u> – Costs of resources used exclusively to provide services for the benefit of one company and are directly charged to that entity. Exhibit KO-12 recaps the direct charges for the 2013 and 2014 Actual Years, 2015 Historical Year, 2016 Prior Year, 2017 Test Year, and 2018 Subsequent Year. As has been demonstrated historically, these charges are largely project-specific and do not only represent the

use of embedded FPL resources. In many cases, the costs actually incurred and billed to affiliates result from contractor or other third party services engaged by FPL for a specific enterprise wide project. FPL fully loads all internal direct charges and uses this methodology whenever possible and practical. In 2015, approximately 45% of the support provided to affiliates was charged using the direct charge method.

2. Operations Support Charges[1] – Operations Support Charges are utilized by FPL to allocate support costs for NEE's Nuclear fleet support operations, which provide services to both FPL and NEER's fleet of nuclear units. These charges are billed monthly based on actual costs for the enterprise support activity. In 2015, approximately 11% of affiliate support was charged via the Nuclear Operations Support Charges, which are described in more detail below:

   a. Nuclear – Services include nuclear operations and security, fuels support, nuclear business management, engineering, and assurance support. Costs are fully loaded and allocated based on the percentage of nuclear generating units across the enterprise; and

   b. Nuclear Information Management – Services include nuclear procurement and work management system application support, Information Management Business Unit management team support, data services, and infrastructure support to

[1] FPL has formerly referred to the Operations Support Charges as Service Fees.

NextEra Energy Resources' nuclear plants. Costs are fully loaded and allocated based on the percentage of nuclear generating units across the enterprise.

3. Corporate Services Charges ("CSC")[2] – A significant portion of the governance costs and general corporate support services that benefit both FPL and its affiliates are billed through the CSC, which is further defined by two distinct allocation methods:

a. Specific Driver – The allocation of costs of ongoing services shared jointly to support utility and affiliate operations that have distinct cost drivers. These drivers or factors have a direct relationship to the causation of the expense and the effect this activity has on the operations of the benefiting entity. Examples of the cost pools that are allocated using specific drivers include corporate systems capital costs and applications, support for computer mainframe operations, payroll processing, benefit programs and corporate security. The drivers to allocate these costs are carefully selected in order to properly allocate between FPL and its affiliates, ensuring that FPL customers are not subsidizing affiliate activities. Drivers for the 2013 and 2014 Actual Years, 2015 Historical Year, 2016 Prior Year, 2017 Test Year, and 2018 Subsequent Year are shown on Exhibit KO-13.

b. Massachusetts Formula – The costs of corporate governance

[2] FPL has formerly referred to the CSC as the Affiliate Management Fee or AMF.

> and strategic activities shared jointly to support utility and affiliate operations that do not have distinct cost drivers are allocated using the Massachusetts Formula, a methodology widely accepted by utility regulators as a fair and reasonable way to allocate common costs among affiliates. The Massachusetts Formula has three components: (1) property, plant and equipment, (2) revenue, and (3) payroll. The annual amounts forecasted for each of these components are used as the basis in calculating the percentage to be charged to each affiliate. Averaging the percentages for property, plant and equipment, revenues and payroll has proven to be a reasonable means of allocating corporate governance and general support services. Exhibit KO-13 depicts the Massachusetts Formula ratios that were used in forecasting the allocation of corporate governance and strategic activities for the 2013 and 2014 Actual Years, 2015 Historical Year, 2016 Prior Year, 2017 Test Year, and 2018 Subsequent Year.

As shown on Exhibit KO-14, despite the significant growth in FPL by all measures, FPL customers receive a steadily declining percentage of these shared governance and corporate services costs. The success of the NEE enterprise provides benefits directly to FPL customers as a result of the sourcing of corporate services from FPL.

Q. Are most of the costs included in the Corporate Services Charges allocated using activity-specific drivers?

A. Yes. For the 2015 Historical Year, 57% of the cost pool was allocated using specific drivers and 43% was allocated using the Massachusetts Formula. FPL makes a significant effort to identify causal relationships between costs and the activities that drive them in order to achieve a more precise distribution of shared costs among FPL and its affiliates. The percentage of costs allocated using specific drivers is expected to increase through the 2018 Subsequent Year.

Q. Does FPL use any other allocation methods to charge shared costs to affiliates?

A. Yes. For significant Information Management ("IM") projects, the business case developed in support of the project will identify expected future benefits to each of the entities that will be utilizing the system or application. This benefit analysis is then used to determine the appropriate sharing of implementation costs between FPL and its benefiting affiliates. Examples of projects utilized by both FPL and NEER that are allocated using this methodology are SAP, which is NEE's Enterprise Resource Planning ("ERP") system, and Maximo, which is the Power Generation Division's new work management system.

Q. Please describe the integrated controls that FPL designs, maintains and relies on to ensure that FPL retail customers do not subsidize the operation of an affiliate.

A. The Cost Measurement and Allocations ("CMA") department within FPL accounting is responsible for ensuring compliance with affiliate rules and regulations. This group, in collaboration with the legal and compliance teams, is the primary control and oversight organization, whose mission is to ensure that FPL complies with affiliate transaction requirements. They monitor the affiliate billing process and work with all business units to ensure that each has an understanding of the affiliate rules and properly charges or allocate costs as required.

In addition, FPL has codified the required practices and procedures that each employee must adhere to in the conduct of corporate shared services and appropriate billings in the CAM, following the guidelines recommended by the NARUC. The CAM is updated annually by the CMA group and can be readily accessed by each and every employee by accessing the internal NEE corporate website.

The Company's Sarbanes-Oxley processes document FPL's required affiliate transaction controls. In addition, other processes ensure proper control over affiliate allocation. For example, bi-weekly payroll reviews by each employee's supervisor are conducted to ensure that any payroll incurred in support of an affiliate is appropriately charged to that affiliate, and asset transfer requirements detail market testing procedures for sales between FPL and affiliates to ensure affiliate rule compliance.

Q. Does the Company perform any internal reviews of its affiliate processes?

A. Yes. During 2013 and 2014, the Internal Audit department performed a review of the processes and procedures employed by CMA related to CSC, Operations Support Charges, and direct charges. The audit report contained no findings of non-compliance with affiliate rules. The controls in place were determined to be effective and the policies and procedures around affiliate transactions were consistently applied throughout the Company.

Q. Is FPL subject to reporting requirements by the FPSC with respect to its affiliate transactions?

A. Yes. FPL complies with affiliate accounting and reporting requirements mandated by this Commission. That reporting includes the required annual filing of the Diversification Report, which includes details of transactions with affiliates and changes in affiliate commercial contracts with FPL.

Q. How has the potential merger with the Hawaiian Electric Companies impacted the allocation of costs that is reflected in the calculation of rate relief requested in this proceeding?

A. The proposed merger with the Hawaiian Electric Companies has not yet been approved by the Hawai'i Public Utility Commission. Unless and until the merger is approved, FPL cannot assume an outcome. If the merger is approved during this rate proceeding, FPL will propose an adjustment as part of rebuttal testimony that would reduce FPL's overall revenue requirement by the estimated amount of corporate services costs to be provided to Hawaiian Electric companies.

Q. Are affiliate costs subsidized by FPL customers?

A. No. To the contrary, FPL will continue to accomplish two important objectives for its customers with respect to corporate support and affiliate charges. It will continue to insure that it complies with all regulatory requirements and that FPL customers do not subsidize affiliates. Second, it will continue to lever the robust, highly specialized, commercial and technical talents of the broader business teams that it has amassed in performing these corporate and fleet services, which enable far greater benefits than it could ever deliver to customers as a standalone business.

Q. Does this conclude your direct testimony?

A. Yes.

Florida Power & Light Company
MFRs AND SCHEDULES SPONSORED AND CO-SPONSORED BY KIM OUSDAHL

MFR Schedule	Period	Title
SOLE SPONSOR:		
A-1	Test Subsequent Okeechobee Limited Scope	FULL REV REQUIREMENTS INCREASE REQUESTED
B-1	Historic Prior Test Subsequent Okeechobee Limited Scope	ADJUSTED RATE BASE
B-3	Historic	13-MONTH AVERAGE BALANCE SHEET - SYSTEM BASIS
B-4	Historic Subsequent	TWO YEAR HISTORICAL BALANCE SHEET
B-18	Historic	FUEL INVENTORY BY PLANT
B-19	Test Subsequent	MISCELLANEOUS DEFERRED DEBITS
B-20	Test Subsequent	OTHER DEFERRED CREDITS
B-21	Historic	ACCUMULATED PROVISION ACCOUNTS - 228.1, 228.2 AND 228.4
B-25	Prior Test Subsequent	ACCOUNTING POLICY CHANGES AFFECTING RATE BASE
C-1	Historic Prior Test Subsequent Okeechobee Limited Scope	ADJUSTED JURISDICTIONAL NET OPERATING INCOME

Florida Power & Light Company
MFRs AND SCHEDULES SPONSORED AND CO-SPONSORED BY KIM OUSDAHL

MFR Schedule	Period	Title
C-2	Historic Prior Test Subsequent	NET OPERATING INCOME ADJUSTMENTS
C-3	Subsequent	JURISDICTIONAL NET OPERATING INCOME ADJUSTMENTS
C-7	Test Subsequent	OPERATION AND MAINTENANCE EXPENSES
C-9	Historic Subsequent	FIVE YEAR ANALYSIS-CHANGE IN COST
C-13	Historic	MISCELLANEOUS GENERAL EXPENSES
C-15	Historic	INDUSTRY ASSOCIATION DUES
C-17	Historic Prior Test Subsequent	PENSION COST
C-18	Historic Subsequent	LOBBYING EXPENSES, OTHER POLITICAL EXPENSES AND CIVIC/CHARITABLE CONTRIBUTIONS
C-22	Historic Test Subsequent Okeechobee Limited Scope	STATE AND FEDERAL INCOME TAX CALCULATION
C-24	Historic Test Subsequent	PARENT(S) DEBT INFORMATION

Florida Power & Light Company
MFRs AND SCHEDULES SPONSORED AND CO-SPONSORED BY KIM OUSDAHL

MFR Schedule	Period	Title
C-25	Historic Prior Test Subsequent	DEFERRED TAX ADJUSTMENT
C-26	Historic	INCOME TAX RETURNS
C-27	Test Subsequent	CONSOLIDATED TAX INFORMATION
C-28	Historic Subsequent	MISCELLANEOUS TAX INFORMATION
C-30	Test Subsequent	TRANSACTIONS WITH AFFILIATED COMPANIES
C-31	Historic Test Subsequent	AFFILIATED COMPANY RELATIONSHIPS
C-32	Historic Test Subsequent	NON-UTILITY OPERATIONS UTILIZING UTILITY ASSETS
C-38	Test Subsequent	O&M ADJUSTMENTS BY FUNCTION
C-39	Historic Subsequent	BENCHMARK YEAR RECOVERABLE O&M EXPENSES BY FUNCTION
C-41	Test Subsequent	O&M BENCHMARK VARIANCE BY FUNCTION

Florida Power & Light Company
MFRs AND SCHEDULES SPONSORED AND CO-SPONSORED BY KIM OUSDAHL

MFR Schedule	Period	Title
C-44	Test Subsequent Okeechobee Limited Scope	REVENUE EXPANSION FACTOR
D-1b	Historic Prior Test Subsequent	COST OF CAPITAL - ADJUSTMENTS
D-4a	Historic	LONG-TERM DEBT OUTSTANDING
D-4b	Prior Test Subsequent	REACQUIRED BONDS
F-1	Historic Subsequent	ANNUAL AND QUARTERLY REPORT TO SHAREHOLDERS
F-2	Historic Subsequent	SEC REPORTS
CO-SPONSOR:		
B-2	Historic Prior Test Subsequent	RATE BASE ADJUSTMENTS
B-5	Prior Test Subsequent	DETAIL OF CHANGES IN RATE BASE
B-6	Historic Test Subsequent Okeechobee Limited Scope	JURISDICTIONAL SEPERATION FACTORS - RATE BASE
B-15	Prior Test Subsequent	PROPERTY HELD FOR FUTURE USE - 13 MONTH AVG

Florida Power & Light Company
MFRs AND SCHEDULES SPONSORED AND CO-SPONSORED BY KIM OUSDAHL

MFR Schedule	Period	Title
B-17	Prior Test Subsequent	WORKING CAPITAL - 13 MONTH AVG
B-22	Historic Prior Test Subsequent	TOTAL ACCUMULATED DEFERRED INCOME TAXES
B-23	Historic Prior Test Subsequent	INVESTMENT TAX CREDITS - ANNUAL ANALYSIS
C-3	Historic Prior Test	JURISDICTIONAL NET OPERATING INCOME ADJUSTMENTS
C-4	Historic Test Subsequent Okeechobee Limited Scope	JURISDICTIONAL SEPERATION FACTORS - NET OPERATING INCOME
C-6	Historic Prior Test Subsequent	BUDGETED VERSUS ACTUAL OPERATING REVENUES AND EXPENSES
C-8	Prior Test Subsequent	DETAIL OF CHANGES IN EXPENSE
C-10	Test Subsequent	DETAIL OF RATE CASE EXPENSES FOR OUTSIDE CONSULTANTS
C-12	Historic Test Subsequent	ADMINISTRATIVE EXPENSES
C-14	Historic	ADVERTISING EXPENSES

Florida Power & Light Company
MFRs AND SCHEDULES SPONSORED AND CO-SPONSORED BY KIM OUSDAHL

MFR Schedule	Period	Title
C-16	Historic	OUTSIDE PROFESSIONAL SERVICES
C-18	Test	LOBBYING EXPENSES, OTHER POLITICAL EXPENSES AND CIVIC/CHARITABLE CONTRIBUTIONS
C-20	Historic Prior Test Subsequent Okeechobee Limited Scope	TAXES OTHER THAN INCOME TAXES
C-21	Historic Prior Test Subsequent	REVENUE TAXES
C-23	Historic Test Subsequent Okeechobee Limited Scope	INTEREST IN TAX EXPENSE CALCULATION
C-29	Historic Prior Test Subsequent	GAINS AND LOSSES ON DISPOSITION OF PLANT AND PROPERTY
C-33	Historic Prior Test Subsequent	PERFORMANCE INDICES
C-36	Historic Prior Test Subsequent	NON-FUEL OPERATION AND MAINTENANCE EXPENSE COMPARED TO CPI
C-37	Test Subsequent	O&M BENCHMARK COMPARISON BY FUNCTION
C-42	Historic Prior Test Subsequent	HEDGING COSTS

Florida Power & Light Company
MFRs AND SCHEDULES SPONSORED AND CO-SPONSORED BY KIM OUSDAHL

MFR Schedule	Period	Title
C-43	Historic Prior Test Subsequent	SECURITY COSTS
D-1a	Historic Prior Test Subsequent Okeechobee Limited Scope	COST OF CAPITAL - 13 MONTH AVG
D-6	Historic	CUSTOMER DEPOSITS
F-5	Test Subsequent	FORECASTING MODELS
F-8	Test Subsequent	ASSUMPTIONS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY
AND SUBSIDIARIES

DOCKET NO.: 160021-EI

EXPLANATION: Provide the calculation of the requested full revenue requirements increase.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/17
____ Prior Year Ended ___/___/___
____ Historical Test Year Ended ___/___/___

Witness: Kim Ousdahl

Line No.	(1) DESCRIPTION	(2) SOURCE	(3) AMOUNT ($000)	
1				
2	JURISDICTIONAL ADJUSTED RATE BASE (1)	SCHEDULE B-1	$	32,536,116
3				
4	RATE OF RETURN ON RATE BASE REQUESTED	SCHEDULE D-1A		6.61%
5				
6	JURISDICTIONAL NET OPERATING INCOME REQUESTED	LINE 2 X LINE 4	$	2,149,618
7				
8	JURISDICTIONAL ADJUSTED NET OPERATING INCOME (1)	SCHEDULE C-1	$	1,618,192
9				
10	NET OPERATING INCOME DEFICIENCY (EXCESS)	LINE 6 - LINE 8	$	531,427
11				
12	EARNED RATE OF RETURN	LINE 8 / LINE 2		4.97%
13				
14	NET OPERATING INCOME MULTIPLIER	SCHEDULE C-44		1.63024
15				
16	REVENUE REQUIREMENT (2)	LINE 10 X LINE 14	$	866,354
17				
18				

19 Notes:
20 (1) Includes amounts associated with West County Energy Center Unit 3, consistent with FPL's 2012 Rate Settlement approved in FPSC Order No. PSC-13-0023-S-EI
21 and monthly earnings surveillance reporting.
22 (2) Total requested increase, excluding the effect of proposed company adjustments related to cost recovery clauses shown on MFR C-2, is $868,732,000.

Supporting Schedules: B-1, C-1, D-1, C-44

Recap Schedules:

Docket No. 160021-EI
MFR A-1 for the 2017 Test Year
Exhibit KO-2, Page 1 of 1

FLORIDA POWER & LIGHT COMPANY
2017 AND 2018 RETURN ON EQUITY CALCULATION WITHOUT RATE RELIEF
Exhibit KO-3
($000)

Line No.		MFR Reference	2017	2018 [(A)]	2018 [(B)]
1	Jurisdictional Adjusted Net Operating Income	C-1	$ 1,618,192	$ 1,575,711	$ 2,110,172
2	Jurisdictional Adjusted Rate Base	B-1	32,536,116	33,870,897	33,870,897
3	**Estimated Earned Rate of Return (Line 1 / Line 2)**		**4.97%**	**4.65%**	**6.23%**
4					
5	Jurisdictional Adjusted Non-Equity Component of Weighted Average Cost of Capital	D-1a	1.42%	1.52%	1.52%
6	**Earnings Available for Common (Lines 3 - 5)**		**3.56%**	**3.14%**	**4.71%**
7					
8	Jurisdictional Adjusted Common Equity Ratio	D-1a	45.13%	45.13%	45.13%
9					
10	**Jurisdictional Adjusted Return on Common Equity (Line 6 / Line 8)**		**7.88%**	**6.95%**	**10.45%**

Notes:
[(A)] Calculation assumes FPL's base rate increase for 2017 is not granted.
[(B)] Calculation assumes FPL's base rate increase for 2017 is granted.

Schedule A-1 | FULL REVENUE REQUIREMENTS INCREASE REQUESTED |

2018 SUBSEQUENT YEAR ADJUSTMENT

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the requested full revenue requirements increase.

Type of Data Shown:
____ Projected Test Year Ended ___/___/___
____ Prior Year Ended ___/___/___
____ Historical Test Year Ended ___/___/___
_X_ Proj. Subsequent Yr Ended 12/31/18
Witness: Kim Ousdahl

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 160021-EI

Line No.	(1) DESCRIPTION	(2) SOURCE	(3) AMOUNT ($000)
1			
2	JURISDICTIONAL ADJUSTED RATE BASE (1)	SCHEDULE B-1	$ 33,870,897
3			
4	RATE OF RETURN ON RATE BASE REQUESTED	SCHEDULE D-1A	6.71%
5			
6	JURISDICTIONAL NET OPERATING INCOME REQUESTED	LINE 2 X LINE 4	$ 2,271,063
7			
8	JURISDICTIONAL ADJUSTED NET OPERATING INCOME (1)	SCHEDULE C-1	$ 1,575,711
9			
10	NET OPERATING INCOME DEFICIENCY (EXCESS)	LINE 6 - LINE 8	$ 695,352
11			
12	EARNED RATE OF RETURN	LINE 8 / LINE 2	4.65%
13			
14	NET OPERATING INCOME MULTIPLIER	SCHEDULE C-44	1.63024
15			
16	REVENUE REQUIREMENT (2)	LINE 10 X LINE 14	$ 1,133,593
17			
18	2017 REVENUE INCREASE REQUESTED	SEE NOTE 3	$ 871,301
19			
20	RATE INCREASE REQUESTED (AFTER FULL 2017 RATE INCREASE)	LINE 16 - LINE 18	$ 262,292
21			
22	Notes:		
23	(1) Includes amounts associated with West County Energy Center Unit 3, consistent with FPL's 2012 Rate Settlement approved in FPSC Order No. PSC-13-0023-S-EI		
24	and monthly earnings surveillance reporting.		
25	(2) Total requested increase, excluding the effect of proposed company adjustments related to cost recovery clauses shown on MFR C-2, is $1,135,597,000.		
26	(3) 2017 Revenue increase requested on Test Year MFR A-1, $866,354,000 adjusted for 2018 Sales Growth.		
27			
28			
29			
30			
31			
32			
33			
34			

Supporting Schedules: B-1, C-1, D-1, C-44 | Recap Schedules:

Docket No. 160021-EI
MFR A-1 for the 2018 Subsequent Year
Exhibit KO-4, Page 1 of 1

Florida Power & Light Company
Nuclear Maintenance
Change in Accounting Methodology from Accrue-In-Advance to Defer-and-Amortize
Exhibit KO-5
($000)

Line No.		2017	2018
1	**Accrue-In-Advance (Current Method)**		
2			
3	**FERC Account 228.4 - Nuclear Maintenance Reserve**		
4	Beginning Balance [a]	$ (67,172)	$ (55,286)
5	Outage Accruals [a]	(83,082)	(87,221)
6	Outage Costs - Represents the costs charged under the current method [a]	94,968	88,025
7	Ending Balance (Lines 4 + 5 + 6)	$ (55,286)	$ (54,482)
8			
9	13-Month Average	$ (53,819)	$ (62,720)
10			
11	Beginning Balance - Participant Credit Portion	(3,627)	(2,469)
12	Outage Accruals	(3,228)	(3,299)
13	Outage Costs (Reversals)	4,386	4,883
14	Ending Balance (Lines 11 + 12 + 13)	(2,469)	(885)
15			
16	13-Month Average	(1,790)	(2,780)
17			
18	**Defer-and-Amortize (Proposed Method)**		
19			
20	**FERC Account 228.4 - Nuclear Maintenance Reserve [a]**		
21	Beginning Balance @ 1/1/2017	$ (67,172)	$ -
22	Transition nuclear maintenance reserve balance to regulatory liability and flow back to customers	67,172	
23	Ending Balance (Lines 21 + 22)	$ -	$ -
24			
25	13-Month Average	$ (5,167)	$ -
26			
27	**FERC Account 254 - Regulatory Liability**		
28	Beginning Balance	$ -	$ (83,447)
29	Transition nuclear maintenance reserve balance to regulatory liability and flow back to customers [a]	(67,172)	-
30	Outage costs incurred prior to 2017 that would still be remaining to be amortized under new method [a]	(57,999)	-
31	Amortization of regulatory liability over a 3 year period	41,724	41,724
32	Ending Balance (Lines 28 + 29 + 30 + 31)	$ (83,447)	$ (41,724)
33			
34	13-Month Average	$ (94,681)	$ (62,586)
35			
36	**FERC Account 182 - Regulatory Asset [a]**		
37	Beginning Balance	$ -	$ 68,052
38	Outage costs incurred prior to 2017 that would still be remaining to be amortized under new method	57,999	-
39	Deferral of 2017 outage costs	95,072	-
40			
41	Amortization of outage costs incurred prior to 2017	(51,827)	(6,171)
42	Amortization of 2017 outage costs	(33,191)	(54,805)
43			
44	Deferral of 2018 outage costs	-	89,788
45	Amortization of 2018 outage costs	-	(20,714)
46			
47	Ending Balance (Sum of Lines 37 - 46)	$ 68,052	$ 76,151
48			
49	13-Month Average	$ 64,338	$ 63,687
50			
51	**Change in Working Capital**		
52	**Accrue-In-Advance (Current Method) - 13-Month Average (Lines 9 + 16)**	**$ (55,609)**	**$ (65,500)**
53	**Defer-and-Amortize (Proposed Method) - 13-Month Average (Lines 25 + 34 + 49)**	**(35,510)**	**1,102**
54	**Increase/(Decrease) in Working Capital - 13-Month Average**	**$ 20,099**	**$ 66,602**
55			
56	**Change in O&M Expense**		
57	**Accrue-In-Advance (Current Method) (Line -5)**	**$ 83,082**	**$ 87,221**
58	**Defer-and-Amortize (Proposed Method) (Lines -31 -41 -42)**	**43,295**	**39,966**
59	**Increase/(Decrease) in Expense**	**$ (39,787)**	**$ (47,255)**
60			
61	**Change in Revenue Requirements**		
62	**Increase in Rate Base (Line 54)**	**$ 20,099**	**$ 66,602**
63	**Retail Separation Factor**	**95.0595%**	**95.1284%**
64	**Increase in Retail Rate Base**	**$ 19,106**	**$ 63,358**
65	**Pre-Tax Cost of Capital (MFR D-1a)**	**9.8659%**	**9.9641%**
66	**Increase in Return on Rate Base**	**$ 1,885**	**$ 6,313**
67			
68	**Decrease in O&M Expense (Line 59)**	**$ (39,787)**	**$ (47,255)**
69	**Retail Separation Factor**	**94.8587%**	**94.8659%**
70	**Increase in Retail O&M**	**$ (37,741)**	**$ (44,829)**
71			
72	**Interest Synchronization**	**$ (170)**	**$ (603)**
73	**RAF and Bad Debt Multiplier**	**1.00137**	**1.00137**
74	**Increase/(Decrease) in Revenue Requirements - (Lines 66 + 70 + 72) * Line 73**	**$ (36,076)**	**$ (39,173)**
75			
76			
77	**Notes:**		
78	[a] Net of participants credits		

Florida Power & Light Company
Fukushima Project Cost by Recovery Mechanism
Exhibit KO-6
($000)

	A	B	C	D
Line No.		2016	2017	2018
1	Base Rates [a]			
2	Plant-in-Service	$ 12,913	$ 12,913	$ 12,913
3	Accumulated Depreciation Reserve	1,427	2,051	2,757
4	**Net Book Value @ 12/31**	$ 11,486	$ 10,862	$ 10,156
5				
6	**13-Month Average - Net Book Value**	**$ 11,797**	**$ 11,174**	**$ 10,631**
7				
8	Capacity Clause [b]			
9	Plant-in-Service	$ 92,506	$ 101,230	$ 116,672
10	Accumulated Depreciation Reserve	2,286	4,480	6,843
11	**Net Book Value @ 12/31**	$ 90,220	$ 96,750	$ 109,830
12				
13	**13-Month Average - Net Book Value**	**$ 74,816**	**$ 93,196**	**$ 102,227**
14				
15				
16				
17	**Company Adjustment Revenue Requirement Calculation:**			
18				
19	**Decrease in Rate Base (Line 6)**		**$ (11,174)**	**$ (10,631)**
20	**Retail Separation Factor**		**0.95326**	**0.95396**
21	**Decrease in Retail Rate Base (Line 19 x 20)**		**$ (10,651)**	**$ (10,142)**
22	**Pre-Tax Cost of Capital**		**9.8659%**	**9.9641%**
23	**Decrease in Return on Rate Base (Line 21 x 22)**		**$ (1,051)**	**$ (1,011)**
24	**Cost of Non-Equity Capital**		**1.4173%**	**1.5156%**
25	**Interest Synch Adjustment ((Line -21 x 24 x 0.38575)/0.61425)**		**$ 95**	**$ 97**
26				
27	**Decrease in Depreciation Expense**		**$ (624)**	**$ (624)**
28	**Retail Separation Factor**		**0.95309**	**0.95379**
29	**Decrease in Retail Depreciation Expense**		**$ (595)**	**$ (595)**
30	**Subtotal (Sum of Lines 23+25+29)**		**(1,551)**	**(1,509)**
31	**RAF and Bad Debt Multiplier**		**1.00137**	**1.00137**
32	**Total Decrease in Revenue Requirements**		**$ (1,553)**	**$ (1,511)**
33				
34				
35				
36				
37				
38	**Notes:**			
39	[a] Test Year utilized for Docket No. 120015-EI contained $10 million of estimated Fukushima capital costs. Proposed Company adjustment removes these assets from base rates and transfers them to the Capacity Clause.			
40	[b] Recovery under FPL's Capacity Clause is reviewed by FPSC's auditors annually.			

Florida Power & Light Company
Clause Recoverable Projects CWIP - FPSC & Company Adjustment
Exhibit KO-7
13-MONTH AVERAGE
($000)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
				2017				2018			
Line No.	Clause	Project	Function	Per Book	FPSC Adjustment	Company Adjustment	Total	Per Book	FPSC Adjustment	Company Adjustment	Total
1	CAPACITY	Incremental Plant Security Costs (1)	Steam	$1	($1)	$0	$0	$0	($0)	$0	$0
2	CAPACITY	Incremental Plant Security Costs (1)	Nuclear	3,595	(3,595)	-	-	2,510	(2,510)	-	-
3	CAPACITY	Incremental Plant Security Costs (1)	Other Generation	0	(0)	-	-	0	(0)	-	-
4	CAPACITY	Incremental Nuclear NRC Compliance Costs(1)	Nuclear	489	(489)	-	-	-	-	-	-
5											
6	ECCR	Load Management: On-Call Program - Residential	Distribution	1,459	-	(1,459)	-	1,462	-	(1,462)	-
7	ECCR	Solar PV for Schools	General Plant	6	-	(6)	-	0	-	(0)	-
8	ECCR	Common Expenses	Intangible	305	-	(305)	-	206	-	(206)	-
9	ECCR	Residential Home Energy Survey	Intangible	691	-	(691)	-	956	-	(956)	-
10											
11	ECRC	38 - Space Coast Solar (2)	General Plant	3	(3)	-	-	0	(0)	-	-
12	ECRC	37 - DeSoto Solar (2)	Other Generation	17	(17)	-	-	9	(9)	-	-
13	ECRC	39 - Martin Solar Energy Center (2)	Other Generation	105	(105)	-	-	55	(55)	-	-
14	ECRC	24 - Manatee Reburn (3)	Steam	4	(4)	-	-	0	(0)	-	-
15	ECRC	31 - CAIR (4)	Steam	376	(376)	-	-	870	(870)	-	-
16	ECRC	33 - CAMR (5)	Steam	276	(276)	-	-	515	(515)	-	-
17	ECRC	45 - 800 MW ESPs for Manatee and Martin (6)	Steam	10	(10)	-	-	0	(0)	-	-
18											
19	ECRC	23 - Spill Prevention Clean-Up & Countermeasures	Distribution	0	-	(0)	-	0	-	(0)	-
20	ECRC	23 - Spill Prevention Clean-Up & Countermeasures	Nuclear	147	-	(147)	-	18	-	(18)	-
21	ECRC	34 - St. Lucie Cooling Water Sys Insp & Maint	Nuclear	5,826	-	(5,826)	-	-	-	-	-
22	ECRC	42 - PTN Cooling Canal Monitoring Systems	Nuclear	24	-	(24)	-	2	-	(2)	-
23	ECRC	03 - Continuous Emission Monitoring	Other Generation	4	-	(4)	-	23	-	(23)	-
24	ECRC	08 - Oil Spill Cleanup / Response Equipment	Other Generation	10	-	(10)	-	0	-	(0)	-
25	ECRC	23 - Spill Prevention Clean-Up & Countermeasures	Other Generation	14	-	(14)	-	0	-	(0)	-
26	ECRC	28 - CWA 318(b) Phase II Rule	Other Generation	169	-	(169)	-	17	-	(17)	-
27	ECRC	03 - Continuous Emission Monitoring	Steam	28	-	(28)	-	5	-	(5)	-
28	ECRC	05 - Maintenance of Above Ground Fuel Tanks	Steam	2	-	(2)	-	0	-	(0)	-
29	ECRC	08 - Oil Spill Cleanup / Response Equipment	Steam	14	-	(14)	-	12	-	(12)	-
30	ECRC	23 - Spill Prevention Clean-Up & Countermeasures	Steam	37	-	(37)	-	18	-	(18)	-
31	ECRC	41 - Manatee Temporary Heating Systems	Steam	(0)	-	0	-	(0)	-	0	-
32	ECRC	50- Steam Electric Effluent Revised Rules	Steam	-	-	-	-	806	-	(806)	-
33	ECRC	54- Coal Combustion Residuals	Steam	809	-	(809)	-	2,098	-	(2,098)	-
34	ECRC	23 - Spill Prevention Clean-Up & Countermeasures	Transmission	22	-	(22)	-	22	-	(22)	-
35											
36											
37											
38		Total		$ 14,444	$ (4,876)	$ (9,568)	$ -	$ 9,605	$ (3,960)	$ (5,646)	$ -
39											
40	**Company Adjustment Revenue Requirement Calculation:**										
41		Decrease in Rate Base (Line 38)				$ (9,568)				$ (5,646)	
42		Retail Separation Factor				95.9785%				96.7200%	
43		Decrease in Retail Rate Base (Line 41 x 42)				$ (9,183)				$ (5,460)	
44		Pre-Tax Cost of Capital				9.8659%				9.9641%	
45		Decrease in Return on Rate Base (Line 43 x 44)				(906)				(544)	
46		Cost of Non-Equity Capital				1.4173%				1.5156%	
47		Interest Synch Adjustment ((Line -43 x 46 x 0.38575)/0.61425)				82				52	
48		Subtotal (Sum of Lines 45+47)				(824)				(492)	
49		RAF and Bad Debt Multiplier				1.00137				1.00137	
50		Total Decrease in Revenue Requirements (Line 48 * 49)				$ (825)				$ (493)	

51

52 **Notes:**
53 (1) Order No. PSC-13-0665-FOF-EI
54 (2) Order No. PSC-08-0491-PAA-EI
55 (3) Order No. PSC-03-1348-FOF-EI
56 (4) Order No. PSC-05-1251-FOF-EI
57 (5) Order No. PSC-06-0972-FOF-EI
58 (6) Order No. PSC-11-0083-FOF-EI

Florida Power & Light Company
Proration of Accumulated Deferred Income Taxes
Activity associated with Book/Tax Depreciation
2017 Test Year
Exhibit KO-8
($000's)

		A	B	C	D	E	F
			From Col A			A * D/Total C	From Col E
Line No.	**Month**	**Activity**	**Accumulated Activity**	**Days to Prorate**	**Future Days in Test Period**	**Prorated Monthly Activity**	**Prorated Accumulated Activity**
1							
2							
3	Beg Balance		$8,110,356				$8,110,356
4							
5	January	$26,531	$8,136,887	31	335	$24,350	$8,134,706
6	February	26,274	8,163,160	28	307	22,099	8,156,805
7	March	27,639	8,190,799	31	276	20,899	8,177,704
8	April	27,095	8,217,894	30	246	18,261	8,195,965
9	May	25,304	8,243,198	31	215	14,905	8,210,870
10	June	24,662	8,267,860	30	185	12,500	8,223,370
11	July	24,494	8,292,354	31	154	10,335	8,233,705
12	August	23,892	8,316,246	31	123	8,051	8,241,756
13	September	23,512	8,339,758	30	93	5,991	8,247,747
14	October	24,650	8,364,408	31	62	4,187	8,251,934
15	November	23,146	8,387,554	30	32	2,029	8,253,963
16	December	23,077	8,410,630	31	1	63	8,254,026
17	*Total*	$300,274		365		$143,670	
18							
19							
20	13-Month Average		$8,264,700				$8,207,147
21							
22	**Adjustment to Decrease ADIT to Prorated 13-Month Average**						**($57,553)**

Florida Power & Light Company
Proration of Accumulated Deferred Income Taxes
Activity associated with Book/Tax Depreciation
2018 Subsequent Year
Exhibit KO-8
($000's)

		A	B	C	D	E	F
			From Col A			A * D/Total C	From Col E
Line No.	**Month**	**Activity**	**Accumulated Activity**	**Days to Prorate**	**Future Days in Test Period**	**Prorated Monthly Activity**	**Prorated Accumulated Activity**
1							
2							
3	Beg Balance		$8,410,630				$8,254,026
4							
5	January	$14,715	8,425,345	31	335	$13,506	$8,424,136
6	February	14,521	8,439,866	28	307	12,214	8,436,349
7	March	14,947	8,454,814	31	276	11,303	8,447,652
8	April	15,261	8,470,075	30	246	10,286	8,457,938
9	May	13,818	8,483,893	31	215	8,139	8,466,077
10	June	13,234	8,497,127	30	185	6,708	8,472,785
11	July	13,116	8,510,243	31	154	5,534	8,478,318
12	August	12,603	8,522,846	31	123	4,247	8,482,565
13	September	13,620	8,536,466	30	93	3,470	8,486,036
14	October	13,713	8,550,178	31	62	2,329	8,488,365
15	November	12,185	8,562,363	30	32	1,068	8,489,433
16	December	12,134	8,574,497	31	1	33	8,489,467
17	*Total*	$163,867		365		$78,836	
18							
19							
20	13-Month Average		$8,495,257				$8,451,781
21							
22	**Adjustment to Decrease ADIT to Prorated 13-Month Average**						**($43,476)**

Florida Power & Light Company
Woodford Project Gas Reserves - Commission Adjustment - Rate Base[1]
Exhibit KO-9
($000)

Line No.	Gas FERC Accounts	2017 13-Month Avg	2018 13-Month Avg
1	325: Natural Gas Plant-Producing Leaseholds	$ 8,697	$ 8,697
2	330: Nat Gas Plant-Prod Wells-Construction	694,073	1,069,073
3	331: Nat Gas Plant-Prod Wells-Equipment	206,929	331,929
4	339: Nat Gas Plant-Asset Retirement Costs	242	242
5	105: Prod Prop Held Future Use	1,369	1,369
6	107: Construction Work in Progress	0	0
7	**Total Plant-in-Service [2]**	**$ 911,310**	**$ 1,411,310**
8			
9	108: Accm Prov Amortiz-ARO	$ (21)	$ (30)
10	111: Accm Prov Amortiz-Prod Leaseholds	(2,332)	(3,098)
11	111: Accm Prov Amortiz-Wells-Construction	(91,885)	(193,082)
12	111: Accm Prov Amortiz-Wells-Equipment	(29,443)	(62,960)
13	**Total Accumulated Depreciation/Depletion [3]**	**$ (123,680)**	**$ (259,171)**
14			
15	131: Cash-Gas Reserves	$ 2,177	$ 2,177
16	**Total Working Capital Assets [4]**	**$ 2,177**	**$ 2,177**
17			
18	230: Asset Retirement Obligation-Liability	$ (275)	$ (291)
19	232: Accounts Payable	(47,037)	(48,359)
20	234: Accounts Payable to Associated Co's	(955)	(1,426)
21	236: Taxes Accr-Federal Inc Tax	41,768	32,351
22	242: Misc Curr & Accr Liab-Other	(23,918)	(24,589)
23	**Total Working Capital Liabilities [5]**	**$ (30,417)**	**$ (42,314)**
24			
25			
26			
27			
28	<u>Notes:</u>		
29	[1] Rate base components associated with the gas reserves investment are removed from capital		
30	structure prorata over all sources of capital.		
31	[2] 2017 Test Year & 2018 SYA, MFR B-2, Page 1, Line 9		
32	[3] 2017 Test Year & 2018 SYA, MFR B-2, Page 1, Line 19		
33	[4] 2017 Test Year & 2018 SYA, MFR B-2, Page 2, Line 5		
34	[5] 2017 Test Year & 2018 SYA, MFR B-2, Page 2, Line 4		

Florida Power & Light Company
Woodford Project Gas Reserves - Commission Adjustment - NOI
Exhibit KO-9
($000)

Line No.	Gas FERC Accounts	2017	2018
1	NET OPERATING INCOME		
2	TOTAL OPERATION & MAINT EXPENSE		
3	FUEL AND INTERCHANGE EXPENSE		
4	752000: Nat Gas Prod&Gath Opers-Gas Wells	$ 2,679	$ 2,234
5	759000: NatGasProd&Gath Opers-Other Expenses	58,188	69,862
6	FUEL AND INTERCHANGE EXPENSE	60,867	72,096
7			
8	OTHER OPERATION & MAINT EXPENSE		
9	923600: Outside Services	1,412	1,440
10	OTHER OPERATION & MAINT EXPENSE	1,412	1,440
11			
12	TOTAL OPERATION & MAINT EXPENSE	62,278	73,536
13			
14	DEPRECIATION EXPENSE		
15	403190: Depreciation Expense-ARO	10	10
16	DEPRECIATION EXPENSE	10	10
17			
18	AMORT PROPERTY		
19	404100: Amort/Depletion Land/Rights	115,681	153,634
20	405200: Amortization of other Gas Plant	16	16
21	AMORT PROPERTY	115,697	153,650
22			
23	TAXES OTHER THAN INCOME TAX		
24	408190: Tax Other Than Inc Tax-Other	4,192	8,873
25	TAXES OTHER THAN INCOME TAX	4,192	8,873
26			
27	OPERATING INCOME TAX		
28	409180: Income taxes, Operating Inc-Federal	(93,617)	(72,351)
29	410196: Prov Def Tax-Oper Income-State	22,756	(19,480)
30	OPERATING INCOME TAX	(70,867)	(91,831)
31			
33	Total (1)	**$ 111,310**	**$ 144,238**

34 **Notes:**

35 (1) Refer to MFR C-3, Line 12 titled "FUEL CLAUSE - GAS RESERVES" which reflects the removal of this amount from Net Operating Income.

Florida Power & Light Company
Cedar Bay Transaction - Commission Adjustment - Rate Base and Net Operating Income
Exhibit KO-9
($000)

Line No.	FERC Account		2017 13-Month Avg		2018 13-Month Avg
1	**Rate Base**				
2					
3	182.3: Other Reg Asset: Cedar Bay Loss on PPA Base [1]	$	5,604	$	-
4	182.3: Other Reg Asset: Cedar Bay Tax GrossUp PPA Loss Base [3]		3,520		-
5	182.3: Other Reg Asset: Cedar Bay Loss on PPA Capacity [2]		412,655		362,491
6	182.3: Other Reg Asset: Cedar Bay Tx GrsUp PPA Loss Capacity [3]		259,148	$	227,645
7	**Total Cedar Bay Regulatory Assets [4]**	**$**	**675,322**	**$**	**590,136**
8					
9	254.6: Other Reg Liab: Book/Tax Difference on Acquired Plant [3]	$	5,686	$	4,928
10	**Total Cedar Bay Regulatory Liabilities [5]**	**$**	**5,686**	**$**	**4,928**
11					
12					
13					
14	**Net Operating Income**				
15					
16	**Cedar Bay Activity**				
17	557901: Oth Exp-Amortization Cedar Bay [6]	$	90,032	$	90,032
18	Income Tax Expense		34,730		34,730
19	Cedar Bay Net Operating Income		**55,302**		**55,302**
20					
21	**All Other Capacity Clause Activity**				
22	All Other Capacity Clause Revenues/Expenses	$	(122,717)	$	(121,614)
23	Income Tax Expense		(47,338)		(46,913)
24	All Other Capacity Clause Net Operating Income		**(75,379)**		**(74,701)**
25					
26	**Total Capacity Clause Net Operating Income [7]**	**$**	**(20,077)**	**$**	**(19,399)**
27					
28					

29 **Notes:**

30 [1] Per settlement agreement approved in Order No. PSC-15-0401-AS-EI, Docket No. 150075-EI, the unamortized balance reflected in base rates will be transferred to FPL's Capacity Costs Recovery Clause beginning on 1/1/2017.

31 [2] Removed from capital structure prorata over all sources of capital.

32 [3] Removed from capital structure as a specific adjustment to ADIT.

33 [4] Removed from Rate Base on MFR B-2, Page 2, Line 14

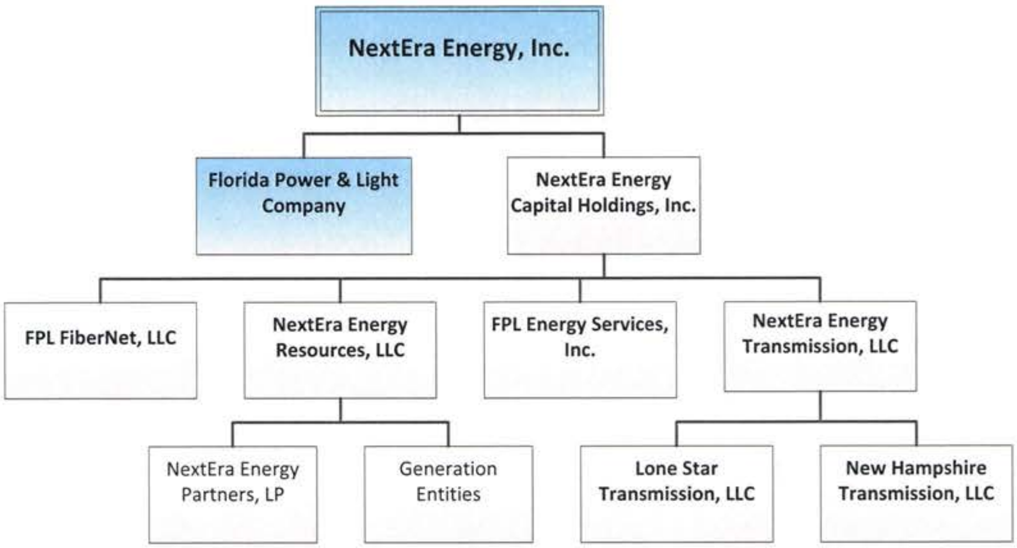
34 [5] Removed from Rate Base on MFR B-2, Page 2, Line 21

35 [6] Represents the amortization of the regulatory asset associated with the Cedar Bay Transaction.

36 [7] Refer to MFR C-3, Line 4 titled "CAPACITY COST RECOVERY" which reflects the removal of this amount from Net Operating Income.

FLORIDA POWER & LIGHT COMPANY

NextEra Energy, Inc. Primary Operating Entities Structure and Support



STRATEGIC AND GOVERNANCE SUPPORT

- Corporate Executive Team
- Investor Relations
- Internal Auditing
- General Counsel

FLEET CONSTRUCTION AND OPERATIONS SUPPORT

- Power Generation
- Nuclear
- Transmission and Substation
- Engineering and Construction
- Integrated Supply Chain
- Environmental

TRADITIONAL CORPORATE SUPPORT

- Human Resources
- Information Management
- Corporate Finance and Accounting
- Corporate Marketing and Communications
- Regulatory and External Affairs

TABLE OF CONTENTS

I. INTRODUCTION

This Cost Allocation Manual (CAM) documents cost allocation policies and practices, and provides guidelines to employees regarding the application of those policies for affiliate transactions.

The over-riding principle of this process is that resources shared between Florida Power and Light (FPL) and its affiliates cannot result in subsidization by the regulated entity on behalf of its non-regulated affiliates. This manual describes the standard services provided between FPL and its affiliates, as well as FPL's inter-company process for charging direct and indirect costs, the Corporate Services Charge (CSC), and other apportionment methods. The costing concepts and principles described herein are applied consistently to all subsidiaries billed by FPL.

When affiliates request services from FPL personnel, FPL employees should direct charge for services to the benefiting affiliate. This manual describes processes to direct charge those costs, as well as the allocation processes used when direct charging is not practical.

II. COST ACCOUNTING CONCEPTS

Costs are apportioned among entities based on three cost characteristics:

- **Direct** – Costs of resources used exclusively for the provision of services that are readily identifiable to an activity. An example of inter-company direct costs would be the fully-loaded salary of an engineer working on an affiliate's power plant.

- **Assigned** – Costs of resources used jointly in the provision of both regulated and non-regulated activities that are apportioned using direct measures of cost causation. The square footage cost of office space used by affiliates would be an example of assignable costs.

- **Unattributable** – Cost of resources shared by both regulated and non-regulated activities for which no causal relationship exists. These costs are accumulated and allocated to both regulated and non-regulated activities through the use of the CSC. The costs associated with NextEra Energy, Inc.'s board of directors is an example of unattributable costs allocated using the Corporate Services Charge (See Corporate Services Charge section for details on unattributable charges).

III. REGULATORY REQUIREMENTS AND REPORTING

FERC Accounting Guidelines

The Uniform System of Accounts (USOA), as prescribed by the Federal Energy Regulatory Commission (FERC), and adopted by the Florida Public Service Commission (FPSC), is found in the Code of Federal Regulations, Title 18, Subchapter C. Part 101. Application of these guidelines indicates that:

- Inter-company transactions are to be recorded in FERC account 146.

- Intra-Utility direct charge transactions are to be recorded in the appropriate account(s) within the operational function receiving the goods or services.
- Intra-Utility allocations of corporate center costs for business unit financial reporting are to be recorded in the Administrative and General (A&G) range of accounts. Administrative and general accounts should contain charges not chargeable directly to a particular operating function.

FERC recognizes explicitly in Order 707-A that the "at cost" pricing rules would be extended to single state holding companies that do not have centralized shared services companies. An important condition to this rule, however, is that such services may not be provided to unaffiliated third parties. The reason for this condition is that a market price is determinable in cases where such services are provided to third parties. Activities between FPL and its affiliates must comply with this Order.

FPSC Rule

The Florida Public Service Commission has adopted rules concerning cost allocation and affiliate transactions (25-6.1351). The purpose of these rules is to establish cost allocation requirements to ensure proper accounting for affiliate transactions and non-regulated utility activities so that these transactions and activities are not subsidized by utility ratepayers. The processes outlined in this cost allocation manual were developed to ensure compliance with this rule.

NARUC Guidelines

The National Association of Regulatory Utility Commissioners (NARUC) has developed a set of guidelines to assist regulated utilities and their affiliates in the development of procedures for recording transactions for services and products between a regulated entity and its affiliates. The prevailing premise of these guidelines is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities. The processes outlined in this manual are in accordance with these guidelines, as described in Exhibit A.

Diversification Report

In addition to the FERC Form No. 1, Annual Report of Major Electric Utilities, Licenses and Others, the FPSC requires the Utility to file an Annual Diversification Report. This report contains:

- Summary of changes to the corporate structure
- Updated structure showing parent and affiliates
- Summary of new or amended contracts with affiliates
- All transactions between regulated and non-regulated activities
- Detail reports of all individual transactions over $500,000 between FPL and affiliates
- Summary of asset transfers between FPL and affiliates
- Employee transfers between FPL and affiliates
- Analysis of non-tariffed services and products provided by the utility

IV. BILLINGS TO AFFILIATES FOR SERVICES PROVIDED BY FPL

FPL supports enterprise and affiliate operations through direct project activities and shared governance, compliance and other support functions. Direct activities are charged to affiliates through specific internal orders (see subsequent sections of this manual for process details). Shared support functions are allocated through the following mechanisms:

1. Corporate Services Charge (CSC)
2. Nuclear Operations Support Charge
3. Information Management Support Charge

All services provided to affiliates, either direct or allocated, are billed at actual cost using fully loaded rates. Payroll is charged by using the employee's actual payroll rate plus loaders, which cover payroll taxes, benefits, and administrative costs.

Corporate Services Charge (CSC) [1]

The Corporate Services Charge was implemented to bill Corporate Staff shared services and capital benefiting both FPL and its affiliates. This charge is based on a cost pool of shared services, which is allocated based on specific drivers or the Massachusetts formula.

Cost Pool – Corporate Shared Services
The Shared Services cost pool is determined annually through an extensive review of shared services and capital provided by FPL's Corporate Staff Departments to entities across the enterprise. The review is performed in conjunction with FPL's budget cycle and identifies the products and services to be allocated based upon each Work Breakdown Structure (WBS). These budgeted costs, along with capitalized hardware and software, are combined to obtain an estimated shared cost pool for the subsequent year. These shared costs are allocated to affiliates using specific drivers (where available) or the Massachusetts Formula.

Allocation – Massachusetts Formula
FPL reviewed options for allocation of the cost pool(s) where there were no specific driver(s) and elected to use the average of Payroll, Revenues and average Gross Property Plant and Equipment. This methodology is commonly referred to as the "Massachusetts Formula" and has been an industry standard for rate regulated allocations. The forecasted amounts for each of the three components are estimated for all applicable entities and given equal weight. An average is then computed for each operating entity, which when compared to the total, yields a ratio used to allocate its share of the cost pool.

The affiliate entities are billed monthly their share of the Corporate Services Charge using the ratios described above and the actual costs incurred for the month by the FPL department providing the service. Specifically, the amount of the charge is determined by multiplying the actual shared costs incurred (accumulated in SAP each month by WBS) by the appropriate driver percentages. The result is then allocated to the affiliates during the SAP settlement process as an inter-company charge.

[1] The CSC was formerly referred to as the Affiliate Management fee (AMF). The name has been changed in 2016 to more accurately describe the costs.

Corporate Shared Services and Capital

The list below includes examples of shared services that are provided by FPL to benefit the entire enterprise. These services are included in the Corporate Services Charge and are allocated to affiliates via the use of specific drivers or the Massachusetts Formula.

Shared Services Allocated via Specific Drivers

- **Information Management** (Specific drivers relating to workstations, mainframe time, etc.)
    - Corporate Applications – HR Employee Information System, Procurement, Financial Data Base, Email Systems
    - Communications & Technology – Telecommunications and Network Operating Centers (NOC)
    - Distributed Systems –Workstation, LAN and WAN Support
    - Mainframe Operations – GO and JB Computer Centers
    - PC Services – Help Desk and Workstation Support
    - Amortization and ROI – Shared Capitalized Hardware and Software

- **Human Resources/Corporate Real Estate/Security** (Specific drivers relating to FTE's and square footage)
    - Employee Relations – Safety Polices, Labor Relations Administration, and other employee related issues
    - Shared Services – Benefits Administration, Help Desk, Payroll, Educational Assistance, Recruiting, Equal Opportunity, Workforce Planning, Drug Testing and Group University
    - Benefit Programs
    - Health Centers
    - Corporate and Shared Facilities
    - Cafeteria Operations – Shared Affiliate Cafeteria Operations for applicable sites (JB, GO, LFO, CSE, PTN & PSL)
    - Security Administration – Facility Security, Data Security

- **Business Unit Leadership**
    - Power Generation Division drivers relating to megawatts
    - Nuclear Division drivers relating to number of units

Shared Services Allocated via Massachusetts Formula

- **Executive and Governance**
    - Salaries, benefits and expenses

- **Finance**
    - Corporate Transactions – Cash Management and Banking
    - Accounting – Cost Measurement & Allocation, Accounting Research & Financial Reporting
    - Corporate Tax
    - Finance and Trust Fund Investments
    - Planning and Analysis

  - Corporate Budgeting
  - Risk Management

- **Corporate Communications**
  - Internal Communications
  - External Media
  - Annual Report

- **General Counsel/Environmental/Compliance**
  - Shareholder Services
  - Board of Directors Fees
  - Environmental Services

- **Engineering and Construction**
  - Integrated Supply Chain – Administration of Corporate Travel and Integrated Supply Chain
  - Accounts Payable

- **Human Resources/Corporate Real Estate/Security**
  - Mail Services – Courier and Mail Services (GO, JB, LFO)

- **Internal Auditing**

- **Corporate Operational Development**
  - Quality, Planning, Analysis
  - Process Improvement Initiatives

Nuclear Operations Support Charges–Nuclear (NUC), IM Nuclear (IMNUC) [2]

Nuclear Operations Support Charges are utilized to bill shared nuclear fleet services. FPL has leveraged its fleet construction, compliance and operating capabilities over the broader enterprise for many years in order to optimize results for its customers. The larger scale of the enterprise fleet has historically allowed for shared expertise and the resulting competitive advantage. Service fee charges are managed by the Business Unit (Operating Business Unit or Staff Group) Budget Coordinators or Analysts and represent ongoing services provided or shared among affiliates. The Nuclear Operations Support Charges includes two types of charges: fleet support to NextEra Energy, Inc. (FPL and NextEra Energy Resources) nuclear plants and specific system support for NextEra Energy Resources nuclear plants.

The Nuclear Operations Support Charges do not receive the non-productive loader because full salaries are allocated based on relevant drivers to each entity served.

[2] *The Nuclear Operations Support Charges were formerly referred to as Service Fees. The name has been changed in 2016 to more accurately describe the costs.*

Nuclear Fleet Operations Support Charge

The Nuclear Fleet Operations Support Charge is billed using actual monthly charges accumulated and then allocated using the number of generating units as the driver. The Nuclear Operations Support Charge includes the following shared services:

- Nuclear Engineering
- Nuclear Assurance
- Nuclear Business Operations
- Nuclear Project Management
- Nuclear Security Access
- Nuclear Security
- Nuclear Licensing and Regulatory Support
- Nuclear Performance Improvement
- Nuclear Emergency Preparedness
- Nuclear Fuel Engineering
- Nuclear Change Management
- Nuclear Fleet Outage Planning - Long term
- Nuclear Training
- Six Sigma - Lean Process Improvement

Specific project related services not included in the Nuclear Fleet Operations Charge, which are direct charged NextEra Energy Resources by FPL Nuclear, are:

- Due Diligence
- Construction Projects
- Transition Teams
- Support of NextEra Energy Resources Capital Projects
- Outage Support
- Nuclear Project Controls (Cost tracking of projects)

Nuclear Information Management Operations Support Charge

The Nuclear Information Management Operations Support Charge is also billed using actual monthly charges that are accumulated and then allocated based on the number of generating units in place. The Information Management Nuclear Support Charge includes the following shared services:

- Nuclear Asset Management System (NAMS) Support
- IM Management
- Data Services
- IMO Nuclear Lead (Infrastructure Support)
- Nuclear Web Applications Support

Inter-Company Direct Billing

In accordance with FERC and FPSC requirements, FPL bills affiliates its fully loaded cost for services provided, using specific internal orders obtained via the following process:

1. **Affiliate Project Manager requests FPL employee services**

   The affiliate project manager contacts the FPL employee's supervisor and requests the services of the employee on a project for a specific amount of time or completion of a job.

2. **Project Manager completes request form for an Affiliate Internal Order (IO)**

   After obtaining approval by the supervisor, the Project Manager requesting the service must complete a request for an internal order - link to form: http://eweb/global/campaigns/sap/MD-Request.shtml
   The following information will be required:

   a) The Work Breakdown Structure (WBS) Element the order will be assigned to and settled to
   b) The settlement rule
   c) The functional area if required
   d) Requesting company code
   e) Overhead Key related to long term assignments, if applicable (See discussion of Long Term Assignment Rates below).

3. **Create Affiliate IO**

   The SAP Master Data Group will create the Affiliate IO using the information obtained in the request form.

4. **Inform Requestor of IO creation**

   After IO creation, the SAP Master Data Group will inform the requester by email.

5. **FPL Employee charges affiliate IO on the timesheet for specific hours worked**

   Charges to the Internal Orders are accumulated each month and loaded with the appropriate overheads billed by SAP during the month end closing process (see information regarding overhead rates below). Also included in the billable charges are any appropriate non-payroll charges.

It is the responsibility of the employee to ensure that any work performed for affiliates is properly recorded in his/her timesheet. It is the responsibility of each employee's supervisor to ensure that all time sheets are reviewed in accordance with FPL's Sarbanes –Oxley processes to ensure that all affiliates are properly charged.

Allocation of Costs for Significant Capital Projects

For significant capital projects which will benefit the enterprise and/or FPL and certain affiliates (typically software development projects), the business case developed in support of the project will identify future expected benefits to each of the entities that will be utilizing the system or application. For these projects, an analysis should be performed during the planning phase to determine the appropriate sharing of costs and each benefitting entity should record their respective share of the capital project. Post implementation, on-going maintenance activity costs are included in the CSC as described in the Information Management paragraph under the Corporate Services Charge section above.

Transfer of Assets from FPL to Affiliates

In addition to services provided, FPL may transfer assets used in its regulated operations to an affiliate. In accordance with FPSC and FERC requirements, FPL will charge the non-regulated affiliate the greater of market price or net book value. It is the responsibility of the Investment Recovery Operations group to ensure that market testing is performed and that proper documentation is maintained. An independent appraiser must verify the market value of a transferred asset with a net book value greater than $1,000,000. On certain occasions, FPL may record the asset at either market price or net book value if it maintains documentation to support and justify that such a transaction benefits regulated operations. When these billings occur, notification must be given to Cost Measurement and Allocation to ensure proper reporting of these transactions as required by FERC and FPSC.

OVERHEAD RATES

FPL Overhead Rates

FPL attaches various overhead rates to payroll charged to affiliates to ensure that all relevant indirect costs associated with each employee are appropriately billed. Overhead rates and the purposes of each are described below:

Rate Description	Type	Rate Purpose
Pension & Welfare	Internal/External	Pension & Welfare recovers company dollars budgeted for current year for expenses related to life, medical & dental insurance, thrift plan and long term disability benefits. Also recovers pension, retiree medical, employee education assistance and benefit costs.
Payroll Tax OH FICA (Social Security & Medicare) FUTA (Federal Unemployment Insurance) SUTA (State Unemployment Insurance)	Internal/External	Recovers estimated company payments for social security, Medicare, state & federal unemployment and workers compensation insurance.
Performance Incentives - Exempt	Internal/External	Recovers the cost of the budgeted performance incentive for exempt employees.
Workers Comp	Internal/External	Recovers estimated payments for workers comp insurance.
A&G Payroll	External	Recovers the O&M payroll of corporate and business unit staff support
A&G Expenses	External	Recovers the O&M expenses of corporate and business unit staff support
Non-Productive	External	Recovers the cost of non-productive time such as vacation, sick time and other non-excused absences plus non-distributed other earnings such as relieving time, shift differential and merit pay. Distribution, Transmission and Substation non-productive is applied to bargaining variable direct labor only.

The internal rates above are based on forecasted data, are calculated annually during the budget cycle, and are in effect beginning in January of each year. The external rates are based on historical data, are calculated during Q1, and are in effect beginning in March of each year. See Exhibit B for a list of rates in effect for 2016.

Long Term Assignment Rates

When FPL employees are used exclusively for affiliate activities for extended periods of time, a reduced Long-Term Loading Rate should be used. This is due to two factors. First, non-productive time (sick, vacation, holiday) is already included in the salary being allocated since it is expected that a full year's salary is allocated. If non-productive time were also loaded, the affiliate would be charged twice. Secondly, the affiliate will be providing the necessary A&G support, such as supervision, office equipment, supplies, etc. therefore, FPL A&G expenses should not be included in the loading rate.

To qualify for reduced loading, the employee must reasonably expect to charge their time to an affiliate internal order for one full year, and be physically located at the affiliate offices. If an employee's charges during the year fall below 75%, they must be removed from the long-term loading rate.

Employees meeting the above requirements must charge a specific Internal Order that has been set up to accommodate long term assignments. When an IO is requested by the Affiliate Project Manager (see step 2 under "Affiliate Direct Charges thru Specific Internal Orders" above), the request must include a special Overhead Key "Z604: Long-Term No External Overheads on the IO Master Record". These inter-company IO's receive payroll taxes and benefits, but no external overheads. Once the employee's charges fall below 75%, they must charge an IO that has been set up to include the external overheads.

FACILITY AND EQUIPMENT CHARGES

The Cost Measurement and Allocation group is responsible for monthly entries to bill the following activities:

Systems Charges:
A small number of affiliates utilize various FPL systems on a limited basis for printing, mailing and payment processing of various items. These systems include the SAP and Payment Processing Center (PPC) systems. The use of these systems is billed on a transactional basis. A cost study is performed by the Customer Service organization in conjunction with the Cost Measurement and Allocation department to determine the cost to FPL per transaction for these systems. The number of transactions is collected monthly and billed to the affiliates at those rates.

The Power Delivery unit (specifically Transmission/Substation) shares various hardware and software applications with a regulated affiliate. The charges are billed based on actual costs and are calculated using specific drivers that best represent the activity (i.e., number of users, number of network devices, number of servers, etc).

Furniture and Computers:
Affiliates are billed monthly for office furniture using a weighted average rate that includes the cost for fully depreciated furniture for which no market exists, and market value for new furniture. A market rate analysis is performed periodically by Corporate Real Estate and was last prepared in 2015.

Affiliates are also billed monthly for personal computers based on cost. All charges are based on the number of FPL owned units utilized by the affiliates.

Office Space:
Space is available to the affiliates in FPL buildings only when vacancies exist. The non-regulated affiliates are charged for the square feet they occupy based on the higher of cost or a market rate, which is updated every five years based on a market study performed by Corporate Real Estate (CRE). Regulated affiliates are billed based on cost. The next market study will be conducted in 2017.

V. BILLINGS TO FPL FOR SERVICES PROVIDED BY AFFILIATES

Limited shared services provided by affiliate personnel are charged to FPL using actual costs allocated based on specific drivers. FPL's Cost Measurement and Allocations group reviews the driver calculations on an annual basis, and receives email notification from the affiliates as driver updates are made in SAP.

Transfer of Assets to FPL from Affiliates

Billings from affiliates to FPL for assets transferred are based on the lower of cost or market. It is the responsibility of the Investment Recovery Operations group to ensure that market testing is performed and that proper documentation is maintained. An independent appraiser must verify the market value of a transferred asset with a net book value greater than $1,000,000. On certain occasions, FPL may record the asset at either market price or net book value if it maintains documentation to support and justify that such a transaction benefits regulated operations. When these billings occur, notification must be given to Cost Measurement and Allocation to ensure proper reporting of these transactions as required by FERC and FPSC.

Affiliate Overhead Rates

The calculation and maintenance of the overhead rates applied to direct charges coming in to the utility are the responsibility of the affiliate performing the services. On an annual basis (typically at the end of Q1), the Cost Measurement and Allocation group requests, from applicable affiliates, the rates that will be used in the upcoming year, along with email confirmation that the rates have been properly updated in SAP.

Affiliate Procurement of Goods under Vendors Common with FPL

When affiliates procure goods from common vendors of FPL, they should do so directly under separate affiliate purchase orders. This ensures invoicing and product delivery will be processed directly to the affiliate, and the affiliate will not be billed for FPL's loading costs. It also ensures that the contract terms (warranties and liabilities) of the purchase order(s) are placed with the affiliate, not with FPL. In some cases, the affiliate has the ability to take advantage of master agreements established between FPL and the vendor. FPL's strategy is to evaluate fleet wide (multi-site) agreements category by category with a focus on total value for FPL and supplier quality, taking advantage of leverage opportunities to consolidate the spend across the entire fleet, establish long term contracts with a limited number of suppliers of proven experience and quality, and to negotiate terms that provide for shared risks and shared benefits for improved performance.

VI. DEFINITIONS

Affiliates – Companies that are related to each other due to common ownership or control.

Cost Allocators – The methods or ratios used to apportion costs. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).

Common Costs – Cost associated with services or products that are of joint benefit to both regulated and non–regulated business units.

Cost Driver – A measurable event or quantity which influences the level of costs incurred and which can be directly traced to an origin of the costs themselves.

Fully Allocated – Services or products bear the sum of the cost drivers plus an appropriate share of the indirect costs.

Non-regulated – Refers to services or products not subject to regulation by regulatory authorities.

Prevailing Market Rate – A generally accepted market value that can be substantiated by clearly comparable transactions, auction or appraisal.

Regulated – Refers to utility services or products subject to rate regulation by regulatory authorities.

Subsidization – The recovery of costs from one class of customers, business unit or entity, that are attributable to another.

Cost Measurement & Allocation Department
Cost Allocation Manual (CAM)
Exhibit A – NARUC Guidelines for Cost Allocations and Affiliate Transactions

Guidelines for Cost Allocations and Affiliate Transactions:

The following Guidelines for Cost Allocations and Affiliate Transactions (Guidelines) are intended to provide guidance to jurisdictional regulatory authorities and regulated utilities and their affiliates in the development of procedures and recording of transactions for services and products between a regulated entity and affiliates. The prevailing premise of these Guidelines is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities unless authorized by the jurisdictional regulatory authority. These Guidelines are not intended to be rules or regulations prescribing how cost allocations and affiliate transactions are to be handled. They are intended to provide a framework for regulated entities and regulatory authorities in the development of their own policies and procedures for cost allocations and affiliated transactions. Variation in regulatory environment may justify different cost allocation methods than those embodied in the Guidelines.

The Guidelines acknowledge and reference the use of several different practices and methods. It is intended that there be latitude in the application of these guidelines, subject to regulatory oversight. The implementation and compliance with these cost allocations and affiliate transaction guidelines, by regulated utilities under the authority of jurisdictional regulatory commissions, is subject to Federal and state law. Each state or Federal regulatory commission may have unique situations and circumstances that govern affiliate transactions, cost allocations, and/or service or product pricing standards. For example, The Public Utility Holding Company Act of 1935 requires registered holding company systems to price "at cost" the sale of goods and services and the undertaking of construction contracts between affiliate companies.

The Guidelines were developed by the NARUC Staff Subcommittee on Accounts in compliance with the Resolution passed on March 3, 1998 entitled "Resolution Regarding Cost Allocation for the Energy Industry" which directed the Staff Subcommittee on Accounts together with the Staff Subcommittees on Strategic Issues and Gas to prepare for NARUC's consideration, "Guidelines for Energy Cost Allocations." In addition, input was requested from other industry parties. Various levels of input were obtained in the development of the Guidelines from the Edison Electric Institute, American Gas Association, Securities and Exchange Commission, the Federal Energy Regulatory Commission, Rural Utilities Service and the National Rural Electric Cooperatives Association as well as staff of various state public utility commissions.

In some instances, non-structural safeguards as contained in these guidelines may not be sufficient to prevent market power problems in strategic markets such as the generation market. Problems arise when a firm has the ability to raise prices above market for a sustained period and/or impede output of a product or service. Such concerns have led some states to develop codes of conduct to govern relationships between the regulated utility and its non-regulated affiliates. Consideration should be given to any "unique" advantages an incumbent utility would have over competitors in an emerging market such as the retail energy market. A code of conduct should be used in conjunction with guidelines on cost allocations and affiliate transactions.

A. DEFINITIONS

1. Affiliates - companies that are related to each other due to common ownership or control.

2. Attestation Engagement - one in which a certified public accountant who is in the practice of public accounting is contracted to issue a written communication that expresses a conclusion about the reliability of a written assertion that is the responsibility of another party.

3. Cost Allocation Manual (CAM) - an indexed compilation and documentation of a company's cost allocation policies and related procedures.

4. Cost Allocations - the methods or ratios used to apportion costs. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).

5. Common Costs - costs associated with services or products that are of joint benefit between regulated and non-regulated business units.

6. Cost Driver - a measurable event or quantity which influences the level of costs incurred and which can be directly traced to the origin of the costs themselves.

7. Direct Costs - costs which can be specifically identified with a particular service or product.

8. Fully Allocated costs - the sum of the direct costs plus an appropriate share of indirect costs.

9. Incremental pricing - pricing services or products on a basis of only the additional costs added by their operations while one or more pre-existing services or products support the fixed costs.

10. Indirect Costs - costs that cannot be identified with a particular service or product. This includes but not limited to overhead costs, administrative and general, and taxes.

11. Non-regulated - that which is not subject to regulation by regulatory authorities.

12. Prevailing Market Pricing - a generally accepted market value that can be substantiated by clearly comparable transactions, auction or appraisal.

13. Regulated - that which is subject to regulation by regulatory authorities.

14. Subsidization - the recovery of costs from one class of customers or business unit that are attributable to another.

B. COST ALLOCATION PRINCIPLES

The following allocation principles should be used whenever products or services are provided between a regulated utility and its non-regulated affiliate or division.

1. To the maximum extent practicable, in consideration of administrative costs, costs should be collected and classified on a direct basis for each asset, service or product provided.

2. The general method for charging indirect costs should be on a fully allocated cost basis. Under appropriate circumstances, regulatory authorities may consider incremental cost, prevailing market pricing or other methods for allocating costs and pricing transactions among affiliates.

3. To the extent possible, all direct and allocated costs between regulated and non-regulated services and products should be traceable on the books of the applicable regulated utility to the applicable Uniform System of Accounts. Documentation should be made available to the appropriate regulatory authority upon request regarding transactions between the regulated utility and its affiliates.

4. The allocation methods should apply to the regulated entity's affiliates in order to prevent

subsidization from, and ensure equitable cost sharing among the regulated entity and its affiliates, and vice versa.

5. All costs should be classified to services or products which, by their very nature, are either regulated, non-regulated, or common to both.

6. The primary cost driver of common costs, or a relevant proxy in the absence of a primary cost driver, should be identified and used to allocate the cost between regulated and non-regulated services or products.

7. The indirect costs of each business unit, including the allocated costs of shared services, should be spread to the services or products to which they relate using relevant cost allocators.

C. COST ALLOCATION MANUAL (NOT TARIFFED)

Each entity that provides both regulated and non-regulated services or products should maintain a cost allocation manual (CAM) or its equivalent and notify the jurisdictional regulatory authorities of the CAM's existence. The determination of what, if any, information should be held confidential should be based on the statutes and rules of the regulatory agency that requires the information. Any entity required to provide notification of a CAM(s) should make arrangements as necessary and appropriate to ensure competitively sensitive information derived therefrom be kept confidential by the regulator. At a minimum, the CAM should contain the following:

1. An organization chart of the holding company, depicting all affiliates, and regulated entities.

2. A description of all assets, services and products provided to and from the regulated entity and each of its affiliates.

3. A description of all assets, services and products provided by the regulated entity to non-affiliates.

4. A description of the cost allocators and methods used by the regulated entity and the cost allocators and methods used by its affiliates related to the regulated services and products provided to the regulated entity.

D. AFFILIATE TRANSACTIONS (NOT TARIFFED)

The affiliate transactions pricing guidelines are based on two assumptions. First, affiliate transactions raise the concern of self-dealing where market forces do not necessarily drive prices. Second, utilities have a natural business incentive to shift costs from non-regulated competitive operations to regulated monopoly operations since recovery is more certain with captive ratepayers. Too much flexibility will lead to subsidization. However, if the affiliate transaction pricing guidelines are too rigid, economic transactions may be discouraged.

The objective of the affiliate transactions' guidelines is to lessen the possibility of subsidization in order to protect monopoly ratepayers and to help establish and preserve competition in the electric generation and the electric and gas supply markets. It provides ample flexibility to accommodate exceptions where the outcome is in the best interest of the utility, its ratepayers and competition. As with any transactions, the burden of proof for any exception from the general rule rests with the proponent of the exception.

1. Generally, the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be at the higher of fully allocated costs or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

2. Generally, the price for services, products and the use of assets provided by a non-regulated affiliate to a regulated affiliate should be at the lower of fully allocated cost or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

3. Generally, transfer of a capital asset from the utility to its non-regulated affiliate should be at the greater of prevailing market price or net book value, except as otherwise required by law or regulation. Generally, transfer of assets from an affiliate to the utility should be at the lower of prevailing market price or net book value, except as otherwise required by law or regulation. To determine prevailing market value, an appraisal should be required at certain value thresholds as determined by regulators.

4. Entities should maintain all information underlying affiliate transactions with the affiliated utility for a minimum of three years, or as required by law or regulation.

E. AUDIT REQUIREMENTS

1. An audit trail should exist with respect to all transactions between the regulated entity and its affiliates that relate to regulated services and products. The regulator should have complete access to all affiliate records necessary to ensure that cost allocations and affiliate transactions are conducted in accordance with the guidelines. Regulators should have complete access to affiliate records, consistent with state statutes, to ensure that the regulator has access to all relevant information necessary to evaluate whether subsidization exists. The auditors, not the audited utilities, should determine what information is relevant for a particular audit objective. Limitations on access would compromise the audit process and impair audit independence.

2. Each regulated entity's cost allocation documentation should be made available to the company's internal auditors for periodic review of the allocation policy and process and to any jurisdictional regulatory authority when appropriate and upon request.

3. Any jurisdictional regulatory authority may request an independent attestation engagement of the CAM. The cost of any independent attestation engagement associated with the CAM, should be shared between regulated and non-regulated operations consistent with the allocation of similar common costs.

4. Any audit of the CAM should not otherwise limit or restrict the authority of state regulatory authorities to have access to the books and records of and audit the operations of jurisdictional utilities.

5. Any entity required to provide access to its books and records should make arrangements as necessary and appropriate to ensure that competitively sensitive information derived therefrom be kept confidential by the regulator.

F. REPORTING REQUIREMENTS

1. The regulated entity should report annually the dollar amount of non-tariffed transactions

associated with the provision of each service or product and the use or sale of each asset for the following:

a. Those provided to each non-regulated affiliate.

b. Those received from each non-regulated affiliate.

c. Those provided to non-affiliated entities.

2. Any additional information needed to assure compliance with these Guidelines, such as cost of service data necessary to evaluate subsidization issues, should be provided.

Cost Measurement & Allocation Department
Cost Allocation Manual (CAM)
Exhibit B – 2016 Overhead Loading Rates

Overhead Rates Applied to Direct Charges

Non-productive payroll	19.87%
Performance Incentive	13.40%
Pension and Welfare	10.09%
Administrative and General Payroll	13.55%
Administrative and General Expense	11.88%
Payroll Taxes	6.48%
Workers Compensation Insurance	Varies by BU

Overhead Rates Applied to the Nuclear Operations Support Charges

Performance Incentive	13.40%
Pension and Welfare	10.09%
Administrative and General Payroll	13.55%
Administrative and General Expense	11.88%
Payroll Taxes	6.48%
Workers Compensation Insurance	Varies by BU

Overhead Rates Applied to Shared Services Payroll Dollars Included in the CSC

Performance Incentive	13.40%
Pension and Welfare	10.09%
Payroll Taxes	6.48%
Workers Compensation Insurance	Varies by BU

FLORIDA POWER & LIGHT COMPANY
Cost Measurement & Allocation Department
Cost Allocation Manual (CAM)
2016

Description	FPL	NEER	FLORIDA FIBERNET	FPLES / Readipower	NEECH/NEE/ Palms	NHT	LST	NEET	TEXAS FIBERNET	Total Affiliate %
MASS FORMULA RATIOS										
MF-Shared	60.87%	36.79%	0.84%	0.43%	0.13%	0.07%	0.63%	0.16%	0.07%	39.13%
SPECIFIC DRIVERS										
Headcount	61.93%	34.73%	1.68%	0.66%	0.32%	0.00%	0.25%	0.25%	0.17%	38.07%
Square Footage - All sites	82.12%	14.66%	0.16%	0.55%	1.88%	0.03%	0.05%	0.54%		17.88%
Square Footage - Juno Beach Office	58.89%	34.98%	0.02%	0.00%	4.74%	0.08%	0.00%	1.30%	0.00%	41.11%
Capitalized Hardware/Software shared with Affiliates	80.38%	16.80%	1.83%	0.65%	0.00%	0.00%	0.18%	0.14%	0.03%	19.63%
Affiliate Megawatts - NUC Executive	50.00%	50.00%								50.00%
Affiliate Megawatts - PGD Executive	56.31%	43.69%								43.69%
Actual number of workstations per Business Unit for support and project activities	66.94%	30.58%	1.33%	0.64%			0.24%	0.17%	0.10%	33.06%
Actual number of workstations per Business Unit (includes Affiliates in FPL/Florida facilities) for support and project activities	86.44%	10.89%	1.59%	0.83%			0.05%	0.20%		13.56%
IM resources for transmission systems supporting Affiliates	87.50%	7.50%					5.00%			12.50%
Servers per Business Unit / Affiliate for support and project activities	78.41%	18.35%	2.68%	0.48%			0.08%			21.59%
Database Administrator Resource - Business Intelligence Data Movement	94.33%	5.67%								5.67%
Database Administrator Resource - Technical Support	98.47%		1.53%							1.53%
HR Systems Support Activities Based on Headcount	66.31%	31.59%	1.27%	0.63%			0.20%			33.69%
SAP User count per Business Unit / Affiliate for support and project activities	59.55%	36.39%	2.62%	0.55%			0.35%	0.33%	0.21%	40.45%

Florida Power & Light Company
Direct Charges to Affiliates
Exhibit KO-12
($000)

Line No.	A Affiliate	B 2013 Actuals	C 2014 Actuals	D 2015 Historical Year	E 2016 Prior Year	F 2017 Test Year	G 2018 Subsequent Year
1	NextEra Energy Resources, LLC [1]	$ 40,718	$ 56,913	$ 61,832	$ 58,535	$ 57,757	$ 57,679
2	FPL Energy Services, Inc. [2]	3,251	3,864	4,003	2,847	2,706	2,807
3	FPL Fibernet, LLC [3]	2,511	2,875	3,078	1,204	1,215	1,237
4	NextEra Energy Capital Holdings, Inc. [4]	11,006	7,544	7,486	4,658	1,918	2,022
5	NextEra Energy Transmission, LLC	846	1,131	756	610	671	739
6	Lone Star Transmission, LLC	773	877	610	866	584	556
7	New Hampshire Transmission, LLC	181	207	83	219	220	227
8	**Total**	**$ 59,266**	**$ 73,413**	**$ 77,847**	**$ 68,939**	**$ 65,071**	**$ 65,266**

9

10

11 **Operations Support Charges to NextEra Energy Resources[5]**

12

Line No.	Affiliate	2013 Actuals	2014 Actuals	2015 Historical Year	2016 Prior Year	2017 Test Year	2018 Subsequent Year
15	NextEra Energy Resources, LLC [6]	$ 14,750	$ 15,552	$ 18,769	$ 22,079	$ 22,711	$ 23,397

16

17

18 **Notes:**

19 [1] Includes NextEra Energy Resources, LLC and related affiliates

20 [2] Includes FPL Readi-Power, LLC

21 [3] Includes FPL Fibernet, LLC and NextEra Fibernet, LLC

22 [4] Includes NextEra Energy, Inc.

23 [5] Operations Support Charges formerly referred to as Service Fees

24 [6] Includes Operational and Information Management support for NEE's Nuclear fleet

Docket No. 160021-EI
Corporate Services Charges - Historical and
Projected Specific Cost Drivers and
Massachusetts Formula Ratios
Exhibit KO-13, Page 1 of 1

Florida Power & Light Company

Corporate Services Charge

Historical and Projected Specific Cost Drivers, and Percent Billed to Affiliates

Exhibit KO-13

Line No.	Description	2013 Actuals	2014 Actuals	2015 Historical Year	2016 Prior Year	2017 Test Year	2018 Subsequent Year
1	Headcount	34.17%	35.52%	36.81%	38.06%	38.06%	38.06%
2	Square Footage	22.61%	16.60%	18.51%	17.88%	17.88%	17.88%
3	Square Footage - Juno Beach Office	33.72%	37.05%	39.93%	41.11%	41.11%	41.11%
4	Capitalized Hardware/Software shared with Affiliates	12.72%	16.74%	18.14%	19.62%	19.58%	19.56%
5	Corporate Nuclear Executives (allocated by # of units)	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
6	Corporate Power Generation Division Executives (allocated by megawatts)	41.40%	43.93%	39.59%	43.69%	45.90%	48.37%
7	Corporate Business Unit resource supporting Affiliates	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%
8	SAP User count per Business Unit / Affiliate for support and project activities	37.14%	37.64%	39.27%	40.45%	40.45%	40.45%
9	Actual % of FPL's Affiliates workforce as a % of total FPL workforce	33.06%	34.58%	35.81%	37.36%	37.36%	37.36%
10	Actual number of workstations per Business Unit for support and project activities	25.08%	28.69%	32.74%	33.06%	33.06%	33.06%
11	Actual number of workstations per Business Unit (includes Affiliates in FPL/Florida facilities) for support and project activities	7.89%	10.34%	10.91%	13.55%	13.55%	13.55%
12	Servers per Business Unit / Affiliate for support and project activities	20.50%	26.17%	23.12%	21.59%	21.59%	21.59%
13	Database Administrator Resource - Business Intelligence Data Movement	4.86%	4.86%	5.67%	5.67%	5.67%	5.67%
14	Database Administrator Resource - Technical Support	1.94%	1.32%	1.53%	1.53%	1.53%	1.53%
15							
16							
17							
18	**Historical and Projected Massachusetts Formula Allocation Drivers**						
19							
20		**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
21	**Company Name**	**Actuals**	**Actuals**	**Historical Year**	**Prior Year**	**Test Year**	**Subsequent Year**
22	FPL	64.67%	64.24%	61.83%	60.87%	60.01%	58.71%
23	NextEra Energy Resources, LLC	32.93%	33.22%	35.59%	36.79%	37.62%	39.00%
24	FPL FiberNet, LLC	1.12%	1.08%	1.18%	0.91%	0.91%	0.92%
25	FPL Energy Services, Inc.	0.43%	0.41%	0.42%	0.43%	0.51%	0.49%
26	NextEra Energy Capital Holdings, Inc.	0.19%	0.17%	0.13%	0.13%	0.13%	0.12%
27	Lone Star Transmission, LLC	0.48%	0.69%	0.63%	0.63%	0.59%	0.55%
28	NextEra Energy Transmission, LLC	0.10%	0.12%	0.14%	0.16%	0.16%	0.16%
29	New Hampshire Transmission, LLC	0.07%	0.08%	0.08%	0.07%	0.07%	0.07%
30	TOTAL	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Florida Power & Light Company
Historical and Projected Corporate Services Charges(1)
Cost Pools and Costs Billed to Affiliates
Exhibit KO-14
($000's)

Line No.	Company Name	2013 Actuals	2013 % of Cost Pool	2014 Actuals	2014 % of Cost Pool	2015 Historical Year	2015 % of Cost Pool	2016 Prior Year	2016 % of Cost Pool	2017 Test Year	2017 % of Cost Pool	2018 Subsequent Year	2018 % of Cost Pool
1	FPL	$181,239	69.82%	$157,918	68.35%	$156,836	66.77%	$162,277	65.12%	$158,427	64.89%	$160,609	64.29%
2	NextEra Energy Resources, LLC	72,400	27.89%	67,221	29.10%	71,640	30.50%	80,198	32.18%	79,096	32.40%	82,506	33.03%
3	FPL Energy Services, Inc.	1,365	0.53%	1,249	0.54%	1,282	0.55%	1,353	0.54%	1,421	0.58%	1,422	0.57%
4	FPL FiberNet, LLC	2,989	1.15%	3,058	1.32%	3,501	1.49%	3,536	1.42%	3,493	1.43%	3,568	1.43%
5	NextEra Energy Capital Holdings, Inc. (2)	414	0.16%	301	0.13%	281	0.12%	301	0.12%	289	0.12%	289	0.12%
6	NextEra Energy Transmission, LLC	232	0.09%	292	0.13%	331	0.14%	470	0.19%	466	0.19%	471	0.19%
7	Lone Star Transmission, LLC	840	0.32%	918	0.40%	920	0.39%	969	0.39%	885	0.36%	868	0.35%
8	New Hampshire Transmission, LLC	94	0.04%	80	0.03%	87	0.04%	85	0.03%	75	0.03%	75	0.03%
9	TOTAL COST POOL	$259,573	100.00%	$231,038	100.00%	$234,876	100.00%	$249,189	100.00%	$244,152	100.00%	$249,807	100.00%
10													
11	Percent decrease of cost pools from 2013										-6%		-4%
12	Percent increase of costs billed to affiliates from 2013										9%		14%
13													
14													
15													
16													
17													
18	**Notes:**												
19	(1) Corporate Services Charges formerly referred to as the Affiliate Management Fee												
20	(2) Includes NextEra Energy, Inc. and Palms Insurance												