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**IN THE SUPREME COURT OF FLORIDA**

**CASE NO.: SC18-226**
Lower Tribunal No.: 20180001-EI

FLORIDA INDUSTRIAL POWER
USERS GROUP,

Appellant,

vs.

JULIE I. BROWN, etc., et al.,

Appellees.

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# AMENDED APPENDIX TO ANSWER BRIEF OF FLORIDA POWER & LIGHT COMPANY

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A conformed copy of the PSC Order under review can be found at **TAB D**

TAB A

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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| In re: Petition for rate increase by Florida Power & Light Company. | DOCKET NO. 160021-EI |
| In re: Petition for approval of 2016-2018 storm hardening plan, by Florida Power & Light Company. | DOCKET NO. 160061-EI |
| In re: 2016 depreciation and dismantlement study by Florida Power & Light Company. | DOCKET NO. 160062-EI |
| In re: Petition for limited proceeding to modify and continue incentive mechanism, by Florida Power & Light Company. | DOCKET NO. 160088-EI<br>ORDER NO. PSC-16-0560-AS-EI<br>ISSUED: December 15, 2016 |

The following Commissioners participated in the disposition of this matter:

JULIE I. BROWN, Chairman
LISA POLAK EDGAR
ART GRAHAM
RONALD A. BRISÉ
JIMMY PATRONIS

ORDER APPROVING SETTLEMENT AGREEMENT

BY THE COMMISSION:

Background

On January 15, 2016, Florida Power & Light Company (FPL) filed a test year letter, as required by Rule 25-6.140, Florida Administrative Code (F.A.C.), notifying the Florida Public Service Commission (Commission) of its intent to file a petition for an increase in rates effective 2017. Pursuant to the provisions of Chapter 366, Florida Statutes (F.S.), and Rules 25-6.0425 and 25-6.043, F.A.C., FPL filed its Minimum Filing Requirements and testimony on March 15, 2016. Docket Nos. 160061-EI (2016-2018 Storm Hardening Plan), 160062-EI (2016 Depreciation and Dismantlement Study) and 160088-EI (Incentive Mechanism), were thereafter consolidated into the rate case docket, Docket No. 160021-EI.[1] Nine parties were granted intervention in the docket.[2] Prehearing Order No. PSC-16-0341-PHO-EI, issued on August 19,

[1] Order No. PSC-16-0182-PCO-EI, issued on May 4, 2016, in Docket No. 160021-EI, In re: Petition for rate increase by Florida Power & Light Company; Docket No. 160061-EI, In re: Petition for approval of 2016-2018 storm hardening plan, by Florida Power & Light Company; Docket No. 160062-EI, In re: 2016 depreciation and dismantlement study by Florida Power & Light Company; Docket No. 160088-EI, In re: Petition for limited proceeding to modify and continue incentive mechanism, by Florida Power & Light Company.

[2] Office of Public Counsel (OPC), Florida Industrial Power Users Group (FIPUG), Wal-Mart Stores East, LP and Sam's East, Inc. (Walmart), Federal Executive Agencies (FEA), South Florida Hospital and Healthcare Association

2016, established 167 issues which included issues associated with the 2016-2018 Storm Hardening Plan, the 2016 Depreciation and Dismantlement Study, the Incentive Mechanism, and the rate increase dockets.

An administrative hearing on FPL's request for a rate increase was conducted on August 22, 2016 - August 26, 2016, and August 29, 2016 - September 1, 2016. At that time the testimony of 35 witnesses was heard and 805 exhibits were admitted into evidence. All parties to the docket filed briefs/post hearing statements on September 19, 2016. On October 6, 2016, FPL and three of the nine intervening parties (signatories)[3] filed a Joint Motion for Approval of Settlement Agreement (Settlement Agreement) resolving all 167 issues raised in the consolidated dockets. On October 27, 2016, a second administrative hearing was held to take supplemental testimony on the terms and conditions of the Settlement Agreement that had not previously been addressed in the prior hearing. At the second hearing, the testimony of 5 witnesses was heard and 6 exhibits were admitted into evidence. Post hearing briefs or comments were filed on November 10, 2016, by FPL, FRF, SFHHA, OPC, AARP, Larsons, Sierra Club, and Wal-Mart. FIPUG has taken no position on the Settlement Agreement. Wal-Mart and FEA do not oppose the Settlement Agreement and the Larsons, AARP, and Sierra Club oppose the Settlement Agreement.

By this Order, we grant the Joint Motion for Approval of Settlement Agreement and approve the Stipulation and Settlement filed on October 6, 2016 (Attachment A). We have jurisdiction over these matters pursuant to Chapter 366, F.S., including Sections 366.04, 366.05, 366.06, 366.07, and 366.076, F.S.

## Settlement Agreement

The major elements of the Settlement Agreement are as follows:

- The term begins on January 1, 2017 and continues at a minimum until December 31, 2020.
- FPL's authorized return on equity (ROE) is set at 10.55 percent (9.60 to 11.60 percent range) for all purposes.
- FPL is authorized to implement revenue increases of $400 million effective January 1, 2017; $211 million effective January 1, 2018; and $200 million effective on the in-service date of the Okeechobee Unit.
- FPL has the ability to construct up to 1,200 MW of solar photovoltaic generation prior to December 31, 2021, recoverable through a Solar Base Rate Adjustment Mechanism (SoBRA) upon placement of each unit into service if it is determined to be cost effective.

(SFHHA), American Association of Retired Persons (AARP), Florida Retail Federation (FRF), Sierra Club, and Daniel R. Larson and Alexandria Larson (Larsons).
[3] OPC, FRF, and SFHHA.

The solar projects shall not exceed $1,750 per kilowatt alternating current (kWac). For projects that do not fall under the Power Plant Siting Act, FPL will file a request for approval of the solar project in the Fuel Cost Recovery Clause docket. If the actual capital expenditures for a project are less than the projected costs used to develop the initial SoBRA, the lower amount shall be the basis for the full revenue requirement and a one-time credit, with interest, will be made through the Capacity Cost Recovery Clause. If the actual costs are higher than FPL projected, FPL may initiate a limited proceeding to recover those costs.

- No other base rate increases can occur before 2021 except the Solar Base Rate Adjustments.

- FPL will not execute any new natural gas financial hedges during the term of the Settlement Agreement.

- A 1.0 billion theoretical depreciation reserve surplus, plus the remainder of the current reserve amount as of December 31, 2016, may be amortized at FPL's discretion over the four year Settlement Agreement term. During this four year period FPL must maintain a minimum return on equity of at least 9.6 percent and cannot exceed a return on equity of 11.6 percent. FPL may not amortize any portion of the depreciation reserve past December 31, 2020, unless it provides notice to the parties no later than March 31, 2020, that it does not intend to seek a general base rate increase to be effective before January 1, 2022.

- FPL's current incentive mechanism is continued with an initial sharing threshold set at $40 million, removal of the current 514,000 MWh threshold on economy sales, and the netting of economy sales and purchases each year to determine the impact of variable power plant operation and maintenance expenses which will be recovered from customers at $.065/MWh if sales are greater than purchases. If purchases are greater than sales, customers will receive a credit for the net variable power plant operation and maintenance expenses saved at the same rate.

- The current storm damage cost recovery mechanism will continue which allows FPL to collect up to a $4 per 1,000 kWh charge beginning 60 days after filing a cost recovery petition and tariff based on a 12 month recovery period if costs do not exceed $800 million. This charge will be used to replace incremental costs associated with the named storm as well as to replenish the storm reserve to the level in effect as of August 31, 2016. If costs exceed $800 million, including restoration of the reserve, FPL may petition to increase the charge beyond $4 per 1,000 kWh.

- FPL will implement a 50 MW battery storage pilot program available to all customer classes at FPL's discretion which, on average, shall not exceed $2,300 per kWac. FPL will defer recovery of these costs until its next general base rate case.

- Upon a showing of customer savings on a Cumulative Present Value Revenue Requirement (CPVRR) basis, FPL is authorized to transfer the Martin-Riveria natural gas pipeline and all related equipment to its FERC-regulated affiliate, the Florida Southeast Connection.

- Commercial Industrial Load Control and Commercial Demand Reduction Credits will remain at current levels. The Cost of Service Methodology to be applied is 12 CP and 1/13 for production plant, 12 CP for transmission plant, and a new negotiated methodology for distribution plant. No revenue class received an increase greater than 1.5 times the system average percentage in total and no class received a rate decrease.

Decision

The standard for approval of a settlement agreement is whether it is in the public interest.[4] A determination of public interest requires a case-specific analysis based on consideration of the proposed settlement taken as a whole.[5] The weight of the evidence presented at both the customer hearings held throughout FPL's service territory and at the technical hearings conducted in Tallahassee fully supports the conclusion that FPL is providing excellent service to its 4.8 million customers at rates that are the lowest in the state and among the lowest in the country. The Settlement Agreement will allow FPL to maintain the financial integrity necessary to make the capital investments over the next four years required to sustain this level of service while providing rate stability and predictability for FPL's customers. The signatories to the Settlement Agreement represent a broad segment of FPL's customer base including both residential and commercial classes. Many of the positions advocated by these groups, including cessation of natural gas hedging, construction of cost-effective solar generation, reduction of FPL's proposed 11.0 percent ROE, and reduction of proposed depreciation rates, are contained in the Settlement Agreement. It is also important to note that the Settlement Agreement constitutes a reduction in revenue requirement for 2017 of over $400 million from FPL's request. AARP, the Sierra Club and the Larsons are opposed to the Settlement Agreement on various grounds, their common objections being the ROE of 10.55% and the creation and use of the $1.0 billion theoretical depreciation reserve surplus. However, a settlement is necessarily a compromise with give and take on both sides to reach the final, agreed upon settlement terms. Having carefully reviewed all briefs filed and evidence presented, we

[4] Order No. PSC-13-0023-S-EI, issued on January 14, 2013, in Docket No. 120015-EI, In re: Petition for increase in rates by Florida Power & Light Company; Order No. PSC-11-0089-S-EI, issued February 1, 2011, in Docket Nos. 080677 and 090130, In re: Petition for increase in rates by Florida Power & Light Company and In re: 2009 depreciation and dismantlement study by Florida Power & Light Company; Order No. PSC-13-0023-S-EIPSC-10-0398-S-EI, issued June 18, 2010, in Docket Nos. 090079-EI, 090144-EI, 090145-EI, 100136-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc., In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc., In re: Petition for expedited approval of the deferral of pension expenses, authorization to charge storm hardening expenses to the storm damage reserve, and variance from or waiver of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc., and In re: Petition for approval of an accounting order to record a depreciation expense credit, by Progress Energy Florida, Inc.; Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc.

[5] Order No. PSC-13-0023-S-EI, at p. 7.

find that taken as a whole the settlement provides a reasonable resolution of all the issues raised in the consolidated dockets. We find, therefore, that the Settlement Agreement establishes rates that are fair, just, and reasonable and is in the public interest.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the Joint Motion for Approval of Settlement Agreement is hereby granted and that the Stipulation and Settlement Agreement filed on October 6, 2016, attached hereto as Attachment A, and incorporated herein by reference, is approved.

By ORDER of the Florida Public Service Commission this 15th day of December, 2016.

Carlotta S. Stauffer

CARLOTTA S. STAUFFER
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
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Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

SBr

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

ATTACHMENT A

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

| | |
|---|---|
| In re: Petition for rate increase by Florida Power & Light Company | Docket No. 160021-EI |
| In re: Petition for approval of 2016-2018 storm hardening plan, by Florida Power & Light Company | Docket No. 160061-EI |
| In re: 2016 depreciation and dismantlement study by Florida Power & Light Company | Docket No. 160062-EI |
| In re: Petition for limited proceeding to modify and continue incentive mechanism by Florida Power & Light Company | Docket No. 160088-EI<br>Filed: October 6, 2016 |

**STIPULATION AND SETTLEMENT**

WHEREAS, Florida Power & Light Company ("FPL" or the "Company"), Citizens through the Office of Public Counsel ("OPC"), the South Florida Hospital and Healthcare Association ("SFHHA") and the Florida Retail Federation ("FRF") have signed this Stipulation and Settlement (the "Agreement"; unless the context clearly requires otherwise, the term "Party" or "Parties" means a signatory to this Agreement); and

WHEREAS, on January 14, 2013, the Florida Public Service Commission ("FPSC" or "Commission") entered Order No. PSC-13-0023-S-EI approving a stipulation and settlement of FPL's rate case in Docket No. 120015-EI, which continues in effect through the last billing cycle in December 2016 (the "2012 Rate Case Settlement"); and

WHEREAS, on March 15, 2016, FPL petitioned the Commission for (i) an increase in rates and charges sufficient to generate additional total annual revenues of $866 million to be effective January 1, 2017; (ii) a subsequent year revenue increase of $262 million to be effective January 1, 2018; (iii) a $209 million limited-scope adjustment for the Okeechobee Clean Energy Center ("the Okeechobee Unit"), to be effective on its commercial in-service date, currently scheduled for June 1, 2019 (the "2019 Okeechobee LSA"), and for other related relief in Docket 160021-EI (the "2016 Rate Petition"); and

WHEREAS, through Notices of Identified Adjustments, FPL updated its request to $826 million in 2017, $270 million in 2018 and $209 million for the 2019 Okeechobee LSA.

WHEREAS, on March 15, 2016, FPL petitioned for approval of its 2016-2018 storm hardening plan in Docket 160061-EI; and

WHEREAS, on March 15, 2016, FPL filed its dismantlement and depreciation studies in Docket No. 160062-EI; and

WHEREAS, on April 15, 2016, FPL petitioned for approval of modification to and continuation of its incentive mechanism in Docket 160088-EI; and

WHEREAS, on May 4, 2016, the Commission consolidated Dockets 160021-EI, 160061-EI, 160062-EI and 160088-EI (collectively, "the Consolidated Proceedings"); and

WHEREAS, the Parties filed voluminous prepared testimony with accompanying exhibits and conducted extensive discovery in the Consolidated Proceedings; and

WHEREAS, the Parties participated in a nine-day technical hearing involving live testimony and cross-examination of 17 FPL direct witnesses, 16 intervenor witnesses, 2 Staff witnesses and 17 FPL rebuttal witnesses; and

WHEREAS, the Parties to this Agreement have undertaken to resolve the issues raised in the Consolidated Proceedings so as to maintain a degree of stability and predictability with respect to FPL's base rates and charges; and

WHEREAS, the Parties have entered into this Agreement in compromise of positions taken in accord with their rights and interests under Chapters 350, 366 and 120, Florida Statutes, as applicable, and as a part of the negotiated exchange of consideration among the parties to this

Agreement each has agreed to concessions to the others with the expectation that all provisions of the Agreement will be enforced by the Commission as to all matters addressed herein with respect to all Parties regardless of whether a court ultimately determines such matters to reflect Commission policy, upon acceptance of the Agreement as provided herein and upon approval in the public interest;

NOW THEREFORE, in consideration of the foregoing and the covenants contained herein, the Parties hereby stipulate and agree:

1. This Agreement will become effective on January 1, 2017 (the "Implementation Date") and continue until FPL's base rates are next reset in a general base rate proceeding (the "Term"); provided, however, that FPL may place interim rates into effect subject to refund pursuant to Paragraph 11(a) of this Agreement. The minimum term of this Agreement shall be four years, from the Implementation Date through December 31, 2020 (the "Minimum Term").

2. Except as set forth in this Agreement, the Parties agree that adjustments to rate base, net operating income and cost of capital set forth in FPL's Minimum Filing Requirements ("MFR") Schedules B-2, C-1, C-3 and D1a, as revised by the filed notices of identified adjustments, shall be deemed approved for accounting and regulatory reporting purposes and the accounting for those adjustments will not be challenged during the Term for purposes of FPL's Earnings Surveillance Reports or clause filings.

3. FPL's authorized rate of return on common equity ("ROE") shall be a range of 9.6% to 11.6%, and shall be used for all purposes. All rates, including those established in clause proceedings during the Term, shall be set using a 10.55% ROE.

4. (a) Effective on January 1, 2017, FPL shall be authorized to increase its base rates and service charges by an amount that is intended to generate an additional $400 million of annual revenues, based on the projected 2017 test year billing determinants set forth in Schedules E-13c and E-13d of FPL's 2017 MFRs filed with the 2016 Rate Petition, and in the respective amounts and manner shown on Exhibit A, attached hereto.

(b) Effective January 1, 2018, FPL shall be authorized to increase its base rates by an amount that is intended to generate an additional $211 million over the Company's then current base rates, based on the projected 2018 test year billing determinants set forth in Schedules E-13c and E-13d of FPL's 2018 MFRs filed with the 2016 Rate Petition, and in the respective amounts and manner shown on Exhibit A, attached hereto.

(c) Attached hereto as Exhibit B are tariff sheets for new base rates and service charges that reflect the terms of this Agreement and implement the rate increase described in Paragraph (4)(a) above, which tariff sheets shall become effective on January 1, 2017.

(d) Attached hereto as Exhibit C are tariff sheets for new base rates and service charges that reflect the terms of this Agreement and implement the additional rate increase described in Paragraph (4)(b) above, which tariff sheets shall become effective on January 1, 2018.

(e) As part of the negotiated exchange of consideration among the parties to this Agreement, (i) the energy and demand charges for business and commercial rates and the utility-controlled demand rates are adjusted as shown on Exhibits B and C, and (ii) the level of utility-controlled demand credits for customers receiving service pursuant to

FPL's Commercial/ Industrial Load Control ("CILC") tariff and the Commercial/Industrial Demand Reduction ("CDR") rider are the same as those currently in effect, which are greater than the proposed credits reflected in FPL's MFRs as originally filed on March 15, 2016. FPL shall be entitled to recover the CILC and CDR credits through the energy conservation cost recovery ("ECCR") clause. It is agreed that the appropriate level of credits is an issue in Demand-Side Management ("DSM") proceedings. The Parties agree that no changes in these credits shall be implemented any earlier than the effective date of new FPL base rates implemented pursuant to a general base rate proceeding, and that such new CILC and CDR credits shall only be implemented prospectively from such effective date. No CILC or CDR customer shall be subject to any charge or debit against such customer's bill for electric service provided during the Term based on the difference between the credits approved by this Agreement and any new credits that may be approved pursuant to future DSM proceedings. At such time as FPL's base rates are reset in a general base rate proceeding, the CILC and CDR credits shall be reset to the level established in FPL's then most recent DSM proceeding, subject to any applicable refund occasioned by a timely exercised right of reconsideration or appellate review of any order associated with the DSM proceeding. No party to this Agreement may object to FPL's recovery of any such refund through the ECCR Clause

(f) The rates set forth in Exhibits B and C are calculated based on a cost of service study that applies (i) the 12 CP and 1/13 methodology for Production Plant, (ii) 12 CP for Transmission Plant and (iii) a negotiated methodology for allocating Distribution Plant, limited by the Commission's traditional gradualism test found in Order No. PSC-09-0283-FOF-EI, pp. 86-87. Under the rates set forth in Exhibits B and C, no rate or revenue class receives (nor shall receive) an increase greater than 1.5 times the system average percentage increase in total and no class receives (nor shall receive) a decrease in rates.

(g) The following proposed tariff changes as filed shall be implemented:

(i) Implementation of the new meter tampering service charge;

(ii) Implementation of metered rates for all new customer-owned street lighting (SL-1) and traffic signal (SL-2) accounts;

(iii) Elimination of the re-lamping option for customer-owned lighting;

(iv) Three changes to the terms of service for the Outdoor Lighting (OL-1) tariff; and

(v) Identified changes to the requirements for surety bonds.

(h) Base rates and credits applied to customer bills in accordance with this Paragraph 4 shall not be changed during the Minimum Term except as otherwise permitted in this Agreement.

5. Nothing in this Agreement shall preclude FPL from requesting the Commission to approve the recovery of costs that are recoverable through base rates under the nuclear cost recovery statute, Section 366.93, Florida Statutes, and Commission Rule 26-6.0423, F.A.C. Nothing in this Agreement prohibits parties from participating without limitation in nuclear cost recovery proceedings and proceedings related thereto and opposing FPL's requests.

6. (a) Nothing in this Agreement shall preclude FPL from petitioning the Commission to seek recovery of costs associated with any storms without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings or the remaining unamortized Reserve Amount as defined in Paragraph 12. Consistent with the rate design method set forth in Order No. PSC-06-0464-FOF-EI, the Parties agree that recovery of storm costs from customers will begin, on an interim basis, sixty days following the filing of a cost recovery petition and tariff with the Commission and will be based on a 12-month recovery period if the storm costs do not exceed $4.00/1,000 kWh on monthly residential customer bills. In the event the storm costs exceed that level, any additional costs in excess of $4.00/1,000 kWh may be recovered in a subsequent year or years as determined by the Commission. All storm related costs subject to interim recovery under this Paragraph 6 shall be calculated and disposed of pursuant to Commission Rule 25-6.0143, F.A.C., and will be limited to costs resulting from a tropical system named by the National Hurricane Center or its successor, to the estimate of incremental costs above the level of storm reserve prior to the storm and to the replenishment of the storm reserve to the level in effect as of August 31, 2016. The Parties to this Agreement are not precluded from participating in any such proceedings and opposing the amount of FPL's claimed costs but not the mechanism agreed to herein, provided that it is applied in accordance with this Agreement.

(b) The Parties agree that the $4.00/1,000 kWh cap in this Paragraph 6 will apply in aggregate for a calendar year for the purpose of the interim recovery set forth in 6(a) above; provided, however, that FPL may petition the Commission to allow FPL to increase the initial 12 month recovery beyond $4.00/1,000 kWh in the event FPL incurs in excess of $800 million of storm recovery costs that qualify for recovery in a given calendar year, inclusive of the amount needed to replenish the storm reserve to the level that existed as of August 31, 2016. All Parties reserve their right to oppose such a petition.

(e) Any proceeding to recover costs associated with any storm shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings or the remaining unamortized Reserve Amount as defined in Paragraph 12.

7. Nothing shall preclude the Company from requesting Commission approval for recovery of costs (a) that are of a type which traditionally, historically and ordinarily would be, have been, or are presently recovered through cost recovery clauses or surcharges, or (b) that are incremental costs not currently recovered in base rates which the Legislature or Commission determines are clause recoverable subsequent to the approval of this Agreement. It is the intent of the Parties in this Paragraph 7 that FPL not be allowed to recover through cost recovery clauses increases in the magnitude of costs of types or categories (including but not limited to, for example, investment in and maintenance of transmission assets) that have been, and traditionally, historically, and ordinarily would be, recovered through base rates. It is further the intent of the Parties to recognize that an authorized governmental entity may impose requirements on FPL involving new or atypical kinds of costs (including but not limited to, for example, requirements related to cyber security), and concurrently or in connection with the imposition of such

requirements, the Legislature and/or Commission may authorize FPL to recover those related costs through a cost recovery clause.

8. The revenue requirement associated with West County Energy Center Unit 3 ("WCEC 3") currently collected through the Capacity Cost Recovery ("CCR") Clause will be moved to base rates on a revenue neutral basis and will not be considered an increase in base rates pursuant to Paragraph 4. FPL is authorized to recover through base rates the revenue requirements associated with WCEC 3, not limited to the unit's fuel savings. FPL's 2017 CCR Clause factor will reflect the elimination of FPL's collection of the WCEC 3 revenue requirement through the CCR Clause.

9. (a) FPL projects that its Okeechobee Unit will enter commercial service in June 2019. Effective as of the commercial in-service date of the Okeechobee Unit, FPL is authorized to increase its base rates by an amount that is intended to generate an additional $200 million for the costs associated with the Okeechobee Unit's first 12 months of operation (the "Annualized Base Revenue Requirement") over the 12 months beginning with the Okeechobee Unit's commercial in-service date. Such base rate increases shall be calculated based on FPL's then-most-current projections of sales (billing determinants) as reflected in its then-most-current CCR Clause filings with the Commission, including, to the extent necessary, projections of such billing determinants into 2020 so as to cover the same 12 months as the first 12 months of the Okeechobee Unit's operation. This base rate adjustment will be referred to as the Okeechobee Limited Scope Adjustment ("Okeechobee LSA").

(b) FPL is authorized to reflect the Okeechobee LSA on FPL's customer bills by adjusting base charges and non-clause recoverable credits and commercial/industrial demand reduction rider credits by an equal percentage. The calculation of the percentage change in rates is based on the ratio of the jurisdictional Annualized Base Revenue Requirement and the forecasted retail base revenues from the sales of electricity during the first twelve months of operation. FPL will begin applying the incremental base rate charges and base credits for the Okeechobee LSA to meter readings made on and after the commercial in-service date of the Okeechobee Unit. Fuel factors will be implemented to incorporate fuel savings contemporaneously with the Okeechobee LSA base rate increase.

(c) The Okeechobee LSA will be calculated using a 10.55% ROE and the capital structure reflected in the 2016 Rate Petition and MFRs as adjusted in accordance with the filed Notice of Identified Adjustments. FPL will calculate the 2019 Okeechobee LSA rates and submit them to the Commission for approval in the CCR Clause projection filing for 2019.

(d) In the event that the actual capital expenditures are less than the projected costs set forth in Order No. PSC-16-0032-FOF-EI, which were used to develop the initial Okeechobee LSA factor, the lower figure shall be the basis for the full revenue requirements and a one-time credit will be made through the CCR Clause. In order to determine the amount of this credit, a revised Okeechobee LSA Factor will be computed using the same data and methodology incorporated in the initial Okeechobee LSA factor, with the exception that the actual capital expenditures will be used in lieu of the capital expenditures on which the Annualized Base Revenue Requirement was based. Thereafter, base rates will be adjusted to reflect the revised Okeechobee LSA factor. The difference between the cumulative base revenues since the implementation of the initial

Okeechobee LSA factor and the cumulative base revenues that would have resulted if the revised Okeechobee LSA factor had been in-place during the same time period will be credited to customers through the CCR Clause with interest at the 30-day commercial paper rate as specified in Rule 25-6.109, F.A.C.

(e) In the event that actual capital costs for the Okeechobee Unit are higher than the projection on which the Annualized Base Revenue Requirement was based, pursuant to the costs set forth in Order No. PSC-16-0032-FOF-EI, FPL at its option may initiate a limited proceeding pursuant Section 366.076, Florida Statutes, limited to the issue of whether FPL has met the requirements of Rule 25-22.082(15), F.A.C. If the Commission finds that FPL has met the requirements of Rule 25-22.082(15), then FPL shall be authorized to increase the Okeechobee LSA by the corresponding incremental revenue requirement due to such additional capital costs. However, FPL's election not to seek such an increase in the Okeechobee LSA shall not preclude FPL from booking any incremental costs for surveillance reporting and all regulatory purposes subject only to a finding of imprudence or disallowance by the Commission. Nothing in this Agreement shall preclude any party from participating in such limited proceeding consistent with the full rights of an intervenor.

(f) Depreciation revenue requirements for the Okeechobee LSA will be revised to reflect the final depreciation rates for the Port Everglades New Generation Clean Energy Center as reflected on Exhibit D herein.

(g) Upon expiration or termination of this Agreement, FPL's base rate levels and credits, including the effects of the Okeechobee LSA as implemented in this Agreement (i.e., uniform percent increase for all rate classes applied to base revenues), shall continue in effect until next reset in a general base rate proceeding except as otherwise noted in this Agreement.

10. (a) FPL projects that for purposes of the cost recovery set forth in this Paragraph, it will undertake construction of approximately 300 MW per calendar year of solar generation reasonably projected to go into service during the Minimum Term or within one year following expiration of the Minimum Term. For each solar project that is approved by the Commission for cost recovery pursuant to the process described in this Paragraph, FPL's base rates will be increased by the incremental annualized base revenue requirement (as defined in Paragraph 10(e)) for the first 12 months of operation (the "Annualized Base Revenue Requirement"), but in no event before the facility is in service. Each such base rate adjustment will be referred to as a Solar Base Rate Adjustment ("SoBRA"), and shall be authorized for solar projects for which FPL files for Commission approval pursuant to this Paragraph during the Minimum Term. The Commission's approval may occur before or after expiration of the Minimum Term. The projects constructed pursuant to this Paragraph must be reasonably scheduled to be placed into service no later than one year following the expiration of the Minimum Term. During the Term of this Agreement, the cost of the components, engineering and construction for any solar project constructed by FPL pursuant to this Paragraph shall be reasonable and in no event shall the total cost of such project exceed $1,750 per kilowatt alternating current ("kWac").

(b) For solar generation projects subject to the Florida Electrical Power Plant Siting Act (i.e., 75 MW or greater), FPL will file a petition for need determination pursuant to Chapter 25-22, F.A.C. If approved pursuant to the procedures described in this

Paragraph and Section 403.519, Fla. Stat., FPL will calculate and submit for Commission confirmation that amount of the SoBRA for each such solar project using the CCR Clause projection filing for the year that solar project will go into service.

(c) Solar generation projects not subject to the Florida Electrical Power Plant Siting Act (i.e., fewer than 75 MW) also will be subject to approval by the Commission as follows: (i) FPL will file a request for approval of the solar generation project at the time of its final true-up filing in the Fuel and Purchased Power Cost Recovery Clause docket) ("Fuel Docket"); (ii) All Fuel Docket deadlines and schedules shall apply; (iii) the issues for determination are limited to the cost effectiveness of each such project (i.e., will the project lower the projected system cumulative present value revenue requirement "CPVRR" as compared to such CPVRR without the solar project) and the amount of revenue requirements and appropriate percentage increase in base rates needed to collect the estimated revenue requirements; and (iv) approval of the solar generation project will be an issue to be resolved at the regularly scheduled Fuel Docket hearing; provided, however, that the Commission on its own initiative or upon good cause shown by an intervenor (which may include any Party to this Agreement or any other entity satisfying the standing requirements of Florida law) may set FPL's request for approval of the solar generation project for a separate hearing to be held in the Fuel Docket before the end of that calendar year. If approved, FPL will calculate and submit for Commission confirmation the amount of the SoBRA for each such solar project using the CCR Clause projection filing for the year that solar project will go into service. For a solar project that is scheduled to go into service in 2017, FPL shall not implement a base rate adjustment until such project is approved by the Commission pursuant to this Paragraph

10. For each solar project approved pursuant to this Agreement, the base rate increase shall be based upon FPL's billing determinants for the first 12 months following such project's commercial in-service date, where such billing determinants are those used in FPL's then-most-current CCR Clause filings with the Commission, including, to the extent necessary, projections of such billing determinants into a subsequent calendar year so as to cover the same 12 months as the first 12 months of each such solar project's operation.

(d) FPL may not receive approval in any one year for incremental SoBRA recovery of more than 300 MW of solar projects for a calendar year; provided, however, to the extent that FPL receives approval for SoBRA recovery of less than 300 MW in a year, the surplus capacity can be carried over to the following years through the period identified in the first sentence of Paragraph 10(a). For example, if FPL receives approval in 2017 for SoBRA recovery of 200 MW of solar capacity, it would be entitled to increase its request in the subsequent year(s) for SoBRA of an additional 100 MW.

(e) Each SoBRA is to be reflected on FPL's customer bills by increasing base charges and base non-clause recoverable credits and commercial/industrial demand reduction rider credits by an equal percentage contemporaneously. The calculation of the percentage change in rates is based on the ratio of the jurisdictional Annualized Base Revenue Requirement and the forecasted retail base revenues from the sales of electricity during the first twelve months of operation. FPL will begin applying the incremental base rate charges and base credits for each SoBRA to meter readings made on and after the commercial in-service date of that solar generation site.

(f) Each SoBRA will be calculated using a 10.55% ROE and the appropriate incremental capital structure consistent with the approach authorized for the Okeechobee LSA and adjusted to reflect the inclusion of investment tax credits on a normalized basis. FPL will calculate and submit for Commission approval the amount of the SoBRA for each solar generation project using the CCR Clause projection filing for the year that solar project is expected to go into service.

(g) In the event that the actual capital expenditures are less than the projected costs used to develop the initial SoBRA factor, the lower figure shall be the basis for the full revenue requirements and a one-time credit will be made through the CCR Clause. In order to determine the amount of this credit, a revised SoBRA Factor will be computed using the same data and methodology incorporated in the initial SoBRA factor, with the exception that the actual capital expenditures will be used in lieu of the capital expenditures on which the Annualized Base Revenue Requirement was based. On a going forward basis, base rates will be adjusted to reflect the revised SoBRA factor. The difference between the cumulative base revenues since the implementation of the initial SoBRA factor and the cumulative base revenues that would have resulted if the revised SoBRA factor had been in-place during the same time period will be credited to customers through the CCR Clause with interest at the 30-day commercial paper rate as specified in Rule 25-6.109, F.A.C.

(h) Subject to the maximum cost of $1,750 per kWac set forth in the subparagraph 10(a), in the event that actual capital costs for a solar generation project are higher than the projection on which the Annualized Base Revenue Requirement was based, FPL at its option may initiate a limited proceeding per Section 366.076, Florida Statutes, limited to the issue of whether FPL has met the requirements of Rule 25-22.082(15), F.A.C. Nothing in this Agreement shall prohibit a Party from participating in any such limited proceeding for the purpose of challenging whether FPL has met the requirements of Rule 25-22.082(15) or otherwise acted in accordance with this Agreement. If the Commission finds that FPL has met the requirements of Rule 25-22.082(15), then FPL shall increase the SoBRA by the corresponding incremental revenue requirement due to such additional capital costs, provided, consistent with subparagraph 10(a) above, FPL is prohibited from recovering through the SoBRA mechanism any costs greater than $1,750 per kWac under any circumstances. However, FPL's election not to seek such an increase in the SoBRA shall not preclude FPL from booking any incremental costs for surveillance reporting and all regulatory purposes subject only to a finding of imprudence or disallowance by the Commission. Nothing in this Agreement shall preclude any Party to this Agreement or any other lawful party from participating, consistent with the full rights of an intervenor, in any such limited proceeding.

(i) FPL's base rate and credit levels applied to customer bills, including the effects of the SoBRAs as implemented pursuant to this Agreement (i.e., uniform percent increase for all rate classes applied to base revenues), shall continue in effect until next reset by the Commission in a general base rate proceeding.

11. (a) Notwithstanding Paragraph 4 above, if FPL's earned return on common equity falls below the bottom of its authorized range during the Minimum Term on an FPL monthly earnings surveillance report stated on an FPSC actual, adjusted basis, FPL may petition the FPSC to amend its base rates, either as a general rate proceeding under Sections 366.06 and 366.07, Florida Statutes, or as a limited proceeding under Section

366.076, Florida Statutes. Throughout this Agreement, "FPSC actual, adjusted basis" and "actual adjusted earned return" shall mean results reflecting all adjustments to FPL's books required by the Commission by rule or order, but excluding pro forma, weather-related adjustments. If FPL files a petition to initiate a general rate proceeding pursuant to this provision, FPL may request an interim rate increase pursuant to the provisions of Section 366.071, Florida Statutes. Nothing in this Agreement shall preclude any Party from participating in any proceeding initiated by FPL to increase base rates pursuant to this Paragraph consistent with the full rights of an intervenor.

(b) Notwithstanding Paragraph 4 above, if, during the Minimum Term of this Agreement, FPL's earned return on common equity exceeds the top of its authorized ROE range reported in an FPL monthly earnings surveillance report stated on an FPSC actual, adjusted basis, any Party other than FPL shall be entitled to petition the Commission for a review of FPL's base rates. In any case initiated pursuant to this Paragraph, all parties will have full rights conferred by law.

(c) Notwithstanding Paragraph 4 above, this Agreement shall terminate upon the effective date of any final order issued in any such proceeding pursuant to this Paragraph 11 that changes FPL's base rates.

(d) This Paragraph 11 shall not (i) be construed to bar or limit FPL to any recovery of costs otherwise contemplated by this Agreement pursuant to Paragraphs 5 through 10 nor, in any proceeding initiated after a base rate proceeding filed pursuant to this Paragraph, shall any Party be prohibited from taking any position or asserting the application of law or any right or defense in litigation related to FPL's efforts to recover such costs; (ii) apply to any request to change FPL's base rates that would become effective after this Agreement terminates; or (iii) limit any Party's rights in proceedings concerning changes to base rates that would become effective subsequent to the termination of this Agreement to argue that FPL's authorized ROE range or any other element used in deriving its revenue requirements or rates should differ from the range set forth in this Agreement.

12. (a) In Order No. PSC-13-0023-S-EI, the Commission authorized FPL to amortize the total depreciation reserve surplus remaining at the end of 2012, plus a portion of FPL's fossil dismantlement reserve with the amounts to be amortized in each year from 2013 through 2016 left to FPL's discretion but not exceed a total of $400 million. That amount was later reduced to $370 million pursuant to the Cedar Bay settlement, Order No. PSC-15-0401-AS-EI. The 2016 Rate Petition and accompanying MFRs projected that FPL would have amortized the entire amount remaining at the end of 2016. The Parties acknowledge that the actual remaining amount may differ from the projection.

(b) The Parties agree that FPL is authorized to apply the depreciation parameters and resulting rates set forth in Exhibit D attached hereto, and acknowledge that application of those rates results in a $125.8 million reduction in 2017 test year depreciation expense (compared to application of the depreciation rates shown in Exhibit 331, Attachment 2) and a theoretical depreciation reserve surplus estimated to be $1,070.2 million at January 1, 2017. The Parties further agree that FPL will use a 10-year amortization period for the capital recovery schedules set forth on Exhibit 109, in lieu of FPL's proposed four-year amortization period.

(c) Notwithstanding the 2012 Rate Case Settlement, the Parties agree that until FPL's base rates are next reset in a general base rate proceeding, FPL may amortize any reserve amount described in Paragraph 12(a) remaining at the end of 2016 and up to $1,000 million of the theoretical depreciation reserve surplus effected by the depreciation rates set forth in Exhibit D (together, the "Reserve Amount"), with the amounts to be amortized in each year of the Term left to FPL's discretion subject to the following conditions: (i) the amount that FPL may amortize during the Term shall not be less than the actual amount of depreciation reserve surplus remaining at the end of 2016; (ii) for any surveillance reports submitted by FPL during the Minimum Term on which its ROE (measured on an FPSC actual, adjusted basis) would otherwise fall below 9.6%, FPL must amortize at least the amount of the available Reserve Amount necessary to maintain in each such 12-month period an ROE of at least 9.6% (measured on an FPSC actual, adjusted basis); and (iii) FPL may not amortize the Reserve Amount in an amount that results in FPL achieving an ROE greater than 11.6% (measured on an FPSC actual, adjusted basis) in any such 12-month period as measured by surveillance reports submitted by FPL. FPL shall not satisfy the requirement of Paragraph 11 that its actual adjusted earned return on equity must fall below 9.6% on a monthly surveillance report before it may initiate a petition to increase base rates during the Minimum Term unless FPL first uses any of the Reserve Amount that remains available for the purpose of increasing its earned ROE to at least 9.6% for the period in question. FPL shall file an attachment to its monthly earnings surveillance report for December 2016 that shows

the final amount of the 2012 "rollover" surplus that remained at the end of 2016. Thereafter, FPL shall file an attachment to its monthly surveillance report for December of each year during the Term that shows the amount of amortization credit or debit to the Reserve Amount on a monthly basis and year-end total basis for that calendar year. FPL may not amortize any portion of the Reserve Amount past December 31, 2020 unless it provides notice to the Parties by no later than March 31, 2020 that it does not intend to seek a general base rate increase to be effective any earlier than January 1, 2022.Any amortization of the Reserve Amount after December 31, 2020 shall be in accord with this Paragraph.

13. The level of FPL's annual dismantlement accrual shall be as set forth in Hearing Exhibit 343.

14. The Parties agree that the provisions of Rules 25-6.0436 and 25-6.04364, F.A.C., pursuant to which depreciation and dismantlement studies are generally filed at least every four years will not apply to FPL until FPL files its next petition to change base rates. The depreciation rates and dismantlement accrual rates in effect as of the Implementation Date shall remain in effect until FPL's base rates are next reset in a general base rate proceeding. At such time as FPL shall next file a general base rate proceeding, it shall simultaneously file new depreciation and dismantlement studies and propose to reset depreciation rates and dismantlement accrual rates in accordance with the results of those studies. The Parties agree to support consolidation of proceedings to reset FPL's base rates, depreciation rates and dismantlement accrual rates.

15. In Order PSC-130023-S-EI, the Commission authorized FPL to implement a Pilot Incentive Mechanism designed to create additional value for customers by FPL engaging in wholesale power purchases and sales, as well as all forms of asset optimization. The Parties agree that FPL is authorized to continue the Incentive Mechanism through the Term subject to the following modifications:

(a) On an annual basis, FPL customers will receive 100% of the Incentive Mechanism gain up to a threshold of $40 million. FPL will retain 60% and customers will receive 40% of incremental gains between $40 million and $100 million. FPL will retain 50% and customers will receive 50% of incremental gains in excess of $100 million.

(b) FPL will net economy sales and purchases in order to determine the impact of variable power plant O&M. If FPL executes more economy sales than economy purchases, FPL will recover the net amount of variable power plant O&M incurred in a given year. If economy purchases are greater than economy sales, FPL's customers will receive a credit for the net variable power plant O&M that has been saved in that year. The per-MWh variable power O&M rate used to calculate these costs shall be as described in FPL's 2017 Test Year MRFs filed with the 2016 Rate Petition, i.e., $0.65/MWh.

(c) Nothing in this Paragraph is intended to enlarge the jurisdiction of the Commission to approve cost recovery of investments beyond that authorized by Chapter 366, Fla. Stat.

16. FPL agrees to the termination of 100% of natural gas financial hedging prospectively for the Minimum Term and will make filings to implement such termination in Docket No. 160001-EI and subsequent fuel clause proceedings. FPL shall not be prohibited from filing a petition and proposed risk management plan with the Commission to address natural gas financial hedging following expiration of the Minimum Term. The Parties understand and intend that FPL will not enter into any new financial natural gas hedging contracts after the date on which this Agreement is executed, except as may be necessary

for FPL to remain in compliance to the minimum extent practicable with the requirements of its currently approved Risk Management Plan.

17. (a) FPL is authorized to transfer to its FERC-regulated affiliate, Florida Southeast Connection ("FSC") the Martin-Riviera ("MR-RV") Lateral natural gas pipeline with all related equipment and inventory, upon a showing that such transfer will result in customer savings on a CPVRR basis pursuant to Paragraph 17(b). FPL will effectuate the transfer of the assets at their net book value as of the transaction date. Simultaneously with the transfer, FPL will contract with FSC to provide firm gas transportation from the Martin plant to the Riviera Beach plant in the same quantities currently available to FPL through its ownership of the MR-RV Lateral.

(b) If FPL negotiates contractual terms with FSC for firm gas transportation that would result in CPVRR savings to customers from the MR-RV Lateral transfer described in Paragraph 17(a), it will file a petition to confirm the cost-effectiveness of the transaction to customers. In that petition, FPL will request approval to implement a simultaneous change to lower base rates and adjust fuel rates to reflect the projected transportation charges. FPL will implement the base rate adjustment as a percentage reduction in base rates for every rate class. All Parties are free to participate in such proceeding.

18. FPL will implement a 50 MW battery storage pilot program ("Battery Storage Pilot") designed to enhance service for large commercial/industrial customers, small retail customers and large retail customers or to enhance operations of existing or planned solar facilities. The Parties to this Agreement will work cooperatively regarding the location of the battery storage projects; however, FPL shall ultimately be responsible for

determining the projects and locations that provide the most benefits at the time of installation. The cost to install battery storage projects pursuant to this Paragraph shall be reasonable and, on average, shall not exceed $2,300 per kWac. The Parties to this Agreement agree that the Battery Storage Pilot implementation in accordance with this Agreement and not in violation of any law are a prudent investment and provides benefits for customers. FPL will pursue cost recovery for the Battery Storage Pilot in its next general base rate case, and the Parties to this Agreement agree not to contest the prudence of the investment that complies with this Agreement.

19. FPL and interested Parties to this Agreement will jointly request a Commission workshop to address a Pilot Demand-Side Management Opt-Out program, including eligibility criteria, verification procedures, cost recovery and other implementation issues. Participation in the workshop and, if applicable, any Opt-Out program will not be limited to the Parties to this Agreement nor shall this Paragraph operate to impair the rights of any substantially affected person to seek additional or different relief as allowed by law.

20. FPL will evaluate whether it is reasonable and appropriate to offer a new tariff for customers who interconnect with an FPL distribution substation.

21. FPL in its next general base rate case will submit for informational purposes a cost of service study that compares revenue requirements by rate class between (a) implementing the Minimum Distribution System ("MDS") methodology at the requested revenue requirement increase, which study gives due consideration to the methodology applied by Tampa Electric Company in its last base rate case and (b) a situation that is identical to (a) in all other respects except that the MDS methodology is not implemented.

22. No Party to this Agreement will request, support, or seek to impose a change in the application of any provision hereof. Except as provided in Paragraph 11, a Party to this Agreement will neither seek nor support any change in FPL's base rates or credits applied to customer bills, including limited, interim or any other rate decreases, that would take effect prior to expiration of the Minimum Term, except for any such reduction requested by FPL or as otherwise provided for in this Agreement. No party is prohibited from seeking interim, limited, or general base rate relief, or a change to credits, to be effective following the expiration of the Minimum Term.

23. Nothing in this Agreement will preclude FPL from filing and the Commission from approving any new or revised tariff provisions or rate schedules requested by FPL, provided that such tariff request does not increase any existing base rate component of a tariff or rate schedule during the Term unless the application of such new or revised tariff, service or rate schedule is optional to FPL's customers.

24. The provisions of this Agreement are contingent on approval of this Agreement in its entirety by the Commission without modification. The Parties agree that approval of this Agreement is in the public interest. The Parties further agree that they will support this Agreement and will not request or support any order, relief, outcome, or result in conflict with the terms of this Agreement in any administrative or judicial proceeding relating to, reviewing, or challenging the establishment, approval, adoption, or implementation of this Agreement or the subject matter hereof. No party will assert in any proceeding before the Commission or any court that this Agreement or any of the terms in the Agreement shall have any precedential value, except to enforce the provisions of this Agreement. Approval of this Agreement in its entirety will resolve all matters and issues

in Docket Nos. 160021-EI, 160061-EI, 160062-EI and 160088-EI pursuant to and in accordance with Section 120.57(4), Florida Statutes. This docket will be closed effective on the date the Commission Order approving this Agreement is final, and no Party shall seek appellate review of any order issued in these Dockets.

25. This Agreement is dated as of October 6, 2016. It may be executed in counterpart originals, and a scanned .pdf copy of an original signature shall be deemed an original. Any person or entity that executes a signature page to this Agreement shall become and be deemed a Party with the full range of rights and responsibilities provided hereunder, notwithstanding that such person or entity is not listed in the first recital above and executes the signature page subsequent to the date of this Agreement, it being expressly understood that the addition of any such additional Party(ies) shall not disturb or diminish the benefits of this Agreement to any current Party.

26. All provisions of this Agreement survive the Minimum Term except Paragraphs 10 and 11.

In Witness Whereof, the Parties evidence their acceptance and agreement with the provisions of this Agreement by their signature.

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TAB B

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

| | |
|---|---|
| In re: Petition for rate increase by Florida Power & Light Company. | DOCKET NO. 160021-EI |
| In re: Petition for approval of 2016-2018 storm hardening plan, by Florida Power & Light Company. | DOCKET NO. 160061-EI |
| In re: 2016 depreciation and dismantlement study by Florida Power & Light Company. | DOCKET NO. 160062-EI |
| In re: Petition for limited proceeding to modify and continue incentive mechanism, by Florida Power & Light Company. | DOCKET NO. 160088-EI<br>ORDER NO. PSC-16-0456-PCO-EI<br>ISSUED: October 12, 2016 |

FOURTH ORDER REVISING ORDER ESTABLISHING PROCEDURE AND SETTING PROCEDURAL SCHEDULE FOR COMMISSION CONSIDERATION OF SETTLEMENT AGREEMENT

## I. **Background**

This docket was opened to consider Florida Power & Light Company's (FPL) petition for a base rate increase. Nine parties were granted intervention in the docket.[1] An administrative hearing on FPL's request for a rate increase commenced on August 22, 2016, and concluded on September 1, 2016. On October 6, 2016, FPL and three of the nine intervening parties (signatories) filed a Joint Motion for Approval of Settlement Agreement (Settlement Agreement).[2] This Order addresses the scheduling of the Commission's consideration of the Settlement Agreement.

In compliance with Sections 120.569 and 120.57, Florida Statutes (F.S.), on October 27, 2016, an administrative hearing will be held, and the record reopened, to take supplemental testimony regarding terms of the Settlement Agreement not previously addressed in the prior hearing. The scope of the hearing is defined in Section III below. The hearing will be conducted according to the provisions of Chapter 120, F.S., and all administrative rules applicable to this Commission.

This Order is issued pursuant to the authority granted by Rule 28-106.211, Florida Administrative Code, (F.A.C.), which provides that the presiding officer before whom a case is

[1] Office of Public Counsel (OPC), Florida Industrial Power Users Group (FIPUG), Wal-Mart Stores East, LP and Sam's East, Inc. (Walmart), Federal Executive Agencies (FEA), South Florida Hospital and Healthcare Association (SFHHA), American Association of Retired Persons (AARP), Florida Retail Federation (FRF), Sierra Club, and Daniel R. Larson and Alexandria Larson (Larsons).

[2] OPC, FRF, and SFHHA.

pending may issue any orders necessary to effectuate discovery, prevent delay, and promote the just, speedy, and inexpensive determination of all aspects of the case.

## II. General Filing Procedures

Filings pertaining to this docket must comply with Rule 28-106.104, F.A.C. Filing may be accomplished electronically as provided in the Commission's Statement of Agency Organization and Operation and the E-Filing Requirements link, posted on our website, www.floridapsc.com. If filing via mail, hand delivery, or courier service, the filing should be addressed to:

Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

The Commission strongly encourages electronic filing, which is available from the Commission's Home Page under the Clerk's Office menu and Electronic Filing web form. The filing party is responsible for ensuring that no information protected by privacy or confidentiality laws is contained in any electronic document. To the extent possible, an electronic copy of all filings shall be provided to parties and staff in Microsoft Word format and all schedules shall be provided in Microsoft Excel format with formulas intact and unlocked.

## III. Scope of Hearing

The purpose of this hearing is to give parties an opportunity to present testimony and conduct cross examination on terms of the Settlement Agreement which were not identified in the prior evidentiary hearing held on August 22, 2016, through August 26, 2016, and August 29, 2016, through September ~~2~~ 2, 2016. The sole issue to be decided in this hearing is whether the Settlement Agreement dated October 6, 2016, is in the public interest and should be approved. In order to fully evaluate this Settlement Agreement, additional information on the terms of the Settlement Agreement discussed in Paragraphs 10 (Solar Base Rate Adjustment), 12 (theoretical depreciation reserve surplus), 16 (natural gas financial hedging), 18 (battery storage pilot program), and 19 (pilot demand side management opt-out program) is necessary. If the parties believe there are additional terms and conditions of the Settlement Agreement that were not addressed in the previous hearing, a Notice of Additional Terms must be filed with the Office of Commission Clerk by 5:00 p.m. on October 14, 2016. On or before October 19, 2016, the Presiding Officer will determine if such additional terms will be addressed at the hearing.

CJD
10.14.16

## IV. Prefiled Testimony and Exhibits

Each party shall file all testimony and exhibits that it intends to sponsor, pursuant to the schedule set forth in Section VIII of this Order. Testimony and exhibits may be filed electronically. If filing paper copies, an original and 15 copies of all testimony and exhibits shall be filed with the Office of Commission Clerk, by 5:00 p.m. on the date due. A copy of all prefiled testimony and exhibits shall be served electronically or by regular mail, overnight mail, or hand delivery to all other parties and staff no later than the date filed with the Commission. Failure of a party to timely prefile exhibits and testimony from any witness in accordance with the foregoing requirements may bar admission of such exhibits and testimony.

The dimensions of each page of testimony shall be 8 ½ x 11 inches. Each page shall be consecutively numbered and double spaced, with 25 numbered lines per page and left margins of at least 1.25 inches. If filing paper copies of the testimony, all pages shall be filed on white, unglossed, three-holed paper and shall be unbound and without tabs.

Each exhibit sponsored by a witness in support of his or her prefiled testimony shall be:

(1) Attached to that witness' testimony when filed;
(2) If filing paper copies, on three-holed paper, unbound, and without tabs;
(3) Sequentially numbered beginning with 1 (any exhibits attached to subsequently filed testimony of the same witness shall continue the sequential numbering system);
(4) Identified in the upper right-hand corner of each page by the docket number, a brief title, and the witness' initials followed by the exhibit's number; and
(5) Paginated by showing in the upper right-hand corner of each page the page number followed by the total number of pages in the exhibit.

An example of the information to appear in the upper right-hand corner of the exhibit is as follows:

Docket No. 012345-EI
Foreign Coal Shipments to Port of Tampa
Exhibit BLW-1, Page 1 of 2

After an opportunity for opposing parties to object to introduction of the exhibits and to cross-examine the witness sponsoring them, exhibits may be offered into evidence at the hearing.

By October 21, 2016, non-signatory parties to the Settlement Agreement may pre-file testimony and exhibits in response to any testimony filed in support of the proposed Settlement Agreement and any additional terms and conditions of the Settlement Agreement approved by the Presiding Officer. On October 21, 2016, in lieu of prefiling testimony and exhibits, a non-signatory party may file a notice listing the witness(es) it plans to sponsor and the terms and conditions of the Settlement Agreement each witness will address at the October 27, 2016, hearing. On October 21, 2016, if additional terms and conditions for discussion at the hearing have been approved by the Presiding Officer, signatory parties may file prefiled testimony to address those terms and conditions or may file a notice listing the witness(es) it plans to sponsor and the terms and conditions of the Settlement Agreement each witness will address at the October 27, 2016, hearing.

## V. Discovery Procedures

A. General Requirements

Discovery shall be conducted in accordance with the provisions of Chapter 120, F.S., and the relevant provisions of Chapter 366, F.S., Rules 25-22, 25-40, and 28-106, F.A.C., and the Florida Rules of Civil Procedure (as applicable), as modified herein or as may be subsequently modified by the Presiding Officer.

Unless subsequently modified by the Presiding Officer, the following shall apply:

(1) Discovery shall be completed by October 25, 2016.
(2) Discovery requests and responses shall be served by e-mail, hand delivery, or overnight mail, and electronic service is encouraged. Discovery served via e-mail shall be limited to 5 MB per attachment, shall indicate how many e-mails are being sent related to the discovery (such as 1 of 6 e-mails), and shall be numbered sequentially. Documents provided in response to a document request may be provided via a CD, DVD, or flash drive if not served electronically.
(3) Sets of interrogatories, requests for admissions, requests for production of documents, or other forms of discovery shall be numbered sequentially in order to facilitate their identification.
(4) Within each set, discovery requests shall be numbered sequentially, and any discovery requests in subsequent sets shall continue the sequential numbering system.
(5) Discovery responses shall be served within 2 calendar days (inclusive of mailing) of receipt of the discovery request. Discovery responses for interrogatories and requests for admission shall be served by electronic mail, hand delivery, or overnight mail. Parties are encouraged to serve discovery responses to requests for production electronically to all parties when possible.
(6) Each page of every document produced pursuant to requests for production of documents shall be identified individually through the use of a Bates Stamp or other equivalent method of sequential identification. Parties shall number their produced documents in an unbroken sequence through the final hearing.
(7) Copies, whether hard copies or electronic, of discovery requests and responses shall be served on all parties and staff. In addition, copies of all responses to requests for production of documents shall be provided to the Commission staff at its Tallahassee office unless otherwise agreed.
(8) Parties shall file in the Commission Clerk's Office a notice of service of any interrogatories or request for production of documents propounded and associated responses in this docket, giving the date of service and the name of the party to whom the discovery was directed.

Unless subsequently modified by the Presiding Officer, the following shall apply:

(1) Interrogatories, including all subparts, shall be limited to 50.
(2) Requests for production of documents, including all subparts, shall be limited to 50.

(3) Requests for admissions, including all subparts, shall be limited to 50.

B. Confidential Information Provided Pursuant to Discovery

Any information provided to the Commission staff pursuant to a discovery request by the staff or any other person and for which proprietary confidential business information status is requested pursuant to Section 366.093, F.S., and Rule 25-22.006, F.A.C., shall be treated by the Commission as confidential. The information shall be exempt from Section 119.07(1), F.S., pending a formal ruling on such request by the Commission or pending return of the information to the person providing the information. If no determination of confidentiality has been made and the information has not been made a part of the evidentiary record in this proceeding, it shall be returned to the person providing the information. If a determination of confidentiality has been made and the information was not entered into the record of this proceeding, it shall be returned to the person providing the information within the time period set forth in Section 366.093, F.S. The Commission may determine that continued possession of the information is necessary for the Commission to conduct its business.

Redacted versions of confidential filings may be served electronically, but in no instance may confidential information be electronically submitted. If the redacted version is served electronically, the confidential information (which may be on a CD, DVD, or flash drive) shall be filed with the Commission Clerk via hand-delivery, U.S. Mail, or overnight mail on the day that the redacted version was served via e-mail.

When a person provides information that it maintains as proprietary confidential business information to the Office of Public Counsel pursuant to a discovery request by the Office of Public Counsel or any other party, that party may request a temporary protective order pursuant to Rule 25-22.006(6)(c), F.A.C., exempting the information from Section 119.07(1), F.S.

When a party other than the Commission staff or the Office of Public Counsel requests information through discovery that the respondent maintains as proprietary confidential business information, or when such a party would otherwise be entitled to copies of such information requested by other parties through discovery (e.g., interrogatory responses), that party and respondent shall endeavor in good faith to reach agreement that will allow for the exchange of such information on reasonable terms, as set forth in Rule 25-22.006(7)(b), F.A.C.

## VI. Hearing Procedures

A. Attendance at Hearing

Unless excused by the Presiding Officer for good cause shown, each party (or designated representative) shall personally appear at the hearing. Failure of a party, or that party's representative, to appear shall constitute waiver of that party's positions on the issues, and that party may be dismissed from the proceeding.

Likewise, all witnesses are expected to be present at the hearing unless excused by the Presiding Officer upon the staff attorney's confirmation prior to the hearing date of the following:

(1) All parties agree that the witness will not be needed for cross-examination.
(2) All Commissioners do not have questions for the witness.

In the event a witness is excused in this manner, his or her testimony may be entered into the record as though read following the Commission's approval of the proposed stipulation of that witness' testimony.

B. Cross-Examination

The parties shall avoid duplicative or repetitious cross-examination. Further, friendly cross-examination will not be allowed. Cross-examination shall be limited to witnesses whose testimony is adverse to the party desiring to cross-examine. Any party conducting what appears to be a friendly cross-examination of a witness should be prepared to indicate why that witness's direct testimony is adverse to its interests.

C. Use of Confidential Information at Hearing

It is the policy of this Commission that all Commission hearings be open to the public at all times. The Commission also recognizes its obligation pursuant to Section 366.093, F.S., to protect proprietary confidential business information from disclosure outside the proceeding. Therefore, any party wishing to use any proprietary confidential business information, as that term is defined in Section 366.093, F.S., at the hearing shall adhere to the following:

(1) When confidential information is used in the hearing that has not been filed as prefiled testimony or prefiled exhibits, parties must have copies for the Commissioners, necessary staff, and the court reporter, in red envelopes clearly marked with the nature of the contents. Any party wishing to examine the confidential material that is not subject to an order granting confidentiality shall be provided a copy in the same fashion as provided to the Commissioners, subject to execution of any appropriate protective agreement with the owner of the material.

(2) Counsel and witnesses are cautioned to avoid verbalizing confidential information in such a way that would compromise confidentiality. Therefore, confidential information should be presented by written exhibit when reasonably possible.

At the conclusion of that portion of the hearing that involves confidential information, all copies of confidential exhibits shall be returned to the proffering party. If a confidential exhibit has been admitted into evidence, the copy provided to the court reporter shall be retained in the Office of Commission Clerk's confidential files. If such information is admitted into the evidentiary record at hearing and is not otherwise subject to a request for confidentiality filed with the Commission, the source of the information must file a request for confidential classification of the information within 21 days of the conclusion of the hearing, as set forth in Rule 25-22.006(8)(b), F.A.C., if continued confidentiality of the information is to be maintained.

## VII. Post-Hearing Procedures

If no bench decision is made, each party may file a post-hearing statement of issues and positions. Pursuant to Rule 28-106.215, F.A.C., a party's proposed findings of fact and conclusions of law, if any, statement of issues and positions, and brief, shall together total no more than 40 pages and shall be filed at the same time.

## VIII. Controlling Dates

The following dates have been established to govern the key activities of this case:

| | | |
|---|---|---|
| (1) | Supplemental testimony in support of Settlement Agreement | October 13, 2016 |
| (2) | Supplemental testimony in opposition to Settlement Agreement or notification of witnesses to appear at hearing; Signatory supplemental testimony for approved additional terms or notification of witnesses to appear at hearing | October 21, 2016 |
| (3) | Discovery response deadline | October 25, 2016 |
| (4) | Hearing | October 27, 2016 |
| (5) | Briefs | November 10, 2016 |

Based on the foregoing, it is

ORDERED by Chairman Julie I. Brown that the provisions of this Order shall govern this proceeding to take supplemental testimony on the specific issues that are a part of the Settlement Agreement but supplemental to the issues in the rate case, unless modified by the Commission.

By ORDER of Chairman Julie I. Brown, as Presiding Officer, this 12th day of October, 2016.

Julie I. Brown

JULIE I. BROWN
Chairman and Presiding Officer
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
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Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

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NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

Any party adversely affected by this order, which is preliminary, procedural or intermediate in nature, may request: (1) reconsideration within 10 days pursuant to Rule 25-22.0376, Florida Administrative Code; or (2) judicial review by the Florida Supreme Court, in the case of an electric, gas or telephone utility, or the First District Court of Appeal, in the case of a water or wastewater utility. A motion for reconsideration shall be filed with the Office of Commission Clerk, in the form prescribed by Rule 25-22.0376, Florida Administrative Code. Judicial review of a preliminary, procedural or intermediate ruling or order is available if review of the final action will not provide an adequate remedy. Such review may be requested from the appropriate court, as described above, pursuant to Rule 9.100, Florida Rules of Appellate Procedure.

TAB C

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

| | |
|---|---|
| In re: Petition for rate increase by Florida Power & Light Company. | DOCKET NO. 160021-EI |
| In re: Petition for approval of 2016-2018 storm hardening plan, by Florida Power & Light Company. | DOCKET NO. 160061-EI |
| In re: 2016 depreciation and dismantlement study by Florida Power & Light Company. | DOCKET NO. 160062-EI |
| In re: Petition for limited proceeding to modify and continue incentive mechanism, by Florida Power & Light Company. | DOCKET NO. 160088-EI<br>ORDER NO. PSC-16-0483-PHO-EI<br>ISSUED: October 24, 2016 |

SECOND PREHEARING ORDER

## I. **Background**

On January 15, 2016, Florida Power & Light Company (FPL) filed a test year letter, as required by Rule 25-6.140, Florida Administrative Code (F.A.C.), notifying the Florida Public Service Commission (Commission) of its intent to file a petition for an increase in rates effective 2017. Pursuant to the provisions of Chapter 366, Florida Statutes (F.S.), and Rules 25-6.0425 and 25-6.043, F.A.C., FPL filed its Minimum Filing Requirements and testimony on March 15, 2016. Docket Nos. 160061-EI (2016-2018 Storm Hardening Plan), 160062-EI (2016 Depreciation and Dismantlement Study) and 160088-EI (Incentive Mechanism), were thereafter consolidated into the rate case docket, Docket No. 160021-EI. Nine parties were granted intervention in the docket.[1] An administrative hearing on FPL's request for a rate increase was conducted on August 22, 2016 - August 26, 2016, and August 29, 2016 - September 1, 2016. On October 6, 2016, FPL and three of the nine intervening parties (signatories)[2] filed a Joint Motion for Approval of Settlement Agreement (Settlement Agreement). Pursuant to Order No. PSC-16-0456-PCO-EI, issued on October 12, 2016, an administrative hearing is scheduled for October 27, 2016, to reopen the record and take supplemental testimony regarding the terms and conditions of the Settlement Agreement not previously addressed in the prior hearing. On October 21, 2016, pursuant to Order No. PSC-16-0456-PCO-EI, AARP timely filed its Notice of Witness Appearance identifying Michael Brosch as its direct witness for the hearing scheduled for October 27, 2016. The sole issue for consideration at the October 27, 2016 hearing is: *Is it in the public interest for the Settlement Agreement to be approved?*

[1] Office of Public Counsel (OPC), Florida Industrial Power Users Group (FIPUG), Wal-Mart Stores East, LP and Sam's East, Inc. (Walmart), Federal Executive Agencies (FEA), South Florida Hospital and Healthcare Association (SFHHA), American Association of Retired Persons (AARP), Florida Retail Federation (FRF), Sierra Club, and Daniel R. Larson and Alexandria Larson (Larsons).

[2] OPC, FRF, and SFHHA.

## II. Jurisdiction

This Commission is vested with jurisdiction over the subject matter by the provisions of Chapter 366, Florida Statutes (F.S.). This hearing will be governed by said Chapter and Chapters 25-6, 25-22, and 28-106, F.A.C., as well as any other applicable provisions of law.

## III. Order of Witnesses

| Witness | Proffered By | Issues # |
|---|---|---|
| **Direct** | | |
| Tiffany Cohen | FPL | Rates |
| Keith Ferguson | FPL | Paragraph 12 – theoretical depreciation reserve surplus, revised depreciation parameters, new depreciation rates, deferral of depreciation and dismantlement studies. |
| Sam Forrest | FPL | Paragraph 16 – termination of financial hedging for natural gas requirements. |
| Robert E. Barrett, Jr. | FPL | Paragraph 10 – Solar Base Rate Adjustment;<br>Paragraph 18 – battery storage pilot program;<br>Paragraph 19 - pilot demand side management opt-out program. |
| *Michael Brosch | AARP | Paragraph 1 – term of the agreement;<br>Paragraph 2 – revisions to MFR Schedules B-2, C-1, C-3, and D1a and use in surveillance reports and clause filings;<br>Paragraph 3 – ROE;<br>Paragraph 4 – base rate increases, CILC tariff, CDR rider, cost of service methodology;<br>Paragraph 6 – storm recovery costs;<br>Paragraph 7 – cost recovery clause exclusion;<br>Paragraph 9 – Okeechobee Limited Scope Adjustment;<br>Paragraph 10 – Solar Base Rate Adjustment;<br>Paragraph 11 – exceptions to 4 year minimum term; |

Paragraph 12 – depreciation reserve surplus, revised depreciation parameters, new depreciation rates, deferral of depreciation and dismantlement studies.

* Live testimony.

**Rebuttal**

FPL may call any of its direct witnesses to rebut the live testimony of Michael Brosch.

## IV. Exhibit List

| Witness | Proffered By | ID | Description |
|---|---|---|---|
| Tiffany Cohen | FPL | TCC-10 | 1,000-kWh Typical Residential Bill Comparison |
| Tiffany Cohen | FPL | TCC-11 | 2017-2020 Typical Bills |
| Tiffany Cohen | FPL | TCC-12 | Parity of Major Rate Classes |
| Keith Ferguson | FPL | KF-9 | Depreciation parameter changes in proposed Settlement Agreement as of December 31, 2016. |

## V. Rulings

Opening statements, if any, shall be limited to 10 minutes for all of the signatories to the Settlement Agreement, to be divided among them as they see fit, and 5 minutes each for the non-signatories. Summaries of witness testimony, if any, shall be limited to 3 minutes. Cross examination on issues addressed in the prior hearing that are contained in the Settlement Agreement will be allowed to the extent the questions are regarding calculations and/or the rationale supporting that portion of the Settlement Agreement. However, questions duplicative of those asked at the previous evidentiary hearing shall be deemed outside the scope of this proceeding and disallowed. All parties shall bring 40 copies of all exhibits they wish to enter into evidence and abide by the rules for any confidential materials contained therein.

Based on the foregoing, it is

ORDERED by Chairman Julie I. Brown that the provisions of this Order and Order No. PSC-16-0456-PCO-EI shall govern the proceeding to be held on October 27, 2016, to take supplemental testimony on the Settlement Agreement, unless modified by the Commission.

By ORDER of Chairman Julie I. Brown, as Presiding Officer, this _____ day of ________________, __________.

Julie Brown

JULIE I. BROWN
Chairman and Presiding Officer
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
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Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

SBr

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

Any party adversely affected by this order, which is preliminary, procedural or intermediate in nature, may request: (1) reconsideration within 10 days pursuant to Rule 25-22.0376, Florida Administrative Code; or (2) judicial review by the Florida Supreme Court, in the case of an electric, gas or telephone utility, or the First District Court of Appeal, in the case of a water or wastewater utility. A motion for reconsideration shall be filed with the Office of Commission Clerk, in the form prescribed by Rule 25-22.0376, Florida Administrative Code. Judicial review of a preliminary, procedural or intermediate ruling or order is available if review of the final action will not provide an adequate remedy. Such review may be requested from the appropriate court, as described above, pursuant to Rule 9.100, Florida Rules of Appellate Procedure.

TAB D

FILED 1/8/2018
DOCUMENT NO. 00180-2018
FPSC - COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

| | |
|---|---|
| In re: Fuel and purchased power cost recovery clause with generating performance incentive factor. | DOCKET NO. 20180001-EI<br>ORDER NO. PSC-2018-0028-FOF-EI<br>ISSUED: January 8, 2018 |

The following Commissioners participated in the disposition of this matter:

JULIE I. BROWN, Chairman
ART GRAHAM
RONALD A. BRISÉ
DONALD J. POLMANN
GARY F. CLARK

FINAL ORDER APPROVING EXPENDITURES AND TRUE-UP AMOUNTS FOR FUEL ADJUSTMENT FACTORS; GPIF TARGETS, RANGES, AND REWARDS; AND PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR CAPACITY COST RECOVERY FACTOR

APPEARANCES:

MATTHEW BERNIER, ESQUIRE, 106 East College Avenue, Tallahassee, Florida 32301-7740; and DIANNE M. TRIPLETT, ESQUIRE, 299 First Avenue North, St. Petersburg, Florida 33701
On behalf of Duke Energy Florida, LLC (DEF)

JOHN T. BUTLER, WILL COX, WADE LITCHFIELD, and MARIA J. MONCADA, ESQUIRES, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408-0420
On behalf of Florida Power & Light Company (FPL)

BETH KEATING, ESQUIRE, Gunster, Yoakley & Stewart, P.A., 215 South Monroe St., Suite 601, Tallahassee, Florida 32301
On behalf of Florida Public Utilities Company (FPUC)

JEFFREY A. STONE, ESQUIRE, One Energy Place, Pensacola, Florida 32520-0780; and RUSSELL A. BADDERS, and STEVEN R. GRIFFIN, ESQUIRES, Beggs & Lane, Post Office Box 12950, Pensacola, Florida 32591-2950
On behalf of Gulf Power Company (Gulf)

JAMES D. BEASLEY, and J. JEFFRY WAHLEN, ESQUIRES, Ausley McMullen, Post Office Box 391, Tallahassee, Florida 32302
On behalf of Tampa Electric Company (TECO)

J.R. KELLY, CHARLES REHWINKEL, PATRICIA A. CHRISTENSEN, and ERIK SAYLER, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida (OPC)

JON C. MOYLE, JR. and KAREN PUTNAL, ESQUIRES, Moyle Law Firm, PA, The Perkins House, 118 North Gadsden Street, Tallahassee, Florida 32301
On behalf of the Florida Industrial Power Users Group (FIPUG)

ROBERT SCHEFFEL WRIGHT and JOHN T. LAVIA, III, ESQUIRES, Gardner, Bist, Bowden, Bush, Dee, LaVia & Wright, P.A., 1300 Thomaswood Drive, Tallahassee, Florida 32308
On behalf of the Florida Retail Federation (FRF)

SUZANNE BROWNLESS, and DANIJELA JANJIC, ESQUIRES, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Florida Public Service Commission (Staff)

MARY ANNE HELTON, ESQUIRE, Deputy General Counsel, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
Advisor to the Florida Public Service Commission

KEITH HETRICK, ESQUIRE, General Counsel, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
Florida Public Service Commission General Counsel

BY THE COMMISSION:

As part of the continuing fuel and purchased power adjustment and generating performance incentive clause proceedings, an administrative hearing was held on October 25-27, 2017, in this docket. White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate-White Springs (PCS Phosphate) was excused from attendance at the final hearing.

At the hearing, we voted to approve stipulated issues 1B, 2B-2I, 2Q, 2R, 3A, 6-11, 13A, 16-22, 23A, 24A-24D and 27-36 as set forth in Attachment A. We also approved Issues 1A, 2A, 4A and 5A, hedging issues contested by FRF, OPC and FIPUG, by bench decision as set forth in Attachment B. As a result of our bench decisions on these issues, we have approved all issues associated with TECO, FPUC, Gulf, and DEF. Testimony was taken on the remaining FPL issues, Issues 2J-2P, which address FPL's solar generation (SoBRA) projects. FIPUG and FPL filed briefs on the SoBRA issues on November 13, 2017. On November 16, 2017, FPL filed an Unopposed Motion for Leave to File Response to New Issue Raised in FIPUG's Post Hearing

Brief with its response attached. The new issue addressed jurisdictional recovery arguments for the SoBRA projects.

We have jurisdiction over this subject matter pursuant to the provisions of Chapter 366, Florida Statutes (F.S.), including Sections 366.04, 366.05, and 366.06, F.S.

**SoBRA PROJECT RECOVERY JURISDICTION**

For the first time in its post hearing brief FIPUG argued that we lack jurisdiction to allow recovery in this docket of 2017 and 2018 solar base rate adjustment charges citing the Florida Supreme Court decisions Citizens v. Graham (Woodford), 191 So. 3d 897 (Fla. 2016) and Citizens v. Graham (FPUC), 213 So. 3d 703 (Fla. 2017). FPL filed its Unopposed Motion for Leave to File Response to New Issue Raised in FIPUG's Post Hearing Brief (Motion) on November 16, 2017, with its response to the jurisdictional issue attached. FIPUG does not object to granting this Motion. The other parties to this docket, having taken no position on the SoBRA issues, Issues 2J through 2P, did not file briefs or take a position on the Motion or the underlying jurisdictional issue. Because no party has objected to FPL's request to file a written response to FIPUG's jurisdictional argument, and due process requires that FPL be given reasonable notice and a fair opportunity to be heard on this issue before a decision is made[1], we hereby grant FPL's Motion and address the jurisdictional issue below.

FIPUG characterizes the recovery of SoBRA charges as FPL's effort to again use the fuel clause to recover predictable capital costs contrary to the purpose of the fuel clause which is to address the volatility of fuel prices between base rate cases. FIPUG points out that while the Legislature has created a clause for nuclear and environmental costs, it has not provided us with express, or implied, authority for a solar energy capital cost recovery clause. FIPUG acknowledges that the process for SoBRA cost recovery being followed here is included in FPL's 2016 Stipulation and Settlement (2016 Agreement), to which it did not object. However, FIPUG counters that jurisdiction cannot be conferred by agreement of the parties or by our approval of a rate case settlement agreement.

FPL counters that FIPUG's reliance on the Woodford and FPUC decisions is misplaced for one simple reason: the capital and return on investment costs for the SoBRA projects are not being recovered through the 2017 and 2018 fuel cost recovery factors. These costs are instead being recovered through increases in FPL's base rate charge, beginning on the commercial operation date of each SoBRA project. In fact, the fuel factors to be implemented from January 1 to March 1, 2018, have been stipulated to by the parties and previously approved by us. These fuel factors cannot change no matter what our final decision on the SoBRA issues.

FPL notes that this cost recovery mechanism is similar to the generation rate base adjustment (GBRA) mechanism found in FPL's 2013 Settlement Agreement to which FIPUG was a signatory. The use of a GBRA mechanism for base rate adjustments in years beyond a test year was approved by the Florida Supreme Court in Citizens v. Public Service Commission, 146 So. 3d 1143, 1157 n.7 (Fla. 2014). Further, between 2013 and 2016, three separate generation projects (Cape Canaveral, Riviera Beach and Port Everglades) utilized the GBRA process in the fuel clause without objection by FIPUG.

[1] Citizens v. Florida Public Service Commission, 146 So. 3d 1143, 1154 (Fla. 2014).

Finally, FPL argues that filing for SoBRA recovery in the fuel docket is simply an administratively efficient process utilizing an existing docket with a known filing schedule to adjust its base rates for previously approved capital projects. This eliminates finding and scheduling separate hearing dates each year as SoBRA projects come on line and synchronizes each SoBRA rate base increase with the associated reduction in fuel costs resulting from the projects' commercial operation. Based on these facts, FPL concludes that no jurisdictional issue actually exists and that we have the authority to approve SoBRA charges in this docket.

Analysis

There is one point on which we and all parties agree: that we derive our authority to act solely from the Legislature. United Telephone Company of Florida v. Public Service Commission, 496 So. 2d 116, 118 (Fla. 1986). In Woodford, FPL sought to recover through the fuel factor the capital, operation and maintenance, and return on investment costs for wells drilled in the Woodford Shale Gas Region in Oklahoma. The Court identified our authority as the ability to "regulate and supervise each public utility with respect to its rates and service and to prescribe a rate structure for all electric utilities." Woodford, 191 So. 3d at 900. An "electric utility" is defined as a municipal or investor-owned utility or a rural electric cooperative that "owns, maintains, or operates an electric generation, transmission, or distribution system within the state." Section 366.02(2), F.S.

Based on this definition, the Court found that the exploration, drilling and production of natural gas did "not constitute generating, transmitting, or distributing electricity in Florida as the meaning of those terms are plainly understood" and "falls outside the purview of an electric utility as defined by the Legislature." Woodford, 191 So. 3d at 901. Further, the Court found that the Woodford project was not a physical hedge of fuel costs which had previously been determined by the Court to be within our regulatory authority. Id. Having determined that the Woodford project was neither an electric utility activity contemplated by the Legislature nor a physical hedge, the Court found that we had exceeded our authority in approving the project costs through the fuel clause. Woodford, 191 So. 3d at 902.

In FPUC, the Court found that we exceeded our authority by allowing the recovery through the fuel factor of capital and return on capital investment costs associated with the construction of a transmission line connecting FPUC's electric system on Amelia Island with that of FPL. The Court focused on the historical purpose of the fuel clause as a means of "adjusting for volatile costs associated with fuel" finding that a transmission line failed to meet this test. FPUC, 213 So. 3d at 718. The Court also relied heavily upon the terms of FPUC's rate case stipulation and settlement agreement, which specifically stated that FPUC could not seek recovery through the fuel clause of costs that had "traditionally and historically" been recovered through base rates and used "investment in and maintenance of transmission assets" as an example of such an expense. FPUC, 213 So. 3d at 708-10. Since no discussion of these settlement agreement terms was included in our final order, the Court found that we had "failed to perform its duty to explain its reasoning" and reversed our decision. FPUC, 213 So. 3d at 710-11.

Both the Woodford and FPUC decisions discuss what types of costs are appropriately recovered through the fuel clause factor: fuel, purchased power and volatile fuel-related costs. The FPUC decision does not address our inherent authority to allow the recovery of the FPL transmission line. Further, if the reasoning in Woodford is applied to the FPUC facts, the Court would find the recovery of transmission lines through base rates appropriate since transmission is specifically listed as an activity engaged in by electric utilities. Section 366.02(2), F.S.

Likewise, applying the reasoning of Woodford to the facts here, there is no question that we have the authority to allow recovery of the costs associated with solar generation projects. As with transmission, generation is listed specifically as an activity engaged in by electric utilities in Section 366.02(2), F.S. It is important to note that FIPUG is not arguing that FPL does not have the right to recover the solar project costs; it is arguing that solar project costs can't be recovered through fuel clause factors. Presumably, FIPUG would not object to FPL filing a separate docket seeking cost recovery for the 2017 and 2018 solar projects using an increase in base rates to do so. Indeed, FIPUG has agreed to such a mechanism to recover solar project capital costs as a signatory to Tampa Electric Company's 2017 Amended and Restated Stipulation and Settlement Agreement.[2]

Since FPL is not requesting recovery through the fuel adjustment clause factor, but is requesting recovery of costs for its solar projects through increases in base rates, FIPUG's complaint does not raise a jurisdictional question at all. Recovery of these costs through base rates is clearly appropriate under both the Woodford and FPUC decisions. We agree with FPL that placement of this issue in the fuel clause docket was purely administrative. We also agree with FPL that to the extent possible, an increase in base rates associated with the solar projects coming on line should be timed to coincide with any fuel savings which result from that solar generation. Litigating the cost effectiveness issues associated with the solar projects, Issues 2J-2P, in this docket cost-effectively accomplishes this goal.

When dissected and examined closely, FIPUG's issue boils down to insisting that rate base cost recovery for the solar projects be filed in a separate docket. FIPUG has not alleged that it did not have adequate notice of the solar project issues, or that it has been harmed in any way by the inclusion of those issues in this docket. Nor could it. FPL filed direct testimony of four witnesses on this point,[3] Commission staff conducted extensive discovery on this issue,[4] FIPUG cross examined FPL witnesses Enjamio and Brannen on this topic at hearing, and FIPUG filed a post hearing brief. Conducting these activities under a separate docket number does not change their nature or provide FIPUG any additional due process rights.

Based on the above, we find that we have the authority to approve the recovery of FPL's 2017 and 2018 solar projects through base rates in this fuel clause docket.

**SoBRA PROJECT RECOVERY**

Overview

FPL proposes to construct and operate 596 MW of solar generation by 2018 pursuant to its 2016 Stipulation and Settlement Agreement (2016 Agreement). FPL contends that the costs for the 2017 and 2018 projects are reasonable and fall below the $1,750 per $kW_{ac}$ cost cap as required by the 2016 Agreement. To ensure reasonable capital costs, FPL completed a

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[2] Document No. 07947-2017 at ¶ 6(f).
[3] Tiffany Cohen, Liz Fuentes, Juan Enjamio and William Brannen.
[4] EXH 84, 86, 87 and 89.

competitive bidding process for the equipment to be installed and the work to be performed. Further, FPL argues that updated efficient designs and reduced interconnection costs lowered the anticipated costs for the 2017 and 2018 projects.

FPL employed two resource plans for the proposed solar generation: a No Solar Plan and 2017-2018 Solar Plan. Based on the assumptions made in each plan, FPL calculates that there is an estimated cumulative present value revenue requirement (CPVRR) savings of $38.6 million. FPL asserts that updates to tax law in August 2017 provided a reduction in costs, in the form of reduced property taxes, for three of the four 2018 solar project sites. FPL calculates that the efficient designs, reduced interconnection costs, and reduced property taxes raise the estimated CPVRR savings under the 2017-2018 Solar Plan to $106 million. It is FPL's position that the 2017 and 2018 projects are cost effective under the 2016 Agreement if the system CPVRR is lower with the solar projects than without them as is the case.

FIPUG argues that the solar projects are not needed to meet the Commission's 15 percent reserve margin or FPL's 20 percent reserve margin. FIPUG contends that FPL's efforts to prove that the SoBRA projects are cost effective are only supported by hearsay evidence. FIPUG adds that FPL customers will lose $127.3 million if fuel prices remain low and no carbon tax is imposed in the future. FIPUG further asserts that the future cost of natural gas and the future cost of carbon resulting from a carbon tax used by FPL in its cost effectiveness analysis is uncorroborated.

Analysis

A. 2017 Project Description

FPL is proposing to construct and operate four PV centers with a total nameplate capacity of 298 $MW_{ac}$ (74.5 $MW_{ac}$ each) with an in-service date of December 31, 2017. Construction of the 2017 solar generation projects began on October 21, 2016. The proposed solar generation projects are Fixed-Tilt Systems with an average projected first year net capacity factor of 26.6 percent. There are no upgrades to existing transmission infrastructure required as part of the construction of the 2017 solar generation projects.

The four proposed sites for the 2017 solar project construction are Coral Farms, Horizon, Wildflower, and Indian River. The Wildflower site is already included in FPL's rate base; therefore, Wildflower land costs are not included in the analysis. All other parcels are new purchases. Not all of the land in the seven newly purchased sites is being used for the 2017 and 2018 solar projects although FPL states that some of this land will be used for future projects. To develop a better understanding of the ratio of land that could be used for future development, a more detailed breakdown of each site was requested from FPL. This breakdown included four categories: total acreage, acreage used by the projects (Site Acreage), non-usable land, and residual land. Residual land consists of property that could possibly be used in future solar developments on the site, and for sites with adequate amounts of residual land, FPL will consider leasing land to parties for farming or cattle grazing activities. The range of acreages of each site is illustrated in Table 1 below:

Table 1
Land Usage

| Site Name | Total Acreage (acres) | Site Acreage (acres) | Non-Usable Land (acres) | Residual Land (acres) |
|---|---|---|---|---|
| Coral Farms | 587 | 541 | 0 | 46 |
| Horizon | 1316 | 552 | 178 | 587 |
| Wildflower | 721 | 466 | 12 | 244 |
| Indian River | 697 | 389 | 56 | 252 |

Source: EXH 87-88

B. 2018 Project Description

FPL is proposing to construct and operate four PV centers with a total nameplate capacity of 298 $MW_{ac}$ (74.5 $MW_{ac}$ each) for an in-service date of March 1, 2018. Construction of the 2018 solar generation projects began on October 21, 2016. The proposed solar generation projects are Fixed-Tilt Systems with an average projected first year net capacity factor of 26.6 percent. There are no upgrades to existing transmission infrastructure required as part of the construction of the 2018 solar generation projects.

The four proposed sites for the 2018 solar project construction are Loggerhead, Barefoot Bay, Hammock, and Blue Cypress. All parcels are new purchases. Not all of the land purchased is being used for construction of the solar projects at the four sites. To develop a better understanding of the ratio of land that could be used for future development, a more detailed breakdown of each site was requested from FPL. This breakdown included four categories: total acreage, acreage used by the projects (Site Acreage), non-usable land, and residual land. Residual land consists of property that could possibly be used in future solar developments on the site, and for sites with adequate amounts of residual land, FPL will consider leasing land to parties for farming or cattle grazing activities. The range of acreages of each site is illustrated in Table 2 below:

Table 2
Land Usage

| Site Name | Total Acreage (acres) | Site Acreage (acres) | Non-Usable Land (acres) | Usable Land (acres) |
|---|---|---|---|---|
| Loggerhead | 564 | 425 | 27 | 112 |
| Barefoot Bay | 462 | 384 | 52 | 25 |
| Hammock | 957 | 407 | 375 | 176 |
| Blue Cypress | 424 | 418 | 0 | 6 |

Source: EXH 87-88

C. Standard for Approval

The SoBRA projects for 2017 and 2018 for which FPL is seeking approval and cost recovery are part of its 2016 Agreement approved by Order No. PSC-16-0560-AS-EI.[5] The 2016 Agreement allows FPL to construct up to 300 MW per calendar year of solar capacity

[5]Order No. PSC-16-0560-AS-EI, issued on December 15, 2016, in Docket No. 20160021-EI, In re: Petition for rate increase by Florida Power & Light Company.

during the period 2017-2021 and to recover through base rates the incremental annualized base revenue requirement for those facilities for the first 12 months of operation commencing when the facilities are placed into service.[6] There are several conditions that must be met for recovery in this case. First, FPL must request recovery for these projects during the term of the 2016 Agreement, or prior to December 31, 2020. Second, the cost of the components, engineering, and construction for any solar project is capped at $1,750 per kilowatt alternating current ($kW_{ac}$). Third, for projects less than 75 MW (as are all of the projects proposed in this case): 1) the request for base rate recovery must be filed in the Fuel Clause docket as part of its final true-up filing; and 2) the issues are "limited to the cost effectiveness of each such project (i.e., will the project lower the projected system CPVRR as compared to each CPVRR without the solar project) and the amount of revenue requirements and appropriate percentage in base rates needed to collect the estimated revenue requirements."[7] If the project meets these requirements, the terms of the 2016 Agreement have been met. Therefore, we find that FIPUG's argument based on reliability criteria is irrelevant.

D. 2017 and 2018 Solar Project Cost Effectiveness Analysis

The in-service date for the 2017 projects is December 31, 2017. The in-service date for the 2018 projects is March 1, 2018. Because of the minor timing difference between the in-service dates, we find that it is appropriate to evaluate both 2017 and 2018 projects together for cost effectiveness. In addition, both the 2017 and 2018 solar generation projects were cumulatively evaluated in the initial filing of the docket.

FPL developed two resource plans to form the basis of the cost effectiveness analysis that it performed. These two resource plans are called the No Solar Plan and 2017-2018 Solar Plan. The No Solar Plan assumes that resource needs will be met by combined cycle units and short term purchase power agreements (PPAs) through the year 2030. The 2017-2018 Solar Plan takes into account the eight solar projects, which initially defers the 2025 combined cycle (cc) unit. The Okeechobee CC Unit is currently under construction. The resource plan filed in regards to FPL's initial filing is shown in Table 3 below:

Table 3
Initial Resource Plan

| Year | No Solar Resource Plan | 2017-2018 Solar Resource Plan |
|---|---|---|
| 2017 | | 298 MW Solar |
| 2018 | | 298 MW Solar |
| 2019 | Okeechobee 3x1 CC Unit | Okeechobee 3x1 CC Unit |
| 2020 | | |
| 2021 | | |
| 2022 | | |
| 2023 | | |
| 2024 | 1-Year 33 MW PPA | |
| 2025 | 1 Greenfield 3x1 CC Unit | 1-Year 119 MW PPA |
| 2026 | | 1 Greenfield 3x1 CC Unit |

[6]2016 Agreement at ¶ 10(a).
[7]2016 Agreement at ¶ 10(c).

| | | |
|---|---|---|
| 2027 | | |
| 2028 | 1-Year 20 MW PPA | |
| 2029 | 1 Greenfield 3x1 CC Unit | 1-Year 287 MW PPA |
| 2030 | | 1 Greenfield 3x1 CC Unit |
| 2031 | Turkey Point 6 | Turkey Point 6 |
| 2032 | Turkey Point 7 | Turkey Point 7 |
| 2033 | Equalizing 599 MW CC | Equalizing 291 MW CC |

Source: EXH 84

FPL filed its 2017 Ten Year Site Plan in April 2017, which included for the first time the Dania Beach Clean Energy Center. In August 2017, FPL filed revised testimony that updated its evaluation of the 2017 and 2018 solar projects. Table 4 below is based on a new resource plan incorporating both the FPL's revised filing and the addition of the Dania Beach Clean Energy Center.

Table 4
Revised Resource Plan

| **Year** | **No Solar Resource Plan** | **2017-2018 Solar Resource Plan** |
|---|---|---|
| 2017 | | 298 MW Solar |
| 2018 | 1-Year 958 MW PPA | 298 MW Solar;<br>1-Year 636 MW PPA |
| 2019 | Okeechobee 3x1 CC Unit;<br>1-Year 155 MW PPA | Okeechobee 3x1 CC Unit |
| 2020 | 1-Year 182 MW PPA | |
| 2021 | 1-Year 263 MW PPA | |
| 2022 | Dania Beach CC | Dania Beach CC |
| 2023 | | |
| 2024 | 1-Year 44 MW PPA | |
| 2025 | 1 Greenfield 3x1 CC Unit | 1-Year 149 MW PPA |
| 2026 | | 1 Greenfield 3x1 CC Unit |
| 2027 | | |
| 2028 | 1-Year 93 MW PPA | |
| 2029 | 1 Greenfield 3x1 CC Unit | 1-Year 363 MW PPA |
| 2030 | | 1 Greenfield 3x1 CC Unit |
| 2031 | Turkey Point 6 | Turkey Point 6 |
| 2032 | Turkey Point 7 | Turkey Point 7 |
| 2033 | Equalizing 574 MW CC | Equalizing 266 MW CC |

Source: EXH 87

The revised resource plan shows that the addition of the 2017 and 2018 solar projects should reduce FPL's need for purchased power agreements.

In completing the analysis, FPL considered multiple components to determine cost effectiveness: solar revenue requirements, avoided generation costs, and avoided system costs. For the proposed solar facilities, the revenue requirements included fixed operation and maintenance (O&M), equipment, installation, land cost, and transmission interconnection cost.

The avoided generation cost component considered avoided generation capital, avoided fixed O&M, avoided transmission interconnection, avoided capital replacement, incremental gas transport, and short-term purchases. The avoided system cost component considers the factors of fuel savings, avoided variable O&M, and emission cost savings. FPL's CPVRR analysis assumed that each project had an actual life of 33 years, with the analysis ending in 2050.

The emission cost savings consideration did not incorporate $CO_2$ pricing until 2028. FPL witness Enjamio identified ICF's $CO_2$ emission's cost forecast as a major assumption in FPL's economic analysis of its proposed solar PV generation projects. The $CO_2$ cost projections used in FPL's cost-effectiveness analyses are based on ICF's $CO_2$ emission cost forecast dated December 2016. ICF is a consulting firm with extensive experience in forecasting the cost of air emissions and is recognized as one of the industry leaders in this field. FPL has used ICF's $CO_2$ emission cost forecasts in many of its filings, including the recently approved 2017 Ten Year Site Plan. No intervenor offered testimony rebutting FPL's $CO_2$ emission cost forecast or provided any alternative emission cost forecast. For these reasons, we find that the $CO_2$ cost projections FPL used in this docket are reasonable and appropriate.

1. CPVRR Analysis - Initial Filing

We reviewed FPL's original CPVRR for the 2017 and 2018 solar generation projects that produced a savings of $38.6 million for the base fuel and environmental forecasts. This calculation included the previously mentioned $CO_2$ pricing in 2028. FPL's CPVRR analysis in support of its 2017-2018 Solar Plan included assumptions related to future fuel prices. The Company employed its standard fuel forecasting methodology to produce its long-term fuel price forecast. No alternative base fuel forecast was provided to us for the purposes of evaluing the Company's 2017-2018 Solar Plan. We find that the forecasted fuel prices used in the Company's CPVRR analysis associated with its current proposal are reasonable. FPL provided a CPVRR analysis with both fuel and environmental compliance sensitivities. In FPL's analysis, a Low, Medium, and High Fuel Forecast and ENV I, ENV II, and ENV III compliance costs were considered. ENV I assumes an annual $0/ton cost for $CO_2$ pricing and low environmental compliance costs, ENV II assumes a most likely cost, and ENV III assumes high environmental compliance costs. The range of savings is illustrated in Table 5 below:

Table 5
Initial CPVRR Filing

| | **Environmental Compliance Cost Forecast** | | | |
|---|---|---|---|---|
| | | **ENV I** | **ENV II** | **ENV III** |
| Fuel Cost Forecast | **High** | ($63.5) | ($136.4) | ($291) |
| | **Medium** | $35 | ($38.6) | ($195.8) |
| | **Low** | $127.3 | $53.6 | ($103.1) |

Source: EXH 84

2. CPVRR Analysis - Revised Filing

FPL witness Enjamio filed revised testimony August 2, 2017, providing an updated economic analysis to reflect a change in cost effectiveness and cost assumptions for the 2017-

2018 solar projects. Specifically, FPL cited changes in tax law effective as of July 1, 2017, that allowed an exemption from property taxes for qualifying solar installations which applied to three of the planned 2018 solar generation project sites, and resulted in a $34 million CPVRR reduction. This testimony resulted in a revised $106 million CPVRR base case scenario.

The terms of the 2016 agreement also require FPL to adhere to a $1,750 per $kW_{ac}$ cost cap for any solar project. This cost cap includes the cost of the components, engineering, and construction for each site. In the initial filing, the 2017 and 2018 solar generation projects had a total anticipated capital cost of $435 million and $457 million, respectively. The 2017 projects were projected to fall under the cost cap with an average cost of $1,461per $kW_{ac}$ and a $1,534 per $kW_{ac}$ average cost for the 2018 projects. In witness Brannen's revised testimony of August 2, 2017, the completion of design competitive solicitations for the construction of the interconnection facilities for the 2017 solar construction projects reduced the projected construction cost by $16 Million. Witness Brannen stated that these same factors also reduced the projected construction cost by $14 million for the 2018 solar construction projects. For the 2017 projects, the new construction cost was a $419 million total with a revised average $1,405 per $kW_{ac}$ cost. The new cost per $kW_{ac}$ is $56 per $kW_{ac}$ less than the initially filed cost and $345 per $kW_{ac}$ less than the $1,750 per $kW_{ac}$ cost cap. For the 2018 projects, the new construction cost was a $443 million total with a revised average $1,485 per $kW_{ac}$ cost. The new cost per $kW_{ac}$ is $49 per $kW_{ac}$ less than the initially filed cost and $265 per $kW_{ac}$ less than the $1,750 per $kW_{ac}$ cost cap. Having reviewed the cost cap assumptions discussed above we find them to be reasonable.

FPL's revised testimony from August 2017 did not include the planned Dania Beach Clean Energy Center. As such, an updated CPVRR evaluation was requested that included the planned Dania Beach Clean Energy Center and updated fuel and environmental compliance sensitivities evaluations. The result of this updated sensitivity analysis is illustrated in Table 6 below:

Table 6
Revised CPVRR Analysis

| | | **Environmental Compliance Cost Forecast** | | |
|---|---|---|---|---|
| | | **ENV I** | **ENV II** | **ENV III** |
| Fuel Cost Forecast | **High** | ($119) | ($195) | ($348) |
| | **Medium** | ($24) | ($96) | ($249) |
| | **Low** | $76 | $6 | ($147) |

Source: EXH 87

Table 6 above shows that in seven of the nine scenarios, the 2017 and 2018 solar projects are cost effective. Notably the base fuel case (medium), ENV I scenario contains no cost for $CO_2$, but is also cost effective. When comparing the change in savings on a CPVRR basis between the initial filing and the revised analysis, there is a substantial increase in savings for all forecasted scenarios. In all forecsted scenarios, avoided fuel costs was the major driving force in producing overall savings for the projects. This fact manifested in even the "worst" case scenario of Low Fuel Cost, ENV I, where there are projected fuel savings in every forecasted year. The first cumulative benefit occurs in 2025. This benefit seems to be driven by the avoided capital that would be required for the Greenfield 3x1 Combined Cycle Unit. For the reasons discussed above, we find that FPL's CPVRR assumptions are reasonable.

FIPUG questions the validity of $CO_2$ emission cost forecasts. However, FPL performed $CO_2$ emission and natural gas price sensitivities analyses, including zero carbon tax scenarios, to support its petition. Results of such sensitivity analyses show that the 2017 and 2018 solar projects are cost-effective in seven out of nine fuel and $CO_2$ sensitivity scenarios, including scenarios that assume zero $CO_2$ cost. The CPVRR and construction cost analyses were performed in a consistent manner and no party presented substantial evidence disputing either the input assumptions or the analyses.

Based on the evidence contained in the record, we find that FPL's proposed 2017 and 2018 solar projects are projected to produce savings under multiple scenarios. FPL has also met the terms of 2016 Agreement in regards to keeping construction cost under the \$1,750 per $kW_{ac}$ cost cap. Therefore, we find that the terms and conditions of the 2016 Agreement have been met and that the 2017 and 2018 solar projects are cost effective.

E. 2017 SoBRA Revenue Requirement

Witness Fuentes testified that the annualized jurisdictional revenue requirement for the first 12 months of operations related to the 2017 SoBRA projects is \$60,523,000. Witness Fuentes further stated that the \$60,523,000 revenue requirement was calculated by following the methodologies approved by the Commission for FPL's generation base rate adjustments (GBRA) for Turkey Point Unit 5 and West County Energy Center Units 1 and 2 in Order No. PSC-05-0902-S-EI,[8] West County Energy Center Unit 3 in Order No. PSC-11-0089-S-EI,[9] and the modernization projects at Canaveral, Riviera Beach, and Port Everglades in Order No. PSC-13-0023-S-EI.[10] Witness Fuentes also testified that the same methodology was used with the recently approved 2019 Okeechobee Limited Scope Adjustment (Okeechobee LSA). The jurisdictional annualized revenue requirement calculation for the 2017 SoBRA projects used several inputs, including the most current estimated capital expenditures presented by FPL witness Brannen.

FIPUG did not sponsor a witness to address this issue, and waived cross-examination of FPL witness Fuentes. In its brief, FIPUG only presented arguments about FPL's reserve margin, the overall cost effectiveness of the 2017 SoBRA projects, and the appropriate cost recovery mechanism for these projects, but did not specifically address this issue.

Having reviewed the testimony, exhibits, and calculations used by FPL witness Fuentes for determining the amount of revenue requirement associated with the 2017 SoBRA projects, we find them to be reasonable and set the jurisdictional annualized revenue requirements associated with the 2017 SoBRA projects at \$60,523,000.

[8]Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 20050045-EI, In re: Petition for rate increase by Florida Power & Light Company, and in Docket No. 20050188-EI, In re: 2005 comprehensive depreciation study by Florida Power & Light Company.
[9]Order No. PSC-11-0089-S-EI, issued February 1, 2011, in Docket No. 20080677-EI, In re: Petition for increase in rates by Florida Power & Light Company, and in Docket No. 20090130-EI, In re: 2009 depreciation and dismantlement study by Florida Power & Light Company.
[10]Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 20120015-EI, In re: Petition for increase in rates by Florida Power & Light Company.

F. 2017 Base Rate Percentage Increase

The SoBRA factors are incremental cost recovery factors that will be applied to base rate charges in order for the Company to collect the revenue necessary to recover the costs associated with building and operating the 2017 SoBRA projects. Witness Cohen testified that the SoBRA factors are based on the ratio of the Company's jurisdictional revenue requirements for each Project (by year) and the forecasted retail base revenue from electricity sales for the first twelve months of each rate year, beginning January 1, 2018 for the 2017 Project and March 1, 2018 for the 2018 Project. Witness Cohen also presented an exhibit to demonstrate the inputs and calculations performed to determine the resulting incremental cost recovery factor of 0.937 percent for the 2017 SoBRA projects.

FPL asserted in its brief that even when all of the SoBRA projects are reflected in customer bills, FPL's typical residential bills will remain below national and statewide averages. Table 7 below reflects the base rate changes and fuel cost recovery changes that will occur for typical monthly residential bills for customers using 1,000 kWh of electricity. Column 3 in Table 7 reflects a typical bill before the application of incremental cost recovery factors for any SoBRA projects. Column 4 in Table 6 reflects a typical bill for a residential customer using 1,000 kWh of electricity when the incremental cost recovery factor of 0.937 percent for the 2017 SoBRA projects is applied, and Column 5 reflects a typical bill for a residential customer using 1,000 kWh of electricity when all of the projects are implemented.[11]

Table 7

FPL Typical 1,000-kWh Residential Customer Bill Comparison For 2018

| (1) | | (2) | | (3) | | (4) | | (5) |
|---|---|---|---|---|---|---|---|---|
| **Bill Components** | | **Present (2017)** | | **Approved in the 2016 Settlement Agreement (Jan, 2018)** | | **Proposed for the 2017 SoBRA Projects (Jan & Feb, 2018)** | | **Proposed for the 2017 & 2018 SoBRA Projects (March, 2018)** |
| Base Rate Charges | | $63.49 | | $65.88 | | $66.49 | | $67.10 |
| Fuel Cost Recovery | | $24.91 | | $23.35 | | $23.17 | | $22.97 |
| Other Charges | | $14.15 | | $13.11 | | $13.12 | | $9.68 |
| | | | | | | | | |
| TOTAL | | $102.55 | | $102.34 | | $102.78 | | $99.75 |

Source: (EXH 51, Exhibit TCC-5, Page 1 of 5)

[11]The estimates shown in Column 4 reflect the application of the incremental cost recovery factor of 0.937 percent for the Horizon, Wildflower, Indian River, and Coral Farms solar generation facilities (2017 SoBRA projects). The estimates shown in Column 5 reflect the data in Column 4 plus the application of the incremental cost recovery factor presented in Issue 2O for the Loggerhead, Barefoot Bay, Hammock, and Blue Cypress solar generation facilities (2018 SoBRA projects). The data presented in Table 7 was prepared based on an exhibit FPL witness Cohen filed on March 1, 2017. That exhibit and this data do not reflect any storm-related charges attributable to named storms that impacted FPL's service territory in the 2017 hurricane season.

FIPUG did not sponsor a witness to address this issue, waived cross-examination of FPL witness Cohen, and did not specifically address this issue in its brief.

Having reviewed the testimony, exhibits, and calculations used by FPL witness Cohen for determining the appropriate incremental cost recovery factor associated with the 2017 SoBRA projects we find that the appropriate base rate percentage increase (SoBRA Factor) for the 2017 SoBRA projects is 0.937 percent.

G. 2018 SoBRA Revenue Requirement

Witness Fuentes testified that the annualized jurisdictional revenue requirement for the first 12 months of operations related to the 2018 SoBRA projects is $59,890,000. Witness Fuentes further stated that the revenue requirement was calculated by following the methodologies approved by this Commission for FPL's generation base rate adjustments (GBRA) for Turkey Point Unit 5 and West County Energy Center Units 1 and 2 in Order No. PSC-05-0902-S-EI,[12] West County Energy Center Unit 3 in Order No. PSC-11-0089-S-EI,[13] and the modernization projects at Canaveral, Riviera Beach, and Port Everglades in Order No. PSC-13-0023-S-EI.[14] Witness Fuentes also testified that the same methodology was used with the recently approved 2019 Okeechobee Limited Scope Adjustment (Okeechobee LSA). The jurisdictional annualized revenue requirement calculation for the 2018 SoBRA projects used several inputs, including the most current estimated capital expenditures presented by FPL witness Brannen.

FIPUG did not sponsor a witness to address this issue, and waived cross-examination of FPL witness Fuentes. In its brief, FIPUG only presented arguments about FPL's reserve margin, the overall cost effectiveness of the 2018 SoBRA projects, and the appropriate cost recovery mechanism for these projects, but did not specifically address this issue.

Having reviewed the testimony, exhibits, and calculations used by FPL witness Fuentes for determining the amount of revenue requirement associated with the 2018 SoBRA projects we find them to be reasonable and set the jurisdictional annualized revenue requirement associated with the 2018 SoBRA projects at $59,890,000.

H. 2018 Base Rate Percentage Increase

Similar to the 2017 recovery factors, the 2018 SoBRA factors are incremental cost recovery factors that will be applied to base rate charges in order for the Company to collect the revenue necessary to recover the costs associated with building and operating the 2018 SoBRA projects. The SoBRA recovery factors are based on the ratio of the Company's jurisdictional revenue requirements for each Project (by year) and the forecasted retail base revenue from electricity sales for the first twelve months of each rate year, beginning January 1, 2018 for the

[12]Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 20050045-EI, In re: Petition for rate increase by Florida Power & Light Company, and in Docket No. 20050188-EI, In re: 2005 comprehensive depreciation study by Florida Power & Light Company.
[13]Order No. PSC-11-0089-S-EI, issued February 1, 2011, in Docket No. 20080677-EI, In re: Petition for increase in rates by Florida Power & Light Company, and in Docket No. 20090130-EI, In re: 2009 depreciation and dismantlement study by Florida Power & Light Company.
[14]Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 20120015-EI, In re: Petition for increase in rates by Florida Power & Light Company.

2017 Project and March 1, 2018 for the 2018 Project. Exhibit 7 demonstrates the inputs and calculations performed by witness Cohen to determine the resulting incremental cost recovery factor of 0.919 percent for the 2018 SoBRA projects.

FIPUG did not sponsor a witness to address this issue, waived cross-examination of FPL witness Cohen, and did not specifically address this issue in its brief.

Having reviewed the testimony, exhibits, and calculations used by FPL witness Cohen for determining the appropriate incremental cost recovery factor associated with the 2018 SoBRA projects, we find that the appropriate base rate percentage increase (SoBRA Factor) for the 2018 SoBRA projects is 0.919 percent.

I. <u>SoBRA tariffs for 2017 and 2018 projects</u>

FPL witness Cohen sponsored exhibits that summarize the tariff changes for all SoBRA projects. The 2017 SoBRA projects are scheduled to enter commercial service by December 31, 2017, and the 2018 SoBRA projects by March 1, 2018. It is FPL's intention to submit revised tariff sheets reflecting the Commission-approved charges if the SoBRA and the associated charges are approved for both the 2017 and 2018 solar projects. FPL further requests that the 2017 and 2018 project tariff sheets become effective on or after the date that each set of projects is placed into service upon written notice to the Commission.

FIPUG did not sponsor a witness to address this issue, waived cross-examination of FPL witness Cohen. In its brief, FIPUG argued that the SoBRA projects were not needed and, therefore, the tariffs should not be approved.

Based on our approval of the 2017 and 2018 SoBRA projects, we hereby approve tariffs sheets which reflect our decisions with an effective date on or after the date that the 2017 and 2018 SoBRA projects are placed into service upon written notice being filed with the Clerk. Further, we direct our staff to verify that the tariffs are consistent with our decision.

**OTHER MATTERS**

Per stipulation of the parties, the new fuel adjustment and capacity factors shall become effective beginning with the first billing cycle for January 2018 through the last billing cycle for December 2018. The first billing cycle may start before January 1, 2018, and the last cycle may be read after December 31, 2018, so that each customer is billed for twelve months regardless of when the recovery factors became effective. The new factors shall continue in effect until modified by us.

We hereby approve revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be appropriate in this proceeding. We direct staff to verify that the revised tariffs are consistent with our decision.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the findings set forth in the body of, and Attachments A and B to, this Order are hereby approved. It is further

ORDERED that Florida Power & Light Company, Florida Public Utilities Company, Gulf Power Company, Duke Energy Florida, LLC, and Tampa Electric Company are hereby authorized to apply the fuel cost recovery factors set forth herein during the period January 2018 through December 2018. It is further

ORDERED that the estimated true-up amounts contained in the fuel cost recovery factors approved herein are hereby authorized subject to final true-up and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that Florida Power & Light Company, Florida Public Utilities Company, Gulf Power Company, Duke Energy Florida, LLC, and Tampa Electric Company are hereby authorized to apply the capacity cost recovery factors set forth herein during the period January 2018 through December 2018. It is further

ORDERED that the estimated true-up amounts contained in the capacity cost recovery factors approved herein are hereby authorized subject to final true-up and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that the revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be appropriate in this proceeding are hereby approved and we direct Commission staff to verify that the revised tariffs are consistent with our decision. It is further

ORDERED that while the Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor docket is assigned a separate docket number each year for administrative convenience, it is a continuing docket and shall remain open.

By ORDER of the Florida Public Service Commission this 8th day of January, 2018.

Carlotta S. Stauffer

CARLOTTA S. STAUFFER
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
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Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

SBr

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

## APPROVED TYPE 2 STIPULATIONS[15]

**ISSUE 1B: What adjustments, if any are needed to account for replacement power costs associated with the February 2017 outage at the Bartow generating plant?**

**STIPULATION:**

Duke Energy Florida and the parties stipulate that Duke has not included the approximately $10,973,639 in retail replacement power associated with the unplanned Bartow outage in developing rates for 2018. These costs will remain in the over/under account to be considered in Docket 20180001-EI for recovery in 2019 rates subject to normal intervenor challenge and Commission reasonableness and prudence review and approval.

**ISSUE 2B: What is the total gain in 2016 under the Incentive Mechanism approved in Order No. PSC-13-0023-S-EI, and how is that gain to be shared between FPL and customers?**

**STIPULATION:**

The total gain in 2016 under the Incentive Mechanism approved in Order No. PSC-13-0023-S-EI, was $62,835,808. This amount exceeded the sharing threshold of $46 million, and therefore the incremental gain above that amount shall be shared between FPL and customers (60% and 40%, respectively), with FPL retaining $10,101,485.

**ISSUE 2C: What is the appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2016 through December 2016?**

**STIPULATION:**

The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL shall be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2016 through December 2016 is $484,305.

**ISSUE 2D: What is the appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for variable power plant O&M costs incurred to generate output for wholesale sales in excess of $514,000 megawatt-hours for the period January 2016 through December 2016?**

[15] A Type 2 Stipulation is one in which all parties either agree with, do not object to, or take no position on, the stipulation presented.

**STIPULATION:**

The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL shall be allowed to recover through the fuel clause for variable power plant O&M costs incurred to generate output for wholesale sales in excess of 514,000 megawatt-hours for the period January 2016 through December 2016 is $2,671,992.

**ISSUE 2E: What is the appropriate amount of actual/estimated Incremental Optimization Costs under the Incentive Mechanism approved by Order No. PSC-16-0560-AS-EI that FPL may recover through the fuel clause for the period January 2017 through December 2017?**

**STIPULATION:**

For the period January 2017 through December 2017, FPL reported Incremental Personnel, Software, and Hardware Costs of $701,442.

**ISSUE 2F: What is the appropriate amount of actual/estimated variable power plant O&M expenses under the revised Incentive Mechanism that FPL may recover through the fuel clause for the period January 2017 through December 2017?**

**STIPULATION:**

For the period January 2017 through December 2017, FPL reported Variable power plant O&M Attributable to Off-System Sales of $1,250,109, and also Variable power plant O&M Avoided due to Economy Purchases of $(817,813). The sum of these amounts is $432,296.

The appropriate amount of actual/estimated variable power plant O&M expenses under the revised Incentive Mechanism that FPL may recover through the fuel clause for the period January 2017 through December 2017 is $432,296.

**ISSUE 2G: What is the appropriate amount of projected Incremental Optimization Costs under the revised Incentive Mechanism that FPL may recover through the fuel clause for the period January 2018 through December 2018?**

**STIPULATION:**

The appropriate amount of projected Incremental Optimization Costs under the revised Incentive Mechanism that FPL may recover through the fuel clause for the period January 2018 through December 2018 is $484,870.

**ISSUE 2H: What is the appropriate amount of projected variable power plant O&M expenses under the revised Incentive Mechanism that FPL may recover through the fuel clause for the period January 2018 through December 2018?**

STIPULATION:

The appropriate amount of projected variable power plant O&M expenses under the revised Incentive Mechanism that FPL may recover through the fuel clause for the period January 2018 through December 2018 is $496,340.

**ISSUE 2I: Have all Woodford-related costs been removed from FPL's requested true-up and projected fuel costs?**

STIPULATION:

Yes. FPL's final true-up calculations for 2016 reflect that $126,520 of Woodford-related costs have been removed from FPL's requested true-up and projected fuel costs for the period of January-December, 2016. There are no actual/estimated Woodford-related costs for the period of January-December, 2017, and no estimated Woodford-related costs for the period of January-December, 2018.

**ISSUE 2Q: Has FPL properly reflected in the fuel and purchased power cost recovery clause the effects of the Indiantown Cogeneration L.P. (Indiantown) facility transaction approved by the Commission in Docket No 160154-EI?**

STIPULATION:

Yes. In Schedule E1-B (Line 4, Column 15), FPL reflected $3,164,987 in Rail Car Lease amounts for the Actual/Estimated period of January-December, 2017 (of this amount $1,288,762 is related to Indiantown). In Schedule E2 (Line 3, Column 15), FPL reflected $2,195,706 in Rail Car Lease amounts for the Estimated period of January-December, 2018 (of this amount $1,123,366 is related to Indiantown).

**ISSUE 2R: How should the effects on the 2018 Fuel and Capacity Clause factors of the St. Johns River Power Park Transaction (SJRPP Transaction), approved by the Commission on September 25, 2017, be addressed?**

STIPULATION:

At the time that FPL made its 2018 Fuel and Capacity Clause projection filing, this Commission was not expected to make a decision on the SJRPP Transaction until after the hearing in this docket, so FPL did not reflect the impacts of that transaction in the calculation of its 2018 Fuel or Capacity Clause factors. However, on September 25, 2017 this Commission approved FPL's and

OPC's stipulation and settlement resolving all issues concerning the SJRPP Transaction. The net impact of the SJRPP Transaction will be a reduction in customer bills for 2018. At this point, FPL cannot prepare and file an updated filing reflecting the SJRPP Transaction in time for parties to have a reasonable opportunity to review it before the hearing scheduled in this docket on October 25-27, 2017. Therefore, FPL proposes to file a mid-course correction for the impacts of the SJRPP Transaction by no later than November 17, 2017, to allow ample time for Commission staff and parties to review and conduct discovery, if any, before the mid-course correction is brought to this Commission for decision at the February 6, 2018 Agenda Conference, with the intent that the revised Fuel and Capacity factors go into effect on March 1, 2018.

**ISSUE 3A: What amount should be refunded through the Fuel Clause to customers as a result of the Florida Supreme Court's March 16, 2017 decision on the FPL Interconnection Line project?**

**STIPULATION:**

$221,415 shall be refunded through the Fuel Clause to customers as a result of the Florida Supreme Court's March 16, 2017 decision on the FPL Interconnection Line project. This amount includes all actual/estimated costs associated with the FPL Interconnection Line project. Schedule E1-b (Page 2 of 3 of Exhibit MC-1) properly reflects the credit of $221,415 in purchased power costs for the FPL Interconnection Line project for the period of January-December, 2017.

**ISSUE 6: What are the appropriate actual benchmark levels for calendar year 2017 for gains on non-separated wholesale energy sales eligible for a shareholder incentive?**

**STIPULATION:**

The appropriate actual benchmark levels for calendar year 2017 for gains on non-separated wholesale energy sales eligible for a shareholder incentive are as follows:

DEF: $3,019,369.

FPL: Pursuant to the Stipulation and Settlement that was approved in Order No. PSC-2016-0560-AS-EI, FPL revised its Incentive Mechanism program, which does not rely upon the three-year average Shareholder Incentive Benchmark specified in Order No. PSC-00-1744-PAA-EI. Setting the appropriate actual benchmark levels for calendar year 2017 for gains on non-separated wholesale energy sales eligible for a shareholder incentive is not applicable to FPL as part of its revised Incentive Mechanism.

GULF: $872,163.

TECO: $1,493,095.

**ISSUE 7: What are the appropriate estimated benchmark levels for calendar year 2018 for gains on non-separated wholesale energy sales eligible for a shareholder incentive?**

**STIPULATION:**

The appropriate estimated benchmark levels for calendar year 2018 for gains on non-separated wholesale energy sales eligible for a shareholder incentive are as follows:

DEF: $1,771,110.

FPL: Pursuant to the Stipulation and Settlement that was approved in Order No. PSC-2016-0560-AS-EI, FPL revised its Incentive Mechanism program, which does not rely upon the three-year average Shareholder Incentive Benchmark specified in Order No. PSC-00-1744-PAA-EI. Setting the appropriate estimated benchmark levels for calendar year 2018 for gains on non-separated wholesale energy sales eligible for a shareholder incentive is not applicable to FPL as part of its revised Incentive Mechanism.

GULF: $1,009,272

TECO: The appropriate estimated benchmark levels for calendar year 2018 for gains on non-separated wholesale energy sales eligible for a shareholder incentive is $881,855. However, on September 27, 2017, Docket Number 20170210-EI was opened to address the Tampa Electric Company Petition for Limited Proceeding to Approve 2017 Amended and Restated Stipulation and Settlement Agreement (2017 ARSSA Petition).

If the 2017 ARSSA Petition is approved, an optimization mechanism will replace incentive program for non-separated wholesale energy sales.

**ISSUE 8: What are the appropriate final fuel adjustment true-up amounts for the period January 2016 through December 2016?**

**STIPULATION:**

The appropriate final fuel adjustment true-up amounts for the period January 2016 through December 2016 are as follows:

DEF: The final adjustment true-up amount for the period January 2016 through December 2016 is $58,893,512, under-recovery. The final true-up amount for the period January 2016 through December 2016 is $85,111,174, under-recovery.

FPL: The final adjustment true-up amount for the period January 2016 through December 2016 is of $28,780,519, under-recovery. The final true-up amount for the period January 2016 through December 2016 is $55,264,203, under-recovery.

FPUC: The final adjustment true-up amount for the period January 2016 through December 2016 is of $2,415,898, under-recovery. The final true up amount for the period January 2016 through December 2016 is $3,705,790, under-recovery.

GULF: The final adjustment true-up amount for the period January 2016 through December 2016 is of $10,797,411, under-recovery. The final true up amount for the period January 2016 through December 2016 is $16,586,321, over-recovery.

TECO: The final adjustment true-up amount for the period January 2016 through December 2016 is of $21,571,557, under-recovery. The final true up amount for the period January 2016 through December 2016 is $101,068,239, over-recovery.

**ISSUE 9: What are the appropriate fuel adjustment actual/estimated true-up amounts for the period January 2017 through December 2017?**

**STIPULATION:**

The appropriate fuel adjustment actual/estimated true-up amounts for the period January 2017 through December 2017 are as follows:

DEF: $136,610,259, under-recovery.

FPL: $45,572,897, over-recovery.

FPUC: $975,518, under-recovery.

GULF: $21,853,354, under-recovery.

TECO: $38,652,694, over-recovery.

**ISSUE 10: What are the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2018 through December 2018?**

**STIPULATION:**

The appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2018 through December 2018 are as follows:

DEF: On August 29, 2017, Docket Number 20170183-EI was opened to address the Duke Energy Florida, LLC Petition for Limited Proceeding to Approve 2017 Second Revised and Restated Stipulation and Settlement Agreement (2017 RRSSA Petition).

If the 2017 RRSSA Petition is approved, the appropriate total fuel adjustment true-up amount to be collected from January 2018 through December 2018 is $97,751,887.

If the 2017 RRSSA Petition is not approved, the appropriate total fuel adjustment true-up amount to be collected from January 2018 through December 2018 is $195,503,774.

FPL: $16,792,378, to be refunded (over-recovery).

FPUC: $3,391,416, to be collected (under-recovery).

Gulf: $32,650,765, to be collected (under-recovery).

TECO: $17,081,137, to be refunded (over-recovery).

**<u>ISSUE 11</u>: What are the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2018 through December 2018?**

**STIPULATION:**

The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2018 through December 2018 are as follows:

DEF: $1,496,427,570.

FPL: $2,870,532,871, which excludes prior period true up amounts, revenue taxes, the GPIF reward, and FPL's portion of gains from its Incentive Mechanism. The replacement power costs and other related costs associated with the August 2016 and January 2017 unplanned outages at St. Lucie Unit I, lasting 27 and 7 days, respectively, and the March 2017 unplanned outage at Turkey Point Unit 3 lasting 9 days are included in this amount. Parties reserve the right to challenge the prudence of FPL's actions or inactions related to the cause of these outages and to seek refunds of the corresponding replacement power costs and other related costs in a subsequent Fuel and Purchased Power Cost Recovery Clause docket.

FPUC: $58,791,697.

GULF: $415,320,095, including prior period true up amounts and revenue taxes.

TECO: $610,721,792, which is adjusted by the jurisdictional separation factor, excluding the GPIF reward and the revenue tax factor, but including the prior period true up amounts.

**ISSUE 13A: What are the appropriate adjustments to FPL's 2017 GPIF targets/ranges to reflect the effects of the Indiantown transaction approved by the Commission in Docket No. 160154-EI?**

**STIPULATION:**

At the time that FPL set its GPIF targets and ranges for the January 2017 through December 2017 period, this Commission had not yet approved the Indiantown transaction identified in Docket No. 20160154-EI. By Order No. PSC-2016-0506-FOF-EI,[16] this Commission approved the Indiantown transaction. Thereafter, FPL recalculated the 2017 GPIF targets and ranges to reflect the effects of the Indiantown transaction approved by this Commission.

The appropriate adjustment to FPL's GPIF targets/ranges for the period January through December 2017, is that the weighted system ANOHR target should be 7,263 Btu/kWh, slightly lower than the prior weighted system ANOHR target of 7,275. The weighted system EAF target of 86.2% remains unchanged.

FPL's revised GPIF targets/ranges that reflect the effects of the Indiantown transaction approved by the Commission are shown in Table 13A-1 below:

**Table 13A-1**
**FPL's Revised GPIF Targets/Ranges for the period January-December, 2017**

| Company | Plant/Unit | EAF | | | ANOHR | | |
|---|---|---|---|---|---|---|---|
| | | Target | Maximum | | Target | Maximum | |
| | | EAF (%) | EAF (%) | Savings ($000's) | ANOHR BTU/KWH | ANOHR BTU/KWH | Savings ($000's) |
| FPL | Canaveral 3 | 79.4 | 82.4 | 1,132 | 6,661 | 6,742 | 2,566 |
| | Manatee 3 | 70.9 | 72.9 | 480 | 6,962 | 7,142 | 4,011 |
| | Ft. Myers 2 | 92.4 | 94.9 | 921 | 7,301 | 7,512 | 8,452 |
| | Martin 8 | 72.9 | 75.4 | 537 | 6,977 | 7,090 | 2,529 |
| | St. Lucie 1 | 93.6 | 96.6 | 5,184 | 10,401 | 10,509 | 576 |
| | St. Lucie 2 | 83.7 | 86.7 | 3,765 | 10,278 | 10,372 | 427 |
| | Turkey Point 3 | 85.1 | 88.1 | 3,830 | 11,106 | 11,286 | 730 |

[16] Order No. PSC-16-0506-FOF, issued November 2, 2016, in Docket No. 160154-EI, In re: Petition for approval of a purchase and sale agreement between Florida Power & Light Company and Calypso Energy Holdings, LLC. for the ownership of the Indiantown Cogeneration LP and related power purchase agreement.

| Company | Plant/Unit | EAF | | | ANOHR | | |
|---|---|---|---|---|---|---|---|
| | | Target | Maximum | | Target | Maximum | |
| | | EAF (%) | EAF (%) | Savings ($000's) | ANOHR BTU/KWH | ANOHR BTU/KWH | Savings ($000's) |
| | Turkey Point 4 | 85.4 | 88.4 | 4,062 | 11,019 | 11,168 | 590 |
| | Turkey Point 5 | 78.3 | 80.3 | 560 | 7,136 | 7,218 | 1,632 |
| | West County 1 | 89.5 | 92 | 791 | 6,951 | 7,137 | 6,225 |
| | West County 2 | 93 | 95.5 | 862 | 6,911 | 7,049 | 4,874 |
| | West County 3 | 76.1 | 78.6 | 830 | 6,980 | 7,121 | 3,975 |
| | Total | | | 22,954 | | | 36,587 |

Source: GPIF Target and Range Summary, Pages 6-7 of 34 (Exhibit CRR-3)

**<u>ISSUE 16</u>: What is the appropriate generation performance incentive factor (GPIF) reward or penalty for performance achieved during the period January 2016 through December 2016 for each investor-owned electric utility subject to the GPIF?**

**STIPULATION:**

The appropriate generation performance incentive factor (GPIF) reward or penalty for performance achieved during the period January 2016 through December 2016 for each investor-owned electric utility subject to the GPIF is as follows:

DEF $2,793,216 reward.

FPL $9,656,036 reward.

GULF $2,043,225 penalty.

TECO $47,392 reward.

**ISSUE 17: What should the GPIF targets/ranges be for the period January 2018 through December 2018 for each investor-owned electric utility subject to the GPIF?**

**STIPULATION:**

The appropriate GPIF targets/ranges be for the period January 2018 through December 2018 for each investor-owned electric utility subject to the GPIF are shown in Tables 17-1 through 17-4 below:

DEF: See Table 17-1 below:

FPL: See Table 17-2 below:

Gulf: See Table 17-3 below:

TECO: See Table 17-4 below:

**Table 17-1**
**DEF GPIF Targets/Ranges for the period January-December, 2018**

| Company | Plant/Unit | EAF | | | ANOHR | | |
|---|---|---|---|---|---|---|---|
| | | Target | Maximum | | Target | Maximum | |
| | | EAF (%) | EAF (%) | Savings ($000's) | ANOHR BTU/KWH | ANOHR BTU/KWH | Savings ($000's) |
| DEF | Bartow 4 | 90.20 | 93.82 | 2,025 | 7,916 | 8,600 | 12,851 |
| | Crystal River 4 | 87.06 | 89.54 | 1,497 | 10,112 | 10,537 | 5,439 |
| | Crystal River 5 | 92.30 | 94.76 | 1,524 | 9,905 | 10,383 | 6,665 |
| | Hines 1 | 92.36 | 93.25 | 252 | 7,314 | 7,797 | 4,759 |
| | Hines 2 | 68.97 | 80.88 | 5,452 | 7,357 | 7,706 | 1,948 |
| | Hines 3 | 87.04 | 88.43 | 515 | 7,285 | 7,708 | 4,074 |
| | Hines 4 | 83.25 | 87.98 | 2,711 | 7,066 | 7,346 | 2,679 |
| | Total | | | 13,976 | | | 38,415 |

Source: GPIF Target and Range Summary, Page 4 of 76 (Exhibit MJJ-1P)

**Table 17-2**
**FPL GPIF Targets/Ranges for the period January-December, 2018**

| Company | Plant/Unit | EAF | | | ANOHR | | |
|---|---|---|---|---|---|---|---|
| | | Target | Maximum | | Target | Maximum | |
| | | EAF (%) | EAF (%) | Savings ($000's) | ANOHR BTU/KWH | ANOHR BTU/KWH | Savings ($000's) |
| FPL | Canaveral 3 | 86.4 | 89.4 | 1,373 | 6,637 | 6,744 | 2,708 |
| | Manatee 3 | 92.9 | 94.9 | 517 | 6,939 | 7,118 | 2,967 |
| | Ft. Myers 2 | 85.9 | 88.4 | 578 | 7,240 | 7,356 | 2,583 |
| | Martin 8 | 80.5 | 83.0 | 657 | 7,006 | 7,163 | 2,743 |
| | Riveria 5 | 85.4 | 87.9 | 1,351 | 6,601 | 6,679 | 2,074 |
| | St. Lucie 1 | 85.0 | 88.0 | 3,916 | 10,441 | 10,545 | 481 |
| | St. Lucie 2 | 85.1 | 88.1 | 3,241 | 10,303 | 10,385 | 357 |
| | Turkey Point 3 | 82.1 | 85.1 | 3,119 | 11,044 | 11,235 | 718 |
| | Turkey Point 4 | 93.6 | 96.6 | 3,597 | 10,970 | 11,177 | 863 |
| | West County 1 | 79.1 | 82.1 | 1,297 | 6,974 | 7,104 | 3,038 |
| | West County 2 | 89.3 | 91.8 | 1,252 | 6,885 | 6,992 | 2,745 |
| | West County 3 | 80.4 | 82.9 | 1,075 | 6,974 | 7,078 | 2,397 |
| | Total | | | 21,973 | | | 23,674 |

Source: GPIF Target and Range Summary, Pages 6-7 of 34 (Exhibit CRR-2)

**Table 17-3**
**GULF 2018 GPIF Targets/Ranges for the period January-December, 2018**

| Company | Plant/Unit | EAF | | | ANOHR | | |
|---|---|---|---|---|---|---|---|
| | | Target | Maximum | | Target | Maximum | |
| | | EAF (%) | EAF (%) | Savings ($000's) | ANOHR BTU/KWH | ANOHR BTU/KWH | Savings ($000's) |
| GULF | Scherer 3 | 97.2 | 98.1 | 12 | 10,495 | 10,810 | 2,089 |
| | Crist 7 | 82.1 | 83.4 | 3 | 10,503 | 10,818 | 500 |
| | Daniel 1 | 82.2 | 84.5 | 0 | 12,205 | 12,571 | 65 |
| | Daniel 2 | 90.7 | 92.9 | 1 | 12,429 | 12,802 | 147 |
| | Smith 3 | 93.2 | 93.7 | 83 | 6,932 | 7,140 | 3,095 |
| | Total | | | 99 | | | 5,896 |

Source: GPIF Unit Performance Summary, Page 41 of 64 (Exhibit CLN-2, Schedule 3)

 ATTACHMENT A

**Table 17-4**
**TECO 2018 GPIF Targets/Ranges for the period January-December, 2018**

| GPIF Targets / Ranges for the period January 2018 through December 2018 | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | Target | Maximum | | Target | Maximum | |
| | | EAF (%) | EAF (%) | Savings ($000's) | ANOHR BTU/KWH | ANOHR BTU/KWH | Savings ($000's) |
| TECO | Big Bend 2 | 61.5 | 68.2 | 615.6 | 11,320 | 11,798 | 778.3 |
| | Big Bend 3 | 66.7 | 72.4 | 1,079.4 | 10,619 | 10,987 | 1,448.4 |
| | Big Bend 4 | 78.7 | 82.0 | 1,473.1 | 10,448 | 10,830 | 2,146.5 |
| | Polk 1 | 74.4 | 77.0 | 211.9 | 9,978 | 10,312 | 1,028.0 |
| | Polk 2 | 83.2 | 85.7 | 1,408.9 | 7,382 | 7,936 | 13,242.8 |
| | Bayside 1 | 82.5 | 83.8 | 770.2 | 7,489 | 7,619 | 1,359.6 |
| | Bayside 2 | 77.3 | 79.1 | 1,505.7 | 7,676 | 7,905 | 2,106.5 |
| | Total | | | 7,064.8 | | | 22,110.1 |

Source: GPIF Target and Range Summary, Page 4 of 40 (Exhibit BSB-2, Document 1)

**<u>ISSUE 18</u>: What are the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2018 through December 2018?**

**STIPULATION:**

The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2018 through December 2018 are as follows:

DEF: On August 29, 2017, Docket Number 20170183-EI was opened to address the Duke Energy Florida, LLC Petition for Limited Proceeding to Approve 2017 Second Revised and Restated Stipulation and Settlement Agreement (2017 RRSSA Petition).

If the 2017 RRSSA Petition is approved, the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2018 through December 2018 is $1,598,120,482.

If the 2017 RRSSA Petition is not approved, the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2018 through December 2018 is $1,695,942,751.

FPL: The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2018 through December 2018 is $2,874,984,279, including prior period true-ups, revenue taxes, FPL's portion of Incentive Mechanism gains, and the GPIF reward.

FPUC: The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2018 through December 2018 is $62,183,113, which includes prior period true up amounts.

GULF: The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2018 through December 2018 is $413,276,870, including prior period true up amounts and revenue taxes.

TECO: The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2018 through December 2018 is $627,802,929, which is adjusted by the jurisdictional separation factor. The amount is $611,208,904 when the GPIF reward or penalty, the revenue tax factor, and the prior period true up amounts are applied.

**<u>ISSUE 19</u>: What is the appropriate revenue tax factor to be applied in calculating each investor-owned electric utility's levelized fuel factor for the projection period January 2018 through December 2018?**

**STIPULATION:**

The appropriate revenue tax factor to be applied in calculating each investor-owned electric utility's levelized fuel factor for the projection period January 2018 through December 2018 is 1.00072.

**<u>ISSUE 20</u>: What are the appropriate levelized fuel cost recovery factors for the period January 2018 through December 2018?**

**STIPULATION:**

The appropriate levelized fuel cost recovery factors for the period January 2018 through December 2018 are as follows:

DEF: On August 29, 2017, Docket Number 20170183-EI was opened to address the Duke Energy Florida, LLC Petition for Limited Proceeding to Approve 2017 Second Revised and Restated Stipulation and Settlement Agreement (2017 RRSSA Petition).

If the 2017 RRSSA Petition is approved, the appropriate levelized fuel cost recovery factors for the period January 2018 through December 2018 is 4.127 cents per kWh (adjusted for jurisdictional losses).

 

If the 2017 RRSSA Petition is not approved, the appropriate levelized fuel cost recovery factors for the period January 2018 through December 2018 is 4.380 cents per kWh (adjusted for jurisdictional losses).

FPL: For the period January and February, 2018 the appropriate levelized fuel cost recovery factor is 2.650 cents per kWh (adjusted for jurisdictional losses). For the period March-December, 2018 the appropriate levelized fuel cost recovery factor is 2.630 cents per kWh (adjusted for jurisdictional losses).

FPUC: The appropriate factor is 6.506¢ per kWh.

GULF: 3.789 cents/kWh.

TECO: The appropriate factor is 3.127 cents per kWh before any application of time of use multipliers for on-peak or off-peak usage.

**ISSUE 21: What are the appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class?**

**STIPULATION:**

The appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class are shown below:

DEF: See Table 21-1 below:

**Table 21-1**
**DEF Fuel Recovery Line Loss Multipliers**
**for the period January-December, 2018**

| Group | Delivery Voltage Level | Line Loss Multiplier |
|---|---|---|
| A. | Transmission | 0.98 |
| B. | Distribution Primary | 0.99 |
| C. | Distribution Secondary | 1.00 |
| D. | Lighting Service | 1.00 |

Source: Menendez Aug. 24, 2017 & Sept. 1, 2017 Testimony, Pages 2-3.

FPL: The appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class are provided in response to Issue No. 22.

FPUC: The appropriate fuel recovery line loss multiplier to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class is 1.0000.

GULF: The appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class are provided in response to Issue No. 22.

TECO: See Table 21-2 below:

**Table 21-2**
**TECO Fuel Recovery Line Loss Multipliers**
**for the period January-December, 2018**

| Delivery Voltage Level | Line Loss Multiplier |
|---|---|
| Distribution Secondary | 1.00 |
| Distribution Primary | 0.99 |
| Transmission | 0.98 |
| Lighting Service | 1.00 |

Source: Schedule E1-D, Page 5 of 30 (Exhibit PAR-3, Document 2)

**ISSUE 22: What are the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses?**

**STIPULATION:**

The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown in Tables 22-1 through 22-11 below:

DEF: On August 29, 2017, Docket Number 20170183-EI was opened to address the Duke Energy Florida, LLC Petition for Limited Proceeding to Approve 2017 Second Revised and Restated Stipulation and Settlement Agreement (2017 RRSSA Petition).

If the 2017 RRSSA Petition is approved, the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown in Table 22-1 below, and if the 2017 RRSSA Petition is not approved, the appropriate fuel cost recovery factors shown in Table 22-1A below:

**Table 22-1**
**Fuel Cost Recovery Factors for DEF with approval of RRSSA Petition**

| Fuel Cost Recovery Factors For the Period January-December, 2018 | | | | | | |
|---|---|---|---|---|---|---|
| Line | Delivery Voltage Level | Fuel Cost Recovery Factors (cents/kWh) | | | Time of Use | |
| | | First Tier | Second Tier | Levelized | On-Peak Multiplier 1.236 | Off-Peak Multiplier 0.890 |
| 1 | Distribution Secondary | 3.838 | 4.838 | 4.132 | 5.107 | 3.677 |
| 2 | Distribution Primary | -- | -- | 4.091 | 5.056 | 3.641 |
| 3 | Transmission | -- | -- | 4.049 | 5.005 | 3.604 |
| 4 | Lighting Secondary | -- | -- | 3.945 | -- | -- |

Source: Schedule E1-E, Page 1 of 1 (Alternative Exhibit CAM-3, Part 2)

**Table 22-1A**
**Fuel Cost Recovery Factors for DEF without approval of RRSSA Petition**

| Fuel Cost Recovery Factors For the Period January-December, 2018 | | | | | | |
|---|---|---|---|---|---|---|
| Line | Delivery Voltage Level | Fuel Cost Recovery Factors (cents/kWh) | | | Time of Use | |
| | | First Tier | Second Tier | Levelized | On-Peak Multiplier 1.236 | Off-Peak Multiplier 0.890 |
| 1 | Distribution Secondary | 4.091 | 5.091 | 4.385 | 5.420 | 3.903 |
| 2 | Distribution Primary | -- | -- | 4.341 | 5.365 | 3.863 |
| 3 | Transmission | -- | -- | 4.297 | 5.311 | 3.824 |
| 4 | Lighting Secondary | -- | -- | 4.186 | -- | -- |

Source: Schedule E1-E, Page 1 of 1 (Exhibit CAM-3, Part 2)

FPL: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses for the period January 2018 through December 2018, are shown in Tables 22-2 through 22-5 below:

**Table 22-2**
**FPL Fuel Cost Recovery Factors for the period January:February, 2018**

| Fuel Recovery Factors – By Rate Group (Adjusted for Line Losses) | | | | |
|---|---|---|---|---|
| For the Period January 2018 through the day prior to the 2018 SoBRA in-service date (projected to be February 28, 2018) | | | | |
| Group | Rate Schedule | Avg. Factor | Loss Multiplier | Fuel Recovery Factor |
| A | RS-1 first 1,000 kWh | 2.650 | 1.00206 | 2.317 |
| | RS-1, all addl. kWh | 2.650 | 1.00206 | 3.317 |
| | GS-1, SL-2, GSCU-1, WIES-1 | 2.650 | 1.00206 | 2.655 |
| A-1 | SL-1, OL-1, PL-1[17] | 2.553 | 1.00206 | 2.558 |
| B | GSD-1 | 2.650 | 1.00202 | 2.655 |
| C | GSLD-1, CS-1 | 2.650 | 1.00150 | 2.654 |
| D | GSLD-2, CS-2, OS-2, MET | 2.650 | 0.99635 | 2.640 |
| E | GSLD-3, CS-3 | 2.650 | 0.97646 | 2.588 |
| A | GST-1 On-Peak | 3.156 | 1.00206 | 3.163 |
| | GST-1 Off Peak | 2.438 | 1.00206 | 2.443 |
| | RTR-1 On-Peak | - | - | 0.508 |
| | RTR-1 Off-Peak | - | - | (0.212) |
| B | GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On Peak | 3.156 | 1.00202 | 3.162 |
| | GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off Peak | 2.438 | 1.00202 | 2.443 |
| C | GSDLT-1, CST-1, HLFT-2 (500-1,9999 kW) On Peak | 3.156 | 1.00150 | 3.161 |
| | GSDLT-1, CST-1, HLFT-2 (500-1,9999 kW) Off Peak | 2.438 | 1.00150 | 2.442 |
| D | GSDLT-2, CST-2, HLFT-3 (2,000+ kW) On Peak | 3.156 | 0.99672 | 3.146 |
| | GSDLT-2, CST-2, HLFT-3 (2,000+ kW) Off Peak | 2.438 | 0.99672 | 2.430 |
| E | GSDLT-3, CST-3, CILC-1(T), ISST-1(T) On Peak | 3.156 | 0.97646 | 3.082 |
| | GSDLT-3, CST-3, CILC-1(T), ISST-1(T) Off Peak | 2.438 | 0.97646 | 2.381 |
| F | CILC-1(D), ISST-1(D) On Peak | 3.156 | 0.99627 | 3.144 |
| | CILC-1(D), ISST-1(D) Off Peak | 2.438 | 0.99627 | 2.429 |

Source: Schedule E1-E, Page 1 of 2 (Appendix II of Exhibit RBD-5)

**Table 22-3**
**FPL Fuel Cost Recovery Factors for the period January-December, 2018**

| Seasonal Demand Time of Use Rider (SDTR) Fuel Recovery Factors | | | | |
|---|---|---|---|---|
| For the Period June - September, 2018 | | | | |
| Group | Rate Schedule | Avg. Factor | Loss Multiplier | Fuel Recovery Factor |
| B | GSD(T)-1 On-Peak | 3.790 | 1.00202 | 3.798 |
| | GSD(T)-1 Off-Peak | 2.507 | 1.00202 | 2.512 |
| C | GSLD(T)-1 On-Peak | 3.790 | 1.00150 | 3.796 |
| | GSLD(T)-1 Off-Peak | 2.507 | 1.00150 | 2.511 |
| D | GSLD(T)-2 On-Peak | 3.790 | 0.99672 | 3.778 |
| | GSLD(T)-2 Off-Peak | 2.507 | 0.99672 | 2.499 |

Source: Schedule E1-E, Page 2 of 2 (Appendix II of Exhibit RBD-5)

[17]Weighted Average 16% On-Peak and 84% Off-Peak

**Table 22-4**
**FPL Fuel Cost Recovery Factors for the period March-December, 2018**

| Fuel Recovery Factors – By Rate Group (Adjusted for Line Losses) | | | | |
|---|---|---|---|---|
| From the 2018 SoBRA in-service date (projected to be March 1, 2018) through December 2018- | | | | |
| Group | Rate Schedule | Avg. Factor | Loss Multiplier | Fuel Recovery Factor |
| A | RS-1 first 1,000 kWh | 2.630 | 1.00206 | 2.297 |
| | RS-1, all addl. kWh | 2.630 | 1.00206 | 3.297 |
| | GS-1, SL-2, GSCU-1, WIES-1 | 2.630 | 1.00206 | 2.635 |
| A-1 | SL-1, OL-1, PL-1[18] | 2.534 | 1.00206 | 2.539 |
| B | GSD-1 | 2.630 | 1.00202 | 2.635 |
| C | GSLD-1, CS-1 | 2.630 | 1.00150 | 2.634 |
| D | GSLD-2, CS-2, OS-2, MET | 2.630 | 0.99635 | 2.620 |
| E | GSLD-3, CS-3 | 2.630 | 0.97646 | 2.568 |
| A | GST-1 On-Peak | 3.132 | 1.00206 | 3.138 |
| | GST-1 Off Peak | 2.420 | 1.00206 | 2.425 |
| | RTR-1 On-Peak | - | - | 0.503 |
| | RTR-1 Off-Peak | - | - | (0.210) |
| B | GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On Peak | 3.132 | 1.00202 | 3.138 |
| | GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off Peak | 2.420 | 1.00202 | 2.425 |
| C | GSDLT-1, CST-1, HLFT-2 (500-1,9999 kW) On Peak | 3.132 | 1.00150 | 3.137 |
| | GSDLT-1, CST-1, HLFT-2 (500-1,9999 kW) Off Peak | 2.420 | 1.00150 | 2.424 |
| D | GSDLT-2, CST-2, HLFT-3 (2,000+ kW) On Peak | 3.132 | 0.99672 | 3.122 |
| | GSDLT-2, CST-2, HLFT-3 (2,000+ kW) Off Peak | 2.420 | 0.99672 | 2.412 |
| E | GSDLT-3, CST-3, CILC-1(T), ISST-1(T) On Peak | 3.132 | 0.97646 | 3.058 |
| | GSDLT-3, CST-3, CILC-1(T), ISST-1(T) Off Peak | 2.420 | 0.97646 | 2.363 |
| F | CILC-1(D), ISST-1(D) On Peak | 3.132 | 0.99627 | 3.120 |
| | CILC-1(D), ISST-1(D) Off Peak | 2.420 | 0.99627 | 2.411 |

Source: Schedule E1-E, Page 1 of 2 (Appendix III of Exhibit RBD-6)

**Table 22-5**
**FPL Fuel Cost Recovery Factors for the period March-December, 2018**

| Seasonal Demand Time of Use Rider (SDTR) Fuel Recovery Factors | | | | |
|---|---|---|---|---|
| For the Period June - September, 2018 | | | | |
| Group | Rate Schedule | Avg. Factor | Loss Multiplier | Fuel Recovery Factor |
| B | GSD(T)-1 On-Peak | 3.761 | 1.00202 | 3.769 |
| | GSD(T)-1 Off-Peak | 2.488 | 1.00202 | 2.493 |
| C | GSLD(T)-1 On-Peak | 3.761 | 1.00150 | 3.767 |
| | GSLD(T)-1 Off-Peak | 2.488 | 1.00150 | 2.492 |
| D | GSLD(T)-2 On-Peak | 3.761 | 0.99672 | 3.749 |
| | GSLD(T)-2 Off-Peak | 2.488 | 0.99672 | 2.480 |

Source: Schedule E1-E, Page 2 of 2 (Appendix III of Exhibit RBD-6)

[18]Weighted Average 16% On-Peak and 84% Off-Peak

FPUC: The appropriate levelized fuel adjustment and purchased power cost recovery factors for the period January 2018 through December 2018 for the Consolidated Electric Division, adjusted for line loss multipliers and including taxes, are shown in Tables 22-6 through 22-8 below:

**Table 22-6**
**FPUC Fuel Cost Recovery Factors for the period January-December, 2018**

| Fuel Recovery Factors – By Rate Schedule | |
|---|---|
| For the Period January through December, 2018 | |
| Rate Schedule | Levelized Adjustment (cents/kWh) |
| RS | 9.666 |
| GS | 9.391 |
| GSD | 9.029 |
| GSLD | 8.769 |
| LS | 7.136 |

Source: Schedule E1, Page 3 of 3 (Exhibit MC-2)

**Table 22-7**
**FPUC Fuel Cost Recovery Factors for the period January-December, 2018**

| Step Rate Allocation For Residential Customers (RS Rate Schedule) | |
|---|---|
| For the Period January through December, 2018 | |
| Rate Schedule and Allocation | Levelized Adjustment (cents/kWh) |
| RS Rate Schedule – Sales Allocation | 9.666 |
| RS Rate Schedule with less than 1,000 kWh/month | 9.320 |
| RS Rate Schedule with more than 1,000 kWh/month | 10.570 |

Source: Schedule E1, Page 3 of 3 (Exhibit MC-2)

**Table 22-8**
**FPUC Fuel Cost Recovery Factors for the period January-December, 2018**

| Fuel Recovery Factors for Time Of Use – By Rate Schedule | | |
|---|---|---|
| For the Period January through December, 2018 | | |
| Rate Schedule | Levelized Adjustment On Peak (cents/kWh) | Levelized Adjustment Off Peak (cents/kWh) |
| RS | 17.720 | 5.420 |
| GS | 13.391 | 4.391 |
| GSD | 13.029 | 5.779 |
| GSLD | 14.769 | 5.769 |
| Interruptible | 7.269 | 8.769 |

Source: Schedule E1, Page 3 of 3 (Exhibit MC-2)

GULF: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses for the period January 2018 through December 2018, are shown in Tables 22-9 and 22-10 below:

**Table 22-9**
**GULF Fuel Cost Recovery Factors for the period January-December, 2018**

| Group | Standard Rate Schedules | Fuel Recovery Loss Multipliers | Fuel Cost recovery Factors (cents/kWh) |
|---|---|---|---|
| A | RS,RSVP, RSTOU,GS,GSD, GSTOU,SBS,OSIII | 1.00555 | 3.810 |
| B | LP,SBS | 0.99188 | 3.758 |
| C | PX, RTP, SBS | 0.97668 | 3.701 |
| D | OSI/II | 1.00560 | 3.776 |

Source: Schedule E1-E, Page 8 of 41 (Exhibit CSB-6)

**Table 22-10**
**GULF Fuel Cost Recovery Factors for the period January-December, 2018**

| Group | Time Of Use Rate Schedules* | Fuel Recovery Loss Multipliers | Fuel Cost Recovery Factors ¢/KWH | |
|---|---|---|---|---|
| | | | On-Peak | Off-Peak |
| A | GSDT | 1.00555 | 4.391 | 3.570 |
| B | LPT | 0.99188 | 4.332 | 3.521 |
| C | PXT | 0.97668 | 4.265 | 3.467 |

Source: Schedule E1-E, Page 8 of 41 (Exhibit CSB-6)

TECO: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses for the period January 2018 through December 2018, are shown in Table 22-11 below:

 ATTACHMENT A

**Table 22-11**
**TECO Fuel Cost Recovery Factors for the period January-December, 2018**

| Metering Voltage Level | Fuel Cost Recovery Factors (cents per kWh) | | |
|---|---|---|---|
| | Levelized Fuel Recovery Factor | First Tier (Up to 1,000 kWh) | Second Tier (Over 1,000 kWh) |
| STANDARD | | | |
| Distribution Secondary (RS only) | -- | 2.818 | 3.818 |
| Distribution Secondary | 3.132 | | |
| Distribution Primary | 3.101 | | |
| Transmission | 3.069 | | |
| Lighting Service | 3.095 | | |
| TIME OF USE | | | |
| Distribution Secondary- On-Peak | 3.330 | | |
| Distribution Secondary- Off-Peak | 3.047 | | |
| Distribution Primary- On-Peak | 3.297 | | |
| Distribution Primary- Off-Peak | 3.017 | | |
| Transmission – On-Peak | 3.263 | | |
| Transmission – Off-Peak | 2.986 | | |

Source: Schedule E1-E, Document Number 2, Page 6 of 30 (Exhibit PAR-3)

**ISSUE 23A: Has DEF included in the capacity cost recovery clause the nuclear cost recovery amount ordered by the Commission in Docket No. 170009-EI?**

**STIPULATION:**

On August 15, 2017, this Commission authorized DEF to include the nuclear cost recovery amount of $49,648,457 in the calculation of its capacity cost recovery factors for the period January through December, 2018 and DEF has appropriately included this amount. If this Commission does not approve the 2017 Settlement, the Levy project will be addressed as set forth in Commission Order No. PSC-2017-0341-PCO-EI, dated August 30, 2017.

**ISSUE 24A: Has FPL included in the capacity cost recovery clause the nuclear cost recovery amount ordered by the Commission in Docket No. 20170009-EI?**

**STIPULATION:**

Yes. FPL included the nuclear cost recovery amount of $7,305,202, over-recovery, in the calculation of its capacity cost recovery factors for the period January through December 2018. In the event that this Commission determines at the October 17, 2017 Special Agenda Conference for Docket 20170009-EI that a different amount is applicable, FPL will reflect the impact of that different amount in the mid-course correction for the SJRPP transaction as described in Issue 2R. Notwithstanding Rule 25-6.0423(6)(c)4, Florida Administrative Code, FPL shall file that mid-course correction by no later than November 17, 2017, with the intent that the revised Fuel and Capacity factors go into effect on March 1, 2018. This stipulation is without prejudice as to the ultimate amount to be recovered or refunded by FPL.

**ISSUE 24B: Has FPL properly reflected in the capacity cost recovery clause the effects of the Indiantown transaction approved by the Commission in Docket No. 160154-EI?**

**STIPULATION:**

Yes. In its 2017 CCR Actual/Estimated True-up filing (Exhibit RBD-4, Page 9 of 15), FPL reflected $89,421,413 in Total Recoverable Costs for the Indiantown transaction for the Actual/Estimated period of January-December, 2017. $50,166,667 of this amount is the Regulatory Asset related to the loss of the Indiantown Purchase Power Agreement, and $39,254,746 is the amount for the Total Return Requirements.

In its 2018 CCR Projection filing (Exhibit RBD-8, Appendix V, Page 14 of 29), FPL reflected $84,768,867 in Total Recoverable Expenses for the Indiantown transaction for the Estimated period of January-December, 2018. $50,166,667 of this amount is the Regulatory Asset related to the loss of the Indiantown Purchase Power Agreement, and $34,602,200 is the amount for the Total Return Requirements.

**ISSUE 24C: What are the appropriate Indiantown non-fuel base revenue requirements to be recovered through the Capacity Clause pursuant to the Commission's approval of the Indiantown transaction in Docket No. 160154-EI for 2017 and 2018?**

**STIPULATION:**

In its 2017 CCR Actual/Estimated True-up filing (Exhibit RBD-4, Page 11 of 15), FPL reflected $13,626,163 in Revenue Requirement Allocation for the Indiantown transaction for the period of January-December, 2017.

In its 2018 CCR Projection filing (Exhibit RBD-8, Appendix V, Page 18 of 29), FPL reflected $4,022,504 in Revenue Requirement Allocation for the Indiantown transaction for the period of January-December, 2018.

**SSUE 24D: Is $5,155,918 the appropriate refund amount associated with the Port Everglades Energy Center (PEEC) GBRA true-up?**

**STIPULATION:**

Yes. The PEEC GBRA refund accrual is $5,099,063, and the cumulative interest is $56,855. As stated in its 2018 CCR Projection filing (Exhibit RBD-8, Appendix V, Page 1 of 29), the appropriate PEEC Generating Base Rate Adjustment cumulative refund amount, including interest, is $5,155,918.

**ISSUE 27: What are the appropriate final capacity cost recovery true-up amounts for the period January 2016 through December 2016?**

**STIPULATION:**

The appropriate final capacity cost recovery true-up amounts for the period January 2016 through December 2016 are as follows:

DEF: The final capacity cost recovery adjustment true-up amount for the period January 2016 through December 2016 is $2,203,058, over-recovery. The final true-up amount for the period January 2016 through December 2016 is $16,868,290, over-recovery.

FPL: The final capacity cost recovery adjustment true-up amount for the period January 2016 through December 2016 is $7,586,581, over-recovery. The final true-up amount for the period January 2016 through December 2016 is $17,227,490, over-recovery.

GULF: The final capacity cost recovery adjustment true-up amount for the period January 2016 through December 2016 is $545,959, over-recovery. The final true-up amount for the period January 2016 through December 2016 is $695,190, over-recovery.

TECO: The final capacity cost recovery adjustment true-up amount for the period January 2016 through December 2016 is $4,411,715, under-recovery. The final true-up amount for the period January 2016 through December 2016 is $7,397,775, under-recovery.

**ISSUE 28: What are the appropriate capacity cost recovery actual/estimated true-up amounts for the period January 2017 through December 2017?**

**STIPULATION:**

The appropriate capacity cost recovery actual/estimated true-up amounts for the period January 2017 through December 2017 are as follows:

DEF: $7,324,397, under-recovery.

FPL: $6,649,359, under-recovery.

GULF: $3,698,545, under-recovery.

TECO: $1,648,777, over-recovery.

**ISSUE 29: What are the appropriate total capacity cost recovery true-up amounts to be collected/refunded during the period January 2018 through December 2018?**

**STIPULATION:**

The appropriate total capacity cost recovery true-up amounts to be collected/refunded during the period January 2018 through December 2018 are as follows:

DEF: $5,121,339, under-recovery.

FPL: $937,222, over-recovery.

GULF: $3,152,586, under-recovery.

TECO: $2,762,938, under-recovery.

**ISSUE 30: What are the appropriate projected total capacity cost recovery amounts for the period January 2018 through December 2018?**

**STIPULATION:**

The appropriate projected total capacity cost recovery amounts for the period January 2018 through December 2018 are as follows:

DEF: Schedule E12-A (Page 1 of 2 of Exhibit CAM-3, Part 3) reflects the total projected purchased power capacity cost recovery amount for the period January 2018 through December 2018, excluding revenue taxes, is $404,721,485.

FPL: $289,174,210.

GULF: $75,738,532.

TECO: $8,131,950.

 

**ISSUE 31: What are the appropriate projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January 2018 through December 2018?**

**STIPULATION:**

DEF: Schedule E12-A (Page 1 of 2 of Exhibit CAM-3, Part 3) reflects the total projected purchased power capacity cost recovery amount for the period January 2018 through December 2018, excluding nuclear cost recovery clause amounts and adjusted for revenue taxes, is $410,137,911. The total projected ISIFI Costs for the period January 2018 through December 2018, adjusted for revenue taxes, is $9,315,359. The sum of these amounts is $419,453,270, which is the appropriate projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January 2018 through December 2018.

FPL: $279,996,930, which includes all prior period true-up amounts, nuclear cost recovery amounts, the Port Everglades Energy Center GBRA True-up, the Indiantown non-fuel based revenue requirement, and revenue taxes.

GULF: $78,947,920, which includes all prior period true-up amounts and revenue taxes.

TECO: $10,902,732, which includes all prior period true-up amounts and revenue taxes.

**ISSUE 32: What are the appropriate jurisdictional separation factors for capacity revenues and costs to be included in the recovery factor for the period January 2018 through December 2018?**

**STIPULATION:**

The appropriate jurisdictional separation factors for capacity revenues and costs to be included in the recovery factor for the period January 2018 through December 2018 are as follows:

DEF: Base – 92.885%, Intermediate – 72.703%, Peaking – 95.924%.

FPL: See Table 32-1 below:

**Table 32-1**
**FPL Jurisdictional Separation Factors**
**for the period January-December, 2018**

| Demand | Separation Factor |
|---|---|
| Transmission | 0.887974 |
| System Average Production Demand (Base & Solar) | 0.956652 |
| Contract Adjusted Demand – Intermediate | 0.941431 |
| Contract Adjusted Demand – Peaking | 0.947386 |
| Distribution | 1.000000 |

Source: Exhibit RBD-8

GULF: The appropriate jurisdictional separation factors are:
FPSC 97.18277%
FERC 2.81723%

TECO: The appropriate jurisdictional separation factor is 1.00.

**ISSUE 33: What are the appropriate capacity cost recovery factors for the period January 2018 through December 2018?**

**STIPULATION:**

The appropriate capacity cost recovery factors for the period January 2018 through December 2018 are shown in Tables 33-1 through 33-6 below.

DEF: On August 29, 2017, Docket Number 20170183-EI was opened the address the Duke Energy Florida, LLC Petition for Limited Proceeding to Approve 2017 Second Revised and Restated Stipulation and Settlement Agreement (2017 RRSSA Petition).

If the 2017 RRSSA Petition is approved, the appropriate capacity cost recovery factors for the period January 2018 through December 2018 are shown in Table 33-1 below.

If the 2017 RRSSA Petition is not approved, the capacity cost recovery factors beginning January 2018 will be the same as those listed in Table 33-1 pending the outcome of the deferred Levy-portion of the 2017 NCRC hearing.

**Table 33-1**
**DEF Capacity Cost Recovery Factors for the period January-December, 2018**
**(with approval of RRSSA Petition)**

| Rate Class | | 2018 Capacity Cost Recovery Factors Cents / kWh | 2018 Capacity Cost Recovery Factors Dollars / kW-month |
|---|---|---|---|
| Residential (RS-1, RST-1, RSL-1, RSL-2, RSS-1) | | 1.433 | |
| General Service Non-Demand (GS-1, GST-1) | | | |
| | At Secondary Voltage | 1.117 | |
| | At Primary Voltage | 1.106 | |
| | At Transmission Voltage | 1.095 | |
| General Service (GS-2) | | 0.782 | |
| General Service Demand (GSD-1, GSDT-1, SS-1) | | | |
| | At Secondary Voltage | | 4.06 |
| | At Primary Voltage | | 4.02 |
| | At Transmission Voltage | | 3.98 |
| Curtailable (CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3) | | | |
| | At Secondary Voltage | | 2.66 |
| | At Primary Voltage | | 2.63 |
| | At Transmission Voltage | | 2.61 |
| Interruptible (IS-1, IST-1, IS-2. IST-2, SS-2) | | | |
| | At Secondary Voltage | | 3.09 |
| | At Primary Voltage | | 3.06 |
| | At Transmission Voltage | | 3.03 |
| Standby Monthly (SS-1, 2, 3) | | | |
| | At Secondary Voltage | | 0.393 |
| | At Primary Voltage | | 0.389 |
| | At Transmission Voltage | | 0.385 |
| Standby Daily (SS-1, 2, 3) | | | |
| | At Secondary Voltage | | 0.187 |
| | At Primary Voltage | | 0.185 |
| | At Transmission Voltage | | 0.183 |
| Lighting (LS-1) | | 0.227 | |

Source: Schedule E12-E, Pages 3-4 of 4 (Exhibit CAM-3, Part 3)

FPL: The appropriate capacity cost recovery factors for the period January 2018 through December 2018 are shown in Tables 33-2 through 33-4 below:

**Table 33-2**
**FPL Capacity Cost Recovery Factors for the period January-December, 2018**

| Rate Schedule | 2018 Capacity Cost Recovery Factors | | | |
|---|---|---|---|---|
| | $/kW | $/kWh | Reservation Demand Charge (RDC) $/kW[19] | Sum of Daily Demand Charge (SDD) $/kW[20] |
| RS1/RTR1 | - | 0.00277 | - | - |
| GS1/GST1 | - | 0.00259 | - | - |
| GSD1/GSDT1/HLFT1 | 0.83 | - | - | - |
| OS2 | - | 0.00114 | - | - |
| GSLD1/GSLDT1/CS1/CST1/HLFT2 | 0.98 | - | - | - |
| GSLD2/GSLDT2/CS2/CST2/HLFT3 | 0.92 | - | - | - |
| GSLD3/GSLDT3/CS3/CST3 | 0.95 | - | - | - |
| SST1T | - | - | $0.13 | $0.06 |
| SST1D1/SST1D2/SST1D3 | - | - | $0.13 | $0.06 |
| CILC D/CILC G | 1.05 | - | - | - |
| CILC T | 1.01 | - | - | - |
| MET | 1.03 | - | - | - |
| OL1/SL1/SL1M/PL1 | - | 0.00021 | - | - |
| SL2/SL2M/GSCU1 | - | 0.00180 | - | - |

Source: Page 20 of 29 (Appendix V of Exhibit RBD-8)

[19]RDC=((Total Capacity Costs )/(Projected Avg 12CP @gen)(.10)(demand loss expansion factor))/12 months
[20]SDD=((Total Capacity Costs )/(Projected Avg 12CP @gen)(21 on peak days)(demand loss expn. factor))/12 months

**Table 33-3**
**FPL Capacity Cost Recovery Factors for the period January-December, 2018**

| Rate Schedule | 2018 Indiantown Capacity Cost Recovery Factors | | | |
|---|---|---|---|---|
| | $/kW | $/kWh | Reservation Demand Charge (RDC) $/kW | Sum of Daily Demand Charge (SDD) $/kW |
| RS1/RTR1 | - | 0.00004 | - | - |
| GS1/GST1 | - | 0.00004 | - | - |
| GSD1/GSDT1/HLFT1 | 0.01 | - | - | - |
| OS2 | - | 0.00003 | - | - |
| GSLD1/GSLDT1/CS1/CST1/HLFT2 | 0.01 | - | - | - |
| GSLD2/GSLDT2/CS2/CST2/HLFT3 | 0.01 | - | - | - |
| GSLD3/GSLDT3/CS3/CST3 | 0.01 | - | - | - |
| SST1T | - | - | - | - |
| SST1D1/SST1D2/SST1D3 | - | - | - | - |
| CILC D/CILC G | 0.02 | - | - | - |
| CILC T | 0.02 | - | - | - |
| MET | 0.02 | - | - | - |
| OL1/SL1/SL1M/PL1 | - | 0.00001 | - | - |
| SL2/SL2M/GSCU1 | - | 0.00003 | - | - |

Source: Page 20 of 29 (Appendix V of Exhibit RBD-8)

**Table 33-4**
**FPL Capacity Cost Recovery Factors for the period January-December, 2018**

| Rate Schedule | 2018 Total Capacity Cost Recovery Factors | | | |
|---|---|---|---|---|
| | $/kW | $/kWh | Reservation Demand Charge (RDC) $/kW | Sum of Daily Demand Charge (SDD) $/kW |
| RS1/RTR1 | - | 0.00281 | - | - |
| GS1/GST1 | - | 0.00263 | - | - |
| GSD1/GSDT1/HLFT1 | 0.84 | - | - | - |
| OS2 | - | 0.00117 | - | - |
| GSLD1/GSLDT1/CS1/CST1/HLFT2 | 0.99 | - | - | - |
| GSLD2/GSLDT2/CS2/CST2/HLFT3 | 0.93 | - | - | - |
| GSLD3/GSLDT3/CS3/CST3 | 0.96 | - | - | - |
| SST1T | - | - | $0.13 | $0.06 |
| SST1D1/SST1D2/SST1D3 | - | - | $0.13 | $0.06 |
| CILC D/CILC G | 1.07 | - | - | - |
| CILC T | 1.03 | - | - | - |
| MET | 1.05 | - | - | - |
| OL1/SL1/SL1M/PL1 | - | 0.00022 | - | - |
| SL2/SL2M/GSCU1 | - | 0.00183 | - | - |

Source: Page 20 of 29 (Appendix V of Exhibit RBD-8)

GULF: The appropriate capacity cost recovery factors for the period January 2018 through December 2018 are shown in Table 33-5 below:

**Table 33-5**
**GULF Capacity Cost Recovery Factors for the period January-December, 2018**

| Rate Class | Capacity Cost Recovery Factor | |
|---|---|---|
| | Cents / kWh | Dollars / kW-month |
| RS, RSVP, RSTOU | 0.835 | - |
| GS | 0.762 | |
| GSD, GSDT, GSTOU | 0.666 | |
| LP, LPT | - | 2.76 |
| PX, PXT, RTP, SBS | 0.560 | - |
| OS-I/II | 0.164 | |
| OSIII | 0.505 | |

Source: Schedule CCE-2, Page 40 of 41 (Exhibit CSB-6)

TECO: The appropriate capacity cost recovery factors for the period January 2018 through December 2018 are shown in Table 33-6 below:

**Table 33-6**
**TECO Capacity Cost Recovery Factors for the period January-December, 2018**

| Rate Class and Metering Voltage | Capacity Cost Recovery Factor | |
|---|---|---|
| | Cents / kWh | Dollars / kW |
| RS Secondary | 0.066 | - |
| GS and CS Secondary | 0.060 | |
| GSD, SBF Standard | | |
| Secondary | - | 0.20 |
| Primary | | 0.20 |
| Transmission | | 0.20 |
| GSD Optional | | |
| Secondary | 0.047 | - |
| Primary | 0.047 | |
| IS, SBI | | |
| Primary | - | 0.14 |
| Transmission | | 0.14 |
| LS1 Secondary | 0.016 | - |

Source: Document Number 1, Page 3 of 4 (Exhibit PAR-3)

**ISSUE 34: What should be the effective date of the fuel adjustment factors and capacity cost recovery factors for billing purposes?**

**STIPULATION:**

The new factors shall be effective beginning with the first billing cycle for January 2018 through the last billing cycle for December 2018. The first billing cycle may start before January 1, 2018, and the last cycle may be read after December 31, 2018, so that each customer is billed for twelve months regardless of when the recovery factors became effective. The new factors shall continue in effect until modified by this Commission.

**ISSUE 35: Should the Commission approve revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be appropriate in this proceeding?**

**STIPULATION:**

Yes. The Commission should approve revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be appropriate in this proceeding. The Commission should direct staff to verify that the revised tariffs are consistent with the Commission's decision.

**ISSUE 36: Should this docket be closed?**

**STIPULATION:**

No. While a separate docket number is assigned each year for administrative convenience this is a continuing docket and shall remain open.

HEDGING ISSUE STIPULATIONS

**ISSUE 1A:** Should the Commission approve as prudent DEF's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in DEF's April 2017 and August 2017 hedging reports?

**STIPULATION:**

Yes. DEF's hedging activities for the period August 1, 2016 through July 31, 2017, are reported in April 2017 and August 2017 filings in Docket No. 20170001-EI and resulted in hedging net expense of $53,819,249 ($53,953,024 expense for natural gas - $133,774 gain on oil). Upon review of these filings, DEF has complied with its Risk Management Plan as approved by this Commission and, therefore, its actions are found to be reasonable and prudent.

**ISSUE 2A:** Should the Commission approve as prudent FPL's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in FPL's April 2017 and August 2017 hedging reports?

**STIPULATION:**

Yes. FPL's hedging activities for the period August 1, 2016 through July 31, 2017, are reported in April 2017 and August 2017 filings in Docket No. 20170001-EI and resulted in hedging net gain of $9,334,634. Upon review of these filings, FPL has complied with its Risk Management Plan as approved by this Commission and, therefore, its actions are found to be reasonable and prudent.

**ISSUE 4A:** Should the Commission approve as prudent Gulf's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in Gulf's April 2017 and August 2017 hedging reports?

**STIPULATION:**

Yes. Gulf's hedging activities for the period August 1, 2016 through July 31, 2017, are reported in April 2017 and August 2017 filings in Docket No. 20170001-EI and resulted in hedging net expense of $29,478,936. Upon review of these filings, Gulf has complied with its Risk Management Plan as approved by this Commission and, therefore, its actions are found to be reasonable and prudent.

**ISSUE 5A:** Should the Commission approve as prudent TECO's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in TECO's April 2017 and August 2017 hedging reports?

**STIPULATION:**

Yes. TECO's hedging activities for the period August 1, 2016 through July 31, 2017, are reported in April 2017 and August 2017 filings in Docket No. 20170001-EI and resulted in hedging net gain of $1,361,535. Upon review of these filings, TECO has complied with its Risk Management Plan as approved by this Commission and, therefore, its actions are found to be reasonable and prudent.

TAB E

FILED NOV 02, 2016
DOCUMENT NO. 08615-16
FPSC - COMMISSION CLERK



BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 160021-EI

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

DOCKET NO. 160061-EI

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

DOCKET NO. 160062-EI

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

DOCKET NO. 160088-EI

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

PROCEEDINGS: HEARING

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

DATE: Thursday, October 27, 2016

| | |
|---|---|
| TIME: | Commenced at 9:30 a.m.<br>Concluded at 1:12 p.m. |
| PLACE: | Betty Easley Conference Center<br>Room 148<br>4075 Esplanade Way<br>Tallahassee, Florida |
| REPORTED BY: | LINDA BOLES, CRR, RPR<br>Official FPSC Reporter<br>(850) 413-6734 |
| | -and- |
| | ANDREA KOMARIDIS<br>Premier Reporting<br>(850)894-0828 |

APPEARANCES:

JOHN T. BUTLER, R. WADE LITCHFIELD, and MARIA MONCADA, ESQUIRES, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Florida Power & Light Company.

J.R. KELLY, PUBLIC COUNSEL; CHARLES REHWINKEL; and PATRICIA A. CHRISTENSEN, ESQUIRES, Office of Public Counsel, c/o the Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

MARK F. SUNDBACK, KENNETH L. WISEMAN, and WILLIAM M. RAPPOLT, ESQUIRES, Andrews Kurth, LLP, 1350 I Street NW, Suite 1100, Washington, DC 20005, appearing on behalf of South Florida Hospital and Healthcare Association.

MAJOR ANDREW UNSICKER, ESQUIRE, USAF Utility Law Field Support Center, Air Force Legal Operations Agency, 139 Barnes Drive, Suite 1, Tyndall Air Force Base, Florida 32403, appearing on behalf of Federal Executive Agencies.

DIANA CSANK, ESQUIRE, 50 F Street, NW, 8th Floor, Washington, DC 20001, appearing on behalf of Sierra Club.

APPEARANCES (Continued):

STEPHANIE EATON, 110 Oakwood Drive, Suite 500, Winston-Salem, North Carolina 27103, appearing on behalf of Wal-Mart Stores East, LP, and Sam's East, Inc.

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

JACK MCRAY, 200 West College Avenue, #304, Tallahassee, Florida, 32301, appearing on behalf of AARP.

SERENA MOYLE, JON C. MOYLE, JR., and KAREN PUTNAL, ESQUIRES, Moyle Law Firm, P.A., 118 North Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

SUZANNE BROWNLESS, KYESHA MAPP, ADRIA HARPER, DANIJELA JANJIC, and MARGO LEATHERS, ESQUIRES, General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the staff of the Florida Public Service Commission.

KEITH HETRICK, ESQUIRE, General Counsel, and MARY ANNE HELTON, ESQUIRE, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing as advisors to the Florida Public Service Commission.

# I N D E X

## WITNESSES

EXHIBITS

| NUMBER: | | ID. | ADMTD. |
|---|---|---|---|
| 807 | Comprehensive Exhibit List | 12 | 12 |
| 808 | As identified on Comprehensive Exhibit List | 12 | 39 |
| 809 | As identified on Comprehensive Exhibit List | 12 | 39 |
| 810 | As identified on Comprehensive Exhibit List | 12 | 39 |
| 811 | As identified on Comprehensive Exhibit List | 12 | 58 |
| 812 | FPL's Response to Staff's 43rd Interrogatories Nos. 507 and 508 and FPL's Response to Staff's 22nd Request for POD No. 101 | 32 | 123 |

**P R O C E E D I N G S**

**CHAIRMAN BROWN:** Thank you so much. And I'd like to call this hearing to order in Docket 160021, the FPL rate case, the sequel. The date is October 27th, 2016. And, staff, can you please read the notice.

**MS. BROWNLESS:** Yes, ma'am. By notice issued on October 12th, 2016, by the Commission Clerk, this time and place has been set for a hearing in Dockets Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI, petition for increase in rates by Florida Power & Light Company, petition for approval of the 2016 to 2018 storm hardening plan by Florida Power & Light Company, 2016 depreciation and dismantlement study by Florida Power & Light Company, and petition for limited proceeding to modify and continue incentive mechanism by Florida Power & Light Company, to take supplemental testimony on the terms and conditions of the settlement agreement dated October 6th, 2016, and any other outstanding matters.

**CHAIRMAN BROWN:** Thank you, Ms. Brownless. And please note that Commissioner Edgar is unable to attend in person due to an illness, but she will be participating by phone. And they're patching her in right now.

At this time, we'll take appearances, and it's great to see you all again.

**MR. LITCHFIELD:** Thank you. Good morning, Madam Chair, Commissioners. Wade Litchfield, John Butler, and Maria Moncada for Florida Power & Light Company.

**CHAIRMAN BROWN:** Thank you.

**MR. REHWINKEL:** Good morning, Commissioners. Charles Rehwinkel, J.R. Kelly, and Patricia Christensen for the people of Florida. Thank you.

**CHAIRMAN BROWN:** Thank you.

**MR. SUNDBACK:** Good morning, Madam Chair and Commissioners. Mark Sundback for the South Florida Hospital and Healthcare Association, along with my partner Ken Wiseman and William Rappolt of our firm. Thank you.

**CHAIRMAN BROWN:** Thank you.

**MAJOR UNSICKER:** Good morning, Commissioners. Major Andrew Unsicker on behalf of Federal Executive Agencies.

**CHAIRMAN BROWN:** Thank you.

**MS. CSANK:** Good morning, Madam Chair, Commissioners. Diana Csank for Sierra Club.

**CHAIRMAN BROWN:** Thank you.

**MS. EATON:** Good morning, Madam Chairman and Commissioners. Stephanie Eaton for Wal-Mart.

**CHAIRMAN BROWN:** Thank you.

**MR. WRIGHT:** Good morning, Madam Chair and Commissioners. It's great to be back as well. Robert Scheffel Wright and John T. Lavia, III, on behalf of the Florida Retail Federation.

**CHAIRMAN BROWN:** Thank you. Could you push your button, please? It's tricky.

**MR. McRAY:** Got it. Good morning. Jack McRay appearing on behalf of AARP.

**CHAIRMAN BROWN:** Thank you.

**MS. MOYLE:** Good morning. Serena Moyle, Jon Moyle, and Karen Putnal on behalf of FIPUG, Florida Independent (sic) Power Users Group.

**CHAIRMAN BROWN:** Thank you, and welcome Ms. Moyle, Mrs. Moyle.

**MS. MOYLE:** Yes, thank you.

**CHAIRMAN BROWN:** Staff.

**MS. BROWNLESS:** Good morning. Suzanne Brownless on behalf of the staff of the Florida Public Service Commission. And I'd also like to enter an appearance for Danijela Janjic, Kyesha Mapp, Margo Leathers, and Adria Harper.

**CHAIRMAN BROWN:** Okay. Thank you. Staff, are there any preliminary matters at this time that we need to address? Pardon me?

**MS. HELTON:** Did you want me to make an appearance?

**CHAIRMAN BROWN:** Yeah, you should make an appearance.

**MS. HELTON:** Mary Anne Helton. I'm here as your advisor today. And I'd also like to make an appearance for your General Counsel, Keith Hetrick.

**CHAIRMAN BROWN:** Thank you. Now preliminary matters.

**MS. BROWNLESS:** Yes, ma'am. My understanding is that Mr. Skop is unable to attend today, and he's asked that he be excused from the proceeding, and also that he has filed -- just filed a written statement in lieu of appearance. Did everybody get a copy of that? And he'd ask -- he's asking that that be read as his opening statement.

**CHAIRMAN BROWN:** Any comments?

**MR. LITCHFIELD:** I'm sorry. We have no objection, but I had understood he wanted it inserted into the record as though read but not necessarily read.

**CHAIRMAN BROWN:** That's correct.

**MS. BROWNLESS:** That's fine.

**CHAIRMAN BROWN:** I'll -- let me read the email real quickly sent at 5:10 in the morning.

"Due to exigent circumstances, I'm unable to attend the FPL settlement hearing as planned this morning. Prior to the hearing I'll be filing a written statement with the Clerk and provide you and the other parties with a copy of the document. The Larsons respectfully request that the opening statement be entered into the record as though read."

You are correct. Thank you.

So any other preliminary matters?

**MS. BROWNLESS:** No, ma'am.

**CHAIRMAN BROWN:** Okay. Let's get to exhibits first.

**MS. BROWNLESS:** Okay. The staff has prepared a second Comprehensive Exhibit List, which includes all exhibits attached to the supplemental witnesses' prefiled testimony, as well as the staff exhibit, which is the Comprehensive Exhibit List itself. The list itself is marked as Exhibit 807 and has been provided to the parties, the Commissioners, and the court reporter. At this time, we would request that Exhibit 807 be entered into record and that all other exhibits be marked as identified therein.

**CHAIRMAN BROWN:** Okay. We -- seeing no objection, we will go ahead and enter Exhibit 807 into the record as though read and mark for identification Exhibit 808, 809, 810, 811. 808 is Tiffany Cohen, which is attached as TCC-10 to her prefiled testimony; 809 is

TCC-11; 810 is TCC-12; and 811 is Mr. Ferguson, KF-9.

(Exhibits 807 through 811 marked for identification.

(Exhibit 807 admitted into the record.)

All right. Moving on to opening statements. The signatories to the settlement agreement shall have ten minutes, to be divided among them as they see fit, and each non-signatory party may have -- shall have five minutes each. But I will note that you -- the non-signatories and as well as the signatories do not have to use all of the time or any of the time.

We will begin with Florida Power & Light, followed by Office of Public Counsel, Hospitals, and FRF. Then we'll move to the non-signatories beginning with AARP, followed by FIPUG, FEA, Wal-Mart, Sierra Club.

All right. And with that, are there any questions before we begin? And I'll be timing.

**MR. LITCHFIELD:** Thank you, Madam Chair.

**COMMISSIONER EDGAR:** Madam Chair.

**CHAIRMAN BROWN:** That is Commissioner Edgar.

**COMMISSIONER EDGAR:** Thank you. I just did want to make sure that you could hear me. I can hear you and, for the record, I am participating by phone.

**CHAIRMAN BROWN:** Thank you.

Okay. With that --

**MR. LITCHFIELD:** Thank you, Madam Chair. Wade Litchfield for Florida Power & Light Company.

Commissioners, good morning. I can assure you that even collectively among the signatories to the joint settlement agreement we will be well short of ten minutes.

Without getting into the details, obviously, of the settlement discussions that culminated in filing the agreement that you have before you and you will be considering for purposes of potential approval, I think it's at least permissible for me to note a couple of things.

One, these discussions did not happen overnight. In fact, as you might expect, a lot of complex issues, a lot of lengthy discussions over several months occurred, and it was only October 6th that we were able to put together a proposal that we all agreed upon and decided to submit it for your approval.

I'd also like to, if I could, comment on the tenor of the negotiations, again without getting into details, which I would be precluded from doing. I just want to note that even though we had very lengthy conversations, the issues, as I said, were very, very complex and we obviously were attempting, as you well know based on the filed positions in this docket, attempting to bring together some pretty divergent interests. I just want to note that at all times those discussions were absolutely professional, civil, cordial, and I just think that's a tribute to everybody who was involved, and I just wanted you to know that.

The discussions led to an agreement that we are submitting to this Commission for approval as reflecting an appropriate resolution of all of the issues in this case. We hope that based on the underlying record, which is very, very extensive, as well as the additional testimony that you will take today, that when you do take this up for actual decision, that you will agree with that view expressed by the signatories.

The Commission does have, as you well know, a long-standing and oft-stated policy in favor of settlement. We recognize today that we are not presenting a document to you that has the signature of each and every intervenor in this case. We do have the Office of Public Counsel, the Florida Retail Federation, and the Hospital Association. We also have three other intervenors who have indicated that they will take no position on the settlement, which we respect, but which we, at least at FPL, believe is meaningful in terms of a statement in that regard.

There are three who continue to oppose the settlement agreement. You'll hear from them today, and we respect their right to express their views, obviously. But with as many intervenors as we do see in these cases, particularly base rate cases these days, even intervenors who have competing interests among themselves, it is, in our view, at least FPL's view, almost a virtual impossibility that we would be able to bring an agreement that included every individual intervenor's signature on it, impossible, in our mind, to satisfy the interests of each and every intervenor and, therefore, not surprising that we don't have complete unanimity with respect to this agreement.

But the test is not whether, and the standard is not whether the agreement meets the stated or alleged interests of each and every intervenor. Neither is the standard whether each and every intervenor agrees that the proposed agreement is in the public interest. Rather, the standard is simply whether overall the agreement, in your view, does meet the public interest.

We, of course, as the joint signatories and as FPL, we believe that the agreement is in the public interest, and to that end we are appreciative of the opportunity today to present additional testimony in support of the agreement consistent with the procedural order that this Commission issued on October 12th. We thank you. We are prepared to proceed accordingly.

**MR. REHWINKEL:** Thank you, Madam Chairman and Commissioners. The Public Counsel's Office, on behalf of all the citizens that we represent in this case, strongly believe that this agreement is in the public interest taken as a whole. The public interest (sic) also strongly believes that the settlement before you produces a reasonable result for all customers, given the range of likely outcomes based on the Public Counsel's judgment after conclusion of the evidentiary record in this docket. Thank you.

**CHAIRMAN BROWN:** Thank you.

**MR. SUNDBACK:** Madam Chair, Commissioners, we are certainly going to make good on FPL's pledge to be done in well less than ten minutes. The settlement, from our perspective, reflects a resolution of numerous intertwined issues in an appropriate manner, and we'd urge you to take into account the complexity of the settlement and its interwoven nature when you evaluate it and, of course, urge that you approve it. Thank you.

**CHAIRMAN BROWN:** Thank you. You were right. Go ahead.

**MR. WRIGHT:** Thank you, Madam Chairman, Commissioners. The Florida Retail Federation supports this settlement. This settlement was reached through extended discussions, as Mr. Litchfield said, literally over a period of some months. This agreement represents a reasonable and mutually acceptable resolution of, as you see before you, many complex issues. Given the facts, the law, the evidence, and the parties' competing positions, we urge you to approve it. Thank you.

**CHAIRMAN BROWN:** Okay. That was five minutes and 35 seconds.

**MR. WRIGHT:** Yay us.

**CHAIRMAN BROWN:** Quite impressive.

All right. We will begin now with AARP. Good morning.

**MR. McRAY:** Good morning, and thank you. Members of the Commission or Commissioners, AARP opposes the settlement stipulation at issue in this hearing. It's apropos that this hearing is occurring near Halloween. It is customary for celebrants of Halloween to don masks and costumes in order to obscure their appearances or to assume identities as someone or something else, my analogy such as the case for this stipulation.

AARP contends that if you strip the costume and mask from the stipulation, what remains is the devil in the details: To wit, the parties/intervenors have not unanimously joined in the stipulation, not even a majority of them have joined in the stipulation. Proponents of the stipulation posit that FPL would be giving back benefits to ratepayers by accepting base rate increases lower than what FPL requested in the rate hearing commenced in August. This is a slight of hand ploy because the record supports that FPL should be reducing rates, not increasing rates.

The stipulation also pulls what I call a proverbial rabbit out of the hat by conditioning the proposal on a concept that was not included in the record at the initial hearing; that is, a theoretical depreciation reserve surplus and depreciation reserve amortization scheme that in essence guarantees that FPL's return on equity will be no lower than 9.6 and up to 11.6 percent, which amount exceeds the amount requested by FPL in the original rate hearing, and that's for each year of the four years to which the stipulation would apply regardless of AA -- excuse me -- FPL's actual performance. Testimony will demonstrate why this is a gift to shareholders at the expense of ratepayers and the 11.6 ROE is far greater than what most states have granted to regulated electric utility providers.

Proponents of the stipulation would also have you believe that the stipulation provides -- the stipulation provides certainty for ratepayers during the four-term (sic) year of the stipulation. But the stipulation offers only certainty of higher rates and is replete with provisos that would allow FPL to seek rate increases during the term of the stipulation and to increase surcharges to ratepayers and put over $1 billion more depreciation on ratepayers' tab after the year 2020.

AARP contends that the four-year rate plans are detrimental to consumers, are replete with uncertainties, and should not be relied upon by FPL or by this Commission. AARP urges the Commissioners to carefully consider the provisions of this settlement because, continuing the Halloween analogy, as the proponents ring the doorbell of the PSC and yell, "Trick or treat," the treat is protection for FPL's shareholders, but the trick is on ratepayers who will clearly bear higher electric rates to support an excessive return on equity for shareholders.

We urge the Commission to reject the proposed stipulation because it is inconsistent with the evidence admitted into the record in this rate case previously, it's not in the public interest, and will not result in just and reasonable rates for FPL's customers. AARP urges the Commission to rely on the evidentiary record already before it and to determine rates only for the 2017 test year. Thank you.

**CHAIRMAN BROWN:** Thank you, Mr. McRay.

Next up is Ms. Moyle with FIPUG.

**MS. MOYLE:** FIPUG does not take a position on the pending motion to approve settlement and otherwise waives its right to make an opening statement.

**CHAIRMAN BROWN:** Thank you. FEA.

**MAJOR UNSICKER:** Thank you, ma'am. FEA does not oppose the agreement as well and takes no position and waives opening statement.

**CHAIRMAN BROWN:** Thank you.

Wal-Mart.

**MS. EATON:** Good morning, Madam Chair. Wal-Mart does have an opening statement.

On behalf of Wal-Mart Stores East, LP, and Sam's East, Inc., collectively Wal-Mart, I hereby make this opening statement in this proceeding related to the petition of Florida Power & Light for approval to modify its rates and charges for electric utility service.

This Commission conducted proceedings on Docket No. 160021-EI and others, which we call the consolidated dockets, throughout the weeks of

August 22nd and August 29th, 2016. Wal-Mart actively participated in the proceeding and caused to be admitted into the evidentiary record the direct testimony and exhibits of Steve W. Chriss, Wal-Mart's senior manager, energy regulatory analysis.

Through the testimony of Mr. Chriss, Wal-Mart addressed key issues regarding FPL's request for an increase in base rates, including the company's proposed ROE; the company's proposal to allocate production capacity costs using a 12 coincident peak and 25 percent energy methodology; the company's rate design for GSLD-1, GSLDT-1, GSD-1, and GSDT-1 for 2017; the company's proposal to institute an incremental change in 2018; and the company's application of the 2019 Okeechobee LSA.

Following the proceedings in August, the parties engaged in negotiations for the purpose of reaching a comprehensive stipulation and settlement of all issues in the consolidated dockets. During the negotiations, Wal-Mart communicated with various parties led by the Office of Public Counsel. These negotiations led to the October 6, 2016, submission of the joint motion for approval of settlement agreement by the settling parties.

Ultimately Wal-Mart decided not to join the settlement agreement because Wal-Mart cannot affirmatively support the high ROE of 10.55 percent agreed upon by the settling parties in paragraph 3, page 3, of the stipulation and settlement based upon reasons set forth in Wal-Mart's post-hearing brief filed on September 19th, 2016, and in the testimony of Mr. Chriss cited therein. However, on balance, Wal-Mart does not oppose approval of the settlement as a whole.

We want to address two specific issues listed in the stipulation and settlement. Paragraph 10, page 12, FPL projects that it will undertake construction of approximately 300 megawatts of new solar generation reasonably projected to go into service during the minimum term or within one year following expiration of the minimum term. Wal-Mart is interested in solar growth using customer utility partnerships. Wal-Mart understands and believes that FPL is also interested in discussions about programs for large users like Wal-Mart to purchase renewable power from FPL.

Also, paragraph 19, page 23, FPL and interested parties to this agreement will jointly request a Commission workshop to address a pilot demand-side management opt-out program, including eligibility criteria, verification procedures, cost recovery, and other implementation issues.

Wal-Mart supports the opening of a workshop on the opt-out. And as the stipulation and settlement expressly states that participation in the workshop and, if applicable, any opt-out program will not be limited to the parties to the stipulation and settlement agreement, Wal-Mart welcomes the opportunity to participate in the workshop and, if applicable, any opt-out program that may be developed by the parties in the consolidated dockets.

In conclusion, while Wal-Mart is not a signatory to the stipulation and settlement, it does not oppose the agreement reached by the settling parties. Wal-Mart appreciates the opportunity to participate in these proceedings and the time and efforts of the Commission staff and other parties in the consolidated dockets. Thank you.

**CHAIRMAN BROWN:** Thank you, Ms. Roberts (sic).

Sierra Club.

**MS. CSANK:** Good morning, Madam Chair, Commissioners. Sierra Club is pleased that under the proposal FPL will not receive a blank check to build more unnecessary fracked gas-burning plants. Sierra Club is also pleased that additional solar is on the table, solar being Florida's homegrown energy resource and a far better deal than FPL's dangerous overreliance on fracked gas imports. However, Commissioners, the proposal before you still contains significant legal flaws. In particular, it takes away your ability to complete the fact-finding process on whether FPL should recover any of the more than $1 billion the company has dedicated to building more fracked gas-burning peaker power plants.

In this very hearing room, FPL admitted that those peakers would be obsolete in as few as four years and that energy storage and solar are competitive alternatives, yet throughout the entirety of this proceeding, FPL has failed to put forward analysis on those alternatives and, in fact, cites this Commission instead to only other fracked gas power plants, in plain violation of Florida law.

With so much money on the line, this Commission and stakeholders must not waive their ability to use all lawful means to protect the millions of Floridians who will be stuck with needlessly higher electricity bills, and this includes the fixed income and low income Floridians who, number one, face a disproportionate burden to pay those bills and, number two, also often face a disproportionate burden from the pollution from all that fracked gas.

So in conclusion, Commissioners, Sierra Club maintains that the proposal before you is not in the public interest and also maintains its objection to the proposal. Thank you.

**CHAIRMAN BROWN:** Thank you.

Okay. Commissioners, any comments or questions before we get into swearing in the witnesses?

Okay. At this time, I'd like to call all of the witnesses who are going to be testifying to stand up and raise your right hand with me, and I'll be swearing you all in together.

Do you swear or affirm to provide the truth in this proceeding?

(Chorus of affirmative responses.)

Thank you. Please be seated.

Okay. Pursuant to the second Prehearing Order here, witness summaries shall be limited to three minutes. AARP has timely filed a notice of witness appearance of Mr. Michael Brosch. Is that the correct way to pronounce his name? Thank you. Who will follow FPL's witnesses.

FPL will then be allowed to re-call one or more of its direct witnesses to present rebuttal testimony to Mr. Brosch, should FPL deem that necessary. And the order of the direct rebuttal witnesses, as laid out in the second Prehearing Order, are as follows:

Tiffany Cohen; Keith Ferguson; Sam Forrest; Robert Barrett, Jr.; and then the intervenor will appear, Mr. Brosch; and then we'll get to rebuttal.

So with that, Florida Power & Light, will you please call your first witness.

**MS. MONCADA:** FPL calls Ms. Tiffany Cohen.

**CHAIRMAN BROWN:** Thank you. Welcome, Ms. Cohen.

Whereupon,

**TIFFANY COHEN**

was called as a witness on behalf of Florida Power & Light Company and, having first been duly sworn, testified as follows:

**EXAMINATION**

**BY MS. MONCADA:**

**Q** Good morning, Ms. Cohen.

**A** Good morning.

**Q** Could you please state your full name and business address for the record.

**A** It's Tiffany Cohen, 700 Universe Boulevard, Juno Beach, Florida 33408.

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

**A** Florida Power & Light as the senior manager of rate development.

**Q** Ms. Cohen, did you prepare and cause to be filed four pages of prefiled testimony in this proceeding on October 13th, and that testimony being entitled "Proposed Settlement Agreement Direct Testimony"?

**A** Yes.

**Q** Do you have any changes or revisions to that prefiled testimony?

**A** No.

**Q** If I asked you the same questions today that were posed in your prefiled testimony, would your answers be the same?

**A** Yes.

**MS. MONCADA:** Madam Chair, I ask that Ms. Cohen's prefiled direct testimony of October 13th be inserted into the record as though read.

**CHAIRMAN BROWN:** We will go ahead and insert Ms. Cohen's prefiled testimony into the record as though read.

**Q. Please state your name and business address.**

A. My name is Tiffany C. Cohen. My business address is Florida Power & Light Company ("FPL" or the "Company"), 700 Universe Boulevard, Juno Beach, Florida 33408.

**Q. Did you previously submit direct and rebuttal testimony in this proceeding?**

A. Yes.

**Q. Are you sponsoring any additional exhibits in this case?**

A. Yes. I am sponsoring the following exhibits:

- TCC-10 1,000-kWh Typical Residential Bill Comparison
- TCC-11 2017-2020 Typical Bills under the Proposed Settlement Agreement
- TCC-12 Parity of Major Rate Classes

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to present the rates projected to result from the Stipulation and Settlement filed on October 6, 2016 (the "Proposed Settlement Agreement"). Under the Proposed Settlement Agreement, the bills for all customers are projected to remain among the lowest in the state and nation. As shown on TCC-10, the projected 2020 typical residential 1,000-kWh bill would remain 30 percent below the current national average and 13 percent below the current Florida average, even without taking into account likely increases in other utilities' rates over the Minimum Term for which the Proposed Settlement Agreement would be in effect. Additionally, rates that are projected to result from the Proposed Settlement Agreement were designed in accordance with the Florida Public Service Commission's ("the Commission") gradualism principle, and rate classes as a whole move towards greater parity.

**Q. Please describe the base rate adjustments currently scheduled under the Proposed Settlement Agreement.**

A. The Proposed Settlement Agreement reflects scheduled general base rate adjustments of $400 million effective January 1, 2017, and $211 million effective January 1, 2018. It also includes a $200 million limited scope adjustment for the costs associated with the Okeechobee Unit effective upon the commercial operation date, currently estimated to be June 2019.

**Q. What are the projected bills for the major rate classes under the Proposed Settlement Agreement?**

A. Exhibit TCC-11 shows the projected typical bills for 2017-2020 under the Proposed Settlement Agreement for the major rate classes. These projected bills reflect the revenue-neutral transfer of the West County Energy Center Unit 3 to base rates, which increases the base portion of customer bills and decreases the capacity charge by the same amount.

Based on current projections of fuel prices and other expected changes to clauses and base rates, the Proposed Settlement Agreement reflects average annual growth of the typical residential bill through 2020 of less than 2 percent.

**Q. Do the rates under the Proposed Settlement Agreement conform to the Commission's gradualism principle?**

A. Yes. All rates were designed in accordance with the Commission's gradualism principle. The concept of gradualism limits the revenue increase for each rate class to 1.5 times the total system average increase, including adjustment clauses, and provides that no rate class receives a decrease in rates.

**Q. Do the rates under the Proposed Settlement Agreement move rate classes as a whole closer to parity?**

A. Yes. This is shown on Exhibit TCC-12, Parity of Major Rate Classes. The parity of all classes that are outside the range of 90 percent to 110 percent is improved under the Proposed Settlement Agreement. Additionally, under the Proposed Settlement Agreement, 9 of 17 rate classes move to within 10 percent of parity in 2017 and 11 of 17 rate classes move to within 10 percent of parity in 2018.

**Q. Should the Proposed Settlement Agreement rates be approved?**

A. Yes. As discussed by FPL witness Barrett, the proposed rates provide customers with predictability and stability as part of the overall Proposed Settlement Agreement. And as noted above, the projected 2020 typical residential bill would remain 30 percent below the current national average and 13 percent below the current Florida average.

**Q. Does this conclude your testimony?**

A. Yes.

**BY MS. MONCADA:**

**Q** Ms. Cohen, were exhibits identified as TCC-10, 11, and 12 attached to your prepared testimony?

**A** Yes.

**Q** Were these prepared under your direction, supervision, or control?

**A** Yes.

**MS. MONCADA:** Madam Chair, I would note that these are marked as 808 through 810.

**CHAIRMAN BROWN:** Thank you. Now we'll turn to Ms. Brownless.

**MS. BROWNLESS:** Thank you.

**EXAMINATION**

**BY MS. BROWNLESS:**

**Q** Ms. Cohen, have you been given a copy of FP&L's responses to staff's 42nd -- 43rd set of interrogatories, No. 507 through 548, and FP&L's responses to staff's 22nd request for production of documents No. 101?

**A** Yes.

**MS. BROWNLESS:** Okay. And we would like -- I think everybody has been provided that exhibit, Your Honor, and we'd like that to be marked for identification as Exhibit No. 812.

**CHAIRMAN BROWN:** Okay. We will go ahead and mark that as Exhibit 812.

(Exhibit 812 marked for identification.)

**BY MS. BROWNLESS:**

**Q** And were the responses to staff interrogatories Nos. 508 through 509, 511, 520, 524, 537 through -41, 543 through -45, and 548 prepared by you or under your direct supervision and control?

**A** Yes.

**Q** If you were asked the same questions today as those in the interrogatories, would your answers be the same?

**A** Yes.

**Q** Are those answers true and correct to the best of your knowledge and belief?

**A** Yes.

**MS. BROWNLESS:** Thank you, ma'am.

**CHAIRMAN BROWN:** Thank you. And I would note, please silence your phones and other electronic devices too so that we can have a nice clear record too. Thank you.

FPL.

**MS. MONCADA:** I apologize. That was my computer. I silenced it.

**CHAIRMAN BROWN:** It was you.

**MS. MONCADA:** It was me.

**CHAIRMAN BROWN:** Thank you.

**EXAMINATION**

**BY MS. MONCADA:**

**Q** Ms. Cohen, would you please provide to the Commission a very brief summary of your very brief testimony.

**A** Yes. Good morning, Madam Chair and Commissioners. My name is Tiffany Cohen, and my testimony describes the rates that result from the terms of the proposed settlement agreement.

First, under the proposed settlement agreement, the bills for all customers are projected to remain among the lowest in the state and the nation. The projected 2020 typical residential bill would remain 30 percent below the current national average and 13 percent below the current Florida average even without taking into account any increases in other utilities' rates through 2020.

Based on current fuel and clause projections and scheduled base rate changes, rates under the proposed settlement reflect average annual growth of the typical residential bill through 2020 of less than 2 percent, and 1 to 2 percent for commercial and industrial typical bills. The bills for most customers are projected to remain lower in 2020 than 2006.

Second, FPL designed the settlement rates in accordance with the Commission's guidelines, which means that no customer received more than 1.5 times the system average increase and no customer received a rate decrease.

In conclusion, Commissioners, the proposed settlement provides customers with predictable and stable rates over the term of the agreement, and we ask that you approve the rates as proposed. This concludes my summary. Thank you.

**MS. MONCADA:** Thank you, Ms. Cohen.

Madam Chair, the witness is available for cross.

**CHAIRMAN BROWN:** Thank you. And we will start out with AARP.

**MR. McRAY:** No questions.

**CHAIRMAN BROWN:** Thank you.

FIPUG.

**MS. MOYLE:** No questions.

**CHAIRMAN BROWN:** Wal-Mart.

**MS. EATON:** No questions.

**CHAIRMAN BROWN:** Thank you.

Sierra Club.

**MS. CSANK:** No questions, Madam Chair.

**CHAIRMAN BROWN:** Staff.

**MS. BROWNLESS:** Yes, ma'am. We have a few questions.

**CHAIRMAN BROWN:** Did I miss anybody? FEA. Oh, I think I may have missed you. Pardon me, FEA.

**MAJOR UNSICKER:** No questions, ma'am.

**CHAIRMAN BROWN:** Thank you.

Staff.

**MS. BROWNLESS:** Yes, ma'am.

**EXAMINATION**

**BY MS. BROWNLESS:**

**Q** Good afternoon. Good morning. Whatever it is.

**A** Good morning.

**Q** Good morning. Is it correct that the rate development of the settlement is based on the billing determinants as filed in the 2016 rate petition?

**A** Yes.

**Q** And can you explain why the rate development of the settlement does not include an adjustment to the billing determinants to account for Adjustment 4 in FP&L's first notice of identified adjustments filed on May 3rd of 2016?

**A** I believe we provided that answer in discovery. Just one minute.

The changes that were identified in the first notice of adjustment would not have had a material impact on the final rates that were determined under the settlement agreement.

**Q** Thank you. Can you please refer to your responses to staff's 43rd set of interrogatories No. 509. When does FP&L anticipate filing its next demand-side management proceeding in which the CILC and CDR tariffs and its credits might be reevaluated?

**A** My understanding is that the goals proceeding would take place in 2019.

**Q** Thank you. And can you confirm for us that if the Commission modifies the CILC or CDR credits in the next DSM proceedings, CILC or CDC -- I'm sorry -- CDR customers would not be impacted by that decision during the term of the settlement agreement?

**A** That is correct.

**Q** And if you could refer to your interrogatory responses to staff's interrogatories No. 543 and 544. In interrogatory No. 543, the negotiated methodology for allocating distribution plant differs from that used in the MFRs and reflects consideration of the economic impact of an alternative method approved by the Commission in prior settlements. Could you please identify for us what the alternative method approved by the Commission in prior settlements is?

**A** Your question is what -- the method that was approved in prior settlements? It's MDS, which is different than what we've implemented here.

**Q** Okay. Would you elaborate further regarding how the negotiated method for allocating distribution plant differs from that used in your MFRs? Did you use an MDS system similar to that of TECO and Gulf?

**A** We used an average of TECO and Gulf's proposed methodology for MDS. How our calculation differs here is that we did not conduct our study, a study on FPL's system.

Second, we kept the customer charge for residential customers at $7.87. Under the methodology that -- it could have gone up to $12, and part of the negotiation, part of the settlement agreement was the residential customer charge would remain at $7.87 for a typical 1,000 kilowatt hour bill.

**MS. BROWNLESS:** Thank you, ma'am. We have no further questions.

**CHAIRMAN BROWN:** Thank you. Commissioners, any questions?

Commissioner Edgar, you are still on the phone; correct?

Okay. I do have a question for you, Ms. Cohen. Your testimony provides --

**COMMISSIONER EDGAR:** Chairman Brown, I'm so sorry to interrupt. I couldn't find the mute button. Yes, I am here and I heard every word.

(Laughter.)

**CHAIRMAN BROWN:** Good, good, good. I want to make sure if you have any questions for Ms. Cohen.

**COMMISSIONER EDGAR:** I'm fine right now. Thank you.

**CHAIRMAN BROWN:** Ms. Cohen, I do have a question. Your testimony on page 4 provides that bills will remain 30 percent below the national average with the settlement agreement, as well as 13 percent below the current Florida average over the life of the settlement agreement --

**THE WITNESS:** Through 2020.

**CHAIRMAN BROWN:** -- through 2020. But that does not contemplate the implementation of the SoBRA.

**THE WITNESS:** Even with the SOBRAs, our bills would remain -- it's still about 30 percent on the national average, and I believe it's about 10 percent on the Florida -- lower than the Florida average.

**CHAIRMAN BROWN:** Okay. Thank you. All right. Redirect.

**MS. MONCADA:** No redirect, Madam Chair.

**CHAIRMAN BROWN:** Okay. Thank you. Exhibits.

**MS. MONCADA:** FPL would ask that 808 through 810 be moved into the record.

**CHAIRMAN BROWN:** Seeing no objections, we will go ahead and enter 808 through 810 into the record.

(Exhibits 808 through 810 admitted into the record.)

Staff, you have 812.

**MS. BROWNLESS:** That will have to be moved into the record when all of the FP&L witnesses have testified.

**CHAIRMAN BROWN:** Thank you.

All right. Would you like this witness excused?

**MS. MONCADA:** Yes. There -- we don't -- for the direct portion but not for rebuttal.

**CHAIRMAN BROWN:** Stay around, Ms. Cohen.

**THE WITNESS:** Yes, ma'am.

**CHAIRMAN BROWN:** Thank you.

All right. The next witness is Mr. Ferguson.

Welcome back, Mr. Ferguson.

**THE WITNESS:** Good morning.

Whereupon,

**KEITH FERGUSON**

was called as a witness on behalf of Florida Power & Light Company and, having first been duly sworn, testified as follows:

**EXAMINATION**

**BY MR. BUTLER:**

**Q** Mr. Ferguson, were you sworn in when the Chair swore in all of FPL's witnesses?

**A** Yes, I was.

**Q** Okay. Would you please state your name and business address for the record.

**A** Yes. It's Keith Ferguson, 700 Universe Boulevard, Juno Beach, Florida 33408.

**Q** And by whom are you employed and in what capacity?

**A** Florida Power & Light. I'm the controller.

**Q** Have you prepared and caused to be filed seven pages of prefiled direct testimony in this proceeding on October 13th, 2016, entitled "Proposed Settlement Agreement Direct Testimony"?

**A** Yes, I have.

**Q** Do you have any changes or revisions to your prefiled direct testimony?

**A** No.

**Q** Okay. So if I asked you the same questions contained in your prefiled direct testimony today, would your answers be the same?

**A** Yes.

**MR. BUTLER:** Madam Chair, I ask that Mr. Ferguson's prefiled direct testimony be inserted into the record as though read.

**CHAIRMAN BROWN:** We will go ahead and insert Mr. Ferguson's prefiled direct testimony into the record as though read.

## I. INTRODUCTION

**Q. Please state your name and business address.**

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

**Q. Did you previously submit direct and rebuttal testimony in this proceeding?**

A. Yes.

**Q. Are you sponsoring any exhibits related to the Stipulation and Settlement filed on October 6, 2016 ("Proposed Settlement Agreement") in this case?**

A. Yes. I am sponsoring the following exhibit:

- KF-9 – Depreciation Parameter Changes in Proposed Settlement Agreement

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to address the following provisions of the Proposed Settlement Agreement: (1) the proposed revised depreciation parameters, and resulting depreciation rates and theoretical depreciation reserve surplus; and (2) the deferral of FPL's filing of its depreciation and dismantlement studies. My testimony will show that these provisions are appropriate and key elements as part of the overall Proposed Settlement Agreement.

**Q. Please summarize your testimony.**

A. As FPL witness Barrett explains, the Proposed Settlement Agreement has a four-year term, which provides an extended period of rate certainty and avoids the need for expensive and disruptive base rate proceedings during that term. The two provisions that I address in my testimony are essential elements of the Proposed Settlement Agreement because they help make the four-year term feasible. These provisions have been deployed by this Commission previously, and they work together in the context of the overall settlement for the benefit of customers.

## II. PROPOSED DEPRECIATION RATES

**Q. Please briefly describe the proposed depreciation rates included in the Proposed Settlement Agreement.**

A. FPL filed a comprehensive depreciation study in Docket No. 160062-EI, on March 15, 2016 (the "2016 Depreciation Study"), consistent with Rule 25-6.0436, F.A.C. The 2016 Depreciation Study developed service lives and net salvage parameters for each depreciable property account based on FPL's historical experience operating its portfolio of assets and expectations about future conditions. In Hearing Exhibit 331, Attachment 2, FPL calculated the depreciation rates and expense that result if the same parameters developed in the 2016 Depreciation Study are applied to the December 31, 2016 plant and reserve balances. Those same depreciation parameters form the basis for the depreciation rates set forth in Exhibit D of the Proposed Settlement Agreement, with the exception of the changes detailed in Exhibit KF-9 that is attached to this testimony.

The changes reflected on Exhibit KF-9 were negotiated with the signatories to the Proposed Settlement Agreement, as a compromise on certain alternative depreciation parameters based on the positions taken by the intervenors in the course of this rate proceeding. Some of the alternative parameters are reflected in the testimony and exhibits presented at hearing by South Florida Hospital and Healthcare Association witness Lane Kollen and Federal Executive Agencies witness Brian Andrews. Other parameters were negotiated for the purpose of the Proposed Settlement Agreement. Broadly, the changes reflect longer estimated lives and greater (typically, less negative) net salvage for certain types of depreciable property than FPL had proposed in the 2016 Depreciation Study. These negotiated parameters reflect a consistent theme of the intervenor positions on depreciation in this proceeding, in which they assert that there is a trend toward longer service lives and greater net salvage for many types of depreciable property. This is one of the compromises that allows the parties to reach a four-year settlement agreement.

**Q. What is the impact on 2017 depreciation expense and the theoretical depreciation reserve imbalance of applying the depreciation rates set forth in Exhibit D of the Proposed Settlement Agreement?**

A. The application of those rates results in a $125.8 million reduction in 2017 test year depreciation expense (compared to application of the depreciation rates shown in Exhibit 331, Attachment 2) and a theoretical depreciation reserve surplus estimated to be $1,070.2 million at January 1, 2017.

**Q. Would using the depreciation parameters and depreciation rates shown in Exhibit D for the purpose of the Proposed Settlement Agreement be reasonable?**

A. Yes, they reflect a compromise with the signatories to the Proposed Settlement Agreement and are not unreasonable within the overall context of a four-year settlement.

## III. DEFERRAL OF DEPRECIATION AND DISMANTLEMENT STUDIES

**Q. Why does the Proposed Settlement Agreement defer filing the depreciation and dismantlement studies until FPL files its next petition to change base rates?**

A. The FPSC rules regarding depreciation and dismantlement studies require FPL to file studies at least every four years *or pursuant to Commission order and within the time specified in the order.* [Emphasis added]. FPL's next studies are currently due to be filed by March 15, 2020. Under the Proposed Settlement Agreement, these studies would not be due until the time that FPL files to reset its base rates in a general base rate proceeding. This timing aligns the review of FPL's next depreciation and dismantlement studies with the review of FPL's next base rate petition. The current due date for the studies of March 15, 2020 and the filing date for FPL's next petition to change base rates may coincide if FPL decides to file for an adjustment in base rates at the end of the Proposed Settlement Agreement's Minimum Term (i.e., to be effective January 1, 2021). However, providing that the filing date for the studies could be deferred until FPL's next rate petition would help facilitate the possibility that the rate petition could be delayed to a later date.

**Q. Does this conclude your testimony?**

A. Yes.

**BY MR. BUTLER:**

**Q** Mr. Ferguson, do you have an exhibit identified as KF-9 attached to your prepared direct testimony?

**A** Yes, I do.

**Q** Okay. Was that exhibit prepared under your direction, supervision, or control?

**A** Yes, it was.

**MR. BUTLER:** I note that that's been marked as 811 on the Comprehensive Exhibit List.

**BY MR. BUTLER:**

**Q** Mr. Ferguson, are you sponsoring any of FPL's responses to staff's discovery request that are identified on the Comprehensive Exhibit List?

**A** Yes.

**CHAIRMAN BROWN:** Go ahead, Ms. Brownless.

**MR. BUTLER:** Ms. Brownless.

**EXAMINATION**

**BY MS. BROWNLESS:**

**Q** Good morning, sir.

**A** Good morning.

**Q** Were the responses to staff interrogatories Nos. 510, 512 through -14, 531 through -36, 542 and POD No. 1 prepared by you or under your direct supervision and control?

**A** Yes.

**Q** If you were asked the same questions today as those in the interrogatories, would your answers be the same?

**A** Yes.

**Q** Are these answers true and correct to the best of your knowledge and belief?

**A** Yes.

**Q** With regard to POD No. 101, is the information contained in these documents true and correct to the best of your knowledge and belief?

**A** Yes.

**MS. BROWNLESS:** Thank you, sir.

**CHAIRMAN BROWN:** Thank you.

**MR. BUTLER:** Thank you.

**EXAMINATION**

**BY MR. BUTLER:**

**Q** Mr. Ferguson, would you please provide your summary to the Commission.

**A** Yes. Good morning, Madam Chair and Commissioners. Thank you for the opportunity to speak with you today.

The purpose of my settlement testimony is to show how the provisions pertaining to depreciation in the proposed settlement agreement negotiated by the signatories help make the four-year term possible -- feasible. These provisions have been deployed by this Commission previously, and they work together in the context of the overall settlement for the benefit of customers.

My testimony makes four points about the negotiated depreciation parameters. First, the starting point of the depreciation rates reflected in Exhibit D to the proposed settlement agreement are the parameters resulting from FPL's 2016 depreciation study which have been adjusted to take into account certain changes negotiated with the signatories. Some of the changes and parameters are reflected in intervenor testimony and exhibits presented at the technical hearing in August.

Second, the negotiated depreciation rates result in a decrease in depreciation expense for 2017 of 125.8 million compared to the application of depreciation rates from FPL's 2016 depreciation study. This is primarily a result of longer estimated lives and greater net salvage for certain types of assets.

Third, in addition to lower depreciation expense, the negotiated depreciation rates also yield a theoretical depreciation reserve surplus estimated to be approximately 1,070,000,000 at January 1st, 2017.

And finally, under the proposed settlement agreement, FPL's next depreciation dismantlement studies would not be filed until the time that FPL petitions to reset its base rates in a general base rate proceeding. The deferral of the studies until FPL's next rate petition would help facilitate the possibility that a rate petition could potentially be delayed to a later date.

In conclusion, the provisions of the proposed settlement agreement related to depreciation reflect a compromise with the other signatories and they work together in the context of the overall agreement for the benefit of customers. That concludes my summary.

**MR. BUTLER:** Thank you, Mr. Ferguson. I tender the witness for cross-examination.

**CHAIRMAN BROWN:** Thank you. And AARP.

**MR. McRAY:** No questions.

**CHAIRMAN BROWN:** Thank you. FIPUG.

**MS. MOYLE:** No questions.

**CHAIRMAN BROWN:** Wal-Mart.

**MS. EATON:** No questions.

**CHAIRMAN BROWN:** Sierra.

**MS. CSANK:** No questions.

**CHAIRMAN BROWN:** FEA.

**MAJOR UNSICKER:** No questions.

**CHAIRMAN BROWN:** Staff.

**MS. BROWNLESS:** A few questions.

**EXAMINATION**

**BY MS. BROWNLESS:**

**Q** Good morning, Mr. Ferguson.

**A** Good morning.

**Q** I'm looking now at paragraph 12 of the settlement agreement on pages 18 through 20.

**A** Okay. Let me get there. Okay.

**Q** And I hope you will excuse my non-technical lawyer language. This section deals in part with the creation of a reserve amount consisting of two parts; is that correct?

**A** That's correct.

**Q** And the first part is any funds that remain from the 2012 rate case reserve amount; correct?

**A** That's correct.

**Q** Plus about approximately 1 billion of theoretical depreciation reserve surplus created in this proceeding.

**A** That's correct.

**Q** Okay. And that depreciation reserve surplus as a result of this proceeding, broadly speaking, comes from the application of longer service lives and higher net value -- net salvage values than that originally proposed by FP&L; is that correct?

**A** That's correct.

**Q** Okay. Now for each year of the minimum four-year term FP&L has the ability to use this reserve amount to maintain an ROE of up to 11.6 percent; is that correct?

**A** Yes. The reserve amount is available at FPL's discretion to stay within the band of 9.6 to 11.6.

**Q** Right. But it must maintain during this four-year term an ROE of at least 9.6 percent; correct?

**A** That's correct.

**Q** Now given the basic structure of how this reserve amount is going to be dealt with, what is -- what are the differences in the mechanism between what's been agreed to here and what was approved in the 2012 settlement agreement?

**A** There's not really significant differences between the mechanisms in the current settlement agreement and the 2012. The 2012 settlement agreement, as you may recall, included kind of the remaining amount from the 2009 settlement agreement plus a portion of the dismantlement reserve. That was also available for FPL's discretion up to 400 million at the time. It got reduced to 370. This is very similar in that same mechanics as that one.

**Q** Okay. And if I look at paragraph 14 of the settlement agreement, it appears to me that this is waiving the filing of the next depreciation and dismantlement study until the next rate case; is that correct?

**A** Yes, in the way that during the minimum term in the settlement agreement we wouldn't be required to file a dismantlement or depreciation study. They may coincide. Right? If we just do the minimum term of the settlement agreement then apply for revised rates beginning in 2021, then the timing would coincide with what our normal cadence would be for those studies. But we wanted to allow for the flexibility in case we're able to extend it beyond the minimum term.

**Q** Because otherwise you'd have to be filing every four years pursuant to the rule; correct?

**A** That's correct. Yeah.

**Q** Okay. And how do you believe deferring the filing of a new dismantlement and depreciation study will help facilitate the possibility that you can stay out longer than four years?

**A** Well, to the extent you're filing depreciation dismantlement studies and you're not changing base rates or applying for base rate changes at the time, then you have kind of a mismatch in the way that you've filed for changes in rates without -- depreciation rates without the commensurate changes in base rates.

**Q** So it's mainly an -- your idea mainly is to keep your rate case increases and your dismantlement studies simultaneously filed.

**A** That's correct. We believe that's probably the most appropriate timing of those studies is to kind of align them with the base rate increases.

**Q** Okay. Looking at your response to our interrogatory No. 534 --

**A** Okay.

**Q** -- can you please confirm that any unamortized balance of the newly proposed reserve amount will remain in accumulated depreciation over the settlement term and therefore reduce the rate base until it's amortized?

**A** That's correct, yes.

**Q** Now if you could turn to paragraph 6A of the settlement agreement.

**A** Yes, I'm there.

**Q** Okay. Is it accurate to say that, based upon this paragraph, storm cost recovery will be limited to the estimate of incremental costs above the level of the storm reserve prior to the storm and to the replenishment of the storm reserve to the level in effect as of August 31st of 2016?

**A** Yes, that's correct.

**Q** And was the storm reserve level in effect as of August 31st, 2016, approximately $112 million?

**A** Yes, that's correct.

**Q** And what do you project the storm reserve to be as of January 1, 2017?

**A** As we filed with the Commission on Friday, we expect to deplete that reserve down to zero, and we'll be likely petitioning this Commission for interim recovery under our current settlement agreement by the end of the year.

**Q** And that would be the 2012 settlement agreement.

**A** That's correct, the 2012.

**Q** And basically, just so we have the record complete, why was your reserve depleted to zero?

**A** We had a little storm called Hurricane Matthew that had a significant impact on our service territory in October.

**Q** And do you know what the storm reserve is under the provision of the 2012 settlement agreement?

**A** Yes. It's approximately $117 million.

**MS. BROWNLESS:** Thank you. That's all we have, sir.

**CHAIRMAN BROWN:** Thank you.

Commissioners?

Ms. Brownless, you asked all my storm reserve questions, all of them. I could come up with one.

Mr. Ferguson, do you foresee the cessation of an accrual, though, being an impediment moving forward under the settlement agreement?

**THE WITNESS:** The accrual of -- I'm sorry.

**CHAIRMAN BROWN:** The storm reserve, on the storm reserve, because it's no longer accruing and you're going to be coming in for a request for a surcharge. But really the reserve level under the settlement agreement can only go up to 112 million.

**THE WITNESS:** Yeah. It's actually 117, which is what it was as of January 1st, 2017. So -- sorry, 2013.

No, you know, I don't see it as an impediment in terms of it's the mechanism that's been in place since the 2012 settlement agreement and, you know, has kind of, you know, served us well. While fortunately we haven't had significant major storms until this year, you know, I think it's a mechanism that's -- that works.

**CHAIRMAN BROWN:** So after the surcharge, FPL intends, though, to get that reserve level up to -- is it the 117 or the --

**THE WITNESS:** That's correct, yeah.

**CHAIRMAN BROWN:** Okay. Got it.

Commissioners, any other questions?

Thank you. Redirect.

**MR. BUTLER:** One brief redirect.

**EXAMINATION**

**BY MR. BUTLER:**

**Q** Mr. Ferguson, you were asked about the recovery under the interim storm recovery mechanism for the -- under the current settlement agreement for Hurricane Matthew, and I think you may have referred to recovering the estimated cost through the surcharge. My question to you is whether or not there would ultimately be a true-up to the actual amount of the storm costs.

**A** Yes. You know, as the nature of these storm costs are typically that they come in over a period of team. And so, you know, while we'll file a petition with kind of our first -- our estimate of what those costs were as the actual costs come in, we would true-up to those actual costs.

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

**CHAIRMAN BROWN:** Thank you. Exhibits?

**MR. BUTLER:** Yes. We would move into evidence Exhibit 811.

**CHAIRMAN BROWN:** Seeing no objection, we'll go ahead and move into the record 811.

(Exhibit 811 admitted into the record.)

Mr. Ferguson --

**MR. BUTLER:** May he be temporarily excused?

**CHAIRMAN BROWN:** Temporarily excused.

**MR. BUTLER:** Thank you.

**THE WITNESS:** Thank you.

**CHAIRMAN BROWN:** Thank you.

Okay. Calling FPL's next witness, Mr. Sam Forrest.

**MR. BUTLER:** Sam Forrest, yes.

Whereupon,

**SAM FORREST**

was called as a witness on behalf of Florida Power & Light Company and, having first been duly sworn, testified as follows:

**EXAMINATION**

**BY MR. BUTLER:**

**Q** Mr. Forrest, were you sworn in with the other FPL witnesses a few moments ago?

**A** Yes, I was.

**Q** Okay. Would you please state your name and business address for the record.

**A** Yes. Sam Forrest, vice president of energy marketing and trading. Business address is 700 Universe

Boulevard, Juno Beach, Florida 33408.

**Q** Okay. I think you just said by whom you were employed and in what capacity, so I'll skip that.

Have you prepared and caused to be filed five pages of prefiled direct testimony in this proceeding on October 13, 2016?

**A** Yes.

**Q** Do you have any changes or revisions to your prefiled direct testimony?

**A** No, I do not.

**Q** So if I asked you the same questions contained in your prefiled direct testimony today, would your answers be the same?

**A** Yes, they would.

**MR. BUTLER:** Madam Chair, I'd ask that Mr. Forrest's prefiled testimony be inserted into the record as though read.

**CHAIRMAN BROWN:** We'll go ahead and insert Mr. Forrest's prefiled direct testimony into the record as though read.

**Q. Please state your name and business address.**

A. My name is Sam Forrest. My business address is Florida Power & Light Company ("FPL"), 700 Universe Boulevard, Juno Beach, Florida 33408.

**Q. Did you previously submit direct and rebuttal testimony in this proceeding?**

A. Yes.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to address the provision of the Stipulation and Settlement filed on October 6, 2016 ("Proposed Settlement Agreement") under which FPL would terminate financial hedging prospectively with respect to natural gas requirements during the Proposed Settlement Agreement's Minimum Term.

**Q. Has FPL agreed to terminate natural gas financial hedging prospectively for the Minimum Term of the Proposed Settlement Agreement?**

A. Yes, as part of the negotiated resolution of the disputed issues that led to the Proposed Settlement Agreement, FPL has agreed to terminate its natural gas financial hedging prospectively for the Minimum Term of the Proposed Settlement Agreement.

**Q. Within the overall context of the Proposed Settlement Agreement, is terminating natural gas financial hedging prospectively for the Minimum Term reasonable?**

A. Yes, the decision to terminate financial hedging of natural gas prospectively for the Minimum Term of the Proposed Settlement Agreement reflects a compromise with the signatories and is not unreasonable within that context. This provision is one element of the Proposed Settlement Agreement, the overall benefits and public interest of which are addressed by FPL witness Barrett.

**Q. What does the Proposed Settlement Agreement provide with respect to hedging following the expiration of the Minimum Term?**

A. The Proposed Settlement Agreement does not prohibit FPL from filing a petition and proposed risk management plan with the Florida Public Service Commission (the "Commission") to address natural gas financial hedges for periods following expiration of the Minimum Term. Of course, any signatory to the Proposed Settlement Agreement and other intervenors would be free to take whatever position they choose on any proposal that FPL might file.

**Q. If the Commission approves the Proposed Settlement Agreement, how does FPL plan to implement the requirement that it terminate natural gas financial hedging prospectively for the Minimum Term?**

A. FPL annually files a Risk Management Plan that describes the level of hedges it will place in a given year, which secures the price for a portion of the volumes of natural gas to be procured during the following year. On August 4, 2016, FPL filed its 2017 Risk Management Plan in the Fuel Clause proceeding, which would provide for FPL to continue executing financial natural gas hedging transactions in 2017 for natural gas to be procured in 2018. FPL's 2017 Risk Management Plan reflects a target hedging level that is 25 percent lower than in previous years consistent with the joint motion that

FPL and the three other major investor-owned utilities filed in Docket No. 160096-EI on April 22, 2016. Unless and until the Proposed Settlement Agreement is approved, FPL will not withdraw that Risk Management Plan. However, on October 19, 2016, FPL will file an alternative 2017 Risk Management Plan in Docket No. 160001-EI under which it would financially hedge zero percent of its natural gas requirements for 2018. FPL will ask the Commission to approve the alternative plan instead of the August 4 plan if the Proposed Settlement Agreement is approved. Similarly, FPL's 2018 and 2019 Risk Management Plans would seek approval to financially hedge zero percent of its natural gas requirements for 2019 and 2020, respectively, if the Proposed Settlement Agreement is approved.

**Q. Has FPL already executed most of its 2016 Risk Management Plan, as previously approved by the Commission?**

A. Yes.

**Q. Will FPL make any changes to its existing hedges that were put in place as part of the 2016 Plan?**

A. No.

**Q. How does FPL intend to execute its 2016 Risk Management Plan through the end of 2016 if the Proposed Settlement Agreement is approved?**

A. FPL's approved 2016 Risk Management Plan allows FPL to execute a portion of the annual hedges within a specific range each month of the year. Upon Commission approval of the Proposed Settlement Agreement, FPL will continue to execute only the minimum trades required to meet the lower end of that range, consistent with Paragraph 16 of the Proposed Settlement Agreement. FPL fully expects that no additional hedges would need to be placed in December 2016 to meet the requirements of the 2016 Risk Management Plan.

**Q. Is it possible that FPL will need to rebalance its hedges for 2017 executed pursuant to the approved 2016 Risk Management Plan?**

A. Yes. However, in accordance with Paragraph 16 of the Proposed Settlement Agreement, FPL will execute only the minimum trades necessary to stay in compliance with the 2016 Risk Management Plan.

**Q. Does this conclude your testimony?**

A. Yes.

**MR. BUTLER:** I note that Mr. Forrest does not have any exhibits attached to his prepared testimony, but I believe that he is sponsoring some of staff's discovery responses.

**CHAIRMAN BROWN:** Yes. Ms. Brownless.

**MS. BROWNLESS:** Thank you.

**EXAMINATION**

**BY MS. BROWNLESS:**

**Q** Were the responses to staff interrogatories No. 521 through -22, 525 through 529 prepared by you or under your direct supervision and control?

**A** Yes, ma'am, they were.

**Q** And if you were asked the same questions today as those in the interrogatories, would your answers be the same?

**A** Yes, they would.

**Q** Are these answers true and correct to the best of your knowledge and belief?

**A** Yes, ma'am.

**MS. BROWNLESS:** That's all I have.

**THE WITNESS:** Okay.

**CHAIRMAN BROWN:** Thank you.

FPL.

**EXAMINATION**

**BY MR. BUTLER:**

Q Mr. Forrest, would you please provide a summary of your testimony to the Commission.

A Yes. Madam Chair, Commissioners, as part of the negotiations that led to the proposed settlement agreement, FPL has agreed to terminate its natural gas financial hedging respectively for the minimum term of the proposed settlement agreement. This decision reflects a compromise with the signatories to the agreement and is not unreasonable within that context.

FPL's approved 2016 risk management plan is largely executed at this late stage in the year. FPL plans to continue to execute hedges in 2017 -- or, excuse me, for 2017 to the minimum extent required to stay in compliance with the 2016 plan but would cease hedging upon Commission approval of the proposed settlement agreement. Thereafter, FPL would not plan to make any changes to the existing hedges that have been put in place as part of the 2016 plan other than executing the minimum rebalancing trades required necessary to stay in compliance with that plan. This approach is consistent with paragraph 16 of the proposed settlement agreement.

FPL recently filed an alternative 2017 risk management plan in order to effectuate the termination of hedging next year consistent with the proposed settlement agreement. Under this alternative 2017 plan, FPL would financially hedge zero percent of its natural gas requirements for 2018. Similarly, upon approval of the proposed settlement agreement, FPL will file and seek approval for 2018 and 2019 risk management plans that provide for FPL to financially hedge zero percent of its natural gas requirements for 2019 and 2020 respectively. And this concludes my summary.

**MR. BUTLER:** Thank you, Mr. Forrest.

I tender the witness for cross-examination.

**CHAIRMAN BROWN:** Thank you. AARP.

**MR. McRAY:** No questions.

**CHAIRMAN BROWN:** No questions.

FIPUG.

**MS. MOYLE:** No questions.

**CHAIRMAN BROWN:** Thank you.

Wal-Mart.

**MS. EATON:** No questions.

**CHAIRMAN BROWN:** Sierra Club.

**MS. CSANK:** No questions.

**CHAIRMAN BROWN:** FEA.

**MAJOR UNSICKER:** No questions, ma'am.

**CHAIRMAN BROWN:** Staff.

**MS. BROWNLESS:** We have a few questions.

**CHAIRMAN BROWN:** That's okay.

**EXAMINATION**

**BY MS. BROWNLESS:**

**Q** Hi, Mr. Forrest. Nice to see you.

**A** Good morning.

**Q** Okay. Is the basic gist of paragraph 16 of the settlement agreement that FP&L will allow existing hedges to settle without being replaced or renewed?

**A** That is correct, yes.

**Q** And that FP&L will immediately stop any further hedging activities for the four-year minimum term as you explained?

**A** Yes, ma'am, that's correct.

**Q** Okay. If the settlement agreement is approved, will FP&L have any hedges in place for 2018?

**A** No, we will not.

**Q** And as that being the case, is it correct that FP&L's forecast of natural gas prices for 2018 will not include any hedging effects?

**A** That is correct, yes.

**Q** FP&L would also be completely unhedged for 2019 and 2020; correct?

**A** That's correct, yes.

**Q** So the bottom line is that during the course of the next year, whatever hedges you put in place pursuant to your 2016 risk management plan will be allowed to settle, and as time carries on through 2017, you'll end up with zero at January 1?

**A** Yes, ma'am, but if I could restate that just a little bit.

**Q** Sure.

**A** So we have hedges in place for 2017 today. Those hedges will be allowed to expire in place. We will continue to hedge 2017 until such time that the Commission rules on this settlement agreement. If they approve the settlement agreement, then we would stop hedging basically at that point. We will have met the minimum requirements of our 2016 risk management plan. So at the end of 2017, once those hedges have rolled off, then starting January 1st of 2018 no additional hedges will be in place at that point. So we'll be unhedged for 2018, '19, and '20.

**Q** Okay. Assume near the end of the settlement period that's in or about the year 2020 a decision was made to resume hedging. How easy or difficult would that be?

**A** Well, similar to how things occur today with a filing of a risk management plan in the fall prior to the year. So we would file a risk management plan in the fall of 2019 which would be our 2020 risk management plan for execution of hedges starting in 2021 and beyond. So it would not be challenging, obviously. We would hopefully participate in whatever process came out of the joint stipulation with the other IOUs, go through that process. And, again, if the Commission is still supportive of hedging at the end of the minimum term, we would just reimplement our hedging policies consistent with whatever comes out of the workshops that'll be held.

**Q** And when you say "joint stipulation," you're talking about the joint stipulation that was filed in the fuel clause docket.

**A** Yes, ma'am, that's correct. Yeah, sorry.

**Q** Okay. Do you agree that as part of calculating your fuel recovery rates, FP&L projects the commodity cost of natural gas for the upcoming year?

**A** Yes, ma'am, that's correct.

**Q** And if you can look at your response to our interrogatory No. 529.

**A** Okay.

**Q** Got that? Okay.

Assume a commodity cost of natural gas of $3 per MMBtu is built into the 2018 fuel rates. If natural gas prices rise to $4 per MMBtu or higher for the last six months of 2018, FP&L would reach the 10 percent threshold for reporting a fuel cost under-recovery according to Rule 25-6.0424. Is that right?

**A** That is correct, yes, assuming that the first half of the year is basically exactly zero. Right? So starting July 1 forward a $1 move would, yeah, would trigger the 10 percent. Yes.

**Q** Okay. Assuming a $3 per MMBtu commodity cost for natural gas in 2018 fuel rates, a $1 swing in the price for six months will trigger this reporting requirement; correct?

**A** Yes. We would have an obligation to notify the Commission that we've hit the 10 percent threshold.

**Q** Okay. And it's also true, is it not, that FP&L does not have to wait to reach the 10 percent threshold to file for a midcourse correction in its fuel rates; is that right? You can ask for a midcourse correction before you reach the 10 percent; is that right?

**A** I'm not aware of that, but I'll trust you, if that's the case.

**MS. BROWNLESS:** Thank you, sir. That's all the questions we have. Thank you.

**CHAIRMAN BROWN:** Thank you.

Commissioners? Commissioner Brisé.

**COMMISSIONER BRISÉ:** Thank you, Madam Chair.

And a couple of questions, though, following up on staff's question regarding the hedging program.

Part of the whole concept of hedging is sort of stability in rates for consumers. So does FPL feel that as a result of this agreement that they can maintain that level of price stability that customers have seen for the last few years with the impact of hedging the way it has played out over the past few years moving forward, considering the conditions of this agreement?

**THE WITNESS:** We have long supported hedging and have been supportive of the Commission in that regard. Certainly, you know, beyond 2017 with the years '18, '19, and '20 not being hedged, there is an element of volatility there that's just not being protected against. So, you know, we think we've long, again, supported hedging. We continue to support hedging if the Commission seems supportive of it at the end of the minimum term. But there is a level of volatility that will be introduced not being hedged.

**COMMISSIONER BRISÉ:** Okay. So from the perspective of the utility being the responsible party with respect to consumers, is this provision in the settlement, from FPL's position, responsible?

**THE WITNESS:** I think it's responsible in the grander scheme of the overall settlement. It's obviously a package that's being presented to the Commission for approval. So I think in that regard, yes, it is responsible. And Witness Barrett, I think, speaks to the public interest of the overall agreement. So, yeah, I mean from that perspective, yes, we absolutely do believe it's responsible.

**COMMISSIONER BRISÉ:** Okay. Thank you.

**CHAIRMAN BROWN:** Commissioners, any other questions?

I have a question for you kind of along the same lines. This is one of the provisions in the settlement agreement that I'm not really crazy about, given the duration, the four-year moratorium. And I want to be clear that if anything comes out of the workshop, which I assume FPL will -- if approved in the 01 docket, will FPL be participating in that workshop, number one?

**THE WITNESS:** Yes, we would like to. Yes.

**CHAIRMAN BROWN:** Okay. And if anything comes out of that workshop, inevitably the only way that Florida Power & Light could comply with whatever comes out would be to amend the settlement agreement. Otherwise, it has to wait until 20 -- the expiration of the settlement agreement.

**THE WITNESS:** That is correct. It would require the agreement of all the parties that are signatories to the agreement.

**CHAIRMAN BROWN:** Okay. Any other questions? Redirect?

**MR. BUTLER:** No redirect. Thank you.

**CHAIRMAN BROWN:** Okay. Thank you. This witness --

**MR. BUTLER:** Ask that he be temporarily excused.

**CHAIRMAN BROWN:** Yes, we will go ahead and do that. He has no exhibits attached to his testimony. Thank you.

All right. The next witness is Mr. Barrett.

**MR. LITCHFIELD:** Correct. Mr. Barrett was sworn earlier, which I will confirm with him when he takes the stand.

Whereupon,

**ROBERT E. BARRETT, JR.**

was called as a witness on behalf of Florida Power & Light Company and, having first been duly sworn, testified as follows:

**EXAMINATION**

**BY MR. LITCHFIELD:**

**Q** Are you well situated, Mr. Barrett?

**A** Yes, thank you.

**Q** Okay. You were sworn earlier; correct?

**A** Yes.

**Q** Would you please provide your name and address for the record.

**A** Yes. Robert Barrett, Jr., 700 Universe Boulevard, Juno Beach, Florida 33408.

**Q** And by whom are you employed and in what capacity?

**A** Florida Power & Light as the vice president of finance.

**Q** And you've prepared and caused to be filed 13 pages of prefiled direct testimony in this proceeding submitted on October 13, 2016?

**A** Yes.

**Q** And I would note that Mr. Barrett did not have any exhibits in connection with that testimony.

Do you have any changes or revisions to your prefiled direct testimony, Mr. Barrett?

**A** No.

**Q** If I were to ask you then the same questions reflected in that testimony today, would your answers be the same?

**A** Yes.

**MR. LITCHFIELD:** Madam Chair, I'd ask that

Mr. Barrett's prefiled direct be inserted into the record as though read.

**CHAIRMAN BROWN:** We will go ahead and insert Mr. Barrett's prefiled direct testimony into the record as though read.

## I. INTRODUCTION

**Q. Please state your name and business address.**

A. My name is Robert E. Barrett, Jr. My business address is Florida Power & Light Company ("FPL" or "the Company"), 700 Universe Boulevard, Juno Beach, Florida 33408.

**Q. Did you previously submit direct and rebuttal testimony in this proceeding?**

A. Yes.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to explain why the Stipulation and Settlement filed on October 6, 2016 (the "Proposed Settlement Agreement"), taken as a whole, is appropriate and in the public interest. My testimony will also discuss the reserve amortization mechanism contained in the Proposed Settlement Agreement and its critical role in enabling the four-year term of the agreement. Next, my testimony will explain the solar base rate adjustment ("SoBRA") mechanism and discuss the process set forth in the Proposed Settlement Agreement for Florida Public Service Commission ("FPSC" or "the Commission") review of the cost-effectiveness of future solar generating facilities and approval of the recovery of the revenue requirements associated with those facilities. My testimony will also discuss the battery storage pilot program and the benefits of such a program for FPL's customers. Finally, my testimony will explain the provision of the Proposed Settlement Agreement to request a Commission workshop to address a pilot demand-side management ("DSM") opt-out program.

## II. SUMMARY

**Q. Please provide an overview of the Proposed Settlement Agreement and describe why it is in the public interest.**

A. The Proposed Settlement Agreement would resolve all of the issues in FPL's base rate case filed on March 15, 2016 ("2016 Rate Petition") as well as the issues in FPL's filed Depreciation and Dismantlement Study and the Incentive Mechanism docket in a fashion that balances the interests that customers have in receiving low bills, high reliability and excellent customer service with the opportunity for investors to have the potential to earn a fair rate of return. The signatories also have affirmed that the Proposed Settlement Agreement would call for the Commission to approve FPL's Storm Hardening Plan and Wooden Pole Inspection Program, as filed.

Through its terms, the Proposed Settlement Agreement provides for a reduction in FPL's base rate request, while allowing for scheduled base rate increases in 2017, 2018 and a limited scope adjustment when the Okeechobee Clean Energy Center enters commercial operation, currently scheduled in June 2019. Taken as a whole, the Proposed Settlement Agreement will provide for a high degree of base rate certainty to all parties and FPL customers for a fixed term of four years; encouraging management to continue its focus on improving service delivery, realizing additional efficiencies in its operations and creating stronger customer value, while maintaining residential bills that are projected to continue to be among the lowest in the state and nation. This negotiated outcome resolves a number of competing considerations in a way that produces an overall result that is in the public interest.

## III. AMORTIZATION OF RESERVE AMOUNT

**Q. What is the Reserve Amount as defined in the Proposed Settlement Agreement?**

A. Paragraph 12(c) of the Proposed Settlement Agreement defines the Reserve Amount as comprised of two parts: (1) the actual remaining portion as of December 31, 2016 of the reserve amount that the Commission authorized FPL to amortize in Order No. PSC-13-0023-S-EI (adjusted for the Cedar Bay Settlement in Order No. PSC-15-0401-AS-EI) plus (2) up to $1,000 million of the theoretical depreciation reserve surplus effected by the depreciation parameters and resulting rates set forth in Exhibit D of the Proposed Settlement Agreement, subject to certain restrictions. FPL witness Ferguson describes the Reserve Amount in more detail.

**Q. What does the Proposed Settlement Agreement provide as it relates to amortization of the Reserve Amount?**

A. Paragraph 12 of the Proposed Settlement Agreement provides FPL with the ability to amortize the Reserve Amount, at its discretion, during the settlement term conditioned by the following: (1) for any period in which FPL's actual FPSC adjusted return on equity ("ROE") would otherwise fall below 9.6%, FPL must amortize any remaining Reserve Amount to at least increase the ROE to 9.6%; and, (2) FPL may not amortize the Reserve Amount in an amount that results in FPL achieving an FPSC adjusted ROE greater than 11.6%.

**Q. Is this provision critical to the settlement?**

A. Yes. The reserve amortization mechanism provides the Company the flexibility necessary to achieve reasonable financial results during the four-year settlement period while also agreeing to substantially lower base revenue increases compared to those requested in the 2016 Rate Petition. Without this flexibility, base rates could not be held constant for such an extended period due to the risk of weather, inflation, rising interest rates, mandated cost increases and other factors affecting FPL's earnings that largely are beyond the Company's control.

**Q. What are the benefits of allowing FPL to amortize the Reserve Amount during the settlement term?**

A. The amortization of the Reserve Amount provides rate certainty and avoids the need for expensive and disruptive base rate proceedings over the four-year settlement period. The Commission approved a similar mechanism in Order No. PSC-13-0023-S-EI, so the Proposed Settlement Agreement provides nothing new in that regard. Specifically, the reserve amortization mechanism allows the Company to forgo a portion of the cash revenue increases it petitioned for, providing significant benefit to customers through lower rates over the four-year period.

## IV. SOLAR BASE RATE ADJUSTMENT

**Q. Please provide an overview of the SoBRA included in the Proposed Settlement Agreement.**

A. The SoBRA is very similar to the generation base rate adjustment ("GBRA") mechanism the Commission has approved in the past. For purposes of SoBRA cost recovery pursuant to the Proposed Settlement Agreement, FPL may construct approximately 300 MW of solar generating capacity per calendar year, projected to go into service no later than 2021. The cost of the components, engineering and construction for any solar project undertaken pursuant to the Proposed Settlement Agreement will be reasonable and will not exceed $1,750 kWac. Through the SoBRA mechanism, FPL will be allowed to recover the annual base revenue requirements reflecting the first twelve months of operations of each solar generation project.

**Q. How will the solar projects and attendant cost recovery pursuant to the SoBRA mechanism be reviewed and approved by the Commission?**

A. For solar projects 75 MW or greater that are subject to the Florida Electrical Power Plant Siting Act ("Siting Act"), FPL will file a petition for a Determination of Need with the Commission. If approved, FPL will calculate and submit for Commission confirmation the SoBRA amount for each such solar project using the annual Capacity Clause projection filing for the year that solar project is scheduled to go into service.

Solar projects less than 75 MW, and therefore not subject to the Siting Act, also will be subject to Commission approval through FPL's Fuel and Purchased Power Cost Recovery Clause docket ("Fuel Docket"). The petition for approval will be made in the annual true-up filing. The cost effectiveness will be determined by whether the solar project lowers FPL's projected system cumulative present value revenue requirement ("CPVRR"). If the solar project is approved as cost-effective, FPL will calculate and submit for Commission confirmation the amount of the SoBRA for each such solar project using the annual Capacity Clause projection filing for the year that solar project is scheduled to go into service and base rates will be adjusted consistent with that amount upon commercial operation of the respective solar project(s).

**Q. How will the SoBRA revenue requirement be calculated?**

A. Each SoBRA will be calculated to recover the estimated revenue requirements for the first twelve months of operation using a 10.55% ROE and the appropriate incremental capital structure consistent with that used for the Okeechobee Limited Scope Adjustment reflected in FPL's 2016 Rate Petition adjusted to reflect the inclusion of investment tax credits on a normalized basis. As the solar generating facilities are expected to increase system efficiency by lowering the overall system fuel cost, FPL also will seek approval in the Fuel Docket for fuel factors that reflect those savings coincident with the projected in-service dates of the various solar projects.

**Q. Does the proposed SoBRA mechanism provide for adjustments to the projected SoBRA factors to account for actual capital expenditures?**

A. Yes. Similar to the previous and existing GBRA mechanism, the initial SoBRA factor will be adjusted automatically if actual capital expenditures are lower than projected. In that event, a revised SoBRA factor will be calculated and a one-time credit will be made through the Capacity Clause, with base rates adjusted on a go-forward basis for the revised factor.

If actual capital expenditures are higher than projected, FPL at its option, may initiate a limited proceeding, to address the limited issue of whether FPL has met the requirements of Rule 25-22.082(15), F.A.C. (i.e., that such costs were prudently incurred and due to extraordinary circumstance). All parties would have the right to participate in the limited proceeding and challenge whether

FPL has met the Rule 25-22.082(15) requirements. If the Commission finds that FPL has met the requirements of Rule 25-22.082(15), then FPL may increase the SoBRA by the corresponding incremental revenue requirement due to such additional capital costs. This process also is identical to the process that was available, but never employed, under the terms that governed the GBRA mechanism throughout the period since a GBRA was first established under FPL's 2005 settlement agreement in Order No. PSC-05-0902-S-EI.

**Q. Is FPL allowed to recover more than an incremental 300 MW of solar generating capacity in a calendar year?**

A. No. FPL may not receive approval for incremental SoBRA recovery of more than 300 MW of solar projects in a calendar year; provided, however, to the extent that FPL receives approval for SoBRA recovery of less than 300 MW in a year, the surplus capacity can be carried over to the following years for approval and recovery. For example, if FPL receives approval for SoBRA recovery in 2017 of 200 MW of solar capacity, it would be entitled to increase its request for SoBRA recovery in subsequent year(s) by an additional 100 MW. Additionally, in 2017, FPL may at its option and for administrative efficiency, petition for approval of up to 300 MW for 2017 SoBRA recovery and up to 300 MW for 2018 SoBRA recovery; provided however, that no base revenue increase may occur in 2017 until the Commission has approved the 2017 SoBRA and those projects have entered commercial service.

## V. BATTERY STORAGE PILOT PROGRAM

**Q. Please explain the battery storage pilot program.**

A. The battery storage pilot program will allow FPL to deploy 50 MW of battery storage technology designed to serve commercial, industrial and retail customers. Parties to this Proposed Settlement Agreement agree that this pilot program is a prudent investment and provides benefits for FPL's customers. Through this program, FPL will be able to gain a better understanding of how battery storage can improve the reliability and efficiency of the system. FPL has agreed that the average installation cost of the battery storage projects will not exceed $2,300/kWac during the term of the agreement, and FPL will not seek incremental recovery of the revenue requirements associated with the pilot program until its next general base rate increase.

## VI. WORKSHOP FOR PILOT DSM OPT-OUT PROGRAM

**Q. Please explain the pilot DSM Opt-Out Program workshop provision of the Proposed Settlement Agreement?**

A. FPL and interested parties will jointly request a Commission workshop to consider a pilot DSM Opt-Out Program. Some of the items to be considered at that workshop will include eligibility criteria for opting out of FPL's DSM programs, procedures for verifying continued compliance with those eligibility criteria, impacts on FPL's cost recovery for DSM and other implementation issues. The workshop will not be limited to the signatories to the Proposed Settlement Agreement, but may include anyone who otherwise would be eligible to participate as determined by the Commission. There is no commitment among parties to the Proposed Settlement Agreement with regard to the appropriate outcome of such a workshop, beyond requesting the workshop and participating in good faith.

**Q. When will FPL and the interested parties make their request for the proposed Commission workshop?**

A. FPL and the interested parties will work with the Commission Staff to determine the appropriate time for the parties to make such a request.

## VII. CONCLUSION

**Q. Should the Commission approve the Proposed Settlement Agreement as consistent with the public interest?**

A. Yes. As in any settlement context, parties will have made concessions relative to their positions in the case. This settlement is no different and must be viewed and accepted (or not) on its whole. There are several factors which FPL would offer in support of the Commission entering an order approving the Proposed Settlement Agreement. First, the Proposed Settlement Agreement provides customers with predictability and stability in their electric rates, while allowing FPL to maintain the financial strength to make investments it believes are necessary to provide customers with safe and reliable power. Second, the Proposed Settlement Agreement also will increase the amount of emissions-free solar power and energy that will be available to serve customers on a cost-effective basis. Third, the Proposed Settlement Agreement reflects an average annual growth in rates of slightly less than 2%, below the expected rate of inflation. For these reasons, FPL submits that the Proposed Settlement Agreement, taken as a whole, is in the public interest and should be approved by this Commission.

**Q. Does this conclude your testimony?**

A. Yes.

**MR. LITCHFIELD:** And I believe that Mr. Barrett is sponsoring certain of staff's discovery responses.

**CHAIRMAN BROWN:** Ms. Brownless.

**EXAMINATION**

**BY MS. BROWNLESS:**

**Q** Good morning, Mr. Barrett.

**A** Good morning.

**Q** Can you please refer to what's been marked as Exhibit No. 812. Were the responses to staff interrogatories No. 515 through -19, 523, 530, 546, 547 prepared by you or under your direct supervision and control?

**A** Yes.

**Q** If you were asked the same questions today as those in the interrogatories, would your answers be the same?

**A** Yes.

**Q** And are these answers true and correct to the best of your knowledge and belief?

**A** Yes, they are.

**MS. BROWNLESS:** Thank you.

**CHAIRMAN BROWN:** Thank you.

**EXAMINATION**

**BY MR. LITCHFIELD:**

**Q** Thank you, Mr. Barrett. Would you provide a brief summary to the Commission.

**A** Yes. Good morning, Madam Chair and Commissioners.

My testimony demonstrates that the proposed settlement agreement taken as a whole represents a fair and balanced outcome for all parties and is in the public interest. This negotiated agreement resolves all the issues in FPL's pending rate filing. Principally it provides for base rate increases in 2017, '18, and the limited scope adjustment for Okeechobee that are substantially reduced from the levels FPL proposed in its filed request. It also establishes FPL's authorized return on equity at 10.55 percent with a range of 9.6 to 11.6 percent. The proposed settlement agreement provides a high degree of base rate certainty over the four-year period while encouraging management to continue its focus on improving service delivery, realizing additional efficiencies in the organization and creating stronger customer value.

My testimony also addresses certain key provisions of the proposed settlement agreement including the reserve amortization mechanism; the solar base rate adjustment, or SoBRA; the battery storage pilot program; and the proposed workshop for a pilot demand-side management opt-out program.

The reserve amortization mechanism in the proposed settlement agreement helps make it possible for FPL to accept the substantial reduction in cash-based revenue increases compared to the filed request while maintaining the flexibility FPL needs to achieve reasonable financial results over the four-year minimum term.

The reserve amortization mechanism provides confidence to customers and the Commission that FPL will be able to avoid the need for expensive and disruptive base rate proceedings over the four-year settlement period. The SoBRA mechanism will allow FPL to recover costs for up to 300 megawatts of solar generating capacity for each calendar year during the settlement term. The cost for each utility under SoBRA must be reasonable and not exceed $1,750 per kilowatt. These solar facilities will also be subjected to Commission review and approval to ensure cost-effectiveness, which will be determined by whether the solar facility results in lower projected costs for customers over the life of the facility.

Upon approval by the Commission, the SoBRA for each facility will become effective once the facility is placed in service. At that time, FPL's fuel charges will also be adjusted downward to reflect the projected fuel savings. The SoBRA mechanism is very similar to the generation base rate adjustment the Commission has approved in the past.

In summary, the proposed settlement agreement is in the public interest as it provides customers with four years of predictability and stability in their electric rates, while allowing FPL to continue improving upon its industry leading performance and maintain the financial strength to make investments it believes are necessary to provide customers with safe and reliable power. That concludes my summary.

**MR. LITCHFIELD:** Thank you. Mr. Barrett is available for cross-examination.

**CHAIRMAN BROWN:** Thank you.

AARP.

**MR. McRAY:** No questions.

**CHAIRMAN BROWN:** All right. FIPUG.

**MS. MOYLE:** No questions.

**CHAIRMAN BROWN:** Okay. Wal-Mart.

**MS. EATON:** Just a few questions.

**EXAMINATION**

**BY MS. EATON:**

**Q** Good morning, Mr. Barrett.

**A** Good morning.

Q Can you hear me okay?
A Yes.
Q Do you have your settlement testimony handy --
A I do.
Q -- in case you have to refer to it? I may refer to a couple of pages in your settlement testimony, if you need to look at it.

I believe you said in your summary that you believe that the settlement agreement taken as a whole is fair and balanced and in the public interest; is that right?
A That's right.
Q And so one of the issues that you testified about in your direct was about the workshop for a pilot DSM opt-out program. I think that was on page 11 of your direct testimony.
A Yes.
Q And I'm just going to call that the workshop. Okay?
A Okay.
Q So is it, in your opinion -- is it your opinion that the workshop, as part of the settlement agreement, is one of the elements that makes the settlement as a whole in the public interest and fair and balanced?

**A** Yes.

**Q** Are you aware that, as proposed, the workshop would be open to any interested party, not just signatories to the proposed settlement agreement?

**A** Yes.

**Q** And are you aware that although not a signatory to the settlement agreement, the workshop is very important to Wal-Mart?

**A** I understand that, yes.

**Q** All right. And so you would agree that as an interested party, Wal-Mart would be able to actively participate in the workshop and at such appropriate time as the Commission staff -- the Commission staff and FPL and the interested parties make the request for the workshop?

**A** Yes.

**MS. EATON:** Thank you. That's all I have.

**CHAIRMAN BROWN:** Thank you, Wal-Mart.

Sierra Club.

**MS. CSANK:** No questions, Madam Chair.

**CHAIRMAN BROWN:** Thank you.

FEA.

**MAJOR UNSICKER:** No questions, ma'am.

**CHAIRMAN BROWN:** Thank you.

Staff.

**EXAMINATION**

**BY MS. BROWNLESS:**

**Q** Hey, Mr. Barrett.

**A** Good morning.

**Q** Does the -- does Florida Power & Light's most recent Ten-Year Site Plan project that Florida Power will have a generation mix of approximately 70.7 percent natural gas in 2018?

**A** Subject to check, I would agree that that's probably right.

**Q** If you can look at paragraph 10D of the settlement agreement, and that's on page 14, I think.

**A** Okay.

**Q** Okay. Would you agree that under the settlement agreement, FPL is limited to 1,200 megawatts of solar generation recoverable through the SoBRA mechanism?

**A** Yes.

**Q** And assuming that you do build the 1,200 megawatts of solar generation, do you know at this time whether or not that would delay any of Florida Power & Light's upcoming natural gas combined cycle facilities?

**A** No, I don't know the answer to that.

**Q** Would you agree that the Commission will have an opportunity to review the cost-effectiveness of the solar generation proposed by FP&L either through the Power Plant Siting Act or through the fuel clause?

**A** Yes. The agreement itself is very explicit about the Commission's ability to review the cost-effectiveness of these plants that we would be putting forward.

**Q** Okay. For those SoBRA projects that will be reviewed through the fuel clause and not through the Power Plant Siting Act, what methods will FP&L use to minimize the cost of these projects?

**A** Well, much like we have done in the solar projects that we are just completing and bringing online this year, I would expect that we would go out and competitively bid for the major components of the project itself. You may recall in my earlier testimony that roughly 90 percent or so of the economic value of those projects that we're building in '16 were competitively bid, that being the panels, the inverters, the EPC, to make sure that we were getting the lowest possible prices that the marketplace was offering. And in addition to that, there's a cap in the agreement itself such that if the costs were above the 1,750, the SoBRA recovery mechanism only provides recovery of the 1,750 unless we made a subsequent petition to the Commission for any excess. But there's sufficient protection in the agreement as far as a cap, and then the process itself of having to demonstrate cost-effectiveness to the Commission I think would provide the assurance that we're getting a reasonable cost.

**Q** Okay. Will FP&L be using CO2 emissions costs in its determination of cost-effectiveness for the SoBRA projects?

**A** Yes. We would evaluate these projects much like we evaluate -- or the same as we evaluate all of our generation additions, which would include the cost of emissions.

**Q** Okay. If you can refer to paragraph 18 in the settlement agreement, and I think that's on page --

**A** Page 22.

**Q** -- 22. This paragraph talks about a battery storage pilot program for 50 megawatts with a cap of $2,300 per kilowatt, or a maximum investment of 115 million; is that correct?

**A** Yes.

**Q** Can you please describe what review FP&L will be requesting from the Commission before implementing this pilot program?

**A** Well, it's the intent of the parties to the settlement agreement that this pilot program be such that the parties have agreed that the investment would be a prudent investment. It would be one that we would not be seeking recovery of until the next time that we set base rates, which would be, at the earliest, after the expiration of the minimum term, which would be 2021.

So we view this as an opportunity to make a modest investment into this new technology to try to figure out how in different applications it plays on our system and where we can provide value to customers. But realizing that it is a pilot, we're not asking explicitly for recovery as part of the increases in this particular settlement agreement. We would be coming back after the expiration of this agreement.

**Q** And would that battery storage pilot be available to residential customers, small commercial customers, industrial customers, to basically everybody?

**A** Well, the agreement calls for us to work with the signatories to the agreement to try to determine where would be some good applications. I would imagine there might be some large customers, some smaller customers, et cetera. I don't think that we have determined yet where that might be. And ultimately we have to make the decision of, from the electrical grid, where does it make the most sense to invest these dollars to get the best learning of how it's going to interact with our system.

**Q** Okay. Paragraph 18 seems to address investment cost only. Is that your understanding?

**A** Yes. The cost of installing. If you're referring to the cap itself, it's the installation cost.

**Q** Okay. Does FP&L anticipate requesting recovery of O&M or energy costs associated with the battery storage pilot?

**A** Well, to the -- no, as part of this settlement agreement. Obviously we've said in this paragraph that we would seek recovery of the investment and any other costs beyond the term of this agreement in the next base rate proceeding.

I might add, though, to the extent that the 50 megawatts of batteries provides, for instance, fuel savings, that will flow right through to customers during this term. But we're not going to be asking for any of the cost recovery until the next rate case.

**Q** Either capital or O&M.

**A** Correct.

**MS. BROWNLESS:** Thank you.

**CHAIRMAN BROWN:** Thank you.

Commissioners? Commissioner Graham.

**COMMISSIONER GRAHAM:** Thank you, Chairwoman. Excuse me.

Mr. Barrett, how are you today?

**THE WITNESS:** I'm well.

**COMMISSIONER GRAHAM:** Can you walk me through what you -- what this DSM workshop looks like and what you guys are anticipating?

**THE WITNESS:** I can't really walk you through what it looks like because I don't know. The settlement agreement, basically we've agreed to request the Commission to hold a workshop to consider the eligibility of people to be able to opt out of DSM, some verification procedures where we could, for instance, have some assurance that folks that are opting out are carrying their weight, that they're paying their fair share, if you will, of demand-side programs, whether it be self-installed or contributing to the systemwide DSM. There's yet a lot to be determined about what the scope of that workshop would be, and we've committed to work with staff and the other parties to put forward an agenda that makes sense at the time that it makes sense for the Commission to consider that workshop.

**COMMISSIONER GRAHAM:** So opt out is not anybody specific. It's anybody and everybody that wants to opt out?

**THE WITNESS:** That's for the workshop to kind of flesh out what that looks like.

I think pragmatically people that would opt out of the DSM program, from my perspective, they would need to demonstrate that they are contributing to demand-side management reductions through their own investments or their own programs to enable them to be able to opt out of the broader scale program. But I don't have a lot of the details about what that might look like.

**COMMISSIONER GRAHAM:** And let's go to the settlement. This doesn't bind, in your opinion, the Commission to do anything. And now if you come before us with a proposal for a workshop and it just doesn't make sense to us, this is still not binding us to move forward with that workshop until we come to the determination this is something we want to do.

**THE WITNESS:** That's correct. The settlement agreement says that we've agreed as parties to request a workshop.

**COMMISSIONER GRAHAM:** Okay. Let's go to the battery storage. Walk me through that a little bit.

**THE WITNESS:** Okay. We think that there is -- that battery storage technology is becoming a more viable and more cost-effective technology, even though today it may not be cost-effective in terms of lowering costs. We think it makes sense to get ahead of the curve and understand what value can be -- can accrue to the system from deploying batteries, whether it be with large customers, small customers, distribution level substations, whatever that might be. We have a small pilot going on right now. This allows us to kind of expand that to a sizable, meaningful pilot program where we think that over the next four years as we do this we'll be able to get some additional learnings, we'll begin to see some scale efficiencies and maybe some cost declines, and that we be better positioned after this pilot to know what's the potential to do further deployment in the future.

So we've asked -- you know, the parties have agreed through negotiations that a cost cap makes sense of $2,300 a kilowatt. So as we talk about a $115 million total investment, up to that number, but we would not be requesting a return on or of that capital through rates until the next time we set base rates. So we would need to cover that in our normal course of business.

**COMMISSIONER GRAHAM:** Do you foresee any sort of mechanism for the Commission to be involved in this program as you're ruling it out and moving forward, and also taking into account some of the knowledge that you've already gained from the small one you've already got started?

**THE WITNESS:** I'm sure we would welcome the Commission's insights and thoughts regarding this. I'm not sure what the right vehicle for that is or the right mechanism for that is. Working with, you know, receiving feedback from staff maybe as to what we might do. We haven't really contemplated any kind of notice provision or workshop or anything like that for this level of investment. We would just -- our engineering teams would get together and determine where it makes sense to do this electrically, and I would imagine we'd be responsive to whatever the Commission wants to hear about it.

**COMMISSIONER GRAHAM:** Thanks. Thanks, Chairman.

**CHAIRMAN BROWN:** Thank you.

Commissioners? Commissioner Brisé.

**COMMISSIONER BRISÉ:** Thank you, Madam Chair.

And these two questions are more generic in nature. So if I understand the settlement properly, the agreement decreases the initial revenue request by roughly 500 million.

**THE WITNESS:** Yeah. 826 was kind of our last number for 2017, so a little over 400 million, yes.

**COMMISSIONER BRISÉ:** Okay. And so a lot of what I heard during the initial hearing was that, you know, we would be improving reliability and excellent customer service and all of that. Does the settlement in any way impact the company's ability to continue to provide the excellent customer service and continue to provide the reliability that the company was seeking to continue?

**THE WITNESS:** No. We see this settlement to be wholly consistent with our ability to continue investing in our infrastructure and improving our customer service, improving our reliability, and delivering great value for our customers.

**COMMISSIONER BRISÉ:** Okay. So the inverse of that question is there will be an increase of $800 million in essence as a result of this rate settlement. What tangible things are consumers getting for the $800 million?

**THE WITNESS:** Well, as we talked about in the general rate proceeding and my testimony and the testimony of particularly our operating witnesses, we're going to continue to invest heavily in our infrastructure through reliability investment projects through storm hardening efforts, which we've just seen some good empirical evidence of the performance of our system that has been hardened. We're going to continue to invest in new technologies on the generation side. So part of this is paying for the new solar plants we're just bringing online this year. The peaker program, which is providing substantial savings to customers. So all of those capital initiatives that I principally testified to are going to be paid for, if you will, by the revenues that are generated from this settlement agreement.

**COMMISSIONER BRISÉ:** So it's still a capital intensive --

**THE WITNESS:** Yes.

**COMMISSIONER BRISÉ:** Okay. Thank you.

**CHAIRMAN BROWN:** Thank you.

Mr. Barrett, getting back to the SoBRA, in the rate case, could you refresh my recollection if there was any commitment and what that was in the general rate case proceeding for solar investment?

**THE WITNESS:** The only solar that was included in the rate case general proceeding back in August was the recovery of the three plants that were coming online this year.

**CHAIRMAN BROWN:** What did that total? What amount was that in megawatts?

**THE WITNESS:** 224.

**CHAIRMAN BROWN:** Okay. So this is an

exciting, aggressive rollout that FPL is contemplating.

**THE WITNESS:** Yes.

**CHAIRMAN BROWN:** 1,200 megawatts over a period of four years. Does FPL contemplate the type of projects that it is going to roll out?

**THE WITNESS:** They would be very similar to what we are rolling out this year. The great thing is we continue to see from a customers' perspective good downward pressure on panel prices. And we think that as we particularly launch into this large program, large in our scale of what we've done to date, that we'll begin to see even better pressure on vendors in terms of being able to bring these to market at a good price.

So -- but it's the same technology basically as PV technology. We're probably looking at multiple sites to get a little geographic diversity. And -- so, but I would think it would be more of the same. And the more they can look sort of similar, the more we can kind of standardize on design, standardize on construction, and even reap more benefits.

**CHAIRMAN BROWN:** So how many projects are you projecting to do a year?

**THE WITNESS:** Well, four projects at about a 75 megawatt number would be 300 megawatts.

**CHAIRMAN BROWN:** Okay. And your last project, what was the price kWatt, per kWatt?

**THE WITNESS:** Per kilowatt?

**CHAIRMAN BROWN:** Yeah.

**THE WITNESS:** I believe they were around 1,850 per kilowatt for the 2016 project. So the parties negotiated an aggressive cost reduction cap of 1,750, which ultimately in the context of the whole settlement we got comfortable taking that risk that we might be able to achieve that.

**CHAIRMAN BROWN:** Okay. And I guess Ms. Brownless was walking you through some questions on this with regard to keeping costs in check under this provision, and you said that all projects are going to be competitively bid; is that correct?

**THE WITNESS:** That's been our approach. I mean, we don't make the panels, we don't make the inverters. We go out into the marketplace and bid for those and establish good pricing for that.

**CHAIRMAN BROWN:** So if costs go down, though, I assume FPL will take -- will try to take advantage of that and pass those benefits on to the customer under the settlement agreement.

**THE WITNESS:** Absolutely. I mean, to the extent we bring in the cost of these projects lower than -- well, first of all, when we present them for cost-effectiveness and approval for recovery, we'll be presenting to you a cost profile. If we bring it even lower than that, then there's mechanisms in the settlement agreement to true that up and pass those savings on to customers.

**CHAIRMAN BROWN:** Okay. And you said it was clear in the settlement agreement about when, and I just want to -- I don't know if it's really clear to me, but it said either before the fuel clause proceeding or during the fuel clause through a separate docket. How do you anticipate the Commission approval?

**THE WITNESS:** Okay. Let me walk through it. There are two paths. One, if it's -- if it's greater than 75 megawatts and falls under the PPSA, the Power Plant Siting Act, then we would, under that circumstance, put out an RFP, unless we have requested a waiver of that provision. We would go through a need determination and there would be an established procedure for that for approval.

Those that fell below 75 megawatts, what we've done is we have crafted this to follow the fuel dockets. So we would be filing a petition in the true-up filing. So let's just, for argument's sake, say March of next year we would be making a petition. And then what we would expect is that it follows all the normal timing and approval process of the fuel and the other clause proceeding. So we would then come along in the projection filing, let's call it August, and suggest what we think that the SoBRA adjustment should be. We would put that forward. All the while, the petition would have shown the cost-effectiveness. You guys would -- the Commission, excuse me, would rule on that in the normal approval process for the clauses in the fall. In no event would any plant get an increase prior to your approval, nor prior to its going into service.

**CHAIRMAN BROWN:** Okay.

**THE WITNESS:** So the soonest something could probably get a SoBRA increase would be late next year after you have reviewed and presumably approved -- let's call it November of '17 -- the '17 tranche of projects.

**CHAIRMAN BROWN:** Great. Thank you. And that is a very interesting provision in the agreement. Again, very aggressive rollout and exciting for the company and for its customers.

Moving on to the battery storage project. I know you've had a lot of questions about that. So my understanding is that FPL will not seek cost recovery of that until the next base rate case proceeding, so no earlier than 2021.

**THE WITNESS:** Correct.

**CHAIRMAN BROWN:** And but the signatories to the settlement agreement have already deemed that prudent up to the amount provided in this settlement agreement; correct?

**THE WITNESS:** Yes.

**CHAIRMAN BROWN:** But -- and since you're not asking for cost recovery from the Commission in the settlement agreement but you are asking for approval of the pilot project, do you think that this provision provides that the Commission is deeming it a prudent project based on the costs provided in here?

**THE WITNESS:** I don't think that the agreement itself binds the Commission to a determination of prudence. I would hope that you would agree with the parties to the settlement agreement that it is a prudent investment in that it provides benefits to customers in consideration of cost and the other aspects to the project. But I don't think this can bind the Commission's finding.

**CHAIRMAN BROWN:** Again, this is a great, great pilot program. Does FPL or its affiliates or parent have any experience with battery storage?

**THE WITNESS:** Our sister company, NextEra Energy Resources, is beginning to do some battery storage projects and deployment, and so we'd be able to leverage the learnings that they've already gotten. And, again, that would accrue to customers' benefit.

**CHAIRMAN BROWN:** Yes. Two more questions, one on the workshop, the pilot DSM opt-out program. Since this is a four-year agreement, when does -- when do the signatories anticipate the workshop coming before the Commission or requesting a workshop?

**THE WITNESS:** I think that what we've agreed is that we would get with staff and try to figure out what would be the best time given the calendar of the Commission.

**CHAIRMAN BROWN:** Not the beginning of the year.

**THE WITNESS:** Okay. It will not be at the beginning of the year. But, you know, we'll obviously work with your staff to determine what would be a good time and what would be a good agenda for that workshop.

**CHAIRMAN BROWN:** Great. Looking forward to that if this gets approved.

And finally there's a provision in the agreement, kind of a catchall on page twenty -- my page, page 24, Section 23, and it provides that nothing in this agreement will preclude FPL from filing and the Commission from approving any new or revised tariff provisions or rates schedules requested by FPL, provided that such tariff request not increase any existing base rate component of a tariff or rate schedule during the term unless the application of such new or revised tariff service rate schedule is optional to FPL's customers.

**THE WITNESS:** Yes.

**CHAIRMAN BROWN:** And I just kind of want a clarification on the term "optional." Does that mean that the general body of ratepayers would be insulated from cost?

**THE WITNESS:** Yes. That we would not have the ability to increase beyond what's already in the agreement any particular rate class their particular rates. We are not precluded, based on this, from offering a new tariff that is optional for people to opt in that may be at a higher rate but provide other benefits. So this just --

**CHAIRMAN BROWN:** Could you give us an example of what this -- something that's already been approved, maybe the voluntary solar.

**THE WITNESS:** That's a great example of something that is optional for customers, thank you, that people don't have to opt into. It's an extra fee on the bill or a voluntary contribution. And so we would not be precluded from programs like that.

**CHAIRMAN BROWN:** Okay.

**THE WITNESS:** So everybody -- existing customers are protected, they're limited to the settlement agreement's provisions for rate increases. But, you know, we may find that customers have asked us to provide something that they want to opt into.

**CHAIRMAN BROWN:** Okay. And then finally just one last question, a general question on the whole issue here of whether this agreement is in the public interest. Could you kind of provide just some quick snippets of why you think this agreement is in the public interest over the general rate case or just in general why this is in the public interest, the highlights?

**THE WITNESS:** Certainly. Well, first and foremost, this resolves all the issues in the rate case and provides for a four-year period where customers are going to know what the base rate increases that they are faced with are going to be over the next four years and that we're not going to be back during that time asking for additional rate relief at levels that are substantially lower than what we felt were necessary and defended, I think, vigorously in the rate proceeding as appropriate. So there is significant savings to customers in the near term.

I think over the four-year period, if you kind of accumulate the rate increases that we filed versus what are contained here, it's about $2 billion less, about half, roughly half of what we had requested, which we, again, we felt was appropriate and also well defended.

There are other provisions in here that -- like the SoBRA that we've been talking about which provides for additional clean renewable power that has to be proven to be cost-effective. So that means not only are we going to get a renewable resource, zero emission and zero fuel cost resource, but it's going to save customers money over the long term or it won't pass the test of being cost-effective. So that's a great feature of this -- of this agreement. The battery storage pilot we've been talking about allows us to kind of get on the front edge of -- and further understand how the battery technology is going to help our customers long term. And we're not asking customers to pay for that in the near term. We're going to have to find a way to cover the revenue requirements of that program.

So -- and there's a lot of puts and takes within this agreement. I think that one thing that -- one of the hallmarks of this was not everybody that signed on got everything they wanted, and I think that that's one of the hallmarks of a great agreement is that there was compromise and through a negotiation.

So for all those reasons, I think that, you know, looking at it over the next four years and the possibility of it even going longer if we're able to find ways to push out beyond the minimum term, I think that -- I hope you would agree that it's in the public interest.

**CHAIRMAN BROWN:** Thank you so much.

Commissioners, any other questions?

Redirect.

**COMMISSIONER EDGAR:** Chairman Brown?

**CHAIRMAN BROWN:** Yes, Commissioner Edgar.

**COMMISSIONER EDGAR:** Hi. I'm still here. I'm still here talking to you from the ceiling. I do have a couple of questions, if I may.

**CHAIRMAN BROWN:** Please take advantage of the time.

**COMMISSIONER EDGAR:** Thank you very much. And as is often the case, you, Madam Chair, asked many of the questions that I had, so I only have a couple. But I am kind of intrigued by the battery storage pilot program. And I'm not sure if it was in the question that the Chair asked a few moments ago or, Mr. Barrett, if it was in your response, but one of you referred to the voluntary solar program that FPL operates. Is this battery storage pilot program intended to be a voluntary sign-up program for customers?

**THE WITNESS:** No, it's not. We're -- we've said that we're not going to ask for any contribution to the revenue requirements of this program until the next base rate case when it would be part of our rate base that we would be asking for a return on. So there's no extra voluntary contribution that we're asking customers to make.

**COMMISSIONER EDGAR:** Okay. And that was one piece of my question. But separate from a contribution, how -- let me back up then.

In your testimony at the top of page 11 you say that FPL will deploy 50 megawatts of battery storage technology, and I'm quoting, designed to serve commercial, industrial, and retail customers. So is this one 50-megawatt project that will be designed to serve all three of those categories in one project?

**THE WITNESS:** I don't believe that would be the intent. I think in order to maximize the value of this pilot program, we would break it up into meaningful sized investments in batteries for the respective installation. I could imagine, you know, several megawatts maybe being associated with a big industrial or a large retail or, excuse me, a large commercial customer. There may be some at a distribution level down to, you know, maybe less than a megawatt. But this is not intended to be one 50 megawatt installation at one location. We're going to try to maximize the learning we get out of this by doing different sizes in different places on the grid.

**COMMISSIONER EDGAR:** Okay. Thank you for that clarification.

And I'm -- I find this provision of the settlement agreement particularly intriguing. I mean, there are many provisions that are intriguing. This is one of them.

So also in your testimony you state that from this pilot program FPL will be able to gain a better understanding of how battery storage can improve the reliability and efficiency of the system. How will that better understanding be gained? In other words, what type of research, data collection, analysis -- you know, how can this project, in whatever pieces and parts it is, add to greater knowledge of how battery storage can improve reliability and efficiency?

**THE WITNESS:** Well, let's let the finance guy put his engineering hat on for a moment. And from what

I understand, there may be opportunities to under -- to gain some better understanding of how a battery bank, battery installation or whatever might work on a long radial line, for instance, or in areas where we have a distribution substation or even -- I mean, I guess it could be deployed with solar to see if that could be firmed up since it's an intermittent resource.

So there are various different technologies. There could be applications where we're looking to shave the peak or to be able to shift the peak or other places where we're looking to improve from reliability just from a continuous power perspective in certain applications. So there are a number of different kinds of benefits or attributes that batteries might provide, and I think we want to try to explore kind of the portfolio of those benefits best we can.

**COMMISSIONER EDGAR:** Yes. But there again how will that data collection, data analysis be obtained? I mean, is it solely an FPL project? Will it be a third-party contractor? Will you bring in outside researchers? I'm just trying to kind of figure out the next steps. And then how the -- how the experience of this project can add to greater understanding ideally for contributing to other projects in the future.

**THE WITNESS:** Well, I think principally the analysis and the data analytics around these installations would be in-house within FPL. We have, you know, pretty experienced engineering professionals and quantitative analysts that would be able to look at how the design of these battery installations would play with our system and interact with our system in a way that provides incremental benefit. Again, whether it be improved reliability, energy storage for peak shaving, or, you know, voltage regulation, those kinds of things that the systems operations people look at on a daily basis and they understand how the system operates. And so I would expect that as they begin to collect that data and then can extrapolate the expected benefits from a larger scale deployment, we would bring that forward. But it's going to take a number of years, I would think, to get enough data to really understand what are we getting for the dollars that we're investing.

**COMMISSIONER EDGAR:** Yes. And that leads me -- thank you so much -- right into my next question, which I don't see a time period in your testimony. It may be elsewhere within the information that's been supplied. But when does FPL expect this project to be implemented and for what period of years?

**THE WITNESS:** Well, it would be -- the best I can say at this point is within the four years. So I would hope that we would be thinking about appropriate installations. We've committed in the agreement to confer with the signatories as to ideas that they might have as well ultimately, you know, us having to decide where on the system it makes the most sense. But in order for it to be a meaningful pilot, there's going to have to be some period of time for us to collect data and be able to report back maybe in the next rate case what we found and was it effective.

So I don't have a particular plan in front of me right today. We wanted to kind of get through this process first and find out if this was something the Commission was amenable to, and then we'll put together a plan and work with the counter-parties.

**COMMISSIONER EDGAR:** Okay. Well, I certainly look forward to additional information as the project develops.

I have one other area that I'd like to ask you a couple of questions about, and this also has been covered in some of the answers you've already given. But I want to be clear on the trigger mechanisms and the process, and that has to do with the storm recovery discussion that is in -- I think it's paragraph 6A and B on page 7 of the settlement agreement.

**THE WITNESS:** Okay.

**COMMISSIONER EDGAR:** And you have spoken to this already, but I'm trying to make sure that I'm clear on -- I see three different pieces here, the first being the $4 per 1,000 kilowatt hour over a 12-month period. And then is it correct that if there is a storm expected, as are being analyzed, but the interim costs appear to exceed the amount that would be recovered through that $4 per 1,000 kilowatt hour 12-month mechanism, if they exceed that amount, then it would roll into another period beyond 12 years (sic), or is that something that would come back to the Commission for review and decision?

**THE WITNESS:** Okay. Let me walk through a couple of examples, if that might help us to --

**MR. LITCHFIELD:** I apologize for interrupting, but just for the clarity of the record, I think Commissioner Edgar said 12 years and I wonder if she meant 12 months.

**CHAIRMAN BROWN:** Commissioner Edgar.

**COMMISSIONER EDGAR:** If I said -- yeah, if I said 12 years, that was in error. I did mean $4 per 1,000 kilowatt hours over a 12-month period. And then if it goes beyond that 12-month period, that's my question.

**CHAIRMAN BROWN:** Mr. Barrett.

**THE WITNESS:** Okay. So the $4 per 1,000 kilowatt hour on a residential bill cap is something that allows us to come within 60 days, once we've depleted the storm reserve, which you heard earlier testimony that it will be depleted as a result of Matthew. And I understand that's part of the 2012 agreement, but this is the same mechanism.

So if we have an event that wipes out the storm reserve and has storm damage that would not exceed the equivalent of $4 per 1,000 kilowatt hours, we would, according to the agreement, put that into place in a surcharge within 60 days of filing a petition.

Now let's say we had a storm that was, call it $600 million, which would be above the $4 cap, we would put the $4 cap into place within 60 days of making a petition. But the amount that is above what would be collected through that surcharge, we would not be able to come back until the 12 months had expired on the original $4 with one exception, and that being if we get above $800 million. If we get above $800 million, the $4 initial surcharge can go into effect within 60 days. We can make another petition to this Commission to increase that $4 to cover the costs that were above what that surcharge was going to collect. So it's meant to cover kind of a catastrophic, kind of an '04, '05 kind of season where we have extraordinary losses and the company's resources would be pretty taxed if it had to wait beyond 12 months to begin recovering that extra amount.

So there's this -- you know, below the $4 is kind of on an interim basis automatic after 60 days, and then it gets reviewed and trued up. Between 4- and the $800 million, we have to wait for 12 months to expire before we can increase that. Above 800, we can come back and say this is extraordinary and petition you to increase the $4 charge.

**COMMISSIONER EDGAR:** And in that extraordinary situation there would be the potential that then a storm cost recovery amount could be above $4 a month.

**THE WITNESS:** Yes.

**COMMISSIONER EDGAR:** Okay. And, again, that would be under the extraordinary circumstances and with additional Commission review.

**THE WITNESS:** Yes.

**COMMISSIONER EDGAR:** Okay. Thank you.

**CHAIRMAN BROWN:** Thank you, Commissioner Edgar.

Redirect.

**MR. LITCHFIELD:** Yes. Thank you, Madam Chair. Just a couple of questions.

**EXAMINATION**

**BY MR. LITCHFIELD:**

**Q** Mr. Barrett, you were asked a few questions about paragraph 19 of the agreement on page 23. This is the provision that obliges the signatories to file a joint request with the Commission to hold a pilot DSM management opt-out workshop.

**A** Yes.

**Q** And my question to you is whether there is anything expressed or implied in the agreement or this provision in particular that requires any party, including FPL, including the Office of Public Counsel, to take a particular position in connection with that workshop.

**A** No. This just says that we'll request a workshop.

**MR. LITCHFIELD:** Thank you. That's it.

**CHAIRMAN BROWN:** All right. Would you like your witness to be excused?

**MR. LITCHFIELD:** I'd like him relieved of present duty but reserved for potential rebuttal.

**CHAIRMAN BROWN:** Thank you.

**MS. BROWNLESS:** And, Madam Chair, I think at this time it would be appropriate for us to move our exhibit into the record because he's the last witness sponsoring.

**CHAIRMAN BROWN:** Okay. Excellent. Seeing no objections to 812, I will go ahead and move 812 into the record.

**MS. BROWNLESS:** Thank you, ma'am.

(Exhibit 812 admitted into the record.)

**CHAIRMAN BROWN:** All right. Mr. Barrett, we may see you later.

**THE WITNESS:** Thank you.

**CHAIRMAN BROWN:** So here's what we're going to do. I'm going to go ahead -- we're almost at the two-hour mark, but we're going to go ahead and take the intervenor witness, AARP, Mr. Brosch, and have AARP first ask direct questions. And then we'll take a break and have a brief lunch break so that the parties can go ahead and prepare potential questions since this is a live proceeding and Mr. Brosch does not have any prefiled testimony. A little unconventional for us, but we are working with it. And since Mr. Brosch does not have any prefiled testimony, I assume that you're -- he does not have a summary and he'll go right into -- you'll go right into questions.

**MR. McRAY:** Directly into questions and responses.

**CHAIRMAN BROWN:** Okay. Sounds good. And you have the floor.

**MR. McRAY:** All right. Thank you. Thank you, Madam Chairman.

At this time we would request that Michael Brosch approach -- come to the witness stand. He's there.

Whereupon,

**MICHAEL L. BROSCH**

was called as a witness on behalf of AARP and, having first been duly sworn, testified as follows:

**EXAMINATION**

**BY MR. McRAY:**

**Q** All right. Mr. Brosch, were you sworn in as a witness this morning along with other witnesses?

**A** Yes, sir.

**Q** Please state your name and your business address.

**A** Michael L. Brosch, P.O. Box 481934, Kansas City, Missouri.

**Q** Are you the same Michael L. Brosch who previously submitted direct testimony and supporting exhibits in this proceeding, the general rate case, that were identified as AARP Exhibits 1.0 through MLB-1.6?

**A** Yes, and I appeared and testified in the previous hearings on this matter.

**CHAIRMAN BROWN:** Thank you. Mr. McRay, can I just ask you to speak up a little bit into the mic so that everyone can hear? Many thanks.

**MR. McRAY:** Yes. All right. Thank you. I will try.

**CHAIRMAN BROWN:** Okay.

**BY MR. McRAY:**

**Q** Mr. Brosch, have you reviewed the non-unanimous stipulation and settlement and the related exhibits that were filed in this docket on October the 6th of 2016?

**A** Yes. I will refer to that filing as simply the stipulation throughout my testimony.

**Q** Have you also reviewed the supplemental testimony of FPL witnesses Barrett, Cohen, Ferguson, and Forrest that was filed in support of the stipulation in this docket on October the 13th of 2016?

**A** Yes.

**Q** Based upon your review of the stipulation and the supportive testimony of FPL's witnesses, what overall conclusion or conclusions have you reached about the stipulation?

**A** My testimony today will explain why the stipulation is contrary to the filed evidence in this docket, is harmful to ratepayers of FPL, is not consistent with the public interest, will not produce just and reasonable rates, and therefore should be rejected by the Commission.

The stipulation provides for somewhat lower base rate increases than FPL asked for in this rate case, but then, in paragraph 12, offsets these rate increase savings by permitting FPL to record negative depreciation expense -- excuse me -- depreciation reserve amortization amounts and reduced annual depreciation expense that will increase rate base at the end of the term of the stipulation by potentially much more than $1 billion.

It doesn't appear that FPL has compromised anything financially in the stipulation relative to its filed rate case positions. Under the stipulation, the company is assured of stronger financial performance than could ever be secured under traditional rate regulation, all at customers' expense.

**Q** What action do you urge the Commission to take at this time?

**A** Instead of approving the multiyear rate plan set forth in the stipulation, the Commission should approve a single 2017 base rate change based upon the evidence submitted in this docket for that single test year. I will focus my testimony at this time on only the portions of the stipulation having the most important impacts upon FPL's residential ratepayers.

**Q** Mr. Brosch, what base rate increases are provided for in the stipulation?

**A** The stipulation provides for several large base rate increases that are specified at paragraphs 4, 9, and 10 and that include 400 million of higher base rates effective January 1, 2017, plus 211 million of additional base rate increases effective January 1, 2018, plus an estimated further incremental base rate increase of approximately 200 million effective upon commercial service of the Okeechobee unit in 2019, plus unspecified additional base rate increases during the term of the stipulation through a new solar base rate adjustment mechanism.

**Q** Is there evidence in the record of this docket that FPL's base revenues should be reduced in 2017 and then not increased in any subsequent years in stark contrast to the stipulated base rate increases?

**A** Yes. My direct testimony recommended reductions in FPL's rate of return and equity ratio that would have significantly reduced the company's proposed 2017 rate increase. I understand that the Office of Public Counsel and other parties have proposed similarly large downward adjustments to the company's asserted revenue requirement. For example, the Office of Public Counsel, in its post-hearing brief, recommended a 2017 base rate reduction of $327 million and then no rate increases for FPL in 2018 or thereafter.

**Q** Does the stipulation adopt any of the rate base or operating income adjustments that were proposed by the Office of Public Counsel or the other parties to this proceeding during the general rate hearing?

**A** No. Paragraph 2 of the stipulation has the parties agreeing to FPL's position on all of the, quote, adjustments to rate base, net operating income, and cost of capital set forth in FPL's minimum filing requirements, MFR Schedules B2, C1, C3, and D1A, as revised by the filed notices of identified adjustments, end quote, where only the company's calculations and none of the other parties' adjustments are, quote, deemed approved for accounting and regulatory reporting purposes, end quote.

This provision effectively eliminates the ratemaking adjustments that were proposed by the parties other than FPL in all future monthly earnings surveillance reporting, resulting in potentially significant understatement of FPL's actual adjusted earnings used to administer the stipulation.

**Q** Does the stipulation adopt any of the much lower return on equity, equity ratio, or overall cost of capital recommendations that were advocated by you and other parties besides FPL in the general rate record of this proceeding?

**A** No. The Schedule D1A I just referenced would lock in FPL's excessive common equity ratio of nearly 60 percent of financial capital that I explained in my direct testimony is excessive and unreasonably costly to ratepayers. To make matters worse, FPL's thick equity ratio adopted in the stipulation would then be applied to an authorized return on equity of up to 11.6 percent in paragraphs 3 and 12C, which exceeds the upper end of the company's own witness, Mr. Hevert's recommended range of returns, and vastly exceeds the recommendations of other witnesses addressing this issue in testimony.

For example, Dr. Woolridge for OPC recommended utilizing an 8.75 percent ROE; South Florida Hospital's witness Baudino recommended a 9.0 percent ROE; and Witness Gorman, appearing on behalf of the Federal Executive Agencies, recommended an ROE of 9.25 percent.

**Q** Mr. Brosch, have FPL's witnesses or any of the other signatories to the stipulation submitted any credible financial forecast evidence to demonstrate that FPL actually needs the large base rate increases that are proposed within the stipulation throughout the next four years?

**A** No. The company-filed MFR schedules reflect its financial forecast results for the 2017 test year and for a 2018 subsequent year, but no financial forecast data was filed by FPL or made available to the Commission, its staff, or other parties in support of any amounts of rate relief after calendar 2018. There is simply no evidence to prove that FPL has any real financial need for the agreed upon rate increases and other stipulated relief to provide FPL a reasonable opportunity to earn a fair return on its capital in each year covered by the stipulation.

**Q** Would approval of the stipulation expose ratepayers to considerable risk of excessive increases in base rate levels?

**A** Yes. As I explained in my earlier filed direct testimony, the uncertainties inherent in attempting to accurately forecast electric sales volumes, capital market conditions, utility expense levels, and rate base investments more than 24 months into the future when coupled with the unavoidable management bias in developing such ratemaking forecasts dictates that speculative multiyear financial forecasts not be relied upon as support for large utility rate increases stretching into 2020. The risks to ratepayers that the stacked multiyear base rate increases within the stipulation will prove excessive argue against its approval by the Commission. Instead of a multiyear approach, if and when changes in FPL's future cost and revenue levels actually demonstrate the need for any base rate increases after 2017, the company can submit a future base rate case application to justify such increases.

**Q** Has this Commission previously rejected subsequent year base rate increases and generation base rate adjustments that were proposed by FPL in Docket No. 080677-EI for the same reasons that you recommend rejection of the stipulated multiyear rate increases today?

**A** Yes. This was explained in my direct testimony with quotations from the Commission's Order No. PSC-10-0153-FOF-EI in that docket you referenced.

**Q** Has FPL provided any evidence providing a financial need for the additional base rate increases within the stipulation that provide targeted cost recovery for the Okeechobee unit or for new solar generating facilities?

**A** No. This is an alarming omission because of the distinct possibility that continuing growth in FPL's future energy sales may yield significant new revenues that could partially or fully pay for the cost of such new generation. Additionally, if any of the company's future expenses decline as a result of FPL's widely touted efficiency measures or NextEra's pending acquisition of Oncor in Texas, such cost savings would also be available to offset the incremental cost of new generating resources. There is simply no way to accurately determine the company's actual financial needs for four years into the future. However, the stipulation simply assumes that an overall financial need for such higher rates will exist and then obligates ratepayers to pay higher base rates for new Okeechobee and solar generation without regard to FPL's other changing revenues and costs at that time.

**Q** Mr. Brosch, does the stipulation include any provisions that could reduce the burden upon ratepayers arising from FPL's many existing tariff surcharges to track and recover changes in fuel cost, capacity charges, environmental costs, conservation charges, or storm costs?

**A** No. FPL's existing fuel adjustment mechanism and other surcharge mechanisms are not restricted by the terms of the stipulation. In fact, paragraph 7 opens the door to additional new surcharges to customers for any new government imposed, quote, requirements on FPL, end quote, that are only vaguely defined in the stipulation and that would further burden ratepayers if implemented.

**Q** Returning to the return on equity issue for just a moment, what return on equity can be achieved by FPL under the terms of the stipulation?

**A** The stipulation virtually assures that FPL will earn at or near 11.6 percent return on equity capital in every year of the stipulation's term. This is a quite excessive result and is inconsistent with the level and direction of ROE levels authorized by other regulators across the country.

Under the stipulation, the company is allowed, in its sole discretion, to charge future ratepayers more depreciation and return on rate base after 2020 to ensure 11.6 percent ROE levels are consistently achieved during the term of the stipulation.

**Q** How does the stipulation provide assurance that FPL will earn up to 11.6 percent ROE levels?

**A** At paragraph 12 of the stipulation, FPL is provided earnings assurance via the 1.07 billion of, quote, theoretical depreciation reserve surplus, end quote. That is specified to be amortized in amounts, quote, to be amortized in each year of the term left to FPL's discretion, end quote, subject generally to maintaining FPL's earned ROE at least 9.6 percent and not exceeding 11.6 percent in each year. The company can be expected to use this discretion over this theoretical reserve amortization process to manage its reported earnings at the top of the permitted earnings range in order to maximize profits for its shareholders. Unfortunately, this large benefit to shareholders during the stipulation term translates into similarly large incremental cost to ratepayers after 2020.

**Q** What is a theoretical -- what is, quote, a theoretical depression -- excuse me -- theoretical depreciation reserve surplus, quote?

**A** The depreciation reserve on the utility's books represents the cumulative amount of utility plant investment that has been paid back by ratepayers through the recovery of depreciation expense within electric rates. Any theoretical surplus in the depreciation reserve balance means that the cumulative recoveries of depreciation from customers to date has been excessive relative to that balance that is needed in the depreciation reserve account at a particular point in time. This result could occur because FPL's existing plant in service is lasting longer than was previously anticipated or because past depreciation expense collections from customers through their electric rates were excessive. Regardless of the causes, the important point to be understood is that the depreciation reserve is a credit balance that reduces FPL's rate base in order to recognize the accumulated depreciation reserve that has been paid for by FPL's customers.

**Q** What does the stipulation direct FPL to do with these ratepayer-provided funds?

**A** The stipulation transfers the theoretical depreciation reserve amount to the sole benefit of FPL's shareholders as a pool of dollars that can be amortized to increase earnings during the term of the stipulation. A designated amount of these ratepayer-provided funds exceeding 1 billion is specified in paragraph 12 that, if fully employed to increase FPL's achieved earnings to 11.6 percent each year at the company's discretion, would eventually increase rate base by more than 1 billion starting in 2021. Then in all subsequent rate cases, ratepayers would be required to pay a return on rate base increased by over 1 billion and would be forced to again pay depreciation expense to recover this investment a second time.

**Q** Could you provide an example of this depreciation reserve amortization procedure to make it easier to understand?

**A** I'll try. It's reasonable to think of electric utilities as being continuously involved in the construction business, constantly adding new utility plant to replace, expand, and upgrade facilities. Utility base rates are designed to recover the principal amount of the utility's plant investments through depreciation expense, along with interest on the unpaid or undepreciated balance in the form of a return on rate base.

An analog to illustrate this could be a typical home mortgage where you pay principal and interest to the return -- to return -- you pay principal and interest to return the amount originally invested in your house along with interest on the unpaid balance to a lender. The stipulation at paragraph 12 would allow FPL to reverse and amortize the cumulative balance of depreciation that has been previously recovered from ratepayers on a discretionary basis. This would be like letting your mortgage lender adjust the amount you owe on your mortgage in his discretion to ensure the bank's earnings never fall below 11.6 percent return on equity.

Four years from now under the stipulation at paragraph 12, FPL will tell ratepayers how much more they owe in higher depreciation and return on rate base charges because some of the depreciation reserve surplus previously collected from ratepayers will have been spent to prop up utility earnings to an 11.6 percent achieved ROE.

**Q** If the depreciation reserve surplus amortization authority of more than $1 billion were to be used by FPL to avoid higher near-term cash rate increases, would ratepayers be better off?

**A** No. Ratepayers would actually be better off with an accurate determination of FPL's truly needed 2017 base rate increase and with periodic future redetermination of the utility's actual financial needs based upon evidence presented in rate cases when they are needed.

In contrast, the stipulation provides FPL an easy path toward consistently earning 11.6 percent equity returns with minimal regulatory oversight and with no need to operate efficiently in order to earn such extraordinary high returns.

**Q** Would the discretion granted to FPL to amortize the depreciation reserve surplus provide any incentive for management efficiency?

**A** No. Any incentive for management efficiency is largely destroyed by the permitted depreciation reserve amortization provision in the stipulation. Unplanned increases in FPL's cost to provide service will have no detrimental impact upon FPL's shareholders under the stipulation because higher costs can be offset by ever larger amounts of depreciation reserve amortizations to ensure that earnings stay near 11.6 percent ROE levels each year.

**Q** Does the stipulation also reduce annual depreciation expense accruals in a fixed amount that will improve FPL's earnings during the term of the stipulation while further adding to revenue requirements after 2020?

**A** Yes. In addition to the depreciation reserve surplus amortizations of more than 1 billion that can be used at FPL's discretion to maintain its earnings at 11.6 ROE, paragraph 12B reduces depreciation accrual rates and annual depreciation expense by another 125.8 million per year. This provision will increase jurisdictional rate base by more than 500 million over the four-year term, obligating ratepayers to even higher depreciation expense and return on rate base for that amount over many subsequent years.

**Q** Mr. Barrett's testimony claims that the stipulation provides a high -- provides a, quote, high degree of base rate certainty to all parties and FPL customers for a fixed term of four years, end quote. Does the stipulation provide any enforceable rate case moratorium to protect ratepayers?

**A** No. If the series of multiple base rate increases in paragraphs 4, 9, and 10, coupled with the discretionary depreciation amortization credits exceeding $1 billion available from paragraph 12C and with the annual depreciation expense reductions exceeding 125 million in paragraph 12B, ultimately prove insufficient to prevent FPL's earnings from falling below 9.6 percent return on equity in any year, the company is allowed, under paragraph 11, to petition for a base rate increase or other needed relief. Thus, FPL assumes no significant risk to its future earnings and has the opportunity to abandon the stipulation within its four-year term if costs grow faster than revenues and reduce the company's achieved return levels.

**Q** Does the stipulation shift more of the proposed rate increases in paragraph 4 to the residential customer class than was initially proposed by FPL in its general rate filings?

**A** Yes. Schedule E5 in the company's filed MFRs initially showed about 53 percent of the base rate increases in 2017 and 2018 assigned to the residential customer class. In contrast, the stipulation Exhibit A now shows more than 65 percent of the proposed 2017 and 2018 base rate increase being assigned to the residential class.

Paragraph 4F of the stipulation refers to a, quote, negotiated methodology for allocating distribution plant, end quote, and the Commission's traditional gradualism test, but provides no details about how the larger share of rate increases now attributed to the residential customers was derived or why this change is reasonable.

**Q** Mr. Brosch, does this conclude your testimony at this time?

**A** Yes.

**CHAIRMAN BROWN:** Thank you very much, Mr. McRay. We are at close to 11:45, and I think it would be great to take about a 30-minute break, maybe grab something to eat before we get to cross. Does that sound reasonable to everyone?

**MR. LITCHFIELD:** We -- that's reasonable to us. The alternative is that we take a longer break and commit to do whatever cross we need to do and whatever rebuttal we need to do back to back without a subsequent break. But we can work with either scenario.

**CHAIRMAN BROWN:** Staff, I think that sounds good. So what would you propose for a lunch break?

**MR. LITCHFIELD:** 1:00.

**CHAIRMAN BROWN:** Yeah. Okay. So we will reconvene at 1:00. I hope you all have a good lunch.

Enjoy.

(Recess taken.)

**CHAIRMAN BROWN:** Thank you very much. I hope everyone had a nice lunch break.

All right. And we are on Mr. Brosch -- Broe-sch? Brah-sch?

**THE WITNESS:** Brah-sch, now.

**CHAIRMAN BROWN:** Thank you. It's now Brosch.

And Florida Power & Light, you have the floor with cross.

**MR. LITCHFIELD:** Thank you, Madam Chair. We have no cross for Mr. Brosch.

**CHAIRMAN BROWN:** Well, that was a very healthy one-hour break.

(Laughter.)

**MR. LITCHFIELD:** We had pages and pages. And ultimately, we -- we decided not to ask them. Thank you. It was helpful, though, to -- to think through.

**CHAIRMAN BROWN:** Okay. Great.

Office of Public Counsel.

**MR. REHWINKEL:** Madam Chairman, thank you for the additional time. The Public Counsel's office has considered cross, but given the testimony we've heard in this docket, both before and today, we think it's fairly reflective of the give-and-take and compromise that goes into this settlement. So, we have decided not to ask any questions. Thank you.

**CHAIRMAN BROWN:** Thank you, Mr. Rehwinkel.

Hospitals.

**MR. SUNDBACK:** No questions, Madam Chair.

**CHAIRMAN BROWN:** Thank you.

Retail Federation.

**MR. WRIGHT:** No questions, Madam Chair. Thank you.

**CHAIRMAN BROWN:** Thank you.

There will be no friendly cross. So, I don't even need to go to the other non-signatories.

Staff?

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

**CHAIRMAN BROWN:** Commissioners.

(No response.)

**CHAIRMAN BROWN:** All right. And so, there is no redirect.

I assume you would like your witness excused?

**MR. McRAY:** Thank you very much. That's correct.

**CHAIRMAN BROWN:** Okay. And there's no exhibits for this witness.

Thank you, Mr. Brosch, for coming.

**THE WITNESS:** My pleasure. Thank you.

**CHAIRMAN BROWN:** All right. Now, we are on to rebuttal.

**MR. LITCHFIELD:** And FPL would ask to call Mr. Barrett as a lone rebuttal witness.

**CHAIRMAN BROWN:** Okay. Mr. Barrett.

And just so you're aware, since there's no prefiled testimony -- I'm sure you're aware -- you will be allowed an opportunity to ask direct questions of Mr. Barrett prior to allowing the others to cross.

**MR. LITCHFIELD:** Yes, thank you.

Whereupon, Robert LB

**~~MICHAEL~~ E. BARRETT, JR.**

was called as a rebuttal witness on behalf of Florida Power & Light Company and, having first been duly sworn, testified as follows:

**EXAMINATION**

**BY MR. LITCHFIELD:**

**Q** Mr. Barrett, you're still under oath from this morning.

**A** Yes.

**Q** And you were present during the time that Mr. Brosch offered his direct testimony in live form here today?

**A** I was.

**Q** And Mr. Brosch was somewhat disparaging of the company's incentive to continue to look for efficiency improvements during the term of the proposed settlement agreement. Do you recall hearing that testimony?

**A** I do.

**Q** Would you please respond to that.

**A** Yes, I would. Frankly, I found it a little bit offensive that he would make those comments regarding our incentive to continue to improve the business. And I guess, upon reflection, it just shows that he doesn't really know much about our company and culture.

We have a proven track record of looking for cost-improvement opportunities. In fact, if we look back just over the last four years, where we've been under a settlement agreement that's very similar to this one in terms of a range of ROE and reserve amortization mechanism, we have substantially improved our cost position to the benefit of customers. In fact, the 2017 O&M that is in our test year is lower than our 2010 O&M.

So, despite the comments that we heard earlier regarding kind of gutting the incentive for us to continue to improve the business -- that's just patently not true. And it's -- our track record would prove otherwise.

The settlement agreement, itself -- this four-year term provides a period of time where we can really focus on running the business, allowing this reserve mechanism to offset some of the fluctuations in the business. And we've demonstrated that we can do that.

**Q** Does FPL expect to continue -- during the term of this proposed settlement agreement, if approved -- continue looking for ways to improve the way it delivers services and find efficiencies?

**A** Absolutely. I would fully expect that, over the next four years, we're going to continue to look for opportunities to increase our efficiency and improve productivity in the business.

**MR. LITCHFIELD:** Madam Chair, those are the only questions I have for Mr. Barrett.

**CHAIRMAN BROWN:** Okay. Thank you.

And I just want to confirm that we've got Commissioner Edgar with us. Yes? Okay. Thank you.

All right. Moving on to cross -- AARP, any cross?

**MR. McRAY:** No questions.

**CHAIRMAN BROWN:** Okay.

FIPUG?

**MS. MOYLE:** No questions.

**CHAIRMAN BROWN:** Walmart?

**MS. EATON:** No questions.

**CHAIRMAN BROWN:** Sierra Club.

**MS. CSANK:** No questions.

**CHAIRMAN BROWN:** FEA.

**MAJOR UNSICKER:** No questions.

**CHAIRMAN BROWN:** Staff.

**MS. BROWNLESS:** No, ma'am. No, thank you.

**CHAIRMAN BROWN:** Commissioners.

(No response.)

**CHAIRMAN BROWN:** Okay.

**COMMISSIONER EDGAR:** No questions.

**CHAIRMAN BROWN:** Thank you, Commissioner Edgar.

All right. Florida Power & Light -- I'm -- yes, Florida Power & Light.

**MR. LITCHFIELD:** Then, we would ask that -- right. Mr. Butler reminds me we have no redirect.

(Laughter.)

**MR. LITCHFIELD:** We would ask that Mr. Barrett, then, be excused.

**CHAIRMAN BROWN:** Okay. Mr. Barrett, you are excused.

**MR. LITCHFIELD:** And --

**THE WITNESS:** Thank you.

**MR. LITCHFIELD:** Yes, thank you.

And our other three witnesses, who were --

were in waiting, but were not necessary to be called upon.

**CHAIRMAN BROWN:** All of the other witnesses may be excused.

(Phone ringing.)

**CHAIRMAN BROWN:** Could you mute that? I think it's coming from the wall -- the ceiling. All right. Thank you.

Okay. That concludes the -- all of the witnesses in this proceeding right now. So, we're going to move on to concluding matters.

And would any of the parties like to file briefs in this?

AARP.

**MR. McRAY:** AARP would reserve the right to file.

**CHAIRMAN BROWN:** Okay. Any other parties?

Sierra?

**MS. CSANK:** Sierra Club would also reserve the right.

**CHAIRMAN BROWN:** Thank you.

**MR. LITCHFIELD:** May I ask a clarifying question, though? Reserving the right sounds like they might file a brief. I think it would be helpful to know whether they, in fact, do intend to or do not intend to.

That, obviously, would affect what we will do.

**CHAIRMAN BROWN:** Okay. So, I will also first note that, if the parties do desire to file briefs, briefs will be due on November 10th and, of course, shall not exceed 40 pages, pursuant to the second pre-hearing officer [sic]. So, just letting that know -- first, can I get confirmation if AARP intends to file a brief?

**MR. McRAY:** We intend to file a brief.

**CHAIRMAN BROWN:** Okay. Again, your mic is off --

**MR. McRAY:** Okay. Sorry.

Yes, AARP intends to file a brief.

**CHAIRMAN BROWN:** Okay. Thank you.

And Sierra.

**MS. CSANK:** Sierra Club does not have a definitive plan whether or not to file a brief and, thus, reserves the right to do so.

**CHAIRMAN BROWN:** Okay. All right. So, at least one party here is filing a brief.

So, again, should parties, then, wish to file briefs, they are due on November 10th and shall not exceed 40 pages. All of it is laid out in the second pre-hearing order.

The post-hearing special agenda is scheduled for Tuesday, November 29th. And we will take up this item at this -- at that time.

Parties, are there any other additional matters to be addressed? Any other additional matters?

Mr. Rehwinkel.

**MR. REHWINKEL:** We just want to make sure, at this point, now, the evidentiary record is closed; is that correct?

**CHAIRMAN BROWN:** Staff.

**MS. BROWNLESS:** Yes, ma'am.

**CHAIRMAN BROWN:** That is confirmed.

Staff, are there any other additional matters to be addressed?

**MS. BROWNLESS:** No, ma'am, not at this time.

**CHAIRMAN BROWN:** Okay. So, it looks like the sequel is concluded for this -- at this time.

So, Commissioners, any other comments? Closing remarks?

Commissioner Graham.

**COMMISSIONER GRAHAM:** I just have to tell Mr. Rehwinkel, he scared me when he asked that question. I remember the last time he asked that question.

**MR. REHWINKEL:** I was just trying to cut myself off.

(Laughter.)

**CHAIRMAN BROWN:** All right. Seeing no additional matters, this hearing is adjourned.

Thank you. Safe travels.

(Hearing concluded at 1:12 p.m.)

STATE OF FLORIDA )
: CERTIFICATE OF REPORTER
COUNTY OF LEON )

WE, LINDA BOLES, CRR, RPR, Official Commission Reporter, and ANDREA KOMARIDIS, Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that we stenographically reported the said proceedings; that the same has been transcribed under our direct supervision; and that this transcript constitutes a true transcription of our notes of said proceedings.

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

DATED THIS 2nd day of November, 2016.

Linda Boles

LINDA BOLES, CRR, RPR
FPSC Official Hearings Reporter
(850)413-6734

ANDREA KOMARIDIS
NOTARY PUBLIC
COMMISSION #EE866180
EXPIRES FEBRUARY 09, 2017
(850)894-0828

TAB F

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 160021-EI

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

DOCKET NO. 160061-EI

PETITION FOR APPROVAL OF 2016-2018 STORM HARDENING PLAN BY FLORIDA POWER & LIGHT COMPANY.
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DOCKET NO. 160062-EI

2016 DEPRECIATION AND DISMANTLEMENT STUDY BY FLORIDA POWER & LIGHT COMPANY.
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DOCKET NO. 160088-EI

PETITION FOR LIMITED PROCEEDING TO MODIFY AND CONTINUE INCENTIVE MECHANISM BY FLORIDA POWER & LIGHT COMPANY.
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PROCEEDINGS: SPECIAL AGENDA

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

DATE: Tuesday, November 29, 2016

TIME: Commenced at 9:35 a.m.
Concluded at 10:15 a.m.

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

REPORTED BY: LINDA BOLES, CRR, RPR
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P R O C E E D I N G S

**CHAIRMAN BROWN:** All right. I'd like to call this special agenda to order today. The date is November 29th, 2016. The time is about 9:35. Welcome, all.

And before we get into the very important work of the day, I have just a few comments I'd like to share with you.

Since we all got together last, which was just a few weeks ago, many changes have gone on in our country. We have now a new president and vice president, newly -- new Cabinet members, new state senators, new state representatives. We will have new FERC commissioners and FCC commissioners. We will also have new state and federal Supreme Court justices. All these developments will impact the work that we do. And it's truly exciting to be in an industry with so many dynamic changes going on around our country and in our state, and I'm looking forward to continuing the work that we do together in this transformational time, and I just wanted to make that quick note.

Also, following our special agenda today, we have a very special guest with us who will be giving a presentation on the dynamic changes in the telecom industry. Commissioner Clyburn with the FCC will be joining us, and I invite you all to join us afterwards to hear her discussion in our internal affairs meeting.

Last, I have some sad and unfortunate news to share with you, although I do believe a lot of you are already aware. Mrs. Blaise Gamba passed away tragically on November 13th. Ms. Gamba appeared before this Commission often. She served over ten years with the law firm of Carlton Fields. She was absolutely a bright, kind, and intelligent woman, and really dedicated a lot of her time to pro bono service and her community. She leaves behind her husband, William, and a very large, loving family.

On a personal note, I remember Blaise. She was the consummate professional, always well prepared, articulate, and it's just so sad to see someone with so much life leave this earth tragically. On behalf of the Commission and the Commissioners, we send our condolences to Mrs. Blaise -- Mrs. Gamba's family, friends, colleagues throughout the state and the nation.

And on that note, we will begin the busy work of the day, starting with Ms. Brownless.

**MS. BROWNLESS:** Good morning. The Commission is here today to discuss and vote upon the Joint Motion for Approval of Settlement Agreement entered into by the company and the Office of Public Counsel, South Florida

Hospital and Healthcare Association, and the Florida Retail Federation. Three other dockets addressing FP&L's 2016 to 2018 storm hardening plan, the 2016 depreciation and dismantlement study, and an incentive mechanism for wholesale electricity and natural gas transactions have been consolidated with this rate case. All issues raised in all four dockets are resolved in the Settlement Agreement we are discussing today.

The Settlement Agreement was filed after an evidentiary hearing was conducted on August 26th through September 1st of this year in which the testimony of 35 witnesses was heard and 805 exhibits were admitted into evidence. All parties filed briefs or post-hearing statements on September 19th.

Subsequent to the filing of the Settlement Agreement on October 6th, the record was reopened and a second hearing was held on October 27th to take supplemental testimony on the terms and conditions of the Settlement Agreement that had not previously been addressed in the prior hearing. At this second hearing, the testimony of five witnesses were heard and six exhibits were admitted into evidence. FP&L, the intervenor signatories, AARP, the Larsons, the Sierra Club, Wal-Mart Stores East, LP, and Sam's East, Inc., filed briefs or comments on the Settlement Agreement on

November 10th.

The remaining six parties to the docket who did not sign the Settlement Agreement take the following positions: FIPUG took no position; Wal-Mart and FEA do not oppose the Settlement Agreement; the Larsons, AARP, and the Sierra Club object. At this time, a summary of the Settlement Agreement will be given.

**CHAIRMAN BROWN:** Thank you.

And welcome, Mr. Maurey.

Commissioners, you have a copy of it, but I believe they're going to put a presentation on the PowerPoint behind us.

**MR. MAUREY:** Thank you. Good morning, Chairman, Commissioners. Andrew Maurey, Commission staff. We will start with the term of the proposed Settlement Agreement.

**CHAIRMAN BROWN:** Mr. Maurey, before you begin, I do also just want to ask the Commissioners to hold off on their questions until staff has completed its presentation. Thank you. Please continue.

**MR. MAUREY:** Okay. Thank you. The term of the settlement is four years beginning January 2017 through December 2020. During that term, there are three base rate increases planned: the first beginning in January of 2017 of 400 million; January 2018 of

211 million; a then a final base rate increase of 200 million associated with the Okeechobee plant, which -- when it goes into service, which is expected in June of 2019. With the exception of the Solar Base Rate Adjustments that will be discussed later in this presentation, there will be no other base rate increases during the term of the settlement.

The return on equity for all regulatory purposes during the term of the settlement will be 10.55 percent. The range of return on equity will be 9.6 to 11.6 percent.

One of the provisions in the settlement is that FPL will refrain from engaging in any incremental financial hedges during the term of the agreement. It is anticipated, given the current hedges that are in place, as they mature, FPL will be unhedged with respect to natural gas prices by January of 2018.

**MR. SHAFER:** Good morning, Commissioners. Greg Shafer, Commission staff.

**CHAIRMAN BROWN:** Microphone, please.

**MR. SHAFER:** I'm sorry.

**CHAIRMAN BROWN:** Thank you.

**MR. SHAFER:** Good morning, Commissioners. Greg Shafer, Commission staff.

As Ms. Brownless noted, the -- Florida Power &

Light's 2016 depreciation study was rolled into this rate case docket, and those issues were addressed by the stipulation and settlement. As a result of the stipulation and settlement, FPL's 2017 depreciation expense will be reduced by $128.8 million, and a $1.0 billion theoretical reserve surplus, plus any remainder of reserve surplus as of December 31st, 2016, may also be amortized over the four-year agreement. The surplus must be used to maintain the company's return on equity of at least 9.6 percent but no higher than 11.6 percent.

The stipulation and settlement also contains several tariff changes of note, the first being the implementation of meter tampering charges. Those meter tampering charges are $200 for residential and small commercial customers and $1,000 for non-demand commercial customers.

Other changes of note include all new street lighting and traffic signals will now be metered, and the -- there's an elimination of the re-lamping option for customer-owned lighting.

I should go back. On the metering of street lighting, that's customer-owned street lighting and traffic signals.

In addition, the Commercial Industrial Load

Control and Commercial Demand Reduction Credits will remain at current levels. Those current levels were established in the 2012 stipulated agreement.

The Cost of Service Methodology to be applied going forward -- or for this settlement will be the 12CP and 1/13th methodology for production plant, the 12CP methodology for transmission plant, and a new negotiated methodology for distribution plant.

In addition, going forward, the company will be required to file an MDS Cost of Service Study, Minimum Distribution System Cost of Service Study, in its next general base rate increase to compare -- to give the Commission the ability to compare that methodology's impact on the revenue requirement by class to other methodologies that may be provided by the company. And I would note that the MFRs currently require the 12CP and 1/13th methodology. And in the current case, the company had also filed a different methodology than that. So going forward, there will be that ability to compare those methodologies.

**MR. BALLINGER:** Good morning, Commissioners. Tom Ballinger with Commission staff.

The settlement also includes a continuation of a pilot Incentive Mechanism that was first approved in the 2012 Settlement Agreement. This would resolve all issues in Docket 160088 that was also consolidated into the rate proceeding.

Per discovery responses, FPL indicated that this would be a four-year pilot, that it would terminate after the four years absent any action from FPL or the Commission. As noted here, the sharing threshold is set to $40 million, and at that point that's when sharing of benefits would accrue, and the 514,000-megawatt-hour threshold was eliminated instead for a net of purchase and sales for O&M purposes.

The settlement also includes a storm damage recovery methodology which is similar to settlements in 2010 and 2012 where it has a $4 surcharge that can be added per 1,000 kilowatt hours to recover the cost of storm damages. There is no accrual going on in current base rates.

Also, the settlement includes a transfer of the West County Energy Center's revenue requirements from the clause to base rates. This is a revenue neutral portion of the settlement. It's basically neutral to ratepayers.

Finally, the Okeechobee limited scope proceeding. This is a -- you've heard this before, GBRAs, which is a Generation Base Rate Adjustment for generation assets going in service. This would go into effect on the in-service date of the Okeechobee unit, which is expected to be June of 2019. The revenue requirement will be capped at $200 million. And it also has a true-up mechanism where if a lower amount comes in below that, the lower amount will be used to set the GBRA. If the cost of the Okeechobee unit is higher than predicted, FPL would have to come in and seek additional recovery of that amount.

A new aspect of this settlement that hasn't been in other settlements is the Solar Base Rate Adjustment. It's very similar to the Okeechobee one of generation base rate, but this applies strictly to solar, and it has a cap of 300 megawatts per year of solar installations that FPL may build. As you see here, it has a cap of a cost not to exceed $1,750 per kilowatt, and, again, as with the other Generation Base Rate Adjustments, it has a true-up mechanism.

There's two types of projects. One could be under a Power Plant Site (sic) Act, which is greater than 75 megawatts. If that were to occur, FPL would issue an RFP and go through the normal siting process. If it's a smaller project, less than 75 megawatts, FPL would file a cost-effectiveness analysis through the fuel clause and the Commission would analyze it there.

This next slide just explains the true-up mechanism again, much like a GBRA. If the cost comes in lower, the lower unit would be -- lower number would be used. If it's higher, FPL may initiate a limited proceeding.

A couple of other options or portions of the settlement. FPL will implement a 50 megawatt battery storage program. This could be for retail customers, either small or large, or it could be combined with the Solar Base Rate Adjustment projects, as I discussed earlier. FPL has the final say on where these projects would be implemented, and it has a cost cap of $2,300 per kilowatt.

On the opt-out workshop there was no timeline given in the settlement, just that the -- FPL and the parties would work together to request the workshop with the Commission to discuss opt-out for DSM programs. Also, participation is not limited to the signatories for that workshop.

**MR. MAUREY:** The next provision deals with the Martin-Riviera pipeline. It's -- FPL is authorized to transfer to its FERC-regulated affiliate the Martin-Riviera lateral, which is currently in rate base, based on a demonstration that doing so would result in cost savings to customers. This is a placeholder for a future petition to pursue that option.

This concludes the overview of the Settlement Agreement. Staff is available for any questions.

**CHAIRMAN BROWN:** Thank you. And, you know, a rate case of this magnitude affecting 4.8 million customers obviously has required a lot of time, a lot of time on staff's part. I want to extend our appreciation for all of your hard work. A lot of you have done a lot of overtime: our technical staff, our legal staff, administrative staff, clerk's office, Mr. Staden's folks, even the Florida Channel. A lot of people have been working a great deal on this case with nine service hearings, two technical hearings covering ten days, over 4,000 discovery documents and prefiled testimony, and, again, thank you all for all the work you've done.

Commissioners, this brings us to the bench for questions at this time. If you would like, we can go paragraph by paragraph or just open it up broadly to questions.

Commissioner Edgar.

**COMMISSIONER EDGAR:** Obviously to staff -- and not that you need it, but I'm looking at page 15 -- can you describe to me, please, the process in a little more detail, not great detail, but a little more detail, as to how the cost-effectiveness will be reviewed, the process and procedure for that, if, indeed, a petition is submitted to the Commission for the transfer of the Martin-Riviera pipeline?

**MR. MAUREY:** Yes, ma'am. If -- after FPL evaluates the potential transfer from rate base to its FERC-regulated affiliate, it will -- if it can demonstrate that from a cumulative present value revenue requirement basis that the payment under -- recovery of those costs under base rates versus recovery through the fuel clause, if it's more cost advantageous to customers, they will make that transfer. If it is not, then the Martin-Riveria lateral will remain in rate base and customers will pay for that service, as they currently do.

**COMMISSIONER EDGAR:** So who ultimately makes that determination of cost-effectiveness for customers?

**MR. MAUREY:** FPL will make a presentation. Staff will evaluate it and bring it to the Commission for their determination that it meets the cost-effective standard.

**COMMISSIONER EDGAR:** Okay. Thank you. That's exactly what I was looking for.

And then -- and I'm not sure who to put this for, so, Mr. Maurey, you're first up.

**MR. MAUREY:** Sure.

**COMMISSIONER EDGAR:** But feel free to point to somebody else.

On page 14 there's a brief mention of the potential workshop for a pilot Demand-Side Management Opt-Out Program. I'm just curious as to a little more background and thinking on that. Clearly this Commission had a, you know, full procedure hearing, et cetera, on that issue generally, or specifically, and I believe at that point in time kind of where we had left it was if more information is forthcoming, that it is something that the Commission would be willing to take another look at. If that's not accurate, feel free to correct me. But recognizing that this is now a part of this overall proposed Settlement Agreement, can you speak to me in a little more detail as to how staff sees that moving forward?

**MR. SHAFER:** First off, Commissioner, I would agree that your -- with your characterization of the proceeding that the Commission held. Staff sent some discovery to the companies -- or to the company regarding the workshop item in the settlement, and essentially the response that we received indicated that at this point there's nothing more in terms of their perspective than a joint request for a workshop. Certainly from the staff perspective and consistent with what we believe the Commission's determination was in the opt-out docket, we would be hopeful that there would be perhaps a strawman or something of that nature for us to consider during the workshop.

I fully expect that the parties will reach out to staff at some point prior to requesting that workshop, and we can, you know, discuss what types of details we'd like to see at that point.

**COMMISSIONER EDGAR:** All right. Thank you, Mr. Shafer.

Madam Chair, at the moment, at the moment those are my questions. I will, at the appropriate time, would like, if you agree, to make a few general comments.

**CHAIRMAN BROWN:** Great. Thank you.

I do -- seeing no other lights from Commissioners, I have a few questions. Actually, Commissioner Brisé, go ahead.

**COMMISSIONER BRISÉ:** Thank you, Madam Chair. I have a few "big picture" questions.

So we can go back to the original request and sort of compare from a dollars' perspective the difference or the delta between the original request and what has been settled out here or has been proposed in this settlement, if we can walk through some of those things.

**MR. MAUREY:** Yes. In the original request, it was approximately a $1.3 billion request over a similar time horizon: January '17, January' 18, and June of 2019. This proposed settlement reduces that to 811 million from the 1.3 billion.

**COMMISSIONER BRISÉ:** And what specifically generated that delta as you go through the settlement?

**MR. MAUREY:** Well, some of the elements of that delta can be explained. The difference in depreciation expense and the difference in return on equity, that explains probably 70 to 75 percent of the delta. The remainder of the delta is not specifically identified.

In its response to discovery, the company -- well, let me back up. The company, in its ask, had put forth a program that it would need $1.3 billion to implement, and it plans to continue to do that program but will do so within its means. It did not specify which investments may or may not be extended or taken up immediately.

**COMMISSIONER BRISÉ:** Okay. That's all I have for now.

**CHAIRMAN BROWN:** Thank you.

Staff, I'm going to ask a few clarifying questions, directing you, though, to the actual agreement and not the PowerPoint presentation.

Starting with the storm cost recovery on page 7, my understanding from the hearing was that the storm reserve was depleted; is that correct?

**MR. MAUREY:** That's correct.

**CHAIRMAN BROWN:** Okay. All right. And is there -- is there envisioned a future -- in the near future a proceeding to replenish that pursuant to the terms under here of the agreement to -- and to what level?

**MR. MAUREY:** Yes. The company has notified the Commission that it intends to file recovery of storm costs associated with Hurricane Matthew. This -- as Mr. Ballinger explained, this provision in the current settlement is almost identical to the settlement or the terms in the current agreement that expires the end of the year. So whether it comes in before December or after December, it will be treated in the same manner. It'll ask for the recovery. It will be implemented within 60 days following the petition. The Commission will have an opportunity to look at the actual costs incurred after a certain period and determine that all the costs that were recovered were permissible through the rule.

**CHAIRMAN BROWN:** And that amount would also include the replenishment of the storm reserve as of August 31st, 2016.

**MR. MAUREY:** That's correct. If they file before the end of December, the amount is very similar. That was set in the 2012 agreement that was -- would be the basis of this agreement as well.

**CHAIRMAN BROWN:** And just one clarifying question. I know we've had these discussions in our briefings, but just for the record, so if the storm costs are greater than $4 per 1,000 kilowatt residential bill, this Commission has the discretion to spread that out over a longer period of time other than 12 months.

**MR. MAUREY:** That's correct.

**CHAIRMAN BROWN:** But if it's $4 or less, it has to be within the 12-month period.

**MR. MAUREY:** That's our understanding, yes.

**CHAIRMAN BROWN:** Okay. Thank you.

Moving on to the SoBRA, the SoBRA. All right. And these are just some clarifying questions again for the record.

Under paragraph 10, page 12, in that first paragraph, there is a provision there or a sentence that says, "The Commission's approval may occur before or after the minimum term." I want to first understand that. It's still limited to the 1,200 megawatts throughout the term and possibly one year after.

**MR. BALLINGER:** Yes, ma'am. That was to allow for -- in case the proceeding continued on beyond the term of the Settlement Agreement, that the project would still go into service after the term of the settlement. But the total megawatts are limited to 1,200 megawatts.

**CHAIRMAN BROWN:** But the Commission has the authority under the Settlement Agreement to approve SoBRAs after the expiration, though, of the agreement?

**MR. BALLINGER:** Yes.

**CHAIRMAN BROWN:** It doesn't say for how long.

**MR. BALLINGER:** No. I think it would determine on the proceeding. I would imagine the proceeding -- the request would be filed during the term of the Settlement Agreement, and it may carry on beyond the term.

**CHAIRMAN BROWN:** But no greater than 1,200 megawatts of capacity can be added even later on.

**MR. BALLINGER:** Correct. Correct.

**CHAIRMAN BROWN:** Okay. Thank you for that confirmation.

Moving on -- actually, the previous request for the three plants, the solar in the rate case, totaled 224 megawatts. Was that based on the -- what kilowatt -- kwatt was that based on?

**MR. BALLINGER:** The cost of those were roughly 1,850, I believe.

**CHAIRMAN BROWN:** And is that -- those are -- those projects are included in this Settlement Agreement, in the revenue requirements for the Settlement Agreement?

**MR. BALLINGER:** They are part of the 2017 revenue requirement.

**CHAIRMAN BROWN:** And they're going to be based on those amounts, not the 1,750 per kwatt.

**MR. BALLINGER:** Correct. As Mr. Maurey said, they're part of the projects that they went forward with. They're part of the 400 million that you had for the 2017 increase. They are covered there. They are not part of the ongoing SoBRAs.

**CHAIRMAN BROWN:** On a separate note, though, in the rate case the company proposed to build 26 new and expanded natural gas combustion turbines. Are those also included in the revenue requirements in the Settlement Agreement?

**MR. BALLINGER:** Yes.

**CHAIRMAN BROWN:** Okay. And the additional storm hardening, et cetera, measures.

**MR. BALLINGER:** Yes, ma'am.

**CHAIRMAN BROWN:** Okay. Moving on to

paragraph -- oh, 18, the storage, the battery storage project. I really hope that we get to see more investments like this from utilities, and I'm really excited about this provision. I'm happy it was included in the Settlement Agreement.

I'm curious about when and if the Commission will get updates on these projects annually and in what docket we would see these, because I'd love to see the results and benefit of this project.

**MR. BALLINGER:** I don't know. The settlement doesn't call for any annual reports. Staff can always ask for information through our discovery process or data requests typically at the ten-year site plan. We can do it through that venue, if you'd like.

I forgot to mention that FPL will not seek recovery of this until its next general base rate proceeding, which may be in four years.

**CHAIRMAN BROWN:** Okay. But I think it's important to have that type of information so we can learn from it and see how it's progressing.

And I'm sorry to go back to paragraph 16, which is the hedging. So with our decision this past month on the hedging for the IOUs, we're going to have a workshop soon; right?

**MR. MAUREY:** That is correct.

**CHAIRMAN BROWN:** Can you -- and FPL intends to participate in it pursuant to the agreement -- I mean, the decision in that proceeding.

**MR. MAUREY:** Yes. It will be bound -- if this is approved, it'll be bound by the provisions of this agreement. However, it will participate in any workshops that involve the other IOUs.

**CHAIRMAN BROWN:** So what if there is a global Settlement Agreement or some type of agreement among the parties, including all the parties, the signatories to this agreement, that comes out of that workshop? Will FPL still be bound and tied to the terms of this? Yes. I know the answer is yes.

**MR. MAUREY:** It will -- our understanding is it's bound to the terms of the Settlement Agreement. However, as we've seen in other Settlement Agreements with similar parties, it's possible for the agreement to be revised and restated in the future to take in a development like that, a change in how hedging is done going forward.

**CHAIRMAN BROWN:** Okay. I mean, I think I said this during the hearing, this is just an area of concern for me. I think it's an extreme. But I understand it's part of an overall compromise and I otherwise wouldn't have even considered it. Natural gas prices are rising even today, so it's an area of concern I have.

Last, there's one other question I have on page 23, which is -- it's paragraph 20. And, again, we talked about this in our multiple briefings, but I still would love some clarification on that on the record, that I don't know what that means. "Offer a new tariff for customers who interconnect with an FPL distribution substation." What -- do you have an idea of what that is -- what scenario that is contemplating?

**MR. BALLINGER:** We're a little befuddled by this one as well. I'm not sure what it means. It doesn't have any reporting requirements, when they'll come to the Commission, what they'll do with the results. It just says FPL will explore it as a new tariff. I guess we'll know it when we see it if it comes in as a new tariff offering at a distribution level.

**CHAIRMAN BROWN:** But then again it's also not -- it's just an evaluation. It's not binding the Commission to approving it.

**MR. BALLINGER:** Correct.

**CHAIRMAN BROWN:** Okay. Those are all the questions I have.

Commissioners, any further questions or discussion? If there are no further questions, we can get into discussion at this time.

Commissioner Edgar.

**COMMISSIONER EDGAR:** Thank you, Madam Chair. You know, it's -- for this case, and not unexpectedly, it's kind of been a long year.

**CHAIRMAN BROWN:** Hasn't it?

**COMMISSIONER EDGAR:** It has. As you mentioned, for any rate case, but particularly for one of our largest service providers, a comprehensive rate case takes a lot of time, a lot of effort, a lot of trees, a lot of computer pages, many, many, many hours. I either thank you or not for the honor and the opportunity to serve as prehearing officer in this case. Actually I do thank you. I appreciate the opportunity to do so for what was either my fourth or fifth FPL comprehensive rate case.

And looking back over the last year, I can tell you all that when I look at where a lot of my time was spent professionally, a lot of it was spent on getting ready for this case and working with staff and looking at the issues and getting ready for hearing.

And I will say, taking just a moment of personal privilege, that it did start a little bumpy -- thank you Public Counsel, Mr. J.R. Kelly -- but I think ultimately the process worked as it should and as it is designed to. And an evidentiary proceeding is, by its nature, especially from the beginning, adversarial. That is the process. But it is also part of the process that while we, on this side of the bench, are looking at the testimony and hearing from the witnesses and questioning and discussing matters with our staff, that perhaps on the other side out there that the parties are talking and discussing and trying to figure out other ways within the process to reach consensus in the public interest on -- and on behalf of the ratepayers.

It's always interesting with a proposed settlement how some items sort of pop up there at the end, and we do have a couple here. As you've mentioned, the battery storage item, the -- and I learned a new acronym: SoBra. I didn't know that we needed a new acronym. We did have GBRA -- we do have GBRA, but apparently now we have SoBRA as well. And as you've mentioned, addressing or having further discussion about hedging and also potentially having further discussion about the DSM opt-out request, and I do hit "request" on that, and also the potential transfer for the Martin-Riviera pipeline transfer, all of which are items that were not really a part initially of this case even though we had four dockets that we had consolidated. And we purposely, purposely procedurally tried to make good use of everybody's time effectively and efficiently by combining related items and related issues that would ideally be more efficient for discovery and for parties and for witnesses.

So with all of that, I also am intrigued and interested in the battery storage item. I do hope, as additional information comes forward on that, that, you know, if indeed there is subsidization in that, that it is transparent. If there isn't, that that is clear as well as my colleagues continue to look at that issue and others.

But looking at the entire almost year that has been spent on this, the coordination of the parties and also the great work of our staff and of my fellow colleagues, at the appropriate time, Madam Chair, I'd like to make a motion in support of approving the Settlement Agreement.

**CHAIRMAN BROWN:** Thank you, Commissioner Edgar, for those comments.

Commissioners, any further comments?

Commissioner Brisé.

**COMMISSIONER BRISÉ:** Thank you, Madam Chair. You know, in recognition of this long, tedious process, we want to -- I personally want to thank all the parties for getting together, even those who are not in agreement with the terms as arrived by those who are signators.

You know, as we traveled within the service territory, there was a couple of things that stood out to me. One is that the quality of the service is good. People were concerned about their pockets. And I think ultimately this settlement handles all of those things. It allows for the service to continue in a way that people will continue to receive the satisfaction that they're looking for and that their pockets won't be injured in the process, while allowing the growth that is necessary to occur. And ultimately that's what I heard throughout the process.

Beyond that, there's a couple of other things that I heard from customers as we were listening to them. They wanted to see more innovation in terms of renewables and all of that, so it creates -- there is space for that to happen within this settlement.

There was also concern about, in certain places, hedging -- right? -- and so the settlement addresses that. Not the way I would like for it to be resolved, but this is a comprehensive settlement where you have parties who have come together and addressed the concerns that they have and they've come to an agreement that makes sense and that they can live with for a period of time.

So at the appropriate time when the motion is made, I will either second it or support it, depending upon who hits the lights first.

**CHAIRMAN BROWN:** Commissioner Patronis.

**COMMISSIONER PATRONIS:** Thank you, Madam Chairman.

I just wanted to echo the sentiments and comments of my colleagues, but especially give staff a big attaboy. That's a meat grinder that y'all dealt with over the last year. And for my first time being able to listen and learn, please appreciate how much I gained out of seeing the process at work and how much you brought me along in understanding greater the full obligations that this Commission has in our duties.

And like Commissioner Brisé said, I know not everybody is pleased, but, you know, it was nice to see accommodations of flexibility when storms did threaten during the hearing in the case. It's a reality. And I remind folks -- they get frustrated with their job, their obligations, their responsibilities -- that this state will run every day, every morning whether you want to show up for work or not, and this group, you know, really stepped up and ensured that the obligations and needs of the state were met every single day whether there was a storm or not. And, anyway, I just appreciate the opportunity I've gotten to be able to participate with y'all today.

**CHAIRMAN BROWN:** Thank you.

One thing -- I'd like to echo what Commissioner Brisé said -- was throughout this process we have heard one thing consistently from the intervenors but also from the customers, and that is definitely FPL's excellent quality of service, which I think is attributed to the smart, prudent decisions that FPL has made over the years. It's improved reliability while also managing to have the lowest rates in the state.

This Commission specifically has supported decisions in the past to invest in cleaner, more efficient energy, and I believe Florida utilities like FPL must continue to do that and -- while also improving the grid reliability. I think the settlement strives to accomplish much of that.

It's a challenging time in an industry that is continuing to evolve. Utilities need to be at the forefront of this, and they work hard for its customers as well in delivering the services that the customers want and need. So there are a great deal of customer protections in this agreement that I want to just highlight. I don't know if we actually got to hear those, but I'd like to highlight that for the record.

I mean, obviously having a specific four-year term establishes base rates that are limited to those identified in the Settlement Agreement, which does provide, as OPC and the other signatories provided in a brief, provides the customers with greater price and planning predictability; the SoBRA and the solar investment, which is definitely an aggressive rollout from what was presented in the rate case, and it's exciting. But there are protections behind that, too, that all projects must be approved by the Commission with a cost-effectiveness test, and I think that clearly benefits customers. The hedging, which OPC and others have expressed concerns over the years, eliminates that risk entirely under the term. So I think there's -- and there's a great deal of other customer protections. So taken as a whole and given the amount of broad support across the customer groups that signed on, the settlement, I do believe, produces rates that are fair, just, and reasonable, and are clearly in the public interest. And seeing no other lights, I think now we are ripe for a motion.

Commissioner Edgar.

**COMMISSIONER EDGAR:** Thank you, Madam Chair, and thank you for the opportunity.

As I mentioned earlier, we did have initially -- what started this all off basically procedurally is a petition that was filed for a comprehensive rate case, comprehensive review. That is very much in the public eye. It is a process that is built for transparency. And having gone through, as the parties did, the discovery process and then the process that all parties -- we at the bench and our staff went through for the evidentiary hearing, a lot of information in the public interest, and I do believe that, again, this shows that the process ultimately works. I am very pleased with the ultimate result, as I mentioned, other things that make the settlement, if anything, even more comprehensive.

And so with that, in keeping with the spirit of the Settlement Agreement and the good, inquisitive, and hard-charging work that was done by all parties on this case, I would move approval of the Settlement Agreement today in its entirety.

**CHAIRMAN BROWN:** Thank you.

Is there a second?

**COMMISSIONER BRISÉ:** Second.

**CHAIRMAN BROWN:** All right. Any further discussion? Seeing none, all those in favor, say aye.

(Vote taken.)

Opposed?

(No response.)

The motion passes unanimously.

Thank you, all parties here, for working and participating in this very long proceeding. We appreciate all the work again that you've -- that everyone has done here. And with that, we will adjourn the special agenda and reconvene our -- convene our internal affairs in the next ten minutes. Thank you.

(Special agenda adjourned at 10:15 a.m.)

STATE OF FLORIDA )
: CERTIFICATE OF REPORTER
COUNTY OF LEON )

I, LINDA BOLES, CRR, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

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

DATED THIS 1st day of December, 2016.

Linda Boles

LINDA BOLES, CRR, RPR
Official FPSC Hearings Reporter
Office of Commission Clerk
(850)413-6734

TAB G

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

| | |
|---|---|
| In re: Petition for limited proceeding to approve 2017 amended and restated stipulation and settlement agreement, by Tampa Electric Company. | DOCKET NO. 20170210-EI |
| In re: Petition for approval of energy transaction optimization mechanism, by Tampa Electric Company. | DOCKET NO. 20160160-EI<br>ORDER NO. PSC-2017-0456-S-EI<br>ISSUED: November 27, 2017 |

The following Commissioners participated in the disposition of this matter:

JULIE I. BROWN, Chairman
ART GRAHAM
RONALD A. BRISÉ
DONALD J. POLMANN
GARY F. CLARK

APPEARANCES:

JAMES D. BEASLEY and JEFFRY WAHLEN, ESQUIRES, Ausley McMullen Law Firm, P.O. Box 391, Tallahassee, Florida 32302
On behalf of Tampa Electric Company (TECO).

J.R. KELLY, VIRGINIA PONDER and CHARLES REHWINKEL, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida (OPC).

KAREN PUTNAL and JON MOYLE, ESQUIRES, Moyle Law Firm, PA, The Perkins House, 118 North Gadsden Street, Tallahassee, Florida 32301
On behalf of the Florida Industrial Power Users Group (FIPUG).

ROBERT SCHEFFEL WRIGHT and JOHN T. LAVIA, III, ESQUIRES, Gardner, Bist, Bowden, Bush, Dee, LaVia & Wright, P.A., 1300 Thomaswood Drive, Tallahassee, Florida 32308
On behalf of the Florida Retail Federation (FRF).

SUZANNE BROWNLESS, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Florida Public Service Commission (Staff).

MARY ANNE HELTON, ESQUIRE, Deputy General Counsel, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
Advisor to the Florida Public Service Commission.

KEITH HETRICK, ESQUIRE, General Counsel, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
Florida Public Service Commission General Counsel.

FINAL ORDER APPROVING 2017 AMENDED AND RESTATED STIPULATION AND SETTLEMENT AGREEMENT

BY THE COMMISSION:

## BACKGROUND

On September 27, 2017, Tampa Electric Company (TECO) filed a petition for limited proceeding to approve its 2017 amended and restated stipulation and settlement agreement (Petition). In its Petition, TECO requested that the Florida Public Service Commission (Commission) hold a limited proceeding pursuant to Sections 366.076, 120.57(2) and 366.06(3), Florida Statutes (F.S.), and Rule 28-106.301, Florida Administrative Code (F.A.C.), to allow the Commission to review and approve the 2017 Amended and Restated Stipulation and Settlement Agreement (2017 Agreement) attached as an exhibit to the Petition.

The 2017 Agreement has been signed by TECO and the following: the Office of Public Counsel (OPC); Florida Industrial Power User's Group (FIPUG); Florida Retail Federation (FRF); Federal Executive Agencies (FEA); and West Central Florida Hospital Utility Alliance (HUA). TECO alleges that the 2017 Agreement amends and extends the term of its 2013 Stipulation and Settlement Agreement (2013 Agreement), which resolved all outstanding issues in its last base rate case proceeding, approved by Order No. PSC-2013-0443-FOF-EI, issued September 30, 2013, in Docket No. 20130040-EI. The 2017 Agreement also includes the asset optimization mechanism originally requested in Docket No. 20160160-EI[1], and constitutes a full resolution of all issues raised in that docket. TECO and all other parties to the 2017 Agreement agree that there are no disputed issues of material fact that must be resolved for us to grant its Petition and approve the 2017 Settlement Agreement.

Based on these representations, we issued Order No. PSC-2017-0384-PCO-EI, on October 4, 2017, setting the Petition for a final hearing, which was held on November 6, 2017. FEA and HUA were excused from attending the final hearing. At the final hearing, TECO presented the testimony of four witnesses: Carlos Aldazabal, Mark Ward, James Rocha, and Bill Ashburn. A Comprehensive Exhibit List was admitted into the record as well as the exhibits

[1] Docket No. 20160160, In re: Petition by Tampa Electric Company for approval of Energy Transaction Optimization Mechanism.

identified thereon. The parties, supporting the 2017 Agreement, waived the right to file post-hearing briefs, and a bench vote was taken at the conclusion of the hearing.

## Settlement Agreement

The major elements of the 2017 Agreement are as follows:

- The 2017 Agreement term (Term) is approximately four years in duration, from the Effective Date (date of vote) through 2021, and is, by and large, a four year extension of the 2013 Agreement.

- The 2017 Agreement retains the existing return on equity (ROE) of 10.25%, with a range of 9.25% to 11.25%, and features an equity ratio of 54% for the Solar Base Rate Adjustment (SoBRA) revenue requirement calculations and TECO's actual equity ratio for surveillance reporting and setting clause rates.

- Base rates to remain at current levels initially, with solar generation cost recovery (SoBRA) included in tranches during the Term at the following dates and maximum cumulative amounts:

| Year | Earliest Rate Change and In-Service Date | Maximum Cumulative SoBRA MW | Maximum Cumulative Annualized SoBRA Revenue Requirement (millions) | Maximum Cumulative Impact on 1,000 KWH Residential Bill |
|---|---|---|---|---|
| 2018 | September 1 | 150 | $30.6 ($10.2 collected over 4 months) | $1.95 |
| 2019 | January 1 | 400 | $81.5 | $3.33 |
| 2020 | January 1 | 550 | $112.1 | $4.47 |
| 2021 | January 1 | 600 | $122.3* | $4.87 |
| * Cost recovery contingent on 2018-2019 tranches constructed at a maximum average capital cost of $1475/kW$_{ac}$. | | | | |

- SoBRA total installed costs for purposes of cost recovery cannot exceed $1,500 per KWac (cap). Projects must be smaller than 75 MW and thus are not subject to the Power Plant Siting Act. Each tranche requires that a new petition for cost recovery be filed in a separate docket.

- SoBRA savings, where actual costs are below the $1,500 per KWac cap, are shared between customers and company on a 75%/25% basis. The full benefit of Renewable Energy Credits (RECs) will be flowed through to retail customers through the Environmental Cost Recovery Clause (ECRC).

- SoBRA costs are allocated equally among all rate classes with the exception of the lighting class. The lighting class is responsible for 40% of its SoBRA revenue requirement, with the remaining 60% of its revenue requirement allocated to the other customer classes.

- If federal or state tax reform is enacted before TECO's next rate case, TECO will flow back to retail customers within 120 days any impacts to revenue requirements through a one-time adjustment to base rates, uniformly applied across customer classes and charges.

- Standby Generator Credits increase from \$4.75/kW/month to \$5.35/kW/month. Contracted Credit Value, or CCV Credit, is increased marginally for secondary, primary, and sub-transmission voltage customers.

- If TECO's coal-fired generating assets and Automatic Meter Reading (AMR) meters are retired during the Term, the related assets will be depreciated using TECO's then-existing depreciation rates.

- The parties consent to TECO's petition to implement its proposed asset optimization/ incentive plan set forth in Docket No. 20160160-EI during the Term, but at modified percentage thresholds of achieved gains to be divided between customers and shareholders.

- TECO will enter into no new natural gas financial hedging contracts through December 31, 2022 and will file a request to close Docket No. 20170057-EI upon approval of the 2017 Agreement or as soon thereafter as practical.

- TECO will not seek recovery of any costs from its customers related to investments in oil and/or natural gas exploration, reserves, acreage and or production for a period of five years after the Effective Date.

- Carryover Provisions applicable from the 2013 Agreement include: named storm damage recovery; the Economic Development Rider; and deferral of depreciation and dismantlement studies until the year before TECO's next rate case.

DECISION

The standard for approval of a settlement agreement is whether it is in the public interest.[2] A determination of public interest requires a case-specific analysis based on consideration of the proposed settlement taken as a whole.[3] The signatories to the 2017 Agreement represent a broad segment of FPL's customer base including both residential and commercial classes. Many of the terms found in the 2017 Agreement were proposed by the signatories and are consistent with terms found in Florida Power & Light Company's, Gulf Power Company's, and Duke Energy Florida, LLC's most recent rate case settlements,[4] e.g., cessation of natural gas hedging, construction of cost-effective solar generation, implementation of an asset optimization program, implementation of a storm damage recovery mechanism, an economic development rider, and the deferral of depreciation studies until the utility's next rate case. The 2017 Agreement essentially maintains the current base rates for another four years adjusted for additions to solar generating capacity spread over the same period. Thus, the 2017 Agreement increases TECO's fuel diversity in a cost effective manner while providing rate predictability. Further, the 2017 Agreement allows ratepayers to receive the benefit of any revisions to the federal income tax code within 4 months of those benefits becoming available. Having carefully reviewed the 2017 Agreement, the exhibits entered into the record, and the testimony provided by TECO's witnesses, we find that taken as a whole it provides a reasonable resolution of all the issues addressed. We find, therefore, that the 2017 Agreement, Attachment A hereto, establishes rates that are fair, just, and reasonable and is in the public interest, and hereby approve it.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Tampa Electric Company's Petition for Limited Proceeding to approve 2017 Amended and Restated Stipulation and Settlement Agreement is hereby granted. It is further

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[2] Order No. PSC-13-0023-S-EI, issued on January 14, 2013, in Docket No. 120015-EI, In re: Petition for increase in rates by Florida Power & Light Company; Order No. PSC-11-0089-S-EI, issued February 1, 2011, in Docket Nos. 080677 and 090130, In re: Petition for increase in rates by Florida Power & Light Company and In re: 2009 depreciation and dismantlement study by Florida Power & Light Company; Order No. PSC-13-0023-S-EIPSC-10-0398-S-EI, issued June 18, 2010, in Docket Nos. 090079-EI, 090144-EI, 090145-EI, 100136-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc., In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc., In re: Petition for expedited approval of the deferral of pension expenses, authorization to charge storm hardening expenses to the storm damage reserve, and variance from or waiver of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc., and In re: Petition for approval of an accounting order to record a depreciation expense credit, by Progress Energy Florida, Inc.; Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc.

[3] Order No. PSC-13-0023-S-EI, at p. 7.

[4] Order No. PSC-16-0560-AS-EI, issued on December 15, 2016, in Docket No. 160021-EI, In re: Petition for rate increase by Florida Power & Light Company; Order No. PSC-17-0178-S-EI, issued on May 16, 2017, in Docket No. 20160186-EI, In re: Petition for rate increase by Gulf Power Company; Order No. PSC-2017-0451-AS-EI, issued on November 20, 2017, in Docket No. 20170183-EI, In re: Application for limited proceeding to approve 2017 second revised and restated settlement agreement including certain rate adjustments by Duke Energy Florida LLC .

ORDERED that the 2017 Amended and Restated Stipulation and Settlement Agreement, attached hereto as Attachment A, and incorporated by reference, is hereby approved. It is further

ORDERED that the tariff sheets, contained in Exhibit A attached to the 2017 Amended and Restated Stipulation and Settlement Agreement, are hereby approved with an effective date of the first billing cycle in January 2018. It is further

ORDERED that in the event no timely appeal is filed, Docket Nos. 20170210-EI and 20160160-EI shall be closed.

By ORDER of the Florida Public Service Commission this 27th day of November, 2017.

Carlotta S Stauffer

CARLOTTA S. STAUFFER
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
www.floridapsc.com

Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

SBr

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida

Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In re: Petition by Tampa Electric Company for a limited proceeding to approve 2017 Amended and Restated Stipulation and Settlement Agreement | ) | DOCKET NO. 2017____-EI |
| In re: Tampa Electric Company's Petition for Approval of Energy Transaction Optimization Mechanism | ) | DOCKET NO. 20160160-EI<br>FILED: September 27, 2017 |

**2017 AMENDED AND RESTATED**
**STIPULATION AND SETTLEMENT AGREEMENT**

THIS AGREEMENT is dated this 27th day of September, 2017 and is by and between Tampa Electric Company ("Tampa Electric" or the "company"), the Office of Public Counsel ("OPC" or "Citizens"), the Florida Industrial Power Users Group ("FIPUG"), the Florida Retail Federation ("FRF"), the Federal Executive Agencies ("FEA"), and the WCF Hospital Utility Alliance ("HUA"). Collectively, Tampa Electric, OPC, FIPUG, FRF, FEA, and HUA shall be referred to herein as the "Parties" and the term "Party" shall be the singular form of the term "Parties." OPC, FIPUG, FRF, FEA, and HUA will be referred to herein as the "Consumer Parties." This document shall be referred to as the "2017 Agreement."

**Background**

On September 8, 2013, Tampa Electric and the Consumer Parties filed a Stipulation and Settlement Agreement ("2013 Stipulation") that resolved all the issues in Tampa Electric's 2013 base rate case (Docket No. 20130040-EI). Therein, among other things, Tampa Electric agreed that the general base rates provided for in the 2013 Stipulation would remain in effect through December 31, 2017, and thereafter, until the company's next general base rate case. The 2013

Stipulation also specified that Tampa Electric would forego seeking future general base rate increases with an effective date prior to January 1, 2018, except in limited circumstances. The Florida Public Service Commission ("FPSC" or "Commission") approved the 2013 Stipulation and memorialized its decision in Order No. PSC-2013-0443-FOF-EI, issued September 30, 2013 ("2013 Stipulation Order").

In late 2016, recognizing that the period in which Tampa Electric agreed to refrain from seeking general base rate increases would expire at the end of 2017, Tampa Electric and the Consumer Parties began discussing whether the company would be willing and able to (a) refrain from seeking a general base rate increase beyond December 31, 2017 and (b) extend the terms of the 2013 Stipulation for an additional period of time. The Parties also discussed the company's desire to build 600 MW of solar photovoltaic generation with cost recovery via a solar base rate adjustment mechanism ("SoBRA").

The Parties have entered into this 2017 Agreement in compromise of positions taken in accord with their rights and interests under Chapters 350, 366 and 120, Florida Statutes, as applicable, and as part of a negotiated exchange of consideration among the Parties to this 2017 Agreement, each Party has agreed to concessions to the others with the expectation, intent, and understanding such that all provisions of the 2017 Agreement, upon approval by the Commission, will be enforced by the Commission as to all matters addressed herein with respect to all Parties.

NOW, THEREFORE, in light of the mutual covenants of the Parties and the benefits accruing to all Parties through this 2017 Agreement, and for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties agree as follows:

1. Term.

This 2017 Agreement will become effective upon the date of the Commission's vote approving it (the "Effective Date") and continue through and including December 31, 2021, such that, except as specified in this 2017 Agreement, no base rates, charges, or credits (including the credits that are specifically the subject of this 2017 Agreement) or rate design methodologies will be changed before January 1, 2022. The period from the Effective Date through December 31, 2021 (subject to Paragraph 7(c)) shall be referred to herein as the "Term". The Parties reserve all rights, unless such rights are expressly waived or released, under the terms of this 2017 Agreement.

2. Return on Equity and Equity Ratio.

(a) Subject to the adjustment Trigger provisions in Subparagraph 2(b), Tampa Electric's authorized return on common equity ("ROE") shall be within a range of 9.25% to 11.25%, with a mid-point of 10.25%, except under the conditions specifically provided in this 2017 Agreement in Paragraphs 2(b) and 7. Tampa Electric's authorized ROE range and mid-point shall be used for all regulatory purposes during the Term, together with an equity ratio as follows: (a) a 54% equity ratio for the SoBRA revenue requirement calculations, (b) the company's actual equity ratio for earnings surveillance reporting, and (c) the actual equity ratio up to a cap of 54% for purposes of setting cost recovery clause rates, triggering an exit from this 2017 Agreement pursuant to paragraph 7, or calculating interim rates.

(b) ROE Trigger Mechanism. The purpose of the provisions in this Subparagraph 2(b) is to provide Tampa Electric with rate relief in the event that market capital costs, as indicated by the interest rate on U.S. Treasury bonds, rise above the level specified herein; these provisions are generically referred to as the "Trigger" mechanism or the "Trigger provisions," or simply as the "Trigger." If at any time during the Term, the average 30-year United States Treasury Bond yield rate for any period of six (6) consecutive months is at least 4.6039% (the "Trigger Point")[1], Tampa Electric's authorized ROE shall be increased by 25 basis points to be within a range of 9.50% to 11.50%, with a mid-point of 10.50% ("Revised Authorized ROE") from the Trigger Effective Date defined below for and through the remainder of the Term, and thereafter until the Commission resets the Company's rates and its authorized ROE. The Trigger Criterion Value ("Trigger Value") shall be calculated by summing the reported 30-year U.S. Treasury Bond rates for each day over a consecutive six-month period for which rates are reported, and dividing the resulting sum by the number of reporting days in such period. The effective date of the Revised Authorized ROE ("Trigger Effective Date") shall be the first day of the month following the day in which the Trigger Value reaches the Trigger Point. If the Trigger Point is reached and the Revised Authorized ROE becomes effective, Tampa Electric's Revised Authorized ROE range and mid-point shall be used for the remainder of the Term for all regulatory purposes, and thereafter until changed by a final non-appealable order ("Final Order") of the Commission.

(c) The ROE in effect at the expiration of the Term of this 2017 Agreement shall continue in effect until the company's ROE is next reset by a Final Order of the Commission whether by operation of Paragraph 7 or otherwise.

[1] This value was derived as provided for in the 2013 Stipulation and reflected in Late Filed Hearing Exhibit 246, in Docket No. 130040-EI as follows: "The Trigger shall be calculated by summing the reported 30-year U.S. Treasury Bond rates for each day over any six-month period, e.g. January 1, 2014 through July 1, 2014, or March 17, 2014 through September 17, 2014, for which rates are reported, and dividing the resulting sum by the number of reporting days in such period."

3. Customer Rates.

(a) Except as specified in this 2017 Agreement, the company's general base rates, charges, credits, and rate design methodologies, for retail electric service in effect on December 31, 2017, shall remain in effect for service rendered and charges imposed through and including December 31, 2021, and thereafter until revised by a future unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as the result of a future general base rate proceeding.

(b) Except as specified in this 2017 Agreement, the company may not petition to change any of its general base rates, charges, credits, or rate design methodologies for retail electric service with an effective date for the new rates, charges, credits, or rate design methodologies earlier than January 1, 2022.

(c) Notwithstanding Subparagraphs 3(a) and 3(b), the company shall be authorized to change its base rates as set forth in Paragraphs 6 and 9, below, in accordance with procedures identified for the SoBRA mechanism and to reduce rates in accordance with Federal Income Tax Reform that may occur during the Term of this 2017 Agreement.

(d) The current lock period for the Contracted Credit Value ("CCV") shall remain 72 months (6 years).

(e) The company's standby generator credit shall be increased from \$4.75/kW/month to \$5.35/kW/month, concurrent with meter reads for the first billing cycle of January 2018. The CCV credit shall be increased from \$9.98/kW/month to \$10.23/kW/month for secondary, \$9.88/kW/month to \$10.13/kW/month for primary, and \$9.78/kW/month to \$10.03/kW/month for sub-transmission voltage customers, concurrently with meter readings for the first billing cycle of January 2018. To the extent that implementation of these revised credits results in an under-recovery or over-recovery of revenues that are subject to the Energy Conservation Cost Recovery ("ECCR") clause, the company shall be authorized to make an adjustment to remedy any such under-recovery or over-recovery in its ECCR charges for 2019 and thereafter. The level of these credits will not change during the Term and will remain in effect after the expiration of the Term until changed, if at all, by a future unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding. The credit modifications addressed in this Subparagraph 3(e) are reflected in the revised tariff sheets set forth in Exhibit A to this 2017 Agreement, the approval of which shall constitute approval of the revised tariff sheets.

(f) The company's Economic Development Rider, which is set forth in Rate Schedule ECONOMIC DEVELOPMENT RATE – EDR of the company's retail tariff, shall remain in effect during the Term and thereafter until modified or terminated by order of the Commission. The Parties intend that the Commission's approval of this 2017 Agreement shall constitute continuing approval of the Economic Development Rider and that such approval shall satisfy the requirements of Rule 25-6.0426(3) - (6), F.A.C., and accordingly, the reductions afforded in Rate Schedule EDR shall be included as a cost in the company's cost of service for all ratemaking purposes and surveillance reporting. The rates in the Economic Development Rider shall be open for new customers and for new applications by existing customers through December 31, 2021, unless the maximum amount of economic development expenditures as specified in Rule 25-6.0426, F.A.C., is met, at which time the Economic Development Rider will be closed to new customers and to new applications by existing customers until the amount again falls below the maximum allowed.

(g) The provisions of this Paragraph 3 shall remain in effect during the Term except as otherwise permitted or provided for in this 2017 Agreement and shall continue in effect until changed by unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding.

4. Other Cost Recovery. Nothing in this 2017 Agreement shall preclude the company from requesting the Commission to approve the recovery of costs that are: (a) of a type which traditionally or historically would be, have been, or are presently recovered through cost recovery clauses or surcharges, or (b) incremental costs not currently recovered in base rates which the Legislature expressly requires shall be clause recoverable subsequent to the approval of this 2017 Agreement. It is the intent of the Parties that, in conjunction with the provisions of Subparagraph 3(a), the company shall not seek to recover, nor shall the company be allowed to recover, through any cost recovery clause or charge, or through the functional equivalent of such cost recovery clauses and charges, costs of any type or category that have historically or traditionally been recovered in base rates, unless such costs are: (i) the direct and unavoidable result of new governmental impositions or requirements; or (ii) new or atypical costs that were unforeseeable and could not have been contemplated by the Parties resulting from significantly changed industry-wide circumstances directly affecting the company's operations. As a part of the base rate freeze agreed to herein, the company will not seek Commission approval to defer for later recovery in rates, any costs incurred or reasonably expected to be incurred from the Effective Date through and including December 31, 2021, which are of the type which historically or traditionally have been or would be recovered in base rates, unless such deferral and subsequent recovery is expressly authorized herein or otherwise agreed to by each of the Parties. The Parties are not precluded from participating in any proceedings pursuant to this

Paragraph 4, nor is any Party precluded from raising any issues pertinent to any such proceedings.

5. Storm Damage.

(a) Nothing in this 2017 Agreement shall preclude Tampa Electric from petitioning the Commission to seek recovery of costs associated with any tropical systems named by the National Hurricane Center or its successor without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings. Consistent with the rate design methods approved in this 2017 Agreement, the Parties agree that recovery of storm costs from customers will begin, on an interim basis (subject to refund following a hearing or a full opportunity for a formal proceeding), sixty days following the filing of a cost recovery petition and tariff with the Commission and will be based on a 12-month recovery period if the storm costs do not exceed $4.00/1,000 kWh on monthly residential customer bills. In the event the company's reasonable and prudent storm costs exceed that level, any additional costs in excess of $4.00/1,000 kWh shall be recovered in a subsequent year or years as determined by the Commission, after hearing or after the opportunity for a formal proceeding has been afforded to all substantially affected persons or parties. All storm related costs shall be calculated and disposed of pursuant to Rule 25-6.0143, F.A.C., and shall be limited to (i) costs resulting from a tropical system named by the National Hurricane Center or its successor, (ii) the estimate of incremental storm restoration costs above the level of storm reserve prior to the storm, and (iii) the replenishment of the storm reserve to $55,860,642. The Parties to this 2017 Agreement are not precluded from participating in any such proceedings and opposing the amount of Tampa Electric's claimed costs (for example, and without limitation, on grounds that such claimed costs were not reasonable or were not prudently incurred) or whether the proposed recovery is consistent with this Paragraph 5, but not the mechanism agreed to herein.

(b) The Parties agree that the $4.00/1,000 kWh cap in this Paragraph 5 shall apply in aggregate for a calendar year; provided, however, that Tampa Electric may petition the Commission to allow Tampa Electric to increase the initial 12 month recovery at rates greater than $4.00/1,000 kWh or for a period longer than 12 months if Tampa Electric incurs in excess of $100 million of storm recovery costs that qualify for recovery in a given calendar year, inclusive of the amount needed to replenish the storm reserve to $55,860,642. All Consumer Parties reserve their right to oppose such a petition.

(c) The Parties expressly agree that any proceeding to recover costs associated with any storm shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of Tampa Electric and shall not apply any form of earnings test or measure or consider previous or current base rate earnings. Such issues may be fully addressed in any subsequent Tampa Electric base rate case.

(d) The provisions of this Paragraph 5 shall remain in effect during the Term except as otherwise permitted or provided for in this 2017 Agreement and shall continue in effect until the company's base rates are next reset by the Commission. For clarity, this means that if this 2017 Agreement is terminated pursuant to Paragraph 7 hereof, the company's rights regarding storm cost recovery under this 2017 Agreement are terminated at the same time, except that any Commission-approved surcharge then in effect shall remain in effect until the costs subject to that surcharge are fully recovered. A storm surcharge in effect without approval of the Commission shall be terminated at the time this 2017 Agreement is terminated pursuant to Paragraph 7 hereof.

6. Solar Base Rate Adjustment Mechanism ("SoBRA").

(a) Notwithstanding the general base rate freeze specified in Paragraph 2, the company shall be allowed to recover the cost of its investment in, and operation of, certain new solar generation facilities and to make solar base rate adjustments consistent with this Paragraph 6. If the applicable federal or state income tax rate for the Company changes before any of the increases provided for in in this Paragraph 6, the Company will adjust the amount of the base rate increase to reflect the new tax rate before the implementation of such increase, pursuant to the applicable methodology in Exhibit C.

(b) Subject to the conditions in Subparagraph 6(c), the planned capacity amounts, earliest in-service and rate adjustment dates, and associated maximum annual revenue requirements (calculated at the Installed Cost Cap specified herein) are as follows:

| Year | Earliest Rate Change And In-Service Date | Maximum Incremental SoBRA MW | Maximum Incremental Annualized SoBRA Revenue Requirements (millions) | Maximum Cumulative SoBRA MW | Maximum Cumulative Annualized SoBRA Revenue Requirements (millions) |
|---|---|---|---|---|---|
| 2018 | September 1 | 150 | $30.6[2] | 150 | $30.6 |
| 2019 | January 1 | 250 | $50.9 | 400 | $81.5 |
| 2020 | January 1 | 150 | $30.6 | 550 | $112.1 |
| 2021 | January 1 | 50 | $10.2 | 600 | $122.3[3] |

(c) The company will seek approval of and cost recovery for specific solar generation projects in SoBRA Tranches up to the amounts as specified in this Paragraph 6. Nothing in this 2017 Agreement requires Tampa Electric to build the full amount of solar generating capacity

[2] The annual revenue requirement is approximately $30.6 million, however, since the first 150 MW Tranche is scheduled to come online September 1, 2018, the revenue requirements collected would be four months of the annual revenue requirements, or $10.2 million.
[3] The 2021 Tranche can be included in and its costs recovered under the SoBRA mechanism only if the projects constituting the 2018 and 2019 Tranches in this table are in-service and operating per design specifications as of December 31, 2019, and were constructed at an average capital cost of no more than $1475 per $kW_{ac}$.

allowed by this 2017 Agreement for any year or in total over the Term of this 2017 Agreement. Commission action may occur before or after expiration of the Term, but to qualify for cost recovery pursuant to these SoBRA provisions, any Tranche must be fully operational and providing service no later than December 31, 2022. A SoBRA Tranche may consist of a single project or may include multiple individual solar projects, which may be located throughout the company's retail service territory. Tampa Electric will construct and bring into full commercial operation, the full Maximum Incremental SoBRA MW for each year's Tranche by the dates shown in the table above. The Rate Change and In-Service Dates specified in the chart in Subparagraph 6(b) are "no sooner than" dates, and the SoBRA rate changes for each Tranche will be implemented effective on the earliest In-Service Date for that Tranche identified in such chart and subsequently trued up to reflect and correct for (1) any delay in the actual In-Service Dates of any of the projects in a particular Tranche beyond the applicable In-Service date for that Tranche and (2) the extent to which the actual installed costs of any project or projects vary from the projected costs used to set the SoBRA rate change but may not exceed the Maximum Incremental Annualized SoBRA Revenue Requirements or Maximum Cumulative Annualized SoBRA Revenue Requirements set forth in Subparagraph 6(b) or the Installed Cost Cap set forth in Subparagraph 6(d). Each SoBRA revenue increase shall be calculated based on the projected In-Service date, operating capacity, and estimated cost of the solar projects to which it corresponds, subject to being trued up as described in this Subparagraph 6(c). The 2021 SoBRA will only be available to the company if (i) for all projects in the 2018 and 2019 Tranches (totaling 400MW subject to the two percent (2%) variance allowance described in the following sentence), the actual average installed cost necessary to make such projects fully operational is less than or equal to \$1,475 per $kW_{ac}$ and (ii) the 2018 and 2019 Tranches in the amount of 400

MW (subject to the 2% variance) are installed and operating at design specifications as of December 31, 2019. The SoBRA Tranches of solar generation capacity and the associated revenue requirements shown in Subparagraph 6(b) are "up to" or maximum amounts; however, the amount of revenues and MW in the 2019 SoBRA Tranche or Tranches may vary by up to 2 percent of the 2019 total (5 MW variance, either greater than or less than the specified maximum for 2019) to accommodate efficient planning and construction of the associated individual solar projects, and the 2019 Tranche or Tranches remain subject to the cost cap contained herein. Tampa Electric shall make a filing with the Commission by February 28, 2020, reflecting whether it has met the requirements to qualify for the 2021 SoBRA Tranche.

(d) For the solar projects that are approved by the Commission for cost recovery pursuant to this Paragraph 6, Tampa Electric's base rates will be increased by the incremental annualized base revenue requirement in steps, one step for each SoBRA Tranche. Each such base rate adjustment will be referred to as a SoBRA, and shall be authorized for solar projects for which Tampa Electric files for Commission approval pursuant to this Paragraph 6. Each project qualifying for SoBRA treatment must consist of either single axis tracking or other solar electric generating equipment or tracking technology that yields greater efficiency or higher capacity value, or both, for the benefit of customers all within the cost caps stated in this Paragraph 6. The types of costs of solar projects that traditionally have been allowed in rate base (including Engineering, Procurement and Construction ("EPC") costs; development costs including third party development fees, if any; permitting fees and costs; actual land costs and land acquisition costs; taxes; utility costs to support or complete development; transmission interconnection costs; installation labor and equipment costs; costs associated with electrical balance of system, structural balance of system, inverters, and modules; AFUDC at the weighted average cost of capital from Exhibit B of this 2017 Agreement; and other traditionally allowed rate base costs) shall be eligible for SoBRA cost recovery. The total installed capital cost of a project eligible for cost recovery through a SoBRA shall not exceed $1,500 per $kW_{ac}$ (the "Installed Cost Cap"). This Installed Cost Cap shall apply on a per project basis, and includes all costs required to make each of the projects in a Tranche fully operational. Each SoBRA will be based on a 10.25% ROE, except under the conditions specifically provided in this 2017 Agreement in Subparagraph 2(b), a 54% equity ratio (based on investor sources of capital), and the incremental capital structure components of long-term debt, short-term debt (if any), common equity, and tax credits, adjusted to reflect the inclusion of investment tax credits on a normalized basis. The debt rate utilized to calculate the revenue requirements associated with the SoBRA projects will be updated to reflect the incremental costs of prospective long-term debt issuances during the first 12 months of operation of each project. The SoBRA Installed Cost Cap is an amount agreed to by and between the Parties that reflects their negotiations regarding all relevant factors affecting or determining the installed cost of each project, including but not limited to capital costs, costs of capital, capital structure, and the other costs and expenses associated with the project.

(e) The Installed Cost Cap is not a "safe harbor" or a "build to" number for the company. The company will use reasonable efforts to design and build solar projects at installed costs below the cap. The Installed Cost Cap will limit the cost recovery of projects under a SoBRA, so if a project costs more than $1,500 per $kW_{ac}$, the company can recover through a SoBRA only the installed cost up to the Installed Cost Cap, but may use the actual installed cost for purposes of preparing its periodic earnings surveillance reports; however, during the company's next general base rate proceeding, the depreciated net book value of any SoBRA project included in rate base for the test year may not exceed the Installed Cost Cap.

(f) The individual solar generation projects contemplated in this 2017 Agreement are not subject to the Florida Electrical Power Plant Siting Act, because each project will be smaller than 75 MW, and accordingly, the projects contemplated herein will be subject to the process and FPSC approval as specified herein. For each SoBRA and associated SoBRA Tranche, Tampa Electric will file a petition for approval of each SoBRA, provided that the SoBRA rate change for each Tranche shall not take effect before the dates specified in the aforementioned chart. Each petition for approval of a SoBRA or SoBRAs shall be filed in a separate stand-alone docket. The petition for approval of the first SoBRA (September 1, 2018) shall be made as soon as reasonably possible after the Commission vote to approve this 2017 Agreement. The petition for approval of each of the remaining SoBRAs shall be made in a separate stand-alone docket; the company may file the petitions for each Tranche for the following year at the time of the company's projection filings in the 2018, 2019 and 2020 Fuel and Purchased Power Cost Recovery Clause dockets ("Fuel Docket(s)") for the 2019, 2020 and 2021 factors, respectively, or the company may file each SoBRA petition at a convenient time throughout each year. The Parties contemplate that there will be a final true-up for the 2021 SoBRA, if needed. The Parties agree to request that, to the extent practicable, the deadlines and schedules in the Fuel Dockets apply to the petitions for approval of SoBRAs, so that the amount of solar generation approved for recovery through a SoBRA and related fuel cost savings can be synchronized with the Fuel Dockets.

(g) The issues for determination in each proceeding for approval of a SoBRA shall be limited to: (1) the cost effectiveness of the solar projects in the Tranche, (2) whether the installed cost of each project in the Tranche is projected to be under the Installed Cost Cap, (3) the amount of revenue requirements and appropriate increase in base rates needed to collect the estimated annual revenue requirement for the projects in a Tranche, (4) a true-up of previously approved SoBRAs for the actual cost of the previously approved projects, subject to the sharing provisions in Subparagraph 6(m), and (5) a true-up through the Capacity Cost Recovery Clause ("CCR") of previously approved SoBRAs to reflect the actual in service dates and actual installed cost for each of the previously-approved projects. The cost effectiveness for the projects in a Tranche shall be evaluated in total by considering only whether the projects in the Tranche will lower the company's projected system cumulative present value revenue requirement ("CPVRR") as compared to such CPVRR without the solar projects.

(h) The Parties expect and intend that the first SoBRA will be effective as of September 1, 2018, based on the Parties' expectation and the company's intent that all projects in the 2018 Tranche will be fully operational and providing service as of September 1, 2018. To accommodate efficient planning and construction by the company, the Consumer Parties agree that Tampa Electric may request the Commission to consider approval of the 2018 Tranche as soon as practicable following approval of this 2017 Agreement. The Parties further intend that Commission action on the remaining SoBRAs will be resolved, to the extent practicable, on a schedule that is contemporaneous with the annual, regularly scheduled Fuel and Purchased Power Cost Recovery Docket hearings, provided, however, that the Commission on its own initiative or upon good cause shown by any Party to this 2017 Agreement or any other entity satisfying the standing requirements of Florida law may set Tampa Electric's request for approval of any SoBRA or SoBRA Tranche for a separate hearing to be held at any convenient time to permit timely resolution before the company's projected In-Service date for the SoBRA Tranche that is the subject of such petition and hearing.

(i) The SoBRA increases approved pursuant to this 2017 Agreement shall be calculated based upon Tampa Electric's billing determinants used in the company's then-most-current ECCR Clause filings with the Commission for the twelve months following the effective date of any respective SoBRA. To the extent necessary, this will include projections of such billing determinants into a subsequent calendar year so as to cover the same 12 months as the first 12 months of each Tranche of solar projects' operations. The exception to this will be the first Tranche of SoBRA, which is to go into effect on September 1, 2018. In the case of this Tranche, the billing determinants used will be from the 2017 ECCR Clause filing for the 12 months of 2018 and the base rate adjustment derived on an annual basis but only applied to bills for the four months from September 2018 through December 2018 and then for the 12 months of 2019. The revenue requirement for each SoBRA Tranche shall be allocated to the rate classes using the 12 CP and $1/13^{th}$ method of allocating production plant and shall be applied to existing base rates, charges and credits using the following principles:

(i) 40% of the revenue requirements that would otherwise be allocated to the lighting class under the 12 CP and $1/13^{th}$ methodology shall be allocated to the lighting class for recovery through an increase in the lighting base energy rate and the remaining 60% shall be allocated ratably to the other customer classes.

(ii) The revenue requirement associated with a SoBRA will be recovered through increases to demand charges where demand charges are part of a rate schedule, and through energy charges where no demand charge is used in a rate schedule.

(iii) Within the GSD and IS rate classes, recovery of SoBRA revenue requirements allocated to those rate classes will be borne by non-standby demand charges only within a rate class, which methodology will not impact RS and GS rate classes.

(j) The solar capacity amounts specified in Subparagraphs 6(b) and 6(c) shall limit the maximum amount of solar capacity for which the company may recover costs through a SoBRA during each year of the Term, which may include recovery during 2022 for any SoBRA that satisfies the capacity and cost caps provided herein; provided, however, if Tampa Electric receives approval for SoBRA recovery for capacity amounts below the capacity amounts specified in Subparagraphs 6(b) and 6(c) in any year, the company can seek recovery of the unused capacity in a future petition for approval up to the Maximum Cumulative SoBRA for the applicable year as set forth in Subparagraph 6(b), provided such request is filed with the Commission during the Term of this 2017 Agreement. A SoBRA may become effective at any time during the Term or within one year after expiration of the Term, as limited by Subparagraph 6(d) and subject to the termination of the company's rights to seek SoBRA recovery if this 2017 Agreement is terminated pursuant to Paragraph 7 hereof.

(k) For each of the SoBRAs specified in Subparagraphs 6(b) and 6(c), the increased base rates shall be reflected on Tampa Electric's customer bills as specified herein. Tampa Electric will begin applying the increased base rate charges for each SoBRA concurrently with meter readings for the first billing cycle of September 2018 for the first SoBRA, subject to true-up as provided in Subparagraph 6(c). Tampa Electric will begin applying each subsequent SoBRA concurrently with meter readings for the first billing cycle of the month the Tranche is projected to go in service, subject to true-up as provided in Subparagraph 6(c). The Parties contemplate and intend that the final true-up for the 2021

SoBRA, if any, would be made to the CCR as soon as practicable following implementation of the 2021 SoBRA, if any.

(l) Subject to the revenue requirement limits in Subparagraph 6(b), the SoBRA for a Tranche will be calculated using the company's projected installed cost per $kW_{ac}$ for each project (subject to the Installed Cost Cap); reasonable estimates for depreciation expense (based on an initial average service life of 30 years for depreciable plant), property taxes and fixed O&M expenses; an incremental capital structure reflecting the then current midpoint ROE and a 54% equity ratio adjusted to reflect the inclusion of investment tax credits on a normalized basis.

(m) If Tampa Electric's actual installed cost for a project is less than the Installed Cost Cap, the company's customers and the company will share in the beneficial difference with 75% of the difference inuring to the benefit of customers and 25% serving as an incentive to the company to seek such cost savings over the life of this 2017 Agreement. By way of illustration, if the actual installed cost of a solar project is $1,400 per $kW_{ac}$, the final cost to be used for purposes of computing cost recovery under this 2017 Agreement and the true-up of the initial SoBRA shall be $1,425 per $kW_{ac}$ [0.25 times ($1,500 - $1,400) + $1,400].

(n) In order to determine the amount of each annual cost true-up, a revised SoBRA will be computed using the same data and methodology incorporated in the initial SoBRA, with the exception that the actual capital expenditures after sharing and the actual in-service date will be used in lieu of the capital expenditures on which the annualized revenue requirement was based. The difference between the cumulative base revenues since the implementation of the initial SoBRA factor and the cumulative base revenues that would have resulted if the revised SoBRA factor (for cost and In-Service date true-ups) had been in place during the same time period will be trued up with interest at the AFUDC rate shown in Exhibit B used for the projects, and will be made through a one-time, twelve-month adjustment through the CCR clause. On a going forward basis, the base rates will be adjusted to reflect the revised SoBRA factors.

(o) Tampa Electric agrees to file monthly reports that will provide the same information as that filed with the Commission in Docket No. 20170007-EI by another utility for its solar projects, in order to reflect the performance of the solar projects after they have been placed in service.

(p) Tampa Electric's base rate and credit levels applied to customer bills, including the effects of the SoBRAs implemented pursuant to this 2017 Agreement, shall continue in effect until next reset by future unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding. Any incentive attributed to the company during the term of this 2017 Agreement under Subparagraph 6(m) above will not be included in rate base in the company's next general base rate proceeding, meaning that when a solar asset plant balance is moved to base rates in the company's next general base rate case, only the actual cost -- not any incentive -- will be included.

(q) For all new solar generation assets that Tampa Electric places in service during the Term, the lowest total installed cost per-kW solar energy resources up to the capacity amounts associated with the SoBRA mechanism will be attributed to the SoBRA mechanism in the event the company constructs more solar generation capacity than is subject to the SoBRA mechanism.

(r) Nothing in this 2017 Agreement shall preclude any Party to this 2017 Agreement or any other lawful party from participating, consistent with the full rights of an intervenor, in any proceeding that addresses any matter or issue concerning the SoBRA provisions of this 2017 Agreement.

7. Earnings.

(a) Notwithstanding Paragraph 2 and subject to the Trigger provisions in Subparagraph 2(b) above, if Tampa Electric's earned return on common equity falls below 9.25% during the Term on a monthly earnings surveillance report stated on an actual Commission thirteen-month average adjusted basis, Tampa Electric may petition the Commission to amend its base rates either through a general rate proceeding under Sections 366.06 and 366.07, Florida Statutes, or through a limited proceeding under Section 366.076, Florida Statutes. Nothing in this 2017 Agreement shall be construed as an agreement by the Consumer Parties that a limited proceeding would be appropriate, and Tampa Electric acknowledges and agrees that the Parties reserve and retain all rights to challenge the propriety of any limited proceeding or to assert that any request for base rate changes should properly be addressed through a general base rate case, as well as to challenge any substantive proposals to change the company's rates in any such future proceeding. This floor of 9.25% shall be subject to adjustment in accordance with the Trigger provision in Subparagraph 2(b). For purposes of this 2017 Agreement, "Commission actual adjusted basis" and "actual adjusted earned return" shall mean results reflecting all adjustments to Tampa Electric's books required by the Commission by rule or order, but excluding pro forma adjustments. No Consumer Parties shall be precluded from participating in any proceeding initiated by Tampa Electric to increase base rates pursuant to this Paragraph 7, and no Consumer Party is precluded from opposing Tampa Electric's request.

(b) Notwithstanding Paragraph 2 and subject to the Trigger in Subparagraph 2(b) above, if Tampa Electric's earned return on common equity exceeds 11.25% during the Term on a monthly earnings surveillance report stated on an actual Commission thirteen-month average adjusted basis, no Consumer Party shall be precluded from petitioning the Commission for a review of Tampa Electric's base rates. In any case initiated by Tampa Electric or any other Party pursuant to Paragraph 7, all Parties will retain full rights conferred by law. The ceiling of 11.25% set forth in this Subparagraph shall be subject to adjustment in accordance with the Trigger provision in Subparagraph 2(b).

(c) Notwithstanding Paragraph 2 and subject to the Trigger provisions in Subparagraph 2(b) above, this 2017 Agreement shall terminate upon the effective date of any Final Order of the Commission issued in any proceeding pursuant to Paragraph 7 that changes Tampa Electric's base rates prior to the last billing cycle of December 2021.

(d) This Paragraph 7 shall not: (i) be construed to bar Tampa Electric from requesting any recovery of costs otherwise contemplated by this 2017 Agreement; (ii) apply to any request to change Tampa Electric's base rates that would become effective after the expiration of the Term of this 2017 Agreement; (iii) limit any Party's rights in proceedings concerning changes to base rates that would become effective subsequent to the Term of this 2017 Agreement to argue that Tampa Electric's authorized ROE range should be different than as set forth in this 2017 Agreement; or (iv) affect the provisions of Subparagraphs 3(d) and 3(e) of this 2017 Agreement.

(e) Notwithstanding any other provision of this 2017 Agreement, the Parties fully and completely reserve all rights available to them under the law to challenge the level or rate structure (or the cost of service methodologies underlying them) of Tampa Electric's base rates, charges, credits, and rate design methodologies effective as of January 1, 2022 or thereafter. It is specifically understood and agreed that this 2017 Agreement does not preclude any Consumer Party from filing before January 1, 2022, an action to challenge the level or rate structure (or the cost of service methodologies underlying them) of Tampa Electric's base rates, charges and credits effective as of January 1, 2022 or thereafter.

8. Depreciation.

(a) The Parties agree and intend that, notwithstanding any requirements of Rules 25-6.0436 and 25-6.04364, F.A.C., the company shall not be required during the Term of this 2017 Agreement to file any depreciation study or dismantlement study. The depreciation and amortization accrual rates approved by the FPSC and currently in effect as of the Effective Date of this 2017 Agreement shall remain in effect during the Term or the company's next depreciation study, whichever is later. The Parties further agree that the provisions of Rules 25-6.0436 and 25-6.04364, F.A.C., which otherwise require depreciation and dismantlement studies to be filed at least every four years, will not apply to the company during the Term, and that the Commission's approval of this 2017 Agreement shall excuse the company from compliance with the filing requirement of these rules during the Term.

(b) Notwithstanding the non-deferral language in Paragraph 4, unless the company proposes a special capital recovery schedule and the Commission approves it, if coal-fired generating assets or other assets are retired or planned for retirement of a magnitude that would ordinarily or otherwise require a special capital recovery schedule, such assets will continue to be depreciated using their then existing depreciation rates and special capital recovery issues will be addressed in conjunction with the company's next depreciation study. If the company installs Automated Meter Infrastructure ("AMI") meters and retires Automated Meter Reading ("AMR") meters during the Term, such assets will continue to be depreciated using their then existing depreciation rates and special capital recovery issues will be addressed in conjunction with the company's next depreciation study.

(c) Notwithstanding the provisions of Subparagraph 8(a) above, the company shall file a depreciation and dismantlement study or studies no more than one year nor less than 90 days before the filing of its next general rate proceeding under Sections 366.06 and 366.07, Florida Statutes, such that there is a reasonable opportunity for the Consumer Parties to review, analyze and potentially rebut depreciation rates or other aspects of such depreciation and dismantlement studies contemporaneously with the company's next general rate proceeding. The depreciation and dismantlement study period shall match the test year in the company's MFRs, with all supporting data in electronic format with links, cells and formulae intact and functional, and shall be served upon all Consumer Parties and all intervenors in such subsequent rate case.

9. Federal Income Tax Reform.

(a) Changes in the rate of taxation of corporate income by federal or state taxing authorities ("Tax Reform") could impact the effective tax rate recognized by the company in FPSC adjusted reported net operating income and the measurement of existing and prospective deferred federal income tax assets and liabilities reflected in the FPSC adjusted capital structure.

When Congress last reduced the maximum federal corporate income tax rate in the Tax Reform Act of 1986, it included a transition rule that, as an eligibility requirement for using accelerated depreciation with respect to public utility property, provided guidance regarding returning to customers the portion of the resulting excess deferred income taxes attributable to the use of accelerated depreciation. To the extent Tax Reform includes a transition rule applicable to excess deferred federal income tax assets and liabilities ("Excess Deferred Taxes"), defined as those that arise from the re-measurement of those deferred federal income tax assets and liabilities at the new applicable corporate tax rate(s), those Excess Deferred Taxes will be governed by the Tax Reform transition rule, as applied to most promptly and effectively reduce Tampa Electric's rates consistent with the Tax Reform rules and normalization rules.

(b) If Tax Reform is enacted before the company's next general base rate proceeding, the company will quantify the impact of Tax Reform on its Florida retail jurisdictional net operating income thereby neutralizing the FPSC adjusted net operating income of the Tax Reform to a net zero. The company's forecasted earnings surveillance report for the calendar year that includes the period in which Tax Reform is effective will be the basis for determination of the impact of Tax Reform. The company will also adjust any SoBRAs that have not yet gone into effect to specifically account for Tax Reform. The impacts of Tax Reform on base revenue requirements will be flowed back to retail customers within 120 days of when the Tax Reform becomes law, through a one-time adjustment to base rates upon a thorough review of the effects of the Tax Reform on base revenue requirements consistent with Subparagraph 9(a). This adjustment shall be accomplished through a uniform percentage decrease to customer, demand and energy base rate charges for all retail customer classes. Any effects of Tax Reform on retail revenue requirements from the Effective Date through the date of the one-time base rate adjustment shall be flowed back to customers through the ECCR Clause on the same basis as used in any base rate adjustment. An illustration is included as Exhibit C. If Tax Reform results in an increase in base revenue requirements, the company will utilize deferral accounting as permitted by the Commission, thereby neutralizing the FPSC adjusted net operating income impact of the Tax Reform to a net zero, through the Term. In this situation, the company shall defer the revenue requirement impacts to a regulatory asset to be considered for prospective recovery in a change to base rates to be addressed in the company's next base rate proceeding or in a limited scope proceeding before the Commission no sooner than the end of the Term.

(c) All Excess Deferred Taxes shall be deferred to a regulatory asset or liability which shall be included in FPSC adjusted capital structure and flowed back to customers over a term consistent with law. If the same Average Rate Assumption Method used in the Tax Reform Act of 1986 is prescribed, then the regulatory asset or liability will be flowed back to customers over the remaining life of the assets associated with the Excess Deferred Taxes subject to the provisions related to FPSC adjusted operating income impacts of Tax Reform noted above. If the Tax Reform law or act is silent on the flow-back period, and there are no other statutes or rules that govern the flow-back period, then there shall be a rebuttable presumption that the following flow-back period(s) will apply: (1) if the cumulative net regulatory liability is less than $100 million, the flow-back period will be five years; or (2) if the cumulative net regulatory liability is greater than $100 million, the flow-back period will be ten years. The company reserves the right to demonstrate by clear and convincing evidence that such five or ten-year maximum period (as applicable) is not in the best interest of the company's customers and should be increased to no greater than 50 percent of the remaining life of the assets associated with the Excess Deferred Taxes ("50 Percent Period"). The relevant factors to support the company's demonstration include, but are not limited to, the impact the flow-back period would have on the company's cash flow and credit metrics or the optimal capitalization of the company's jurisdictional operations in Florida. If the company can demonstrate, by clear and convincing evidence, that limiting the flow-back period to the 50 Percent Period, in conjunction with the other Tax Reform provisions related to deferred taxes within this 2017 Agreement, will be the sole basis for causing a full notch credit downgrade by each of the major rating agencies (i.e. Standard & Poor's and Moody's), as expressly reflected in a publicly available report of the agencies, it may file to seek a longer flow-back period.

10. Incentive Plan. The Parties consent to the FPSC's approval of and request that the Commission approve the company's Asset Optimization/Incentive Program as set forth in its Petition in Docket No. 160160-EI, dated June 30, 2016, for a four-year period beginning January 1, 2018, but with the following sharing thresholds: (a) up to \$4.5MM/year, 100% gain to customers; (b) greater than \$4.5MM/year and less than \$8.0MM/year, 60% to shareholders and 40% to customers; and (c) greater than \$8.0MM/year, 50% to shareholders and 50% customers.

11. Other.

(a) Except as specified in this 2017 Agreement, the company will enter into no new natural gas financial hedging contracts for fuel through December 31, 2022.

(b) The company agrees that it will not seek to recover any costs from its customers related to investments in oil and/or natural gas exploration, reserves, acreage and/or production, including but not limited to investments in gas or oil exploration or production projects that utilize "fracking" (hydraulic fracturing) or similar technology, for a period of no less than five years after the Effective Date.

(c) The company may not make separated/stratified sales from energy generated by solar assets being recovered through a SoBRA during the Term.

(d) For any non-separated or non-stratified wholesale energy sales during the Term, the company will credit its fuel clause for an amount equal to the company's incremental cost of generating or purchasing the amount of energy sold during the hours that any such sale was made.

(e) The full benefits of solar renewable energy credits ("RECs") (including any and all rights attaching to environmental attributes) associated with the solar projects subject to this 2017 Agreement, if any, will be retained for, and flowed through to, retail customers through the Environmental Cost Recovery Clause.

(f) All dollar values, asset determinations, rate impact values and revenue requirements in this 2017 Agreement are intended by the Parties to be retail jurisdictional in amount or formulation basis, unless otherwise specified.

12. New Tariffs. Nothing in this 2017 Agreement shall prelude Tampa Electric from filing and the Commission from approving any new or revised tariff provisions or rate schedules requested by Tampa Electric, provided that any such tariff request does not increase any existing base rate component of a tariff or rate schedule, or any other charge imposed on customers during the Term unless the application of such new or revised tariff, rate schedule, or charge is optional to Tampa Electric's customers.

13. Application of 2017 Agreement. No Party to this 2017 Agreement will request, support, or seek to impose a change to any term or provision of this 2017 Agreement. Except as provided in Paragraph 7, no Party to this 2017 Agreement will either seek or support any reduction in Tampa Electric's base rates, charges, or credits, including limited, limited-scope,

interim, or any other rate decreases, or changes to rate design methodologies, that would take effect prior to the first billing cycle for January 2022, except for any such reduction in base rates or charges (but not credits) requested by Tampa Electric or as otherwise provided for in this 2017 Agreement. Tampa Electric shall not seek interim, limited, or general base rate relief during the Term except as provided for in Paragraphs 6 or 7 of this 2017 Agreement. Tampa Electric is not precluded from seeking interim, limited or general base rate relief that would be effective during or after the first billing cycle in January 2022, nor are the Consumer Parties precluded from opposing such relief. Such interim relief may be based on time periods before January 1, 2022, consistent with Section 366.071, Florida Statutes, and calculated without regard to the provisions of this 2017 Agreement. Tampa Electric will not seek to adjust either the standby generator credit or the CCV credit either during the Term of this 2017 Agreement or thereafter, except by unanimous Agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding.

14. Commission Approval.

(a) The provisions of this 2017 Agreement are contingent on approval of this 2017 Agreement in its entirety by the Commission without modification. The Parties further agree that this 2017 Agreement is in the public interest, that they will support this 2017 Agreement and that they will not request or support any order, relief, outcome, or result in conflict with the terms of this 2017 Agreement in any administrative or judicial proceeding relating to, reviewing, or challenging the establishment, approval, adoption, or implementation of this 2017 Agreement or the subject matter hereof.

(b) No Party will assert in any proceeding before the Commission that this 2017 Agreement or any of the terms in the 2017 Agreement shall have any precedential value. The

Parties' agreement to the terms in the 2017 Agreement shall be without prejudice to any Party's ability to advocate a different position in future proceedings not involving this 2017 Agreement. The Parties further expressly agree that no individual provision, by itself, necessarily represents a position of any Party in any future proceeding, and the Parties further agree that no Party shall assert or represent in any future proceeding in any forum that another Party endorses any specific provision of this 2017 Agreement by virtue of that Party's signature on, or participation in, this 2017 Agreement. It is the intent of the Parties to this 2017 Agreement that the Commission's approval of all the terms and provisions of this 2017 Agreement is an express recognition that no individual term or provision, by itself, necessarily represents a position, in isolation, of any Party or that a Party to this 2017 Agreement endorses a specific provision, in isolation, of this 2017 Agreement by virtue of that Party's signature on, or participation in, this 2017 Agreement.

(c) The Parties intend, and agree to request that the Commission's order state that approval of this 2017 Agreement in its entirety will resolve all matters in Docket No. 20160160-EI pursuant to and in accordance with Section 120.57(4), Florida Statutes, and that Docket No. 20160160-EI will be closed effective on the date the Commission's order approving this 2017 Agreement becomes final. The Parties further agree to request that Docket No. 20170057-EI be closed upon approval of this 2017 Agreement or as soon thereafter as is reasonably practical.

(d) No Party shall seek appellate review of any Commission order approving this 2017 Agreement.

15. Disputes. To the extent a dispute arises among the Parties about the provisions, interpretation, or application of this 2017 Agreement, the Parties agree to meet and confer in an effort to resolve the dispute. To the extent that the Parties cannot resolve any dispute, the matter may be submitted to the Commission for resolution.

16. Execution. This 2017 Agreement is dated as of September 27, 2017. It may be executed in counterpart originals and a facsimile of an original signature shall be deemed an original.

[Remainder of page intentionally left blank]

IN WITNESS WHEREOF, the Parties evidence their acceptance and agreement with the provisions of this 2017 Agreement by their signature(s):

Tampa Electric Company
702 N. Franklin Street
Tampa, FL 33601

By ______________________
Gordon L. Gillette, President

Signature Page to 2017 Agreement

Office of Public Counsel
J. R. Kelly, Esquire
Public Counsel
Charles Rewinkle, Esquire
Associate Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, FL 32399-1400

By: ______________________
J.R. Kelly

Signature Page to 2017 Agreement

The Florida Industrial Power Users Group
Jon C. Moyle, Jr., Esquire
Moyle Law Firm
The Perkins House
118 North Gadsden Street
Tallahassee, FL 32301

By: ______________________ Sept. 27, 2017
Jon C. Moyle, Jr.

Signature Page to 2017 Agreement

WCF Hospital Utility Alliance
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Kenneth L. Wiseman, Esquire
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1350 I Street, N.W., Suite 1100
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Kenneth L. Wiseman

Signature Page to 2017 Agreement

Federal Executive Agencies
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Signature Page to 2017 Agreement

Florida Retail Federation
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By: Robert Scheffel Wright
Robert Scheffel Wright

TAB H

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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| In re: Fuel and purchased power cost recovery clause with generating performance incentive factor. | DOCKET NO. 150001-EI<br>ORDER NO. PSC-15-0586-FOF-EI<br>ISSUED: December 23, 2015 |

The following Commissioners participated in the disposition of this matter:

ART GRAHAM, Chairman
LISA POLAK EDGAR
RONALD A. BRISÉ
JULIE I. BROWN
JIMMY PATRONIS

FINAL ORDER APPROVING EXPENDITURES AND TRUE-UP AMOUNTS FOR FUEL ADJUSTMENT FACTORS; GPIF TARGETS, RANGES, AND REWARDS; AND PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR CAPACITY COST RECOVERY FACTORS

APPEARANCES:

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On behalf of the Citizens of the State of Florida (OPC)

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On behalf of the Florida Industrial Power Users Group (FIPUG)

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On behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs (PCS Phosphate)

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On behalf of the Florida Public Service Commission (Staff)

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Advisors to the Florida Public Service Commission

BY THE COMMISSION:

## Background

As part of the continuing fuel and purchased power adjustment and generating performance incentive factor clause proceedings, an administrative hearing was held on November 2-3, 2015. At the hearing, we approved, with modifications, certain stipulated issues for Tampa Electric Company (TECO), Gulf Power Company (Gulf), Florida Power & Light Company (FPL), Florida Public Utilities Company (FPUC), and Duke Energy Florida, LLC. (DEF) by bench decision. These stipulations, as modified, are found in Attachment A. Although we approved some stipulated issues for each of these investor-owned utilities (IOUs), testimony and other evidence was presented at the November 2-3, 2015 hearing on hedging-related issues for the generating IOUs, and also for company-specific issues for FPUC. TECO, Gulf, FPL, FPUC, DEF, Florida Industrial Power Users Group (FIPUG), the Office of Public Counsel (OPC), and PCS Phosphate (PCS) filed briefs on November 13, 2015.[1]

We have jurisdiction over this subject matter pursuant to the provisions of Chapter 366, Florida Statutes (F.S.), including Sections 366.04, 366.05, and 366.06, F.S.

## Hedging

Our analysis of this issue will begin by providing a background on how our policy on hedging has been developed and the key actions we have taken regarding the hedging programs that Florida's four largest IOUs use today.

### Background

Hedging allows utilities to manage the risk of volatile swings in the price of fuel. Prior to 2001, IOUs had carried out a small number of financial hedging transactions. In response to significant fluctuations in the price of natural gas and fuel oil during 2000 and 2001, this Commission raised issues regarding the utilities' management of fuel price risk as part of the 2001 fuel clause proceeding. The specific issues raised involved the reasonableness of hedging as a tool to manage fuel price risk and the appropriate regulatory treatment of hedging gains and losses. These issues were spun off to Docket No. 011605-EI for further investigation.

At the hearing for Docket No. 011605-EI, parties reached a settlement of all issues. By Order No. PSC-02-1484-FOF-EI ("Hedging Order"),[2] we approved the settlement of the issues. Specifically, the settlement provided a framework that incorporated hedging activities into fuel procurement activities. For natural gas, fuel oil, and purchased power, the settlement allowed Florida's generating IOUs to charge prudently incurred hedging gains and losses to the fuel clause. The Hedging Order specified that this Commission will review each IOU's hedging activities as part of the annual fuel proceeding.

The Hedging Order required utilities to file risk management plans as part of true-up filings. The intent of this requirement was to allow this Commission and parties to the fuel docket to monitor utility hedging activities. As part of the annual final true-up filings in the fuel docket, utilities were required to state the volumes of fuel hedged, the type of hedging instruments, the average length of the term of the hedge positions, and fees associated with hedging transactions.

Although the Hedging Order allowed utilities flexibility in the development of risk management plans, the order also set forth guidelines utilities were to follow. For example, the order required that risk management plans identify the objectives of the hedging programs and the minimum quantities to be hedged. The order also required that plans provide mechanisms and controls for the proper oversight within the utility of hedging activities, as well as include the method for assessing and monitoring fuel price risk.

In tandem with Docket No. 011605-EI, Commission staff conducted a review of Internal Controls of Florida's Investor-Owned Utilities for Fuel and Wholesale Energy Transactions.

[1]The Florida Retail Federation (FRF) filed a notice of joinder in OPC's brief on the same date.
[2]Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, In re: Review of investor-owned electric utilities' risk management policies and procedures.

This study examined the practices, procedures, controls, and policies these companies followed when purchasing fossil fuels and wholesale energy. The study period looked at data from 1998 through 2001. The study concluded that Florida IOUs had engaged in physical hedging in fuel procurement but very limited financial hedging. At the time, the IOUs had not set up the proper controls to engage in extensive financial hedging. Also, for the period studied, TECO and Gulf had little exposure to the volatility of natural gas prices.

The next time we reviewed our policy on hedging was at the 2007 fuel hearing. Parties raised questions regarding the period for which we were determining the prudent costs of hedging activities. We deferred our decision on the prudence of 2007 hedging activity costs to 2008 in order to allow for sufficient development of data and review of the matter.

Following the 2007 fuel hearing, two audits of the IOU's hedging programs were conducted by Commission staff. First, staff conducted a management audit reviewing the IOUs' hedging programs to assess the costs and benefits realized since the entry of the Hedging Order. Also reviewed was the IOUs' accounting treatment of 2007 hedging activities to determine compliance with their risk management plans filed in 2006.

The management audit assessed the current and historical strategies of the fuel procurement hedging programs within each company at that time, evaluated hedging objectives set forth in each company's risk management plan, and quantified the net costs and benefits of each company's hedging program. Specifically, the structure and performance of hedging natural gas and fuel oil through the use of physical purchases and/or financial instruments for the years 2003 through 2007 was examined. Information was collected regarding each company's policies and procedures, organizational charts, risk management plans, and historical hedging transactions, and an analysis conducted for each company. In June 2008, a report was issued entitled Fuel Procurement Hedging Practices of Florida's Investor-Owned Electric Utilities.

In its 2008 report, Commission staff found that each company shared a universal goal in purchasing financial hedges for its fuel procurement; that is, to reduce the impacts of the price extremes that can occur in the natural gas and fuel markets. In their hedging activities, the companies were not attempting to speculate on price movements in the market. Rather each was working to stabilize its annual fuel costs by initializing and settling financial hedging transactions through authorized financial counterparties. The volumes of gas and fuel oil hedged were less than the total volumes expected to be purchased. Overall, staff believed that the use of financial hedges for fuel purchases provided a benefit to utility customers.

In response to the deferral of the determination of the prudent costs in the 2007 fuel hearing, on January 31, 2008, FPL filed a petition requesting that we approve FPL's proposed volatility mitigation mechanism (VMM) as an alternative to FPL's hedging program. The VMM proposal involved FPL collecting under recoveries of fuel costs over two years instead of one year, as is the current practice. On March 11, 2008, a workshop was held to get stakeholder input on this proposal. All parties to the 2002 settlement attended.

By Order No. PSC-08-0316-PAA-EI,[3] we clarified the Hedging Order in several areas. IOUs were required to file a Hedging Information Report by August 15th of each year. We also

[3]Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, in Docket No. 080001-EI, In re: Fuel and purchased power cost recovery clause with generating performance inventive factor.

specified that it would make a determination of prudence of hedging results for the twelve month period ending July 31st of the current year. Additional workshops were held on June 9, 2008, and June 24, 2008, regarding FPL's VMM petition and guidelines for hedging programs. FPL withdrew its VMM petition on August 5, 2008.

Following the workshops, we established guidelines for risk management plans by Order No. PSC-08-0667-PAA-EI.[4] At that time we determined that utility hedging programs provide benefits to customers. The guidelines clarified the timing and content of regulatory filings for hedging activities, but allowed the IOUs flexibility in creating and implementing risk management plans. Each year in the fuel clause, our auditors review utility hedging results for the twelve month period ending July 31 of the current year. In addition, each year we approve the IOUs' risk management plans for hedging transactions the utility will enter the following year and beyond.

No other hedging-related orders have been issued to date, although on several occasions since the issuance of these three orders, Commission staff has presented hedging-related information to us at our publically noticed Internal Affairs meetings.

Since the 1990s, natural gas-fired generation has become a large part of the generation mix for Florida IOUs, and the increasing role for natural gas is expected to continue. Natural gas prices have been volatile over the years, with significant price spikes in 2000, 2003, 2005, and 2008. Since 2008, natural gas supply has increased significantly due to shale gas production.

Analysis

This issue focuses on three somewhat overlapping arguments: (1) the significant opportunity costs of hedging programs that IOUs incurred as part of fuel costs paid by customers; (2) whether the volatility of natural gas prices has declined to the point where hedging is no longer effective or necessary; and (3) whether conditions in the natural gas market are stable and eliminate the need for hedging.

The intervenors have argued in their briefs, supported by testimony of record, that hedging should be discontinued due to the large cumulative actual and projected net losses for each IOU from 2002 until 2015. The IOUs counter in their testimony and briefs that the purpose of hedging, as recognized in our previous hedging orders, is to reduce price volatility. While gains and losses can occur, the IOUs contend that assessing the merits of retaining hedging programs based on resultant gains or losses simply encourages price speculation, a practice that neither party believes to be in the ratepayers' best interests.

IOU witnesses acknowledged that there have been significant net cumulative hedging losses for natural gas. FPL had losses of $3.5 billion for the period 2002 to 2014 for natural gas ($3.162 billion when fuel oil hedging gains are included) and projects hedging losses of $490 million for 2015. DEF incurred $1.2 billion in losses for the period 2002 to 2014 and estimates $196 million in losses for 2015. Gulf Power incurred $127 million in losses from 2002 to 2014 and estimates $44 million for 2015. Tampa Electric incurred losses of $381 million for the

[4]Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI, In re: Fuel and purchased power cost recovery clause with generating performance inventive factor.

period 2002 to 2014 and estimates $40 million for 2015. FPL's recently approved Woodford project is also estimated to experience hedging losses for 2015. OPC witness Lawton testified that this prolonged period of losses should signal a re-evaluation of the necessity for hedging programs. However, there were earlier periods before 2008 when gains did offset losses. Customers have consistently benefited from falling prices for the unhedged portion of the IOUs' gas supply portfolios which fluctuates year to year based upon each IOU's approved Risk Management Plan. Each IOU witness testified that the goal of its hedging program was to reduce price volatility and that our previously approved hedging guidelines and procedures provide reasonable tradeoffs for mitigating volatility.

We agree that the level of opportunity savings and costs – hedging gains and losses – should not be a chief consideration in deciding whether to continue fuel price hedging. When gas prices are falling, losses will occur. Conversely, when gas prices are rising, gains will occur. The main objective of IOU hedging programs is to reduce the customer's exposure to fuel price volatility, not to reduce fuel costs. Therefore, these programs should be well disciplined to accomplish this objective and to be non-speculative.

As emphasized by intervenors, the cumulative losses are currently large. These losses are the result of steadily falling natural gas prices in the open market. Customers continue to experience the benefits of the current downward trend in prices for the unhedged portions of the IOUs' natural gas purchases. Should the market price of natural gas trend or spike upward, hedging savings will occur but, overall, fuel costs will increase.

OPC witness Lawton testified that since price volatility has decreased and is trending downward, hedging is unnecessary. IOU witnesses both agreed and disagreed that price volatility had decreased since 2001. DEF witness McAllister agreed with witness Lawton that natural gas prices are less volatile. Gulf witness Ball stated that Gulf does not forecast price volatility and suggests such a forecast is not possible. However, witness Ball also testified that, with a few exceptions, in recent history price volatility has been lower. TECO witness Caldwell agreed that fuel price volatility decreased during the period 1997 to 2015.

FPL witness Yupp strongly disagreed with OPC's conclusion. While the price of natural gas has trended downward over the last several years, and the trend line in natural gas volatility has done the same, witness Yupp testified that the volatility of natural gas prices has varied considerably year to year. Thus, while the trend line for natural gas volatility shows a decline, there is a very low correlation of the trend line with the yearly data. That being the case, the trend line in price volatility is not a statistically valid predictor of next year's price volatility point. Based on this analysis, witness Yupp concluded that one cannot reasonably conclude that natural gas price volatility has decreased as natural gas prices have fallen or will decrease in the future. Witness Yupp testified that hedging had been successful in reducing price volatility as measured by the fact that FPL only met the plus or minus ten percent mid-course correction threshold established by Rule 25-6.0424, F.A.C., once for the period 2002 to 2014 with hedging. Had FPL not hedged, this threshold would have been exceeded nine times. Witness Yupp also testified that the current EIA forecasts for natural gas prices show a confidence interval of ranging more toward higher prices than lower prices. Gulf witness Ball affirmed this aspect of the EIA forecast and OPC witness Lawton acknowledged this fact. The confidence intervals for natural gas prices included in EIA's forecast are consistent with the economic reality that gas prices cannot indefinitely continue to decrease as the price of any commodity cannot fall below the price of production for sustained periods of time.

OPC has argued that the annual fuel factor smoothes out price volatility and is a cost-free alternative to hedging. Witness Lawton stated that the annual or level fuel factor effectively shields customers from day-to-day changes in market prices. However, witness Lawton acknowledges that the cumulative effect of unexpected changes in market prices could lead to a mid-course correction to fuel factors. DEF witness McCallister agreed that the level fuel factor can reduce the customer's exposure to price volatility within any given year, assuming no mid-course correction. However, without hedging true-up amounts in subsequent years could be significant. TECO witness Caldwell testified that while the annual fuel factor provides some smoothing over a twelve month period, it does not limit the potential for fuel costs to increase or decrease, i.e., fuel price volatility. Witness Caldwell also testified that spreading an under-recovery over more time, as suggested by FPL in 2008 by its validation mitigation mechanism (VMM), without hedging any portion of the natural gas portfolio presents a risk of stacking under-recoveries if prices rise making the rate impact on ratepayers even greater.

The record is clear that setting a level or annual factor has some smoothing effect within any given year assuming no mid-course corrections. The record is also clear that by providing certainty to a portion of expected gas consumption, hedging reduces annual true-up amounts and the number of mid-course corrections required by our rules.

A review of the testimony reveals that both intervenor and IOU witnesses generally agree that price volatility cannot be accurately or consistently forecasted. The record before us indicates that from 2002 to date natural gas price volatility has varied up and down significantly, with 2009 and 2014 reaching levels of 99.6 percent and 96.7 percent, respectively. Therefore, while natural gas prices have trended downward in the last few years, the level of price volatility cannot be predicted with any certainty. It is important to remember that the impact on ratepayers of even small variations in the price of natural gas is significant, e.g., a one cent change in natural gas prices results in $6 million in additional fuel expense for FPL's customers. The increased dependence on natural gas for each of Florida's IOUs means customers will have significant exposure to the uncertainties of natural gas prices if hedging were completely discontinued.

As stated in our past decisions, the objective of the IOUs' hedging programs is to reduce the customers' exposure to price volatility. Currently, natural gas prices are low compared to prices since 2008. One could reasonably assume that prices are more likely to rise than to continue downward, and FPL witness Yupp provides calculations, reasons, and an opinion supporting this possibility. That prices may be approaching or going below the variable cost of production is a noteworthy consideration. However, the low prices and possible price direction should not be a chief consideration since it would necessarily involve some degree of speculation about the future direction of prices.

Intertwined with price volatility are the supply and demand conditions of the natural gas market. All witnesses agreed that natural gas market conditions in 2015 are different from those of 2002. All witnesses agreed that the growth of shale gas production has increased the supply of natural gas. TECO witness Caldwell noted that the natural gas market seems to move in cycles of significant production increases, due to new sources, followed by increases in demand

Natural gas prices are more volatile when weather events affect supply or demand. In January 2014, the polar vortex had a significant effect on natural gas prices. Weather events, such as very cold periods during the winter, can increase demand, prices, and volatility. However, additional pipelines under construction that connect the Marcellus Shale to northeastern states may diminish this effect.

Regarding shale gas production and the current abundant supply of natural gas, FPL witness Yupp noted that the market price may be below the cost of production for many producers. The market price cannot be below the cost of production for any extended period of time. He further noted that production costs vary among producers. Rig counts are down and this could impact gas supply, but this too may not be a complete indicator of future gas production.

Gulf witness Ball alluded to future events that could disrupt shale gas production, e.g., existing or proposed local, state, or federal environmental regulations either banning or restricting shale gas production, or increased demand for natural gas based upon federal power plant regulations reducing carbon emissions. He testified that OPC has minimized any potential threats to shale gas production. However, while opining that environmental concerns have largely been put to rest, OPC witness Lawton acknowledged that New York currently bans hydraulic fracking.

Demand for natural gas, particularly for electric generation, for both Florida and the country as a whole is increasing. In 2016, DEF, FPL, TECO and Gulf estimate 73, 72, 52 and 44 percent of their generation, respectively, will be from natural gas. In addition, natural gas will begin to be exported in late 2015, and a number of export terminals are under construction or are planned.

The decision of whether to continue fuel price hedging turns on what one expects price volatility and natural gas market conditions to do in the future. While natural gas prices have trended down, price volatility is uncertain and cannot be reliably forecasted. What this record clearly establishes is that without hedging, customers have a very significant exposure to natural gas price volatility due to a very dynamic natural gas market. Today natural gas prices are low and gas supply is forecasted to be abundant. However, demand for natural gas is increasing and is heavily influenced by weather and uncertain supply conditions. Given these factors, on balance we find that the continuation of natural gas hedging process as outlined in our previous orders is in the customers' best interests.

Our decision to continue hedging at this time is based on the evidence presented in this record which in large part consists of arguments to either completely eliminate hedging or to continue the procedures in place at this time. There was no written testimony from any party and very limited cross examination on possible changes to the manner in which the IOUs conduct natural gas financial hedging activities or alternatives to hedging: cost sharing of hedging gains and losses between the IOUs and ratepayers, alternative accounting treatment for recovery of gains and losses (VMM program), or imposing limits on the percentage of natural gas purchases hedged. All witnesses agreed that any changes to the hedging protocol should be prospective and that the current hedges should be allowed to terminate on their original contract dates. Notwithstanding our decision on hedging, we recognize that the cost of this program is significant by any measure for each Florida IOU and deserves further analysis. Therefore, we direct our staff, in conjunction with the parties to this docket, to explore possible changes to the current hedging protocol that will minimize potential losses to customers.

Risk Management Plans

Consistent with our decision above, we find that the 2016 Risk Management Plans of DEF, FPL, TECO and Gulf shall be approved. Each plan provides the appropriate governance for a well-disciplined and prudently managed utility hedging program and is consistent with the Hedging Guidelines. These plans are structured to reduce price volatility risk in a structured manner and with the exception of FPL's plan, which includes participation in the Woodford Gas Reserves Project, is very similar to risk management plans approved in past years.

Company-Specific Fuel Adjustment Issues

Florida Power & Light Company

Woodford Gas Reserve Project

On June 25, 2014, FPL petitioned the Commission for a determination that it was prudent for FPL to acquire an interest in a natural gas reserve project (the Woodford Project) and that the revenue requirement associated with investing in and operating the gas reserve project was eligible for recovery through the Fuel Clause. In Order No. PSC-15-0038-FOF-EI[5] (Woodford Order), the Commission found that the Woodford Project was in the public interest and its costs were recoverable through the Fuel Clause. OPC and FIPUG have filed appeals of the Woodford Order with the Florida Supreme Court, which are pending as of the date of this order[6].

As summarized in the Woodford Order, the Woodford Project is a capital investment by which FPL invests directly in shale gas reserves in the Woodford Shale region of Oklahoma and ratepayers pay natural gas production costs rather than the market price on the physical gas produced.

[5]Order No. PSC-15-0038-FOF-EI, issued January 12, 2015, in Docket No. 150001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.
[6]On March 30, 2015, the Florida Supreme Court consolidated OPC's three appeals and the FIPUG appeal into a single case (Florida Supreme Court Case No. SC15-95).

> Historically, production costs have been less volatile than market prices. We find the Woodford Project will act as a hedge that is designed to decouple costs from market prices.[7] The Woodford Project costs are based solely on the operations and maintenance costs, and on the investment that is required, and is essentially fixed. FPL purchases more natural gas than any other electric utility in the country. The reality is that in this state, and nationally, we continue to grow the need for natural gas to provide electricity as we move away from coal. Although the Woodford Project is relatively small and will have a small effect on FPL's overall cost of natural gas and on price hedging, it will act as a long-term physical hedge (30 years or longer in duration) compared to financial hedges, which typically lock in prices for 12 – 24 months. Fuel and related costs that are subject to volatile changes are recoverable through the Fuel Clause.[8] We have allowed non-fuel items to be recovered through the Fuel Clause as long as they are projected to result in fuel savings.[9] FPL's natural gas price forecasts of October 2013 and July 2014 indicate that the Woodford Project will likely produce positive customer fuel savings over the life of the Project based on combinations of two factors: well productivity and natural gas market price. Under FPL's July 2014 natural gas price forecast, 6 of 9 sensitivities produce positive customer savings. ...

Order No. PSC-15-0038-FOF-EI at pp. 4-5.

The Woodford Project order is presently on appeal at the Florida Supreme Court. However, no motions to stay have been filed and the Woodford Order remains in full force and effect. Further, FPL has moved forward with its investment, and drilling and production activity began earlier this year. Therefore, we find that FPL is entitled to recover its Woodford Project costs through the Fuel Clause in the amount of $24,611,461 for the period January 2015 through December 2015. For the period January 2016 through December 2016, we find that the appropriate projected costs FPL shall be allowed to recover through the Fuel Clause for the Woodford natural gas exploration and production project is $53,777,690.

Florida Public Utilities Company

FPL Interconnection and legal and consultant fees

FPUC has requested that it be allowed to recover $107,333 in 2016, representing the depreciation expense, taxes other than income taxes and a return on investment associated with the $3.5 million dollar cost of rerouting FPUC's 138 KV transmission line to parallel an existing

[7]Customers currently bear certain drilling, production, and shale gas risks (earthquakes, environmental issues, etc.) as these factors are embedded in the market price of gas.
[8]Order No. 14546, issued July 8, 1985, in Docket No. 850001-EI-B, In re: Cost recovery Methods for Fuel-Related Expenses.
[9]Order Nos. PSC-97-0359-FOF-EI, issued March 31, 1997, in Docket 970001-EI, In re: Fuel and purchased power cost recovery clause and generating performance incentive factor (FPL investment in rail cars) and PSC-01-2516-FOF-EI, issued December 26, 2001, in Docket 010001-EI, In re: Fuel and purchased power cost recovery clause and generating performance incentive factor (Incremental Power Plant Security Costs).

FPL 230 KV line and upgrading FPL's substation to accommodate this interconnection. At this time, FPUC's 138 KV transmission is directly connected to the JEA 138 KV transmission network. If construction is started in 2016, the completion date is expected during the latter half of 2017. FPUC has estimated that savings will result from this interconnection for essentially two reasons: 1) improved system reliability on FPUC's transmission system; and 2) the ability to purchase power from other wholesale providers without incurring additional transmission wheeling costs which should result in lower purchased power costs. FPL will be constructing the transmission line with the costs to be reimbursed by FPUC.

FPUC does not generate any electricity but is solely dependent on wholesale purchase power agreements to meet its capacity and energy needs. At this time, FPUC has wholesale power purchase agreements with JEA which serve its Northeast Division (Amelia Island) and Gulf Power Company (Gulf) which serve its Northwest Division (Marianna). Both of these wholesale purchased power contracts include payments for JEA's and Gulf's transmission rate base costs to provide power to FPUC. However, FPUC does not currently recover any of its own transmission rate base costs through the fuel clause. FPUC's current contract with JEA is set to expire on December 31, 2017, the same time that FPUC's interconnection with FPL is expected to be completed. FPUC is required to purchase all of its wholesale purchased power from JEA during the term of the current contract. Thus, the projected $2.3 million in savings for future purchased power costs associated with the FPL interconnection cannot materialize until after January 1, 2018.

FPUC intends to issue a request for proposals (RFP) soliciting capacity and energy for delivery beginning in 2018. FPUC anticipates that as a result of its RFP it will be able to contract for wholesale capacity and energy at significantly lower rates once the FPL interconnection is completed.

Our basic guidelines for recovery of capital costs through the fuel adjustment clause are found in Order No. 14546.[10] Since the issuance of Order No. 14546 in 1985, we have issued 19 orders interpreting and applying these two principles to various proposed rate base capital costs for which recovery through the fuel clause was requested.[11] FPUC's arguments focus on why its proposed transmission project qualifies for recovery through the fuel adjustment clause.

However, OPC, FRF, FIPUG, and PCS all take the position that the rate case stipulation and settlement agreement entered into between OPC and FPUC on August 29, 2014 and

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[10]Order No. 14546, issued on July 8, 1985, in Docket No. 850001-EI,-B, In re: Cost Recovery Methods for Fuel-Related Expenses.

[11]Order No. PSC-11-0080-PAA-EI, issued on January 31, 2011, in Docket No. 100404-EI, In re: Petition by Florida Power & Light Company to recover Scherer Unit 4 Turbine Upgrade costs through environmental cost recovery clause or fuel cost recovery clause (This order includes a list of all orders between 1985 and 2005); Order No. PSC-12-0498-PAA-EI, issued on September 27, 2012, in Docket No. 120153-EI, In re: Petition to recover capital costs of Polk Fuel Cost Reduction Project through the Fuel Cost Recovery Clause, by Tampa Electric Company; Order No. PSC-13-0505-PAA-EI, issued on October 28, 2013, in Docket No. 130198-EI, In re: Petition for prudence determination regarding new pipeline system by Florida Power & Light Company; Order No. PSC-14-0309-PAA-EI, issued on June 12, 2014, in Docket No. 140032-EI, In re: Petition to recover capital costs of Big Bend fuel cost reduction project through the fuel cost recovery clause, by Tampa Electric Company; Order No. PSC-15-0038-FOF-EI, issued on January 12, 2015, in Docket No. 150001-EI, In re: Fuel purchased power cost recovery clause with generating performance incentive factor.

approved by this Commission in Order No. PSC-14-0517-S-EI, issued on September 29, 2014, (Order No. PSC-14-0517)[12] prohibits the recovery of costs associated with the FPL interconnection through the fuel clause.

Section I, Term, of the settlement agreement prohibits FPUC from increasing its base rates during the minimum term of the agreement, or until after December 31, 2016. The settlement agreement also states in Section VI, Other Cost Recovery, as follows:

> Nothing in this agreement shall preclude the Company from requesting the Commission to approve the recovery of costs that are: (a) of a type which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges or (b) incremental costs not currently recovered in base rates which the Legislature or Commission determines are clause recoverable subsequent to the approval of this settlement. Except as provided in this Agreement, it is the intent of the Parties in this Paragraph VI that FPUC not be allowed to recover through cost recovery clauses increases in the magnitude of costs, incurred after implementation of the new base rates, of types or categories (including but not limited to, for example, investment in and maintenance of transmission assets) that have been traditionally and historically recovered through FPUC's base rates.

Additionally, FPUC has included actual and estimated consulting and legal fees in its fuel costs for 2014, 2015, and 2016. Actual costs included in its 2014 true-up calculation are $122,933. FPUC included $111,135 in its 2015 estimated/actual costs, and $387,000 its 2016 projected costs.

FPUC believes that costs incurred and projected to be incurred for the FPL interconnection and contracted consultants and legal services are directly fuel-related and will ultimately produce fuel savings that will flow to FPUC's customers through the fuel adjustment clause, and thus, are appropriate for recovery through the fuel cost recovery clause. FPUC argued that this Commission has clearly stated that the purpose of the clause proceedings is to provide for recovery of volatile costs that tend to fluctuate between rate case proceedings, which if incorporated in base rates, would unduly penalize the utility or its customers.[13]

No party filed testimony in the proceeding in opposition to FPUC's requested legal and consulting fees. In support of its request, FPUC witness Young argued that the consultants hired by FPUC engaged in activities related to the negotiation of a new power purchased contract with Eight Flags Energy, modification of FPUC's existing agreement with Rayonier Performance Fibers, and analysis of FPUC's current power purchase agreement to determine opportunities to produce fuel cost reductions. FPUC witness Cutshaw emphasized that the costs being requested are not associated with administrative functions associated with fuel procurement, nor associated

[12]Order No. PSC-14-0517-S-EI, issued on September 29, 2014, in Docket No. 140025-EI, In re: Application for rate increase by Florida Public Utilities Company.

[13]Order No. PSC-05-0748-FOF-EI, issued July 14, 2005, in Docket No. 041272-EI, at p.37, In Re: Petition for approval of storm cost recovery clause for recovery of extraordinary expenditures related to Hurricanes Charley, Frances, Jeanne, and Ivan, by Progress Energy Florida, Inc.

with the Company's internal staff responsible for fuel procurement. FPUC witness Young stated that the costs FPUC is seeking to recover are similar to costs we have traditionally and historically allowed to be recovered through the fuel clause. In addition, witness Young pointed out that the costs requested have not been included in FPUC's base rates as these costs are volatile and fluctuate between rate case proceedings.

FPUC argued that it has met its burden of proof by demonstrating that the legal and consulting fees it proposes for recovery through the fuel clause are: (1) prudent expenses associated with retaining outside expertise that the Company does not otherwise have in-house; (2) work for which these consultants were retained are associated with projects that are either currently producing fuel savings or are reasonably expected to produce savings for the Company and its customers; and (3) expenses of a type that we have traditionally allowed FPUC to recover through the fuel adjustment clause.

OPC argued that the settlement agreement precludes FPUC from seeking recovery in the fuel clause of its legal and consulting fees as does Order No. 14546. It is OPC's position that FPUC is barred from seeking recovery in the fuel clause for the cost of types or categories that have traditionally and historically been recovered through FPUC's base rates. In addition, OPC argued that the base rate freeze provision in the settlement agreement also prohibits FPUC from recovering these costs through cost recovery clauses.

OPC contended that consulting and legal generation-related costs have traditionally and historically been recovered through base rates for both FPUC and other electric utilities. OPC acknowledged that FPUC was allowed recovery through the fuel clause of its legal and consulting fees associated with the issuance and evaluation of RFPs for purchased power agreements.[14] However, it is OPC's contention that generic legal and consulting activities have not been specifically identified and allowed to be recovered through the fuel clause.

In addition, OPC argued that Order No. 14546 sets forth the policy that costs permitted for recovery through the fuel clause must produce fuel savings contemporaneous with cost recovery. OPC asserted that FPUC is merely speculating that the consulting and legal activities for which it is seeking recovery in 2015 and 2016 will actually result in lower purchased power costs. While FPUC witness Young testified that some of the consultant and legal activities "produced" savings, OPC argued that he could identify no specific savings that were achieved as a result of those activities. OPC also maintained that FPUC conceded that the outside consulting and legal fees are fuel procurement and administration charges or costs that Order No. 14546 specifically precludes from recovery through the fuel clause

[14] Order No. PSC-05-1252-FOF-EI (Order No. 05-1252), issued in December 23, 2005, in Docket No. 050001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Our basic guidelines for recovery of costs through the fuel adjustment clause are found in Order No. 14546.[15] In Order No. 14546 the parties stipulated to, and we approved, two basic principles for recovery of expenses through the fuel clause:

> 1. When similar circumstances exist, the Commission should attempt to treat, for cost recovery purposes, specific types of fossil fuel-related expenses in a uniform manner among the various electric utilities. At times, however, it may be appropriate to treat similar types of expenses in dissimilar ways.
>
> 2. Prudently incurred fossil fuel-related expenses which are subject to volatile changes should be recovered through an electric utility's fuel adjustment clause. The volatility of fossil fuel-related costs may be due to a number of factors including, but not necessarily limited to: price, quantity, number of deliveries, and distance. Except as noted below, these volatile fossil fuel-related charges are incurred by the utility for goods obtained or services provided prior to the delivery of fuel to the electric utility's dedicated storage facilities. (Dedicated storage facilities mean storage facilities which are used solely to serve the affected electric utility.) All other fossil fuel-related costs should be recovered through base rates.[16]

In addition, the parties recommended that the policy be flexible so that costs normally recovered through base rates could be recovered through the fuel adjustment clause where the utility took advantage of a cost-effective transaction and those costs were not recognized or anticipated in the level of costs used to establish the utility's base rates. In those instances, "[t]he Commission shall rule on the appropriate method of cost recovery based upon the merits of each individual case."[17] Order No. 14546 was intended to identify costs that were appropriate for cost recovery yet recognize that we retain the ability in individual cases to rule on the method of cost recovery.

As the starting point of our analysis, we disagree with OPC that FPUC has not "traditionally and historically" recovered consulting and legal fees through the fuel clause. In Docket Nos. 060001-EI, 070001-EI, 080001-EI, 090001-EI, 10001-EI, 110001-EI, 120001-EI, 130001-EI, and 140001-EI, legal and consulting fees associated with fuel-related work were included in FPUC's true-up filings which we approved without objection. Further, in Order No. PSC-05-1252, we approved the recovery of fees for Christensen and Associates related to the preparation and evaluation of a RFP for purchased power for its Northwest Division. In Order No. PSC-05-1252, we cited the fact that FPUC was a small, non-generating, investor-owned electric utility that did not have the resources internally to prepare an RFP and evaluate responses.[18] Because FPUC has "traditionally and historically" recovered these types of costs through the fuel clause, we find that the terms of the settlement agreement do not apply and do not prohibit recovery through the fuel clause at this time.

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[15] Order No. 14546, issued on July 8, 1985, in Docket No. 850001-EI,-B, In re: Cost Recovery Methods for Fuel-Related Expenses.
[16] Id. at p.2.
[17] Id. at p. 3.
[18] Order No. PSC-05-1252-FOF-EI, issued December 23, 2005, in Docket No. 050001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

FPUC has been aggressively seeking opportunities to reduce fuel costs to its consumers. To properly and thoroughly explore fuel-saving opportunities, FPUC engages legal and consulting assistance as it continues to lack in-house expertise. The costs that FPUC is requesting to be recovered in this proceeding are associated with legal and consulting fees incurred in the development and enactment of projects designed to reduce fuel rates to FPUC's customers, costs associated with the development and negotiations of power supply contracts, and costs to consultants engaged in performing due diligence in review and analysis of the Renewable Energy Agreement between FPUC and Rayonier.

In 2016, FPUC will begin discussions with various purchased power providers in preparation for the 2017 expiration of its Northeast Division wholesale power contract with JEA. FPUC is presently reliant upon JEA for all its power needs in its Northeast Division and is prohibited from taking power from another wholesale power provider until the expiration of its wholesale power purchase agreement in December 2016. In order to obtain the lowest price and most favorable terms in its wholesale power contract to serve its Northeast Division, FPUC needs significant research, analysis, and negotiation unavailable in-house. These consulting and legal fees are not currently being recovered in FPUC's base rates. Nor were these fees anticipated in FPUC's last rate case, as these types of costs fluctuate significantly from year to year.

We find that there is no compelling reason to deviate from our past decisions. FPUC remains a small, non-generating electric utility lacking the in-house expertise to find and evaluate potential opportunities for fuel savings and craft and evaluate requests for proposals for generation needs. These costs were not included in its last rate case. At the time of its last rate case, similar costs were being recovered through the fuel clause. The costs FPUC is requesting for recovery through the fuel clause are not related to FPUC's internal staff for routine fuel and purchased power procurement and administration. FPUC projects that the opportunities being evaluated by its contracted consultants and legal professionals will result in fuel savings.

All parties agree that the proposed interconnection with FPL will result in improved system reliability for Amelia Island. Nor is there disagreement that interconnection with FPL will offer wholesale power purchase options not currently available to FPUC when its wholesale power agreement with JEA expires in December 2016. The disagreement rests with OPC's conclusion that Order No. 14546 prohibits cost recovery until cost savings are received by ratepayers. We do not read Order No. 14546 that restrictively.

Therefore, we find that the interconnection with FPL and the consulting and legal fees associated with the development and enactment of projects designed to reduce fuel rates to FPUC's customers, costs associated with the development and negotiations of power supply contracts, and costs to consultants engaged in performing due diligence in review and analysis of the Renewable Energy Agreement between FPUC and Rayonier shall be recovered through the fuel cost recovery clause. Further, as agreed to by FPUC at hearing, the consultant's costs for the preparation of Commission filings for the consolidation of FPUC's fuel divisions shall be removed from its requested costs included in its true-up and projected filings. In order to facilitate that adjustment, we direct FPUC to file revised true-up and projection schedules reflecting removal of the costs associated with the preparation of Commission filings within 20 days of our vote.

Final fuel true-up amounts

FPUC has removed $2,046 in expenses associated with consultant fees from its request for cost recovery of the final true-up amounts for the period January 2014 through December 2014. The expenses were for work performed to restructure FPUC's Fuel schedules (A-Schedules and E-Schedules), when the Northeast and Northwest Divisions were consolidated. The appropriate final fuel adjustment true-up amount for the period January 2014 through December 2014 is properly reflected in the brief FPUC filed on November 13, 2015. Therefore, we find that the appropriate final fuel adjustment true-up amount for the period January 2014 through December 2014 is an under-recovery of $1,474,307.

FPUC has removed $4,532 in expenses from its request for cost recovery of the final true-up amounts for the period January 2015 through December 2015. The expenses were for work performed to restructure FPUC's Fuel schedules (A-Schedules and E-Schedules), when the respective divisions were consolidated. The appropriate fuel adjustment actual/estimated true-up amount for the period January 2015 through December 2015 is properly reflected in the brief FPUC filed on November 13, 2015. Therefore, we find that the appropriate fuel adjustment actual/estimated true-up amount for the period January 2015 through December 2015 is an under-recovery of $107,841.

FPUC has removed $6,578 from its request for cost recovery of 2014 and 2015 true-up amounts. This amount is the sum of the expense amounts referenced above and properly reflected in the brief FPUC filed on November 13, 2015. Therefore, we find that the appropriate total fuel adjustment true-up amount to be collected from January 2016 through December 2016 is an under-recovery of $1,582,148.

Consistent with our decision including the FPL interconnection and legal and consulting fees, the appropriate projected total fuel and purchased power cost recovery amounts for FPUC for the period January 2016 through December 2016 is $67,488,997.

FPUC has removed expenses associated with the preparation of Commission filings from its request for cost recovery of 2014 and 2015 true-up amounts. Therefore, we find that the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2016 through December 2016 is $68,971,145.

Based on previous adjustments made we find that the appropriate levelized fuel cost recovery factor for FPUC for the period January 2016 through December 2016 is 6.692 cents per kilowatt hour.

Based on the previous adjustments made, we find that the appropriate fuel cost recovery factors for FPUC for each rate class/delivery voltage level class adjusted for line losses is as stated below:

| Rate Schedule | Adjustment |
|---|---|
| RS | $0.10619 |
| GS | $0.10169 |
| GSD | $0.09709 |
| GSLD | $0.09407 |
| LS | $0.07211 |
| Step rate for RS | |
| RS Sales | $0.10619 |
| RS with less than 1,000 kWh/month | $0.10188 |
| RS with more than 1,000 kWh/month | $0.11438 |

The appropriate adjusted Time of Use (TOU) and Interruptible rates for the Northwest Division are:

Time of Use/Interruptible

| Rate Schedule | Adjustment On Peak | Adjustment Off Peak |
|---|---|---|
| RS | $0.18588 | $0.06288 |
| GS | $0.14169 | $0.05169 |
| GSD | $0.13709 | $0.06459 |
| GSLD | $0.15407 | $0.06407 |
| Interruptible | $0.07907 | $0.09404 |

Effective Date

Per stipulation of the parties, the new factors shall be effective beginning with the first billing cycle for January 2016 through the last billing cycle for December 2016. The first billing cycle may start before January 1, 2016, and the last cycle may be read after December 31, 2016, so that each customer is billed for twelve months regardless of when the recovery factors became effective. The new factors shall continue in effect until modified by us.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the findings set forth in the body of this Order are hereby approved. It is further

ORDERED that the stipulations of the parties contained in the Notice of Stipulations filed on October 30, 2015, as modified by our bench decision, attached hereto as Attachment A, is incorporated into and made a part of this Order. It is further

ORDERED that Florida Power & Light Company, Florida Public Utilities Company, Gulf Power Company, Duke Energy Florida, LLC., and Tampa Electric Company are hereby authorized to apply the fuel cost recovery factors set forth herein during the period January 2016 through December 2016. It is further

ORDERED that the estimated true-up amounts contained in the fuel cost recovery factors approved herein are hereby authorized subject to final true-up and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that Florida Power & Light Company, Florida Public Utilities Company, Gulf Power Company, Duke Energy Florida, LLC, and Tampa Electric Company are hereby authorized to apply the capacity cost recovery factors set forth herein during the period January 2016 through December 2016. It is further

ORDERED that the estimated true-up amounts contained in the capacity cost recovery factors approved herein are hereby authorized subject to final true-up and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that the Fuel and Purchased Power Cost Recovery Clause With Generating Performance Incentive Factor docket is an on-going docket and shall remain open.

By ORDER of the Florida Public Service Commission this 23rd day of December, 2015.

Carlotta S. Stauffer

CARLOTTA S. STAUFFER
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
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Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

SBr

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

ATTACHMENT A

STIPULATIONS

ISSUE 2A: The Commission should approve as prudent DEF's actions to mitigate the volatility of natural gas, residual oil, fuel oil, and purchased power prices, as reported in DEF's April 2015 and August 2015 hedging reports.

ISSUE 2C: No adjustments are needed to account for replacement costs associated with the July 2014 forced outage at the Hines plant.

ISSUE 3A: Yes, the Commission should approve as prudent FPL's actions to mitigate the volatility of natural gas, residual oil, fuel oil, and purchased power prices, as reported in FPL's April 2015 and August 2015 hedging reports.

ISSUE 3C: The total gain in 2014 under the Incentive Mechanism approved in Order No. PSC-13-0023-S-EI, was $67,626,867. This amount should be shared between FPL and its customers, with FPL retaining $12,976,120.

ISSUE 3D: The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2014 through December 2014 is $460,428.

ISSUE 3E: The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for variable power plant O&M costs incurred to generate output for wholesale sales in excess of 514,000 megawatt-hours for the period January 2014 through December 2014 is $2,259,985.

ISSUE 3F: The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2015 through December 2015 is $441,826.

ISSUE 3G: The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for variable power plant O&M costs incurred to generate output for wholesale sales in excess of 514,000 megawatt-hours for the period January 2015 through December 2015 is $2,759,649.

ISSUE 3H: The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2016 through December 2016 is $473,512

ISSUE 3I: The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for variable power plant O&M costs incurred to generate output for wholesale sales in excess of 514,000 megawatt-hours for the period January 2016 through December 2016 is $1,498,826.

ISSUE 3J: This issue has been deferred until 2016 to allow FPL to continue negotiations for potential reimbursement of St. Lucie 2 replacement power costs associated with the extended refueling outage in 2014.

ISSUE 3N: The Commission should approve FPL's proposed generation base rate adjustment (GBRA) factor of 3.899 percent for the Port Everglades Energy Center (PEEC) expected to go in-service on June 1, 2016.

ISSUE 3O: This issue has been dropped with the understanding that any party may raise it again in the 2016 proceeding.

ISSUE 3P: FPL has properly reflected in the fuel and purchased power cost recovery clause the effects of acquiring the Cedar Bay facility and terminating the existing Cedar Bay power purchase agreement consistent with the terms of the settlement agreement between FPL and OPC approved in Docket No. 150075-EI.

ISSUE 5A: The Commission should approve as prudent Gulf's actions to mitigate the volatility of natural gas, residual oil, fuel oil, and purchased power prices, as reported in Gulf's April 2015 and August 2015 hedging reports.

ISSUE 6A: The Commission should approve as prudent TECO's actions to mitigate the volatility of natural gas, residual oil, fuel oil, and purchased power prices, as reported in TECO's April 2015 and August 2015 hedging reports.

ISSUE 6C: The appropriate amount of capital costs for the Big Bend fuel conversion project that TECO should be allowed to recover through the Fuel Clause for the period January 2015 through December 2015 is $3,744,426.

ISSUE 6D: The appropriate amount of capital costs for the Big Bend fuel conversion project that TECO should be allowed to recover through the Fuel Clause for the period January 2016 through December 2016 is $4,894,041.

ISSUE 6E: No adjustments are needed to account for replacement costs associated with the June 2015 forced outage at Big Bend Unit 2.

ISSUE 6F: The cost of the natural gas burned during the testing of natural gas as a co-fired fuel at Big Bend Station is appropriate for recovery.

ISSUE 7: The appropriate actual benchmark levels for calendar year 2015 for gains on non-separated wholesale energy sales eligible for a shareholder incentive are as follows:

| | |
|---|---|
| Duke: | $1,739,843 |
| Gulf: | $ 677,983 |
| TECO: | $1,479,981 |
| FPL: | Not applicable |

ISSUE 8: The appropriate actual benchmark levels for calendar year 2016 for gains on non-separated wholesale energy sales eligible for a shareholder incentive are as follows:

| | |
|---|---|
| Duke: | $2,704,668 |
| Gulf: | $ 752,900 |
| TECO: | $1,532,270 |
| FPL: | Not applicable |

ISSUE 9: The appropriate final fuel adjustment true-up amounts for the period January 2014 through December 2014 are as follows:

| | |
|---|---|
| FPL: | $10,088,837 (over-recovery) refunded as part of mid-course correction approved by Order No. 15-0161-PCO-EI |
| Duke: | $11,604,966 (over-recovery) |
| Gulf: | $ 8,084,753 (over-recovery) |
| TECO: | $ 2,919,025 (under-recovery) |

ISSUE 10: The appropriate fuel adjustment actual/estimated true-up amounts for the period of January 2015 through December 2015 are as follows:

| | |
|---|---|
| FPL: | $66,818,243 under-recovery |
| Duke: | $67,126,064 over-recovery |
| Gulf: | $11,285,334 over-recovery |
| TECO: | $30,509,575 over-recovery |

ISSUE 11: The appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2016 through December 2016 are as follows:

| | |
|---|---|
| FPL: | $66,818,243 to be collected (under-recovery) |
| Duke: | $78,731,032 to be refunded (over recovery) |
| Gulf: | $19,370,087 to be refunded (over-recovery) |
| TECO: | $27,590,550 to be refunded (over-recovery) |

ISSUE 12: The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2016 through December 2016 are as follows:

| | |
|---|---|
| FPL: | $3,023,588,111, which excludes prior period true up amounts, revenue taxes, the GPIF reward or penalty, or FPL's portion of the gains from its Incentive Mechanism. |
| Duke: | $1,480,800,063 |

| | |
|---|---|
| Gulf: | $400,060,296, including prior period true up amounts and revenue taxes |
| TECO: | $668,014,513, which is adjusted by the jurisdictional separation factor, excluding the GPIF reward or penalty, and the revenue tax factor, but including the prior period true up amounts. |

ISSUE 14A: FPL has properly reflected in its 2016 GPIF targets/ranges the effects of acquiring the Cedar Bay facility and terminating the existing Cedar Bay power purchase agreement consistent with the terms of the settlement agreement between FPL and OPC approved in Docket No. 150075-EI.

ISSUE 17: The appropriate generation performance incentive factor (GPIF) reward or penalty for performance achieved during the period January 2014 through December 2014 for each investor-owned electric utility subject to the GPIF is as follows:

| | |
|---|---|
| FPL: | $23,303,114 reward |
| DEF: | $8,613,797 penalty |
| Gulf: | $2,648,312 reward |
| TECO: | $1,258,600 reward |

ISSUE 18: The appropriate GPIF targets/ranges for the period January 2016 through December 2016 for each investor-owned electric utility subject to the GPIF are shown below:

**GPIF Targets / Ranges for the period January 2016 through December 2016**

| Company | Plant/Unit | EAF | | | ANOHR | | |
|---|---|---|---|---|---|---|---|
| | | Target | Maximum | | Target | Maximum | |
| | | EAF (%) | EAF (%) | Savings ($000's) | ANOHR BTU/KWH | ANOHR BTU/KWH | Savings ($000's) |
| FPL | Ft. Myers 2 | 90.3 | 92.8 | 2,696 | 7,344 | 7,190 | 6,035 |
| | Martin 8 | 82.3 | 84.3 | 1,681 | 7,017 | 6,927 | 2,261 |
| | Manatee 3 | 92.6 | 95.1 | 2,127 | 7,011 | 6,873 | 3,765 |
| | St. Lucie 1 | 85.1 | 88.1 | 6,754 | 10,471 | 10,391 | 406 |
| | St. Lucie 2 | 92.5 | 95.5 | 6,470 | 10,270 | 10,175 | 439 |
| | Turkey Point 3 | 90.8 | 94.3 | 7,125 | 11,102 | 10,838 | 1,272 |
| | Turkey Point 4 | 84.6 | 87.6 | 5,710 | 11,082 | 10,872 | 861 |
| | Turkey Point 5 | 93.5 | 95.5 | 1,638 | 7,132 | 7,047 | 2,207 |
| | West County 1 | 90.8 | 93.3 | 2,759 | 6,967 | 6,772 | 5,750 |
| | West County 2 | 90.1 | 92.6 | 3,106 | 6,891 | 6,671 | 6,027 |
| | West County 3 | 91.7 | 94.2 | 2,777 | 6,851 | 6,673 | 5,883 |
| | Total | | | 42,843 | | | 34,906 |

**GPIF Targets / Ranges for the period January 2016 through December 2016**

| Company | Plant/Unit | EAF | | | ANOHR | | |
|---|---|---|---|---|---|---|---|
| | | Target | Maximum | | Target | Maximum | |
| | | EAF (%) | EAF (%) | Savings ($000's) | ANOHR BTU/KWH | ANOHR BTU/KWH | Savings ($000's) |
| DEF | Bartow 4 | 88.6 | 91.0 | 1,471 | 7,427 | 6,984 | 13,149 |
| | Crystal River 4 | 83.2 | 87.4 | 934 | 10,465 | 10,053 | 5,227 |
| | Crystal River 5 | 94.6 | 97.1 | 1,031 | 10,345 | 9,851 | 7,392 |
| | Hines 1 | 92.4 | 93.2 | 413 | 7,319 | 6,855 | 6,758 |
| | Hines 2 | 57.6 | 69.4 | 5,403 | 7,343 | 6,931 | 2,987 |
| | Hines 3 | 82.9 | 84.5 | 1,028 | 7,227 | 6,745 | 6,298 |
| | Hines 4 | 85.0 | 85.5 | 250 | 6,983 | 6,634 | 4,880 |
| | Total | | | 10,530 | | | 46,692 |

**GPIF Targets / Ranges for the period January 2016 through December 2016**

| Company | Plant/Unit | EAF | | | ANOHR | | |
|---|---|---|---|---|---|---|---|
| | | Target | Maximum | | Target | Maximum | |
| | | EAF (%) | EAF (%) | Savings ($000's) | ANOHR BTU/KWH | ANOHR BTU/KWH | Savings ($000's) |
| GULF | Crist 6 | 95.7 | 97.0 | 25 | 10,760 | 10,437 | 838 |
| | Crist 7 | 82.3 | 83.4 | 51 | 10,449 | 10,136 | 1,809 |
| | Daniel 1 | 92.9 | 95.0 | 10 | 10,698 | 10,377 | 455 |
| | Daniel 2 | 95.2 | 96.2 | 13 | 10,605 | 10,287 | 529 |
| | Smith 3 | 83.2 | 84.1 | 12 | 6,874 | 6,668 | 2,312 |
| | Total | | | 111 | | | 5,943 |

| **GPIF Targets / Ranges for the period January 2016 through December 2016** | | | | | | | |
|---|---|---|---|---|---|---|---|
| Company | Plant/Unit | EAF | | | ANOHR | | |
| | | Target | Maximum | | Target | Maximum | |
| | | EAF (%) | EAF (%) | Savings ($000's) | ANOHR BTU/KWH | ANOHR BTU/KWH | Savings ($000's) |
| TECO | Big Bend 1 | 78.7 | 82.0 | 383 | 10,683 | 10,473 | 1,399 |
| | Big Bend 2 | 68.7 | 72.3 | 894 | 10,460 | 10,025 | 2,528 |
| | Big Bend 3 | 76.6 | 79.5 | 649 | 10,654 | 10,441 | 1,337 |
| | Big Bend 4 | 76.9 | 80.6 | 673 | 10,458 | 10,075 | 2,660 |
| | Polk 1 | 81.5 | 83.7 | 154 | 10,191 | 9,837 | 1,320 |
| | Bayside 1 | 76.1 | 78.2 | 836 | 7,232 | 6,967 | 2,912 |
| | Bayside 2 | 83.1 | 84.9 | 1,711 | 7,484 | 7,267 | 2,816 |
| | Total | | | 5,299 | | | 14,971 |

ISSUE 19: The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2016 through December 2016 are as follows:

FPL: $3,128,284,160, which includes prior period true up amounts, revenue taxes, the GPIF reward or penalty, or FPL's portion of the gains from its Incentive Mechanism.

Duke: $1,394,464,724

Gulf: $402,708,608, including prior period true up amounts and revenue taxes.

TECO: $715,605,063, which is adjusted by the jurisdictional separation factor. The amount is $689,768,483, when the GPIF reward or penalty, the revenue tax factor, and the prior period true up amounts are applied.

ISSUE 20: The appropriate revenue tax factor to be applied in calculating each investor-owned electric utility's levelized fuel factor for the projection period January 2016 through December 2016 is 1.00072.

ISSUE 21: The appropriate levelized fuel cost recovery factors for the period January 2016 through December 2016 are as follows:

FPL: For FPL, the fuel factors shall be reduced as of the in-service date of Port Everglades Energy Center (PEEC) to reflect the projected jurisdictional fuel savings for PEEC. The following separate factors for January 2016 through May 2016 and for June 2016 through December 2016 are approved:

a) 2.898 cents/kWh for January 2016 through the day prior to the PEEC in-service date (projected to be May 31, 2016);

b) 2.837 cents/kWh from the PEEC in-service date (projected to be June 1, 2016) through December 2016.

Duke: 3.677 cents per kWh (adjusted for jurisdictional losses)

Gulf: 3.650 cents/kWh

TECO: The appropriate factor is 3.671 cents per kWh before any application of time of use multipliers for on-peak or off-peak usage.

ISSUE 22: The appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class are shown below:

FPL: The appropriate fuel cost recovery line loss multipliers are provided below:

| GROUPS | RATE SCHEDULE | JANUARY - DECEMBER<br>Fuel Recovery Loss Multiplier |
|---|---|---|
| A | RS-1 first 1,000 kWh | 1.00313 |
| A | RS-1 all additional kWh | 1.00313 |
| A | GS-1, SL-2, GSCU-1 | 1.00313 |
| A-1 | SL-1, OL-1, PL-1 (1) | 1.00313 |
| B | GSD-1 | 1.00305 |
| C | GSLD-1, CS-1 | 1.00205 |
| D | GSLD-2, CS-2, OS-2, MET | 0.99278 |
| E | GSLD-3, CS-3 | 0.96536 |
| A | GST-1 On-Peak | 1.00313 |
| | GST-1 Off-Peak | 1.00313 |
| A | RTR-1 On-Peak | - |
| | RTR-1 Off-Peak | - |
| B | GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak | 1.00305 |
| | GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak | 1.00305 |
| C | GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak | 1.00205 |
| | GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak | 1.00205 |
| D | GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak | 0.99349 |
| | GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak | 0.99349 |
| E | GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak | 0.96536 |
| | GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak | 0.96536 |
| F | CILC-1(D), ISST-1(D) On-Peak | 0.99234 |
| | CILC-1(D), ISST-1(D) Off-Peak | 0.99234 |

| GROUPS | RATE SCHEDULE | JUNE - SEPTEMBER Fuel Recovery Loss Multiplier |
|---|---|---|
| B | GSD(T)-1 On-Peak | 1.00305 |
| | GSD(T)-1 Off-Peak | 1.00305 |
| C | GSLD(T)-1 On-Peak | 1.00205 |
| | GSLD(T)-1 Off-Peak | 1.00205 |
| D | GSLD(T)-2 On-Peak | 0.99349 |
| | GSLD(T)-2 Off-Peak | 0.99349 |

DEF:

| Fuel Recovery Line Loss Multipliers | | |
|---|---|---|
| Group | Delivery Voltage Level | Line Loss Multiplier |
| A | Transmission | 0.9800 |
| B | Distribution Primary | 0.9900 |
| C | Distribution Secondary | 1.0000 |
| D | Lighting Service | 1.0000 |

FPUC: The appropriate line loss multiplier is 1.0000.

Gulf:

| Fuel Recovery Line Loss Multipliers | | |
|---|---|---|
| Group | Rate Schedules | Line Loss Multipliers |
| A | RS, RSVP, RSTOU, GS,GSD, GSDT, GSTOU, OSIII, SBS(1) | 1.00773 |
| B | LP, LPT, SBS(2) | 0.98353 |
| C | PX, PXT, RTP, SBS(3) | 0.96591 |
| D | OSI/II | 1.00777 |

(1) Includes SBS customers with a contract demand in the range of 100 to 499 kW
(2) Includes SBS customers with a contract demand in the range of 500 to 7,499 kW
(3) Includes SBS customers with a contract demand over 7,499 kW

TECO:

| Fuel Recovery Line Loss Multipliers | |
|---|---|
| Metering Voltage Schedule | Line Loss Multiplier |
| Distribution Secondary | 1.0000 |
| Distribution Primary | 0.9900 |
| Transmission | 0.9800 |
| Lighting Service | 1.0000 |

ISSUE 23: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses is:

: FPL: The tables below (which also include the fuel recovery loss multiplier listed in the preceeding stipulation for Issue 22).

| GROUPS | RATE SCHEDULE | JANUARY 2016 - MAY 2016 | | |
|---|---|---|---|---|
| | | Average Factor | Fuel Recovery Loss Multiplier | Fuel Recovery Factor |
| A | RS-1 first 1,000 kWh | 2.898 | 1.00313 | 2.580 |
| A | RS-1 all additional kWh | 2.898 | 1.00313 | 3.580 |
| A | GS-1, SL-2, GSCU-1 | 2.898 | 1.00313 | 2.907 |
| A-1 | SL-1, OL-1, PL-1 (1) | 2.679 | 1.00313 | 2.687 |
| B | GSD-1 | 2.898 | 1.00305 | 2.907 |
| C | GSLD-1, CS-1 | 2.898 | 1.00205 | 2.904 |
| D | GSLD-2, CS-2, OS-2, MET | 2.898 | 0.99276 | 2.877 |
| E | GSLD-3, CS-3 | 2.898 | 0.96536 | 2.798 |
| A | GST-1 On-Peak | 4.037 | 1.00313 | 4.050 |
| | GST-1 Off-Peak | 2.420 | 1.00313 | 2.428 |
| A | RTR-1 On-Peak | - | - | 1.143 |
| | RTR-1 Off-Peak | - | - | (0.479) |
| B | GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak | 4.037 | 1.00305 | 4.049 |
| | GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak | 2.420 | 1.00305 | 2.427 |
| C | GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak | 4.037 | 1.00205 | 4.045 |
| | GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak | 2.420 | 1.00205 | 2.425 |
| D | GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak | 4.037 | 0.99349 | 4.011 |
| | GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak | 2.420 | 0.99349 | 2.404 |
| E | GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak | 4.037 | 0.96536 | 3.897 |
| | GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak | 2.420 | 0.96536 | 2.336 |
| F | CILC-1(D), ISST-1(D) On-Peak | 4.037 | 0.99234 | 4.006 |
| | CILC-1(D), ISST-1(D) Off-Peak | 2.420 | 0.99234 | 2.401 |

(1) WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

ESTIMATED FOR THE PERIOD OF: JANUARY 2016 THROUGH MAY 2016

OFF PEAK: ALL OTHER HOURS

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| GROUPS | RATE SCHEDULE | JUNE - SEPTEMBER | | |
| | | Average Factor | Fuel Recovery Loss Multiplier | Fuel Recovery Factor |
| B | GSD(T)-1 On-Peak | 5.434 | 1.00305 | 5.451 |
| | GSD(T)-1 Off-Peak | 2.568 | 1.00305 | 2.576 |
| C | GSLD(T)-1 On-Peak | 5.434 | 1.00205 | 5.445 |
| | GSLD(T)-1 Off-Peak | 2.568 | 1.00205 | 2.573 |
| D | GSLD(T)-2 On-Peak | 5.434 | 0.99349 | 5.399 |
| | GSLD(T)-2 Off-Peak | 2.568 | 0.99349 | 2.551 |

| GROUPS | RATE SCHEDULE | JUNE 2016 - DECEMBER 2016 | | |
|---|---|---|---|---|
| | | Average Factor | Fuel Recovery Loss Multiplier | Fuel Recovery Factor |
| A | RS-1 first 1,000 kWh | 2.837 | 1.00313 | 2.519 |
| A | RS-1 all additional kWh | 2.837 | 1.00313 | 3.519 |
| A | GS-1, SL-2, GSCU-1 | 2.837 | 1.00313 | 2.846 |
| A-1 | SL-1, OL-1, PL-1 [(1)] | 2.622 | 1.00313 | 2.630 |
| B | GSD-1 | 2.837 | 1.00305 | 2.846 |
| C | GSLD-1, CS-1 | 2.837 | 1.00205 | 2.843 |
| D | GSLD-2, CS-2, OS-2, MET | 2.837 | 0.99278 | 2.817 |
| E | GSLD-3, CS-3 | 2.837 | 0.96536 | 2.739 |
| A | GST-1 On-Peak | 3.952 | 1.00313 | 3.964 |
| | GST-1 Off-Peak | 2.369 | 1.00313 | 2.376 |
| A | RTR-1 On-Peak | - | - | 1.118 |
| | RTR-1 Off-Peak | - | - | (0.470) |
| B | GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak | 3.952 | 1.00305 | 3.964 |
| | GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak | 2.369 | 1.00305 | 2.376 |
| C | GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak | 3.952 | 1.00205 | 3.960 |
| | GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak | 2.369 | 1.00205 | 2.374 |
| D | GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak | 3.952 | 0.99349 | 3.926 |
| | GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak | 2.369 | 0.99349 | 2.354 |
| E | GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak | 3.952 | 0.96536 | 3.815 |
| | GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak | 2.369 | 0.96536 | 2.287 |
| F | CILC-1(D), ISST-1(D) On-Peak | 3.952 | 0.99234 | 3.922 |
| | CILC-1(D), ISST-1(D) Off-Peak | 2.369 | 0.99234 | 2.351 |

[(1)] WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

| GROUPS | RATE SCHEDULE | JUNE 2016 - SEPTEMBER 2016 | | |
|---|---|---|---|---|
| | | Average Factor | Fuel Recovery Loss Multiplier | Fuel Recovery Factor |
| B | GSD(T)-1 On-Peak | 5.319 | 1.00305 | 5.335 |
| | GSD(T)-1 Off-Peak | 2.514 | 1.00305 | 2.522 |
| C | GSLD(T)-1 On-Peak | 5.319 | 1.00205 | 5.330 |
| | GSLD(T)-1 Off-Peak | 2.514 | 1.00205 | 2.519 |
| D | GSLD(T)-2 On-Peak | 5.319 | 0.99349 | 5.284 |
| | GSLD(T)-2 Off-Peak | 2.514 | 0.99349 | 2.498 |

DEF:

| Fuel Cost Factors (cents/kWh) GSD-1, GSDT-1, SS-1, CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3, IS-1, IST-1, IS-2, IST-2, SS-2, LS-1 | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | Time of Use | |
| Group | Delivery Voltage Level | First Tier Factor | Second Tier Factors | Levelized Factors | On-Peak | Off-Peak |
| A | Transmission | -- | -- | 3.608 | 4.860 | 3.034 |
| B | Distribution Primary | -- | -- | 3.645 | 4.910 | 3.065 |
| C | Distribution Secondary | -- | -- | 3.682 | 4.960 | 3.097 |
| D | Lighting Secondary | -- | -- | 3.445 | -- | -- |

| Fuel Cost Factors (cents/kWh) RS-1, RST-1, RSL-1, RSL-2, RSS-1 | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | Time of Use | |
| Group | Delivery Voltage Level | First Tier Factor | Second Tier Factors | Levelized Factors | On-Peak | Off-Peak |
| C | Distribution Secondary | 3.353 | 4.353 | 3.634 | 4.895 | 3.056 |

| Fuel Cost Factors (cents/kWh) GS-1, GST-1, GS-2 | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | Time of Use | |
| Group | Delivery Voltage Level | First Tier Factor | Second Tier Factors | Levelized Factors | On-Peak | Off-Peak |
| A | Transmission | -- | -- | 3.574 | 4.814 | 3.006 |
| B | Distribution Primary | -- | -- | 3.611 | 4.864 | 3.037 |
| C | Distribution Secondary | -- | -- | 3.647 | 4.913 | 3.067 |

Gulf:

| Group | Rate Schedules* | Line Loss Multipliers | Fuel Cost Factors ¢/KWH | | |
|---|---|---|---|---|---|
| | | | Standard | Time of Use | |
| | | | | On-Peak | Off-Peak |
| A | RS, RSVP, RSTOU, GS,GSD, GSDT, GSTOU, OSIII, SBS(1) | 1.00773 | 3.678 | 4.494 | 3.342 |
| B | LP, LPT, SBS(2) | 0.98353 | 3.590 | 4.387 | 3.261 |
| C | PX, PXT, RTP, SBS(3) | 0.96591 | 3.526 | 4.308 | 3.203 |
| D | OSI/II | 1.00777 | 3.631 | N/A | N/A |

*The recovery factor applicable to customers taking service under Rate Schedule SBS is determined as follows: (1) customers with a contract demand in the range of 100 to 499 kW will use the recovery factor applicable to Rate Schedule GSD; (2) customers with a contract demand in the range of 500 to 7,499 kW will use the recovery factor applicable to Rate Schedule LP; and (3) customers with a contract demand over 7,499 kW will use the recovery factor applicable to Rate Schedule PX.

TECO:

| Metering Voltage Level | Fuel Charge Factor (cents per kWh) | |
|---|---|---|
| Secondary | 3.676 | |
| RS Tier I (Up to 1,000 kWh) | 3.361 | |
| RS Tier II (Over 1,000 kWh) | 4.361 | |
| Distribution Primary | 3.639 | |
| Transmission | 3.602 | |
| Lighting Service | 3.627 | |
| Distribution Secondary | 3.937 | (on-peak) |
| | 3.564 | (off-peak) |
| Distribution Primary | 3.898 | (on-peak) |
| | 3.528 | (off-peak) |
| Transmission | 3.858 | (on-peak) |
| | 3.493 | (off-peak) |

ISSUE 24A: Yes. For the Crystal River 3 Uprate project, the amount to be included is $56,510,403, which was approved by the Commission in a bench vote at Hearing on August 18, 2015. At Hearing, on August 18, 2015, the Commission approved

DEF's stipulation with the parties to leave the Levy portion of the NCRC charge at $0 for 2016 and 2017.

ISSUE 25A: As approved by the Commission at its October 19, 2015 Special Agenda Conference, FPL has included $34,249,614.

ISSUE 25B: The appropriate 2016 projected non-fuel revenue requirements for West County Energy Center Unit 3 (WCEC-3) to be recovered through the Capacity Clause is $145,515,209.

ISSUE 25C: FPL has properly reflected in the capacity cost recovery clause the effects of acquiring the Cedar Bay facility and terminating the existing Cedar Bay power purchase agreement consistent with the terms of the settlement agreement between FPL and OPC approved in Docket No. 150075-EI.

ISSUE 28: The appropriate final capacity cost recovery true-up amounts for the period January 2014 through December 2014 are as follows:
Duke: $13,962,445 under-recovery.
Gulf: $893,047 under-recovery.
FPL: $2,951,171 under-recovery.
TECO: $140,386, over-recovery.

ISSUE 29: The appropriate final capacity cost recovery actual/estimated true-up amounts for the period January 2015 through December 2015 are as follows:
Duke: $24,680,810 under-recovery
Gulf: $910,906 over-recovery
FPL: $7,699,316 over-recovery
TECO: $2,063,383 over-recovery

ISSUE 30: The appropriate final capacity cost recovery true-up amounts to be collected/refunded during the period January 2016 through December 2016 are as follows:
Duke: $38,643,256, to be collected (under-recovery).
Gulf: $17,859, to be refunded (over-recovery).
FPL: $4,748,145, to be refunded (over-recovery).
TECO: $2,203,769, to be refunded (over-recovery).

ISSUE 31: The appropriate projected total capacity cost recovery amounts for the period January 2016 through December 2016 are as follows:
FPL: Jurisdictionalized, $321,148,426 for the period January 2016 through December 2016, excluding prior period true-ups, revenue taxes, nuclear cost recovery amount, and WCEC-3 jurisdictional non-fuel revenue requirements.
Duke: $358,842,970.
Gulf: $85,495,331.
TECO: $30,473,670.

ISSUE 32: The appropriate projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January 2016 through December 2016 are as follows:
FPL: The projected net purchased power capacity cost recovery amount to be recovered over the period January 2016 through December 2016 is $496,417,572, including prior period true-ups, revenue taxes, the nuclear cost recovery amount and WCEC-3 revenue requirements.
Duke: The appropriate projected net purchased power capacity cost recovery amount, excluding nuclear cost recovery, is $397,772,416. The appropriate nuclear cost recovery amount is that which is approved in Issue 24A.
Gulf: $85,539,016 including prior period true-up amounts and revenue taxes.
TECO: The total recoverable capacity cost recovery amount to be collected, including the true-up amount and adjusted for the revenue tax factor, is $28,290,255.

ISSUE 33: The appropriate jurisdictional separation factors for capacity revenues and costs to be included in the recovery factor for the period January 2016 through December 2016 are as follows:
FPL: The appropriate jurisdictional separation factors are:

| | |
|---|---|
| FPSC | 94.67506% |
| FERC | 5.32494% |

Duke: Base – 92.885%, Intermediate – 72.703%, Peaking – 95.924%, consistent with the Revised and Restated Stipulation and Settlement Agreement approved in Order No. PSC-13-0598-FOF-EI.
Gulf: 97.07146%.
TECO: The appropriate jurisdictional separation factor is 1.0000000.

ISSUE 34: The appropriate capacity cost recovery factors for the period January 2016 through December 2016 are shown below:

FPL: See the table on the next page.

ESTIMATED FOR THE PERIOD OF: JANUARY 2016 THROUGH DECEMBER 2016

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RATE SCHEDULE | Jan 2016 - Dec 2016 Capacity Recovery Factor | | | | 2016 WCEC-3 Capacity Recovery Factor | | | | Total Jan 2016 - Dec 2016 Capacity Recovery Factor | | | |
| | ($KW) | ($/kwh) | RDC ($/KW) (1) | SDD ($/KW) (2) | ($KW) | ($/kwh) | RDC ($/KW) | SDD ($/KW) | ($KW) | ($/kwh) | RDC ($/KW) (1) | SDD ($/KW) (2) |
| RS1/RTR1 | - | 0.00348 | - | - | - | 0.00140 | - | - | - | 0.00488 | - | - |
| GS1/GST1 | - | 0.00326 | - | - | - | 0.00140 | - | - | - | 0.00466 | - | - |
| GSD1/GSDT1/HLFT1 | 1.09 | - | - | - | 0.46 | - | - | - | 1.55 | - | - | - |
| OS2 | - | 0.00240 | - | - | - | 0.00126 | - | - | - | 0.00366 | - | - |
| GSLD1/GSLDT1/CS1/CST1/HLFT2 | 1.22 | - | - | - | 0.56 | - | - | - | 1.78 | - | - | - |
| GSLD2/GSLDT2/CS2/CST2/HLFT3 | 1.19 | - | - | - | 0.51 | - | - | - | 1.70 | - | - | - |
| GSLD3/GSLDT3/CS3/CST3 | 1.22 | - | - | - | 0.66 | - | - | - | 1.88 | - | - | - |
| SST1T | - | - | $0.15 | $0.07 | - | - | $0.06 | $0.03 | - | - | $0.21 | $0.10 |
| SST1D1/SST1D2/SST1D3 | - | - | $0.15 | $0.07 | - | - | $0.06 | $0.03 | - | - | $0.22 | $0.10 |
| CILC D/CILC G | 1.35 | - | - | - | 0.63 | - | - | - | 1.98 | - | - | - |
| CILC T | 1.28 | - | - | - | 0.55 | - | - | - | 1.83 | - | - | - |
| MET | 1.38 | - | - | - | 0.66 | - | - | - | 2.04 | - | - | - |
| OL1/SL1/PL1 | - | 0.00059 | - | - | - | 0.00036 | - | - | - | 0.00095 | - | - |
| SL2, GSCU1 | - | 0.00225 | - | - | - | 0.00064 | - | - | - | 0.00289 | - | - |

Duke:

| Rate Class | | Capacity Cost Recovery Factor | |
|---|---|---|---|
| | | Cents / kWh | Dollars / kW-month |
| Residential | | 1.418 | |
| General Service Non-Demand | | 1.100 | |
| | At Primary Voltage | 1.089 | |
| | At Transmission Voltage | 1.078 | |
| General Service 100% Load Factor | | 0.779 | |
| General Service Demand | | | 3.94 |
| | At Primary Voltage | | 3.90 |
| | At Transmission Voltage | | 3.86 |
| Curtailable | | | 2.32 |
| | At Primary Voltage | | 2.30 |
| | At Transmission Voltage | | 2.27 |
| Interruptible | | | 3.14 |
| | At Primary Voltage | | 3.11 |
| | At Transmission Voltage | | 3.08 |
| Standby Monthly | | | 0.383 |
| | At Primary Voltage | | 0.379 |
| | At Transmission Voltage | | 0.375 |
| Standby Daily | | | 0.182 |
| | At Primary Voltage | | 0.180 |
| | At Transmission Voltage | | 0.178 |
| Lighting | | 0.217 (cents/kWh) | |
| | | | |

Gulf:

| Rate Class | Capacity Cost Recovery Factor | |
|---|---|---|
| | Cents / kWh | Dollars / kW-month |
| RS, RSVP, RSTOU | 0.919 | |
| GS | 0.812 | |
| GSD, GSDT, GSTOU | 0.705 | |
| LP, LPT | | 2.98 |
| PX, PXT, RTP, SBS | 0.581 | |
| OS-I/II | 0.123 | |
| OSIII | 0.544 | |
| | | |

TECO:

| **Rate Class and Metering Voltage** | **Capacity Cost Recovery Factor** | |
|---|---|---|
| | Cents / kWh | Dollars / kW |
| RS Secondary | 0.178 | |
| GS and TS Secondary | 0.166 | |
| GSD, SBF Standard | | |
| Secondary | | 0.530 |
| Primary | | 0.520 |
| Transmission | | 0.520 |
| GSD Optional | | |
| Secondary | 0.123 | |
| Primary | 0.122 | |
| IS, SBI | | |
| Primary | | 0.430 |
| Transmission | | 0.420 |
| LS1 Secondary | 0.021 | |
| | | |

ISSUE 35: The new factors should be effective begin with the first billing cycle for January 2016 through the last billing cycle for December 2016. The first billing cycle may start before January 1, 2016, and the last cycle may be read after December 31, 2016, so that each customer is billed for twelve months regardless of when the recovery factors became effective. The new factors shall continue in effect until modified by this Commission.

ISSUE 36: Yes. The Commission should approve revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be appropriate in this proceeding. The Commission should direct staff to verify that the revised tariffs are consistent with the Commission's decision.

ISSUE 37: This docket is an on-going docket and should remain open.

TAB I

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

| | |
|---|---|
| In re: Fuel and purchased power cost recovery clause with generating performance incentive factor. | DOCKET NO. 130001-EI<br>ORDER NO. PSC-13-0665-FOF-EI<br>ISSUED: December 18, 2013 |

The following Commissioners participated in the disposition of this matter:

RONALD A. BRISÉ, Chairman
LISA POLAK EDGAR
ART GRAHAM
EDUARDO E. BALBIS
JULIE I. BROWN

APPEARANCES:

JOHN T. BUTLER, and KENNETH M. RUBIN, ESQUIRES, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408-0420
On behalf of Florida Power & Light Company (FPL).

JOHN T. BURNETT, DIANNE M. TRIPLETT, and MATTHEW BERNIER, ESQUIRES, Duke Energy Florida, Inc., Post Office Box 14042, St. Petersburg, Florida 33733
On behalf of Duke Energy Florida, Inc. (DEF).

BETH KEATING, ESQUIRE, Gunster, Yoakley & Stewart, P.A., 215 South Monroe St., Suite 601, Tallahassee, Florida, 32301
On behalf of Florida Public Utilities Company (FPUC).

JEFFREY A. STONE, RUSSELL A. BADDERS, and STEVEN R. GRIFFIN, ESQUIRES, Beggs & Lane, Post Office Box 12950, Pensacola, Florida 32591-2950
On behalf of Gulf Power Company (GULF).

JAMES D. BEASLEY, J. JEFFRY WAHLEN, and ASHLEY M. DANIELS, ESQUIRES, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302
On behalf of Tampa Electric Company (TECO).

J.R. KELLY, PATRICIA A. CHRISTENSEN, CHARLES REHWINKEL, JOSEPH A. MCGLOTHLIN, and ERIK SAYLER, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida (OPC).

KAREN PUTNAL, and JON C. MOYLE, JR., ESQUIRES, Moyle Law Firm, PA, The Perkins House, 118 North Gadsden Street, Tallahassee, Florida 32301
On behalf of the Florida Industrial Power Users Group (FIPUG).

ROBERT SCHEFFEL WRIGHT, and JOHN T. LAVIA, III, ESQUIRES, Gardner, Bist, Wiener, Wadsworth, Bowden, Bush, Dee, LaVia & Wright, P.A., 1300 Thomaswood Drive, Tallahassee, Florida 32308
On behalf of the Florida Retail Federation (FRF).

JAMES W. BREW, and F. ALVIN TAYLOR, ESQUIRES, Brickfield, Burchette, Ritts & Stone, P.C., 1025 Thomas Jefferson St., NW, Eighth Floor, West Tower, Washington, DC 20007; RANDY B. MILLER, White Springs Agricultural Chemicals, Inc., Post Office Box 300, White Springs, FL 32096
On behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs (PCS Phosphate).

MARTHA BARRERA, and JULIA GILCHER, ESQUIRES, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Florida Public Service Commission (Staff).

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

## FINAL ORDER APPROVING EXPENDITURES AND TRUE-UP AMOUNTS FOR FUEL ADJUSTMENT FACTORS; GPIF TARGETS, RANGES, AND REWARDS; AND PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR CAPACITY COST RECOVERY FACTORS

BY THE COMMISSION:

### Background

As part of the continuing fuel and purchased power adjustment and generating performance incentive clause proceedings, an administrative hearing was held on November 4, 2013. At the hearing, we ruled on most issues listed in Order No. PSC-13-0514-PHO-EI[1] (Prehearing Order) by making bench decisions for all issues for Duke Energy Florida, Inc., Tampa Electric Company, Gulf Power Company, and Florida Public Utilities Company. Although we also decided some issues for Florida Power & Light Company (FPL) at the November 4, 2013 hearing, we heard testimony on and requested briefs for Issues 18B, 25B, and 25C. On November 15, 2013,

[1] Order No. PSC-13-0514-PHO-EI, issued October 28, 2013, in Docket No. 130001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

FPL filed a post hearing brief for Issues 18B, 25B, and 25C, and the Office of Public Counsel (OPC) filed a post hearing brief addressing Issues 18B and 25B. No other parties filed briefs. Intervenors agreed with OPC or took no position on these issues.

We have jurisdiction over this subject matter pursuant to the provisions of Chapter 366, Florida Statutes (F.S.), including Sections 366.04, 366.05, and 366.06, F.S.

## COMPANY-SPECIFIC FUEL ADJUSTMENT

### Duke Energy Florida, Inc.

Hedging activities

We reviewed Duke Energy Florida, Inc.'s (DEF) hedging activities and approve as prudent DEF's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in DEF's April 2013 and August 2013 hedging reports.

2014 Risk Management Plan

We reviewed DEF's 2014 Risk Management Plan and, finding that it is consistent with Hedging Guidelines, it is hereby approved.

### Florida Power & Light Company

Hedging Activities

We reviewed Florida Power & Light Company's (FPL) hedging activities and approve as prudent FPL's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in FPL's April 2013 and August 2013 hedging reports.

2014 Risk Management Plan

We reviewed FPL's 2014 Risk Management Plan and, finding that it is consistent with Hedging Guidelines, it is hereby approved.

Incremental Optimization Costs

Upon review, we find that the appropriate amount of Incremental Optimization Costs for Personnel, Software, and Hardware Costs that FPL shall be allowed to recover through the Fuel Clause is $263,527 for the period January 2013 through December 2013 and $389,472 for the period January 2014 through December 2014.

Upon review, we find that the appropriate amount of Incremental Optimization Costs for Variable Power Plant Operations and Maintenance Costs over the 514 Megawatt Threshold that FPL shall be allowed to recover through the Fuel Clause is $1,853,392 for the period January

2013 through December 2013 and $1,722,910 for the period January 2014 through December 2014. We recognize OPC's statement that by taking "no position" with respect to the issue of the amount that the Commission should authorize FPL to recover in the instant proceeding to implement FPL's "asset optimization" program approved in Order No. PSC-13-0023-S-EI, OPC does not waive and expressly reaffirms its appeal of Order 0023 now pending before the Florida Supreme Court in Case No. SC13-144. OPC also stated while Order No. PSC-13-0023-S-EI is effective during the pendency of the appeal, any amounts approved to be collected in conjunction with the issues regarding incremental optimization costs are subject to the ruling of the Florida Supreme Court in that appeal.

**Florida Public Utilities Company**

Allocation of transmission costs

Upon review, we find that, for purposes of calculating the 2014 fuel factors, a portion of the transmission costs included in the Agreement for Generation Services with Gulf Power Company (Gulf) shall be reallocated to Florida Public Utilities Company's (FPUC) Northeast Division to offset an interdivisional inequity associated with transmission assets that serve only the Northeast Division and currently recovered through consolidated base rates. To effectuate a permanent solution to this issue, FPUC shall file with its 2015 projection testimony in Docket No. 140001-EI testimony and supporting schedules to allow for consideration of the consolidation of fuel factors for the two divisions for future fuel cost recovery, unless this issue is otherwise addressed for our consideration through an alternative proceeding prior to FPUC's 2015 projection filing.

Gulf Power Company's lump sum payment to FPUC

Upon review, we find that the lump sum payment made by Gulf to FPUC to true-up capacity payments upon the reinstatement of Amendment No. 1 to FPUC's Agreement for Generation Services with Gulf was addressed in Docket No. 130233-EI. The lump sum payment will be applied to reduce the regulatory asset established by Order No. PSC-12-0600-PAA-EI, issued November 5, 2012, in Docket No. 120227-EI.

**Gulf Power Company**

Hedging activities

Upon review, we find that Gulf's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in Gulf's April 2013 and August 2013 hedging reports are prudent and they are thus approved.

2014 Risk Management Plan

We reviewed Gulf's 2014 Risk Management Plan and, finding that it is consistent with Hedging Guidelines, it is hereby approved.

**Tampa Electric Company**

Hedging activities

Upon review, we find that Tampa Electric Company's (Tampa Electric) actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in its April 2013 and August 2013 hedging reports are prudent and they are thus approved.

2014 Risk Management Plan

We reviewed Tampa Electric's 2014 Risk Management Plan and, finding that it is consistent with Hedging Guidelines, it is hereby approved.

Capital Costs for Polk Unit One project

Upon review, we find that the appropriate amount of capital costs for the Polk Unit One ignition oil conversion project that Tampa Electric shall recover through the Fuel Clause is $2,356,259 for the period January 2013 through December 2013 and $4,250,042 for the period January 2014 through December 2014.

**GENERIC FUEL ADJUSTMENT**

Upon review, we find the appropriate actual benchmark levels for calendar year 2013 for gains on non-separated wholesale energy sales eligible for a shareholder incentive shall be:

| | |
|---|---|
| Duke: | $589,283. |
| Gulf: | $595,146. |
| TECO: | $1,366,094. |

The appropriate estimated benchmark levels for calendar year 2014 for gains on non-separated wholesale energy sales eligible for a shareholder incentive shall be:

| | |
|---|---|
| Duke: | $387,112. |
| Gulf: | $462,977. |
| TECO: | $650,665. |

The appropriate fuel adjustment true-up amounts for the period January 2012 through December 2012 shall be:

| | |
|---|---|
| FPL: | $4,550,654 under-recovery. |
| Duke: | $72,210,688 under-recovery. |

FPUC: $1,118,689 under-recovery for the Northwest Division.
$1,785,473 over-recovery for the Northeast Division.

Gulf: $9,333,695 under-recovery.

TECO: $903,071 over-recovery.

The appropriate fuel adjustment actual/estimated true-up amounts for the period January 2013 through December 2013 shall be:

FPL: $143,214,959 under-recovery.

Duke: $39,015,505 over-recovery.

FPUC: $363,316 over-recovery for the Northwest Division.
$900,204 over-recovery for the Northeast Division.

Gulf: $6,665,066 under-recovery.

TECO: $14,727,476 over-recovery.

The appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2014 to December 2014 are:

FPL: $147,765,613 under-recovery.

Duke: $33,195,183 under-recovery.

FPUC: $755,373 under-recovery for the Northwest Division.
$2,685,677 over-recovery for the Northeast Division.

Gulf: $15,998,761 under-recovery.

TECO: $15,630,547 over-recovery.

The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2014 through December 2014 shall be:

FPL: $3,481,028,444.

Duke: $1,583,009,063.

FPUC: $31,438,731 for the Northwest Division.

$33,272,998 for the Northeast Division.

Gulf: $463,407,364.

TECO: $ 717,157,390

**GENERATING PERFORMANCE INCENTIVE FACTOR**

Upon review, the appropriate generation performance incentive factor (GPIF) reward or penalty for performance achieved during the period January 2012 through December 2012 for each investor-owned electric utility subject to the GPIF shall be:

FPL: $20,679,970 reward.

Duke: $3,262,447 reward.

Gulf: $1,662,342 reward.

TECO: $1,177,059 penalty.

The GPIF targets/ranges for the period from January 2014 through December 2014 for each investor-owned electric utility subject to GPIF shown in the exhibits referenced below shall be:

| Company | Exhibit | Page(s) |
|---|---|---|
| FPL | CRR-1 | 6-7 |
| DEF | MJJ-1P | 4 |
| GULF | MAY-2 | 29, 33 |
| TECO | BSB-2 | 4 |

We examined whether the existing GPIF mechanism should be modified and upon review, we find that the setting of performance targets shall be the same for all companies subject to the GPIF. The method for calculating the GPIF's incentive cap of 50 percent of the fuel savings shall be modified by the revision of lines 22 and 23 of the Original Sheet No. 3.516 in the GPIF Manual. The reward and penalty amounts at different performance levels shall be calculated as a linear interpolation from the maximum allowed GPIF reward (line 23), thereby preserving the symmetrical relationship between rewards and penalties. The revisions are shown below.

Original Sheet No. 3.516 as Revised

## GENERATING PERFORMANCE INCENTIVE FACTOR
## CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

| | | | | | | |
|---|---|---|---|---|---|---|
| LINE 1 | BEGINNING OF PERIOD BALANCE OF COMMON EQUITY | | | $ | 10,849,749,770 | |
| | END OF MONTH BALANCE OF COMMON EQUITY | | | | | |
| LINE 2 | MONTH OF | January | 2012 | $ | 10,983,930,940 | |
| LINE 3 | MONTH OF | February | 2012 | $ | 11,043,325,330 | |
| LINE 4 | MONTH OF | March | 2012 | $ | 11,128,965,610 | |
| LINE 5 | MONTH OF | April | 2012 | $ | 11,196,334,650 | |
| LINE 6 | MONTH OF | May | 2012 | $ | 11,333,068,500 | |
| LINE 7 | MONTH OF | June | 2012 | $ | 11,681,736,330 | |
| LINE 8 | MONTH OF | July | 2012 | $ | 11,828,681,570 | |
| LINE 9 | MONTH OF | August | 2012 | $ | 11,987,094,020 | |
| LINE 10 | MONTH OF | September | 2012 | $ | 12,073,906,876 | |
| LINE 11 | MONTH OF | October | 2012 | $ | 12,172,856,430 | |
| LINE 12 | MONTH OF | November | 2012 | $ | 12,463,562,700 | |
| LINE 13 | MONTH OF | December | 2012 | $ | 12,530,193,155 | |
| LINE 14 | AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13) | | | $ | 11,636,415,837 | |
| LINE 15 | 25 BASIS POINTS | | | | 0.0025 | |
| LINE 16 | REVENUE EXPANSION FACTOR | | | | 61.3808% | |
| LINE 17 | MAXIMUM INCENTIVE DOLLARS PER FINANCIAL DATA (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16 ) | | | $ | 47,394,364 | |
| LINE 18 | JURISDICTIONAL SALES | | | | 102,225,549,000 | KWH |
| LINE 19 | TOTAL SALES | | | | 104,462,720,986 | KWH |
| LINE 20 | JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19) | | | | 97.86% | |
| LINE 21 | MAXIMUM JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20) | | | $ | 46,380,125 | |
| LINE 22 | INCENTIVE CAP (50 PECENT OF PROJECTED FUEL SAVINGS AT 10 GPIF-POINT LEVEL FROM SHEET NO. 3.515) | | | $ | 45,541,500 | |
| LINE 23 | MAXIMUM ALLOWED GPIF REWARD (AT 10 GPIF-POINT LEVEL) (THE LESSER OF LINE 21 AND LINE 22) | | | $ | 45,541,500 | |

Issued by: Florida Public Service Commission — Effective 1/1/2014

We examined the issue of whether FPL should be excluded from the GPIF program for the duration of its Pilot Asset Optimization Program (Pilot Program). Asset optimization involves gas storage utilization, city-gate gas sales using existing transport, production area gas sales, capacity release of gas transport and electric transmission, and the outsourcing of the optimization function. FPL's stated position is that uncontroverted evidence shows that the Pilot Program does not overlap the GPIF program; rather, it complements the GPIF with incentives to generate customer benefits in other areas. OPC supported excluding FPL from the GPIF during the Pilot Program. OPC argued that the programs are designed to instill the same incentive to operate efficiently, thus customers should not bear the risks and potential costs of duplicative financial incentives.

We adopted the GPIF program by Order No. 9558, issued September 19, 1980, in Docket No. 800400-CI. The GPIF program provides incentives for investor-owned utilities to optimize the efficiency of their base load units. Annual performance targets for unit availability and heat rate are set and actual performance is then compared to the targets in the following year. If the utilities participating in the GPIF program exceed their targets, shareholders are financially rewarded. If targets are not achieved, then shareholders are financially penalized. FPL witness Rote acknowledged that the GPIF program has operated effectively to incent utilities to strive for the efficient operation of base load units. He also testified that the GPIF mechanism is "an even handed, symmetric methodology."

FPL responded to a staff interrogatory that "[F]rom a high-level perspective, performance improvements in availability and heat rate should increase FPL's ability to make off-system economy sales as these improvements drive lower marginal costs and therefore, improve FPL's competitive position in the power market." On the flip-side, FPL also stated that degradation in base load unit availability and heat rate increase FPL's opportunity to make off-system wholesale purchases. FPL witness Rote testified that theoretically, unit performance can impact FPL's position in the wholesale market. We find that the efficient operation of the utility's base load units are the foundation for any off-system sales or purchases.

We find that if FPL's base load generating units perform poorly, they would likely be penalized under the GPIF program, but consequently, the Company's market position would be improved to make off-system purchases. Gains on these purchases would be included towards achieving or exceeding its threshold under the Pilot Program. Conversely, if FPL's units exceed their targets under the GPIF, the Company would likely receive a reward while also improving its market position for off-system sales. Gains from these transactions would also be included towards achieving or exceeding its threshold under the Pilot Program. Thus, if FPL receives either a reward or penalty under the GPIF program, it is likely that the Company also would receive a credit towards its threshold goal under the Pilot Program.

We approved FPL's Pilot Program in Order No. PSC-13-0023-S-EI,[2] finding it to be beneficial to both FPL and its customers because FPL customers would receive 100 percent of

[2] See Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 120015-EI, In re: Petition for increase in rates by Florida Power & Light Company

the gain from electric wholesale sales and purchases and asset optimization up to a threshold of $36 million (Customer Savings Threshold). FPL customers would also receive 100 percent of the gain for the first $10 million above the Customer Savings Threshold (Additional Customer Savings). Incremental gains above the Customer Savings Threshold and the Additional Customers Savings (totaling $46 million) would be shared between FPL and customers. The Pilot Program has a four year term and we have the option to review the Pilot Program after two years. We also ordered that, as part of the fuel cost recovery clause, FPL annually file a final true-up schedule showing its gains in the prior calendar year on short-term wholesale sales, short-term wholesale purchases, and all forms of asset optimization it undertook in that calendar year. If we determine that the program is not providing the kinds of benefits that are anticipated, or if we determine the pilot program is otherwise unsatisfactory, we may terminate the program.

We determine herein 2012 GPIF rewards/penalties, and the Pilot Program was not in effect during that year. Since performance targets have previously been set for 2013, we find that FPL shall be eligible for any GPIF rewards/penalties associated with its 2013 unit performance. However, we note that if FPL receives either a reward or penalty under the GPIF for 2014, it is likely that the Company also would receive a credit towards its threshold goal under the Pilot Program. The Pilot Program may also be more comprehensive than the GPIF at targeting similar behavior, i.e. the efficient operation of base load generating units. Based on the current schedule, the initial two years of the Pilot Program will be at the end of 2014. FPL shall address these specific interrelationships when we review the Pilot Program during 2015.

**FUEL FACTOR CALCULATION**

Upon review, we find that the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2014 through December 2014 shall be:

| | |
|---|---|
| FPL: | $3,501,708,414. |
| Duke: | $1,620,630,360. |
| FPUC: | $31,438,731 for the Northwest Division.<br>$33,272,998 for the Northeast Division. |
| Gulf: | $465,069,706. |
| TECO: | $732,787,937. |

Upon review, we find that the appropriate revenue tax factor to be applied in calculating each investor-owned electric utility's levelized fuel factor for the projection period January 2014 through December 2014 shall be 1.00072.

Upon review, we find that the appropriate levelized fuel cost recovery factors for the period January 2014 through December 2014 shall be:

FPL: For January 2014 through the day prior to the RBEC in-service date (projected to be May 31, 2014), the appropriate levelized fuel cost recovery factor is 3.383 cents per kilowatt hour;

For the RBEC in-service date through December 2014, the appropriate levelized fuel cost recovery factor is 3.263 cents per kilowatt hour.

Duke: The appropriate levelized fuel cost recovery factor is 4.303 cents/kWh.

FPUC: The appropriate levelized fuel cost recovery factor is 6.069 cents/kWh for the Northwest Division.
The appropriate levelized fuel cost recovery factor is 4.844 cents/kWh for the Northeast Division.

Gulf: The appropriate levelized fuel cost recovery factor is 4.169 cents/kWh.

TECO: The appropriate levelized fuel cost recovery factor is 3.904 cents/kWh.

Upon review, we find that the fuel recovery line loss multipliers used by each utility in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class shall be:

FPL: The appropriate fuel cost recovery loss multipliers are provided in response to Issue No. 23.

DEF:

| Group | Delivery Voltage Level | Line Loss Multiplier |
|---|---|---|
| A. | Transmission | 0.9800 |
| B. | Distribution Primary | 0.9900 |
| C. | Distribution Secondary | 1.0000 |
| D. | Lighting Service | 1.0000 |

FPUC: Northwest Division (Marianna): 1.0000 (All rate schedules)
Northeast Division (Fernandina Beach): 1.0000 (All rate schedules)

Gulf:

| Group | Rate Schedules | Line Loss Multipliers |
|---|---|---|
| A | RS, RSVP,GS, GSD, GSDT, GSTOU, OSIII, SBS(1) | 1.00773 |
| B | LP, LPT, SBS(2) | 0.98353 |
| C | PX, PXT, RTP, SBS(3) | 0.96591 |
| D | OSI/II | 1.00777 |

(1) Includes SBS customers with a contract demand in the range of 100 to 499 KW
(2) Includes SBS customers with a contract demand in the range of 500 to 7,499 KW
(3) Includes SBS customers with a contract demand over 7,499 KW

TECO:

| Metering Voltage Schedule | Line Loss Multiplier |
|---|---|
| Distribution Secondary | 1.0000 |
| Distribution Primary | 0.9900 |
| Transmission | 0.9800 |
| Lighting Service | 1.0000 |

## GENERATING PERFORMANCE INCENTIVE FACTOR

Upon review, we find that the fuel cost recovery factors used by each utility in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class adjusted for line losses shall be:

FPL:

DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)

ESTIMATED FOR THE PERIOD OF: JUNE 2014 THROUGH DECEMBER 2014

OFF PEAK: ALL OTHER HOURS

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| | | JUNE - SEPTEMBER | | |
| GROUPS | RATE SCHEDULE | Average Factor | Fuel Recovery Loss Multiplier | Fuel Recovery Factor |
| B | GSD(T)-1 On-Peak | 6.001 | 1.00284 | 6.018 |
| | GSD(T)-1 Off-Peak | 2.777 | 1.00284 | 2.785 |
| C | GSLD(T)-1 On-Peak | 6.001 | 1.00186 | 6.012 |
| | GSLD(T)-1 Off-Peak | 2.777 | 1.00186 | 2.782 |
| D | GSLD(T)-2 On-Peak | 6.001 | 0.99328 | 5.961 |
| | GSLD(T)-2 Off-Peak | 2.777 | 0.99328 | 2.758 |

Note: On-Peak Period is defined as June through September, weekdays 3:00pm to 6:00pm
Off Peak Period is defined as all other hours.

Note: All other months served under the otherwise applicable rate schedule
See Schedule E-1E, Page 1 of 2.

Note: Totals may not add due to rounding.

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH MAY 2014

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| | | JANUARY - DECEMBER | | |
| GROUPS | RATE SCHEDULE | Average Factor | Fuel Recovery Loss Multiplier | Fuel Recovery Factor |
| A | RS-1 first 1,000 kWh | 3.383 | 1.00293 | 3.067 |
| A | RS-1 all additional kWh | 3.383 | 1.00293 | 4.067 |
| A | GS-1, SL-2, GSCU-1, WIES-1 | 3.383 | 1.00293 | 3.393 |
| A-1 | SL-1, OL-1, PL-1 [1] | 3.093 | 1.00293 | 3.102 |
| B | GSD-1 | 3.383 | 1.00284 | 3.393 |
| C | GSLD-1, CS-1 | 3.383 | 1.00186 | 3.389 |
| D | GSLD-2, CS-2, OS-2, MET | 3.383 | 0.99253 | 3.358 |
| E | GSLD-3, CS-3 | 3.383 | 0.96479 | 3.264 |
| A | GST-1 On-Peak | 4.841 | 1.00293 | 4.855 |
| | GST-1 Off-Peak | 2.761 | 1.00293 | 2.769 |
| A | RTR-1 On-Peak | - | - | 1.462 |
| | RTR-1 Off-Peak | - | - | (0.624) |
| B | GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak | 4.841 | 1.00283 | 4.855 |
| | GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak | 2.761 | 1.00283 | 2.769 |
| C | GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak | 4.841 | 1.00186 | 4.850 |
| | GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak | 2.761 | 1.00186 | 2.766 |
| D | GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak | 4.841 | 0.99328 | 4.808 |
| | GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak | 2.761 | 0.99328 | 2.742 |
| E | GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak | 4.841 | 0.96479 | 4.671 |
| | GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak | 2.761 | 0.96479 | 2.664 |
| F | CILC-1(D), ISST-1(D) On-Peak | 4.841 | 0.99253 | 4.805 |
| | CILC-1(D), ISST-1(D) Off-Peak | 2.761 | 0.99253 | 2.740 |

[1] WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

## DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH MAY 2014

OFF PEAK: ALL OTHER HOURS

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| GROUPS | RATE SCHEDULE | JUNE - SEPTEMBER | | |
| | | Average Factor | Fuel Recovery Loss Multiplier | Fuel Recovery Factor |
| B | GSD(T)-1 On-Peak | 6.221 | 1.00284 | 6.239 |
| | GSD(T)-1 Off-Peak | 2.879 | 1.00284 | 2.887 |
| C | GSLD(T)-1 On-Peak | 6.221 | 1.00186 | 6.233 |
| | GSLD(T)-1 Off-Peak | 2.879 | 1.00186 | 2.884 |
| D | GSLD(T)-2 On-Peak | 6.221 | 0.99328 | 6.179 |
| | GSLD(T)-2 Off-Peak | 2.879 | 0.99328 | 2.860 |

Note: On-Peak Period is defined as June through September, weekdays 3:00pm to 6:00pm
Off Peak Period is defined as all other hours.

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1E, Page 1 of 2.

Note: Totals may not add due to rounding

## FUEL RECOVERY FACTORS - BY RATE GROUP
## (ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

ESTIMATED FOR THE PERIOD OF: JUNE 2014 THROUGH DECEMBER 2014

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| GROUPS | RATE SCHEDULE | JANUARY - DECEMBER | | |
| | | Average Factor | Fuel Recovery Loss Multiplier | Fuel Recovery Factor |
| A | RS-1 first 1,000 kWh | 3.263 | 1.00293 | 2.947 |
| A | RS-1 all additional kWh | 3.263 | 1.00293 | 3.947 |
| A | GS-1, SL-2, GSCU-1, WIES-1 | 3.263 | 1.00293 | 3.273 |
| A-1 | SL-1, OL-1, PL-1 (1) | 2.984 | 1.00293 | 2.992 |
| B | GSD-1 | 3.263 | 1.00284 | 3.272 |
| C | GSLD-1, CS-1 | 3.263 | 1.00186 | 3.269 |
| D | GSLD-2, CS-2, OS-2, MET | 3.263 | 0.99253 | 3.239 |
| E | GSLD-3, CS-3 | 3.263 | 0.96479 | 3.148 |
| A | GST-1 On-Peak | 4.669 | 1.00293 | 4.683 |
| | GST-1 Off-Peak | 2.663 | 1.00293 | 2.671 |
| A | RTR-1 On-Peak | - | - | 1.410 |
| | RTR-1 Off-Peak | - | - | (0.602) |
| B | GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak | 4.669 | 1.00283 | 4.682 |
| | GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak | 2.663 | 1.00283 | 2.671 |
| C | GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak | 4.669 | 1.00186 | 4.678 |
| | GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak | 2.663 | 1.00186 | 2.668 |
| D | GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak | 4.669 | 0.99328 | 4.638 |
| | GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak | 2.663 | 0.99328 | 2.645 |
| E | GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak | 4.669 | 0.96479 | 4.505 |
| | GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak | 2.663 | 0.96479 | 2.569 |
| F | CILC-1(D), ISST-1(D) On-Peak | 4.669 | 0.99253 | 4.634 |
| | CILC-1(D), ISST-1(D) Off-Peak | 2.663 | 0.99253 | 2.643 |

(1) WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

DEF: The appropriate levelized fuel adjustment and purchased power cost recovery factors for the period January 2014 through December 2014 shall be as follows:

| Fuel Cost Factors (cents/kWh)<br>GSD-1, GSDT-1, SS-1, CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3, IS-1, IST-1, IS-2, IST-2, SS-2, LS-1 | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | Time of Use | |
| Group | Delivery Voltage Level | First Tier Factor | Second Tier Factors | Levelized Factors | On-Peak | Off-Peak |
| A | Transmission | -- | -- | 4.320 | 5.577 | 3.707 |
| B | Distribution Primary | -- | -- | 4.364 | 5.634 | 3.744 |
| C | Distribution Secondary | -- | -- | 4.408 | 5.691 | 3.782 |
| D | Lighting Secondary | -- | -- | 4.139 | -- | -- |

| Fuel Cost Factors (cents/kWh)<br>RS-1, RST-1, RSL-1, RSL-2, RSS-1 | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | Time of Use | |
| Group | Delivery Voltage Level | First Tier Factor | Second Tier Factors | Levelized Factors | On-Peak | Off-Peak |
| C | Distribution Secondary | 4.077 | 5.077 | 4.359 | 5.627 | 3.740 |

| Fuel Cost Factors (cents/kWh)<br>GS-1, GST-1, GS-2 | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | Time of Use | |
| Group | Delivery Voltage Level | First Tier Factor | Second Tier Factors | Levelized Factors | On-Peak | Off-Peak |
| A | Transmission | -- | -- | 4.277 | 5.522 | 3.670 |
| B | Distribution Primary | -- | -- | 4.320 | 5.577 | 3.707 |
| C | Distribution Secondary | -- | -- | 4.364 | 5.634 | 3.744 |

FPUC: The appropriate levelized fuel adjustment and purchased power cost recovery factors for the period January 2014 through December 2014 for the Northwest Division, adjusted for line loss multipliers and including taxes, are as follows:

**Northwest Division**

| Rate Schedule | Adjustment |
|---|---|
| RS | $0.10185 |
| GS | $0.09829 |
| GSD | $0.09322 |
| GSLD | $0.08965 |
| OL,Ol1 | $0.07595 |
| SL1, SL2, and SL3 | $0.07616 |
| Step rate for RS | |
| RS with less than 1,000 kWh/month | $0.09740 |
| RS with more than 1,000 kWh/month | $0.10990 |

Consistent with the fuel projections for the 2014 period, the appropriate adjusted Time of Use (TOU) and Interruptible rates for the 2014 period are:

Time of Use/Interruptible

| Rate Schedule | Adjustment On Peak | Adjustment Off Peak |
|---|---|---|
| RS | $0.18140 | $0.05840 |
| GS | $0.13829 | $0.04829 |
| GSD | $0.13322 | $0.06072 |
| GSLD | $0.14965 | $0.05965 |
| Interruptible | $0.07465 | $0.08965 |

The appropriate levelized fuel adjustment and purchased power cost recovery factors for the period January 2014 through December 2014 for the Company's Northeast Division, adjusted for line loss multipliers and including taxes, are as follows:

**Northeast Division**

| Rate Schedule | Adjustment |
|---|---|
| RS | $0.09337 |
| GS | $0.08335 |
| GSD | $0.08220 |
| GSLD | $0.08245 |
| OL | $0.05228 |
| SL | $0.05206 |
| Step rate for RS | |
| RS with less than 1,000 kWh/month | $0.08975 |
| RS with more than 1,000 kWh/month | $0.10225 |

Gulf: The appropriate levelized fuel adjustment and purchased power cost recovery factors for the period January 2014 through December 2014

| Group | Rate Schedules* | Line Loss Multipliers | Fuel Cost Factors ¢/KWH | | |
|---|---|---|---|---|---|
| | | | Standard | Time of Use | |
| | | | | On-Peak | Off-Peak |
| A | RS, RSVP,GS, GSD, GSDT, GSTOU, OSIII, SBS(1) | 1.00773 | 4.201 | 5.016 | 3.867 |
| B | LP, LPT, SBS(2) | 0.98353 | 4.100 | 4.896 | 3.774 |
| C | PX, PXT, RTP, SBS(3) | 0.96591 | 4.027 | 4.808 | 3.707 |
| D | OSI/II | 1.00777 | 4.155 | N/A | N/A |

*The recovery factor applicable to customers taking service under Rate Schedule SBS is determined as follows: (1) customers with a contract demand in the range of 100 to 499 KW will use the recovery factor applicable to Rate Schedule GSD; (2) customers with a contract demand in the range of 500 to 7,499 KW will use the recovery factor applicable to Rate Schedule LP; and (3) customers with a contract demand over 7,499 KW will use the recovery factor applicable to Rate Schedule PX.

TECO: The appropriate levelized fuel adjustment and purchased power cost recovery factors for the period January 2014 through December 2014 The appropriate factors are as follows:

| Metering Voltage Level | Fuel Charge Factor (cents per kWh) | |
|---|---|---|
| Secondary | 3.910 | |
| Tier I (Up to 1,000 kWh) | 3.609 | |
| Tier II (Over 1,000 kWh) | 4.609 | |
| Distribution Primary | 3.871 | |
| Transmission | 3.832 | |
| Lighting Service | 3.872 | |
| Distribution Secondary | 4.124 | (on-peak) |
| | 3.820 | (off-peak) |
| Distribution Primary | 4.083 | (on-peak) |
| | 3.782 | (off-peak) |
| Transmission | 4.042 | (on-peak) |
| | 3.744 | (off-peak) |

## COMPANY-SPECIFIC CAPACITY COST RECOVERY FACTOR

### Duke Energy Florida, Inc.

Upon review, we find that Duke included in the capacity cost recovery clause, the nuclear cost recovery amount ordered in Order No. PSC-13-0493-FOF-EI, issued October 18, 2013 in Docket No. 130009-EI. On August 5, 2013, we approved Duke's Motion to Defer filed in Docket 130009-EI. The Motion to Defer provided for recovery of the requested CR3 Uprate costs filed on May 1, 2013, which have been included in the capacity cost recovery clause. For the Levy Nuclear Project, the amount is a function of the rates filed for collection as presented in Exhibit 9 of DEF's Revised and Restated Stipulation and Settlement Agreement.

### Florida Power & Light Company

Upon review, we find that FPL included in the capacity cost recovery clause, the nuclear cost recovery amount of $43,461,246 approved by Order No. PSC-13-0493-FOF-EI, issued October 18, 2013, in Docket No. 130009-EI.

We next consider the issue of whether the costs (Operations and Maintenance and Capital Costs) related to Nuclear Regulatory Commission (NRC) requirements stemming from the Fukushima incident that exceed the levels of such costs that FPL included in its 2013 test year in Docket No. 120015-EI are eligible for recovery through the capacity cost recovery clause.

FPL argues that the costs should be recovered through the capacity cost recovery clause. FPL states that NRC compliance costs associated with the Fukushima event will be incurred in order to allow FPL's nuclear plants to continue operating and saving FPL customers substantial fossil fuel costs. FPL states the level of NRC compliance costs associated with the Fukushima event included in base rates does not address either: (a) the incremental increase in the compliance costs that FPL expects in 2013 and 2014; or (b) the high degree of uncertainty that exists as to the ultimate level of compliance costs. Both of these considerations make base rate recovery problematic and clause recovery appropriate.

FPL argues that its requested recovery of Fukushima-related costs falls squarely within the parameters for Capacity Clause recovery in Order No. PSC-05-0748-FOF-EI,[3] which states:

> The original purpose of recovery clauses was to address on-going costs which could fluctuate between rate cases and unduly penalize either the utility or customers, if such costs were included in base rates.
>
> [A]ll four current clauses address costs that are unpredictable, volatile and irregular, due to forces outside the utility's control.

FPL further argues that its response to NRC mandated Fukushima-related actions are continuing to evolve and follow varying schedules ranging from 60 days to several years. FPL further contends that the Fukushima-related costs are driven by an external unanticipated event outside its control.

FPL additionally supports its request by citing Order No. PSC-01-2516-FOF-EI,[4] which approved, for recovery through the Capacity Clause, incremental security costs associated with the events of September 11, 2001 (9/11).[5] The Order stated the following:

> We find that recovery of this incremental cost through the fuel clause is appropriate in this instance because there is a nexus between protection of FPL's nuclear generation facilities and the fuel cost savings that result from the continued operation of those facilities.

By Order No. PSC-05-0748-FOF-EI, this Commission found that clause recovery of 9/11 costs was appropriate based on an immediate need to protect the health, safety and welfare of the utility and its customers.[6] FPL argues that the approval of Capacity Clause recovery for 9/11 costs is analogous to its requested recovery of Fukushima-related costs which are driven by an external event outside of the Utility's control, expected to be recurring and volatile over time, and necessary to ensure the safety of FPL's nuclear plants.

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[3] See Order No. PSC-05-0748-FOF-EI, issued July 14, 2005, in Docket No. 041272-EI, In re: Petition for approval of storm cost recovery clause for recovery of extraordinary expenditures related to Hurricanes Charley, Frances, Jeanne, and Ivan, by Progress Energy Florida, Inc.

[4] See Order No. PSC-01-2516-FOF-EI, issued December 26, 2001, in Docket No. 010001-EI, In re: Fuel and purchased power cost recovery clause and generating performance incentive factor.

[5] 9/11 costs were first recovered through the fuel cost recovery clause and, subsequently, the capacity cost recovery clause.

[6] See Order No. PSC-05-0748-FOF-EI, issued July 14, 2005, in Docket No. 041272-EI, In re: Petition for approval of storm cost recovery clause for recovery of extraordinary expenditures related to Hurricanes Charley, Frances, Jeanne, and Ivan, by Progress Energy Florida, Inc.

FPL also contends that its request for the recovery of costs incremental to the amounts included in base rates is consistent with Order No. PSC-05-0748-FOF-EI. FPL asserts that this methodology of seeking only the incremental costs eliminates double recovery.

OPC argues that FPL's attempt to increase customers' bills by equating costs of the NRC's Fukushima-related evaluations with the extraordinary, unique clause treatment of post-9/11 security costs should be rejected. OPC states that FPL's claim that it would otherwise have no opportunity to recover such base rate-related costs above MFR-projected levels is untrue. Further, OPC adds, whereas the immediate threat of additional terrorist attacks precipitated emergency wartime measures, FPL emphasizes that Fukushima-related initiatives present no safety emergency. FPL's rationale that such costs are eligible because they are necessary and uncertain would absurdly qualify every compliance measure and even equipment replacements for clause recovery.

OPC further argues that FPL's request for Capacity Clause recovery of Fukushima-related costs shall be rejected asserting that these costs are base rate-related and as long as base rates generate revenues that are sufficient to recover the cost of service and provide a fair return, FPL will have recovered all Fukushima-related costs. OPC adds that a myriad of components of the ratemaking formula are subject to variances above and below projections, and if revenues become such that base rates do not produce an overall fair return, the remedy is a base rate proceeding. OPC also contends that the treatment of 9/11 costs does not provide a basis for granting FPL's request, since the events of 9/11 exposed an immediate threat to safety, whereas FPL does not characterize the NRC's initiatives relative to the Fukushima incident as an emergency or an immediate danger. OPC additionally expresses concern with authorizing Capacity Clause recovery of Fukushima-related costs based on the characterization that the costs are uncertain, and are necessary for the continued operation of the Company's nuclear units. OPC further remarks that these characteristics would be true of any compliance costs as well as any replacement of necessary parts.

On March 11, 2011, an earthquake occurred off the coast of Japan. The earthquake and resulting tsunami caused significant damage to nuclear units at Fukushima. The Fukushima event raised concerns about the safety of the U.S. nuclear fleet and led to reviews by plant operators, the NRC, and the Institute of Nuclear Power Operations. In its 2013 test year, FPL included forecasted Fukushima-related costs.[7] FPL testified that the rate case forecast was developed in 2011 and at that time, there was insufficient information available to prepare a reasonable estimate for the Fukushima costs. FPL elaborated that it is now clear that the Fukushima-related costs will exceed the rate case forecast in the years to come. FPL is seeking to recover, through the Capacity Clause, the incremental NRC compliance costs that exceed the amounts included in its 2013 test year forecast.

We agree that many base rate-related costs are subject to variances arising from powers outside of a utilities' control, and the appropriate mechanism for addressing those variances is in a rate case proceeding. However, FPL's request to recover the incremental costs associated with

---

[7] By Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 120015-EI, the Commission approved a settlement which increased FPL's base rates based on the Company's forecasted 2013 test year.

the Fukushima Event through the Capacity Clause appears to be appropriate based on the language of Order No. PSC-13-0023-S-EI. The Order approved a settlement (Settlement) which contains the following language:

> It is further the intent of the Parties to recognize that an authorized governmental entity may impose requirements on FPL involving new or atypical kinds of costs (including but not limited to, for example, requirements related to cybersecurity or the requirements for seismic and flood protection at nuclear plants arising out of the Fukushima Daiichi event), and concurrently or in connection with the imposition of such requirements, the Legislature and/or Commission may authorize FPL to recover those related costs through a cost recovery clause.

Although the Settlement does not state a specific standard for which to allow recovery of Fukushima-related costs, it does indicate that the costs must be imposed by a governmental entity. We considered FPL witness Grissette's testimony that the costs projected to be incurred are as a result of compliance with NRC requirements. The Settlement additionally required that the costs must be new or atypical. To that point, witness Grissette testified that the Fukushima Event has resulted in new and evolving regulations. Furthermore, based on the timing of NRC orders and NRC information requests in response to the Fukushima Event (March 2012), it is reasonable to describe the costs being requested for recovery as new. Thus, we find that these costs satisfy the terms of the Settlement with respect to seeking recovery of Fukushima-related costs through a cost recovery clause. We also find that comparison of the Fukushima Event with the 9/11 event is not necessary in this case because the nature of the Fukushima Event was known when the Settlement was approved.

We note that many base rate-related costs are subject to variances arising from powers outside of a utilities' control and the appropriate mechanism for addressing those variances is in a rate case proceeding. Likewise, nuclear compliance shall not serve as the sole basis for allowing cost-recovery through a clause. However, the Settlement addresses these issues. Therefore, FPL's request for recovery of Fukushima-related costs through the Capacity Clause shall be approved.

We next consider the issue of the appropriate amount of Incremental Nuclear Regulatory Commission (Fukushima) Compliance O&M and capital costs that FPL shall be allowed to recover through the Capacity Clause. FPL projected the 2013 and 2014 costs for NRC compliance with post-Fukushima standards. The costs involve seismic and flooding evaluations, design modifications, instrumentation, and training for FPL's nuclear generating units. The costs include estimated capital costs and O&M expenses and are incremental to costs included in FPL's 2013 test year in Docket No. 120015-EI. The amounts are $116,265 for 2013 and $1,621,570 for 2014. No post-hearing position was provided in OPC's brief.

We find that FPL shall be allowed to recover Incremental Nuclear Regulatory Commission (Fukushima) Compliance O&M expense and capital costs through the Capacity Clause in the amount of $116,265 for the period January-December 2013, and $1,621,570 for the period January-December 2014. The estimated costs shall be trued-up to actual costs and will be audited as part of the audit process for the capacity clause.

Upon review, we find that the appropriate 2014 projected non-fuel revenue requirements for FPL's West County Energy Center Unit 3 (WCEC-3) to be recovered through the Capacity Clause is $159,210,391.

Upon review, we find that FPL's proposed generation base rate adjustment (GBRA) factor for the Riviera Beach Energy Center shall be 4.565 percent. The GBRA for the Riviera Beach Energy Center was approved in Final Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket 120015-EI. Previously, we recognize OPC's qualified statement that by taking no position with respect to the issue of the amount that we authorize FPL to collect regarding the Riviera GBRA approved in Order No. PSC-13-0023-S-EI, OPC does not waive and expressly reaffirms its appeal of Order No. PSC-13-0023-S-EI.

## GENERIC CAPACITY COST RECOVERY FACTOR

Upon review, we find that the appropriate capacity cost recovery true-up amounts for the period January 2012 through December 2012 shall be:

FPL: $7,913,484 under-recovery.

Duke: $9,768,250 under-recovery.

Gulf: $102,776 over-recovery.

TECO: $126,648 under-recovery.

Upon review, we find that the appropriate capacity cost recovery actual/estimated true-up amounts for the period January 2013 through December 2013 shall be:

FPL: $25,357,191 under-recovery

Duke: $14,592,001 under-recovery.

Gulf: $2,263,786 under-recovery.

TECO: $465,117 under-recovery.

Upon review, we find that the appropriate total capacity cost recovery true-up amounts to be collected/refunded during the period January 2014 through December 2014 shall be:

FPL: $33,270,675 under recovery

Duke: $24,360,251 under-recovery

Gulf: $2,161,000 under-recovery

TECO: $591,765 under-recovery

Upon review, we find that the appropriate projected total capacity cost recovery amounts for the period January 2014 through December 2014 shall be:

FPL: $510,012,148 (Jurisdictionalized, and excluding prior period true-ups, revenue taxes, nuclear cost recovery amounts, and West County Energy Center Unit-3 jurisdictional non-fuel revenue requirements).

Duke: $317,169,968

Gulf: $61,868,429

TECO: $30,881,044.

Upon review, we find the appropriate projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January 2014 through December 2014 shall be:

FPL: $746,376,916 (including prior period true-ups, revenue taxes, the nuclear cost recovery amount and West County Energy Center Unit-3 revenue requirements.

Duke: $341,776,120, excluding nuclear cost recovery

Gulf: $64,075,540

TECO: $31,495,469.

Upon review, we find the appropriate jurisdictional separation factors for capacity revenues and costs to be included in the recovery factor for the period January 2014 through December 2014 shall be:

FPL: FPSC 95.206884%
FERC 4.793116%

Duke: Base 92.885%
Intermediate 72.703%
Peaking 95.924%

Gulf: 97.07146%

TECO: 1.00.

Upon review, we find the appropriate capacity cost recovery factors for the period January 2014 through December 2014 shall be:

FPL: The January 2014 through December 2014 factors are as follows:

| RATE SCHEDULE | Total January 2014 - December 2014 Capacity Recovery Factor | | | |
|---|---|---|---|---|
| | ($/KW) | ($/kwh) | RDC ($/KW) | SDD ($/KW) |
| RS1 / RTR1 | - | 0.00786 | - | - |
| GS1 / GST1 / WIES1 | - | 0.00665 | - | - |
| GSD1 / GSDT1 / HLFT1 | 2.32 | - | - | - |
| OS2 | - | 0.00569 | - | - |
| GSLD1 / GSLDT1 / CS1 / CST1 / HLFT2 | 2.60 | - | - | - |
| GSLD2 / GSLDT2 / CS2 / CST2 / HLFT3 | 2.59 | - | - | - |
| GSLD3 / GSLDT3 / CS3 / CST3 | 2.95 | - | - | - |
| SST1T | - | - | 0.33 | 0.15 |
| SST1D1 / SST1D2 / SST1D3 | - | - | 0.34 | 0.16 |
| CILC D / CICL G | 2.80 | - | - | - |
| CILC T | 2.73 | - | - | - |
| MET | 2.98 | - | - | - |
| OL1 / SL1 / PL1 | - | 0.00159 | - | - |
| SL2, GSCU1 | - | 0.00530 | - | - |

Duke: The January 2014 through December 2014 factors are as follows:

| Rate Class | CCR Factor |
|---|---|
| Residential | 1.644 cents/kWh |
| General Service Non-Demand | 1.303 cents/kWh |
| @ Primary Voltage | 1.290 cents/kWh |
| @ Transmission Voltage | 1.277 cents/kWh |
| General Service 100% Load Factor | 0.897 cents/kWh |
| | |
| General Service Demand | 4.26 $/kW-month |
| @ Primary Voltage | 4.22 $/kW-month |
| @ Transmission Voltage | 4.17 $/kW-month |
| Curtailable | 3.13 $/kW-month |
| @ Primary Voltage | 3.10 $/kW-month |
| @ Transmission Voltage | 3.07 $/kW-month |
| Interruptible | 3.61 $/kW-month |
| @ Primary Voltage | 3.57 $/kW-month |
| @ Transmission Voltage | 3.54 $/kW-month |
| Standby Monthly | 0.418 $/kW-month |

| | |
|---|---|
| @ Primary Voltage | 0.414 $/kW-month |
| @ Transmission Voltage | 0.410 $/kW-month |
| Standby Daily | 0.199 $/kW-month |
| @ Primary Voltage | 0.197 $/kW-month |
| @ Transmission Voltage | 0.195 $/kW-month |
| Lighting | 0.239 cents/kWh |

Gulf: The January 2014 through December 2014 factors are as follows:

| RATE CLASS | CAPACITY COST RECOVERY FACTORS ¢/KWH[8] |
|---|---|
| RS, RSVP | 0.680 |
| GS | 0.602 |
| GSD, GSDT, GSTOU | 0.522 |
| LP, LPT | 0.455 |
| PX, PXT, RTP, SBS | 0.430 |
| OS-I/II | 0.091 |
| OSIII | 0.403 |

TECO: The January 2014 through December 2014 factors are as follows:

| Rate Class and Metering Voltage | Capacity Cost Recovery Factor Cents per kWh | $ per kW |
|---|---|---|
| RS Secondary | 0.202 | |
| GS and TS Secondary | 0.186 | |
| GSD, SBF Standard | | |
| Secondary | | 0.63 |
| Primary | | 0.62 |
| Transmission | | 0.62 |
| GSD Optional | | |
| Secondary | 0.150 | |
| Primary | 0.149 | |
| IS, SBI | | |
| Primary | | 0.39 |
| Transmission | | 0.38 |

---

[8] The 2014 capacity factors presented in Gulf's petition were not revised to reflect the final capacity factors as calculated and presented on pages 39 and 40 of Witness Dodd's Exhibit RWD-3.

| | |
|---|---|
| LS1 Secondary | 0.025 |

Upon review, we find the effective date of the fuel adjustment factors shall begin with the first billing cycle for January 2014 and thereafter through the last billing cycle for December 2014. The first billing cycle may start before January 1, 2014, and the last cycle may be read after December 31, 2014, so that each customer is billed for twelve months regardless of when the recovery factors became effective. The new factors shall continue in effect until modified by this Commission.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the findings set forth in the body of this Order are hereby approved. It is further

ORDERED that Florida Power & Light Company, Florida Public Utilities Company, Gulf Power Company, Duke Energy Florida, Inc., and Tampa Electric Company are hereby authorized to apply the fuel cost recovery factors set forth herein during the period January 2014 through December 2014. It is further

ORDERED the estimated true-up amounts contained in the fuel cost recovery factors approved herein are hereby authorized subject to final true-up and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that Florida Power & Light Company, Duke Energy Florida, Inc., Gulf Power Company, and Tampa Electric Company are hereby authorized to apply the capacity cost recovery factors as set forth herein during the period January 2014 through December 2014. It is further

ORDERED that the estimated true-up amounts contained in the capacity cost recovery factors approved herein are hereby authorized subject to final true-up and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that the Fuel and Purchased Power Cost Recovery Clause With Generating Performance Incentive Factor docket is an on-going docket and shall remain open.

By ORDER of the Florida Public Service Commission this 18th day of December, 2013.

Carlotta S. Stauffer

CARLOTTA S. STAUFFER
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
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Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

MFB

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice shall not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

TAB J

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

| In re: Fuel and purchased power cost recovery clause with generating performance incentive factor. | DOCKET NO. 120001-EI<br>ORDER NO. PSC-12-0664-FOF-EI<br>ISSUED: December 21, 2012 |
|---|---|

The following Commissioners participated in the disposition of this matter:

RONALD A. BRISÉ, Chairman
LISA POLAK EDGAR
ART GRAHAM
EDUARDO E. BALBIS
JULIE I. BROWN

APPEARANCES

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On behalf of Florida Power & Light Company (FPL).

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On behalf of Progress Energy Florida, Inc. (PEF).

BETH KEATING, ESQUIRE, Gunster, Yoakley & Stewart, P.A., 215 South Monroe St., Suite 601, Tallahassee, Florida, 32301
On behalf of Florida Public Utilities Company (FPUC).

JEFFREY A. STONE, RUSSELL A. BADDERS, and STEVEN R. GRIFFIN, ESQUIRES, Beggs & Lane, Post Office Box 12950, Pensacola, Florida 32591-2950
On behalf of Gulf Power Company (GULF).

JAMES D. BEASLEY, and J. JEFFRY WAHLEN, ESQUIRES, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302
On behalf of Tampa Electric Company (TECO).

J.R. KELLY, PATRICIA A. CHRISTENSEN, CHARLES REHWINKEL, JOSEPH A. MCGLOTHLIN, and ERIK SAYLER, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida (OPC).

CAPTAIN SAMUEL MILLER, ESQUIRE, USAF/AFLOA/JACL/ULFFSC, 139 Barnes Drive, Suite 1, Tyndall AFB, Florida 32403 -5319
On behalf of the Federal Executive Agencies (FEA).

VICKI GORDON KAUFMAN, and JON C. MOYLE, JR., ESQUIRES, Moyle Law Firm, PA, The Perkins House, 118 North Gadsden Street, Tallahassee, Florida 32301
On behalf of the Florida Industrial Power Users Group (FIPUG).

ROBERT SCHEFFEL WRIGHT, and JOHN T. LAVIA, III, ESQUIRES, Gardner, Bist, Wiener, Wadsworth, Bowden, Bush, Dee, LaVia & Wright, P.A., 1300 Thomaswood Drive, Tallahassee, Florida 32308
On behalf of the Florida Retail Federation (FRF).

JAMES W. BREW, and F. ALVIN TAYLOR, ESQUIRES, Brickfield, Burchette, Ritts & Stone, P.C., 1025 Thomas Jefferson St., NW, Eighth Floor, West Tower, Washington, DC 20007; RANDY B. MILLER, White Springs Agricultural Chemicals, Inc., Post Office Box 300, White Springs, FL 32096
On behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs (PCS Phosphate).

MARTHA BARRERA, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Florida Public Service Commission (Staff).

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

FINAL ORDER APPROVING EXPENDITURES AND TRUE-UP AMOUNTS FOR FUEL ADJUSTMENT FACTORS; GPIF TARGETS, RANGES, AND REWARDS; AND PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR CAPACITY COST RECOVERY FACTORS

BY THE COMMISSION:

Background

As part of the continuing fuel and purchased power adjustment and generating performance incentive clause proceedings, an administrative hearing was held by the Commission on November 5, 2012 in this docket. At the hearing, we addressed several issues listed in Order No. PSC-12-0597-PHO-EI[1] (Prehearing Order) by making bench decisions.

[1] Order No. PSC-12-0597-PHO-EI, issued November 1, 2012, in Docket No. 120001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Several of the positions on these issues were not contested by the parties and were presented to us for approval without objections, but some contested issues remained for our consideration. The contested issues are 1D for PEF, and Issues 2C, 24B, 24C, and 24D for FPL. We requested that briefs be filed to address the remaining issues, which were timely filed.

The Federal Executive Agencies (FEA), Progress Energy Florida, Inc. (PEF), Florida Power & Light Company (FPL), the Office of Public Counsel (OPC), the Florida Industrial Power Users Group (FIPUG), and White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphates – White Springs (PCS) filed post hearing filings. The Florida Retail Federation (FRF) participated in the hearing phase of this case, but did not file a brief. On November 14, 2012, we received notification from FPL, OPC, and FRF, of a stipulation on Issues 2C, 24B, 24C, and 24D, which we approved at the November 27, 2012 Agenda Conference.

We have jurisdiction over this subject matter pursuant to the provisions of Chapter 366, Florida Statutes (F.S.), including Sections 366.04, 366.05, and 366.06, F.S.

## COMPANY-SPECIFIC FUEL COST RECOVERY ISSUES

### Florida Power & Light Company

Hedging Activities for August 2011 through July 2012

We reviewed FPL's hedging activities for August 2011 through July 2012 and found its actions to mitigate the price volatility of natural gas, residual oil, and purchased power prices were reasonable and prudent.

Risk Management Plan for 2013

We reviewed FPL's 2013 Risk Management Plan and found that FPL's 2013 Risk Management Plan is consistent with the Hedging Guidelines.

New RTR-1 Rider

In its rate case, Docket No. 120015-EI, FPL proposed a new optional residential time-of-use base rate rider, RTR-1. Under the RTR-1 Rider as proposed in the rate case, the standard residential base energy and fuel factors will be adjusted by applying adders to reflect on-peak usage and credits to reflect off-peak usage. We approved the RTR-1 Rider at the commencement of the rate case hearing as stipulated Issue 146. Prior to the evidentiary hearing in Docket No. 120015-EI, FPL, FIPUG, FEA, and SFHHA entered into a proposed settlement agreement which they presented to us as a proposed settlement of all issues in Docket No. 120015-EI. The RTR-1 rider is also included in the proposed settlement agreement between FPL, FEA, FIPUG and SFHHA as Tariff Sheet 8.203. We have not reached a decision and issued a final order in Docket No. 120015-EI prior to our decision in this Docket No. 120001-EI. However, both the stipulation and proposed settlement agreement contemplate that the RTR-1 rider will become effective after FPL's billing system has been modified to accommodate the rider, which FPL expects to be completed in mid-2013. In Docket No. 120001-EI, FPL has provided fuel factors that correspond to both the RST-1 base rate and the RTR-1 rider:

**2013 RTR-1 Fuel Charges/Credits**

| January 2013 through May 2013 | | |
|---|---|---|
| cents per kWh | | |
| Rate Schedule | January-March / November-December | April-October |
| RTR-1 On-Peak | 0.579 | 1.596 |
| RTR-1 Off-Peak | (0.212) | (0.819) |

| June 2013 through December 2013 | | |
|---|---|---|
| cents per kWh | | |
| Rate Schedule | January-March / November-December | April-October |
| RTR-1 On-Peak | 0.551 | 1.517 |
| RTR-1 Off-Peak | (0.201) | (0.777) |

Accordingly, we approve the fuel factors for both the RST-1 base rate and the RTR-1 rider subject to the following limitations. The existing residential time-of-use base rate (RST-1) will remain in effect until a final order has been issued in Docket No. 120015-EI approving the RTR-1 Rider. We direct FPL to apply the fuel factors for the RST-1 base rate until the RTR-1 rider goes into effect following the issuance of the final order in Docket No. 120015-EI, and then to switch to the fuel factors for the RTR-1 rider with respect to customers who elect to take service under that rider. It is acknowledged that the OPC, FRF and others have objected to the proposed settlement agreement signed by FPL, FIPUG, SFHHA and FEA in Docket No. 120015-EI and that agreement to the stipulation language on this issue does not constitute waiver by OPC, FRF, or other parties of their objections to the proposed settlement agreement and to any orders impacted by our consideration of the proposed settlement agreement in Docket No. 120015-EI.

**Progress Energy Florida, Inc.**

Hedging Activities for August 2011 through July 2012

We reviewed PEF's hedging activities for August 2011 through July 2012 and found its actions to mitigate the price volatility of natural gas, residual oil, and purchased power prices were reasonable and prudent.

Risk Management Plan for 2013

We reviewed PEF's 2013 Risk Management Plan and found that PEF's 2013 Risk Management Plan is consistent with the Hedging Guidelines.

Refund Pursuant to the Settlement Agreement

The parties raised an issue of whether PEF correctly reflected the $129 million refund pursuant to the Settlement Agreement approved in Order No. PSC-12-0104-FOF-EI in the calculation of the 2013 factor. Testimony and evidence was entered into the record. Upon the conclusion of the record, OPC stated it was satisfied that PEF correctly accounted for the $129 million refund. No other party objected. Having reviewed the testimony and evidence in the record, we find that PEF correctly reflected the $129 million refund pursuant to the Settlement Agreement approved in Order No. PSC-12-0104-FOF-EI in the calculation of the 2013 factor.

Inclusion of Projected Nuclear Electric Insurance Limited Recoveries

In the fall of 2009, during a refueling outage, PEF began work to replace the steam generator at its nuclear generating unit, Crystal River 3. On October 2, 2009, PEF discovered a delamination of layers of concrete for a wall in CR3's containment building. On March 14, 2011, a second delamination was discovered during re-tensioning tendons in another wall of the containment building. Since the first delamination event in October of 2009, CR3 has remained out of service. If PEF decides to repair the plant, it will not return to service until 2014 or later.[2] We established Docket No. 100437-EI to investigate the prudence and reasonableness of PEF's actions regarding the delamination and the prudence of PEF's replacement power costs associated with the outage.[3]

PEF has replacement power insurance and repair insurance with Nuclear Electric Insurance Limited (NEIL) for Crystal River 3. In the 2010 and 2011 fuel adjustment clause proceedings, we allowed PEF to recover replacement power costs associated with the CR3 outage in 2011 and 2012 fuel factors. These replacement power costs were calculated after deducting estimated amounts for NEIL replacement power reimbursements.[4] The NEIL policy has a 12 week deductible and pays for 110 weeks for one event or claim. The single event claim would have covered through August 2012. The policy maximum for one event is $490 million for replacement power reimbursements.

NEIL has paid $162 million in replacement power reimbursements to PEF. The amount was paid in six payments from June 2010 to May 2011. These payments covered the period through December 17, 2010. NEIL also has paid $136 million in repair cost reimbursements. Of the $162 million replacement power reimbursements, PEF reduced fuel costs by $147.2 million in 2010 and 2011 and it reduced capacity costs by $3.7 million in 2010. The remaining $10.9 million was included in the 2012 true-up calculation and will reduce 2013 fuel factors.

[2] See also Paragraphs 9 and 10 in the Stipulation and Settlement Agreement approved by Order No. PSC-12-0104-FOF-EI, issued March 8, 2012, in Docket No. 120022-EI, In re: Petition for limited proceeding to approve stipulation and settlement agreement by Progress Energy Florida, Inc.
[3] See page 4 of Order No. PSC-11-0579-FOF-EI, issued December 16, 2011, in Docket No. 110001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.
[4] Id.

In January 2012, PEF entered into a settlement agreement with OPC, FIPUG, FRF, PCS, and FEA.[5] This agreement addressed issues involving nuclear cost recovery, base rates, the CR3 outage, fuel cost recovery and NEIL reimbursements.[6]

In calculating its 2013 fuel factors, PEF considered NEIL reimbursements by reducing fuel costs by $327.6 million. This amount is essentially the $490 million maximum policy amount for one event minus the $162 million already paid. PEF assumed it will receive NEIL reimbursements during 2013.

FIPUG questioned whether PEF should base its estimated insurance reimbursements for 2013 on one delamination event at Crystal River Unit 3 or two delamination events. PEF has based its projected amount on one event and has included that insurance reimbursement in its calculation of its 2013 projected fuel costs. The amount estimated to be reimbursed reduces estimated fuel costs and fuel factors for 2013. The amount of the reduction to fuel costs would be larger if PEF assumed it would be reimbursed for two events rather than one.

PEF stated it based its estimate on one event because any other estimation would be speculative. PEF noted the facts and information available today are the same as in last year's fuel hearing. PEF further stated that the prudence, timing, substance, pace of the negotiations, and ultimate amount of recovery from NEIL are not at issue in this docket. In support of its argument that the best known information should be the basis for its projection, PEF cited to page 9 of Order No. PSC-11-0579-FOF-EI, issued Dec. 16, 2011 in last year's fuel docket (110001-EI). In this order, we stated that more facts surrounding the first delamination event were known than for the second and that PEF was reasonable to assume insurance proceeds based on a single event. PEF further argued that there is no evidence in the record of these proceedings to support a fuel factor calculation based on two event coverage from NEIL mainly because PEF does not have the facts needed to do the calculation. In the event that NEIL determines that there are two events and pays PEF accordingly, the Utility stated that it will, as always, true-up to actual costs.

FIPUG proposed this issue and presented its argument through cross examination of PEF witness Olivier, through exhibits, and through its brief. FIPUG believes it is reasonable for PEF to include estimated NEIL payments based on two events. FIPUG analyzed the NEIL policy and concluded that the two delaminations are covered. FIPUG suggested that we seek details about the status of the pending 2009-10 PEF insurance claim for replacement fuel directly from NEIL but understands that NEIL will probably refuse any invitation by us to discuss the pending claim. FIPUG also understands that asking PEF whether NEIL will conclude there was a single event or two events calls for speculation. FIPUG argued that additional replacement fuel insurance factor dollars, beyond coverage for only one event, should be assumed when establishing the fuel factor.

[5] See Order No. PSC-12-0104-FOF-EI paragraph 11A of the attached Settlement.
[6] Id.

FEA stated that any additional costs to FEA will directly and negatively impact the military mission in Florida. FEA's goal is to make sure that PEF is operating prudently, while at the same time, providing reliable service. Like FIPUG, FEA believed PEF should file two insurance claims for the delamination that occurred at the Crystal River Unit 3. FEA argued that the paid insurance claim would be a significant savings which in turn would be passed to FEA consumers.

PCS agrees with PEF's $327 million imputation. PCS states that ratepayers should receive the full benefit of the September 2009 delamination which was a covered event under the NEIL policy. PCS argues that the reimbursement imputation that PEF proposes properly serves that purpose. PCS further states that PEF may have no control over NEIL's process or the timing of the eventual disposition of the CR3 insurance claims. However, PCS recommends that we require PEF to justify the basis for its claims in a separate docket if NEIL disallows coverage.

NEIL has stopped making reimbursements pending further review of PEF's claim. NEIL has not determined whether it will treat the second delamination as two events for claim purposes. The claim process has been going on for approximately three years. If NEIL determines two events, on the date a second event is determined to have occurred, reimbursements for the first event would stop and the process would start over. Therefore, the two event scenario does not necessarily mean that each event will result in $490 million in reimbursements. The first delamination was covered by a NEIL policy for the term April 1, 2009 to April 1, 2010 and the second delamination would be covered by a NEIL policy for the term April 1, 2010 to April 1, 2011. Regarding the determination of one event or two events, PEF and NEIL will begin non-binding mediation later this year, which, if unsuccessful, could lead to binding arbitration.

The best information available to PEF today is that NEIL has acknowledged one delamination event and it has not reached a determination regarding a second event. PEF witness Olivier stated that PEF's assumption of a $327.6 million NEIL payment for 2013 is reasonable, given the policy maximum and that NEIL has made payments. In the alternative, she also stated that it would be reasonable to assume no NEIL reimbursements would be received in 2013 given that none were received in 2012 and given that accounting guidance requires certainty. In its brief, FIPUG acknowledged that NEIL, at this time, has shared no details of its investigation with anyone including PEF. Estimating the replacement power reimbursements based on two events would not be feasible because the starting point – start date – for the second event is unknown and would be speculative.

According to witness Olivier, PEF is seeking the maximum amount of replacement power reimbursements, including a claim for two events. We note that all proceeds from NEIL – for replacement power and for repair – will be applied to benefit customers.

In its brief, FIPUG also raises questions about NEIL's handling of the PEF claim. FIPUG suggested that we question NEIL as to why it has taken more than three years to resolve PEF's claim. FIPUG listed eight questions it believes we should require NEIL to answer. FIPUG implied that a reason for the delay is that NEIL is not authorized to conduct business in the State of Florida. PEF argued that these issues are beyond the scope of this fuel proceeding. Questions raised to the insurance company are beyond our jurisdiction. Our jurisdiction is limited to public utilities as that term is defined by statute. Insurance companies are not regulated by us. However, we can review whether a utility has prudently procured insurance. It does not appear that FIPUG has raised that issue in this docket. As noted by PCS Phosphate in its brief, this issue may be appropriate in a separate docket if NEIL disallows coverage. That event has not occurred. Accordingly, we decline to take action on FIPUG's recommendation to require NEIL to answer questions.

Whether NEIL will pay PEF based on one delamination event or two is the subject of mediation and possibly binding arbitration later this year. PEF witness Olivier stated that PEF will work to maximize the amount of NEIL proceeds. All NEIL replacement power proceeds will be applied to reduce fuel costs. We will examine the outage and replacement power costs associated with the CR3 steam generator replacement project in Docket No. 100437-EI.

Accordingly, we find that the appropriate amount for PEF to include in its 2013 projections to account for potential insurance recoveries from NEIL is $327.6 million. This amount is based on NEIL reimbursements assuming one delamination event at CR3. When the final amount of NEIL reimbursements is determined, the difference between that amount and the above amount, if any, shall be applied to fuel costs.

**Florida Public Utilities Company**

Demand Allocation costs

FPUC proposed a new method to allocate demand costs to its different rate classes. FPUC raised an issue as to whether we believed their allocation was appropriate. We e reviewed the testimony and exhibits as well as the stipulation and accordingly, we find that it is appropriate to recognize a modification of the demand allocation methodology applied to the Northeast (Fernandina Beach) Division such that demand is based upon load research data from Gulf Power Company's system, instead of FPL's load research data historically used. The demand allocation used for the Company's Northwest Division will remain consistent with that which has been historically applied to the Northwest Division.

Legal and Consulting Fees Associated with the Time of Use and Interruptible Rates

FPUC filed testimony and exhibits requesting that it be allowed to recover through the Fuel Clause the legal and consulting fees incurred in developing the Company's Time of Use and Interruptible Rates for its Northwest Division. Our staff conducted discovery. After discovery, FPUC agreed that it shall remove the legal and consulting fees incurred in the development of its Time of Use and Interruptible Service rates for its Northwest Division from its calculations of the fuel factors to be applied in 2013. The costs may then be moved into the regulatory asset established in Docket No. 120227-EI, and approved by us at our October 16, 2012, Agenda Conference.

**Gulf Power Company**

Hedging Activities for August 2011 through July 2012

We reviewed Gulf's hedging activities for August 2011 through July 2012 and found its actions to mitigate the price volatility of natural gas, residual oil, and purchased power prices were reasonable and prudent.

Risk Management Plan for 2013

We reviewed Gulf's 2013 Risk Management Plan and found that Gulf's 2013 Risk Management Plan is consistent with the Hedging Guidelines.

**Tampa Electric Company**

Hedging Activities for August 2011 through July 2012

We reviewed TECO's hedging activities for August 2011 through July 2012 and found its actions to mitigate the price volatility of natural gas, residual oil, and purchased power prices were reasonable and prudent.

Risk Management Plan for 2013

We reviewed TECO's 2013 Risk Management Plan and found that TECO's 2013 Risk Management Plan is consistent with the Hedging Guidelines.

**GENERIC FUEL COST RECOVERY ISSUES**

The actual benchmark levels for calendar year 2012 for gains on non-separated wholesale energy sales eligible for a shareholder incentive pursuant to Order No. PSC-00-1744-PAA-EI were uncontested by the parties. After reviewing the testimony and exhibits, we concurred with the utilities' positions. Accordingly, the appropriate actual benchmark levels for calendar year 2012 for gains on non-separated wholesale energy sales eligible for a shareholder incentive are:

| | |
|---|---|
| FPL: | $6,680,369 |
| PEF: | $ 896,041. |
| GULF: | $ 749,310. |
| TECO: | $2,461,613. |

The estimated benchmark levels for the calendar year 2013 for gains on non-separated wholesale energy sales eligible for a shareholder incentive pursuant to Order No. PSC-00-1744-PAA-EI were uncontested by the parties. After reviewing the testimony and exhibits, we concurred with the utilities' positions. Accordingly, the appropriate estimated benchmark levels for calendar year 2013 for gains on non-separated wholesale energy sales eligible for a shareholder incentive are:

| | |
|---|---|
| FPL: | $4,430,522, which has been adjusted from $4,453,225, to include actual data for July 2012. This benchmark level is subject to adjustments in the 2012 final true-up filing to include all actual data for the year 2012. |
| PEF: | $ 617,914. |
| GULF: | $ 626,203. |
| TECO: | $1,365,169. |

Each investor-owned electric utility presented evidence regarding the appropriate final fuel adjustment true-up for their company for 2011. No party challenged FPL, FPUC, Gulf and TECO's positions. FIPUG challenged PEF's position as not properly reflected projected NEIL insurance payments.

PEF witness Garrett asserted that the projected end of year balance in 2011 for fuel was $123,159,202 under-recovery. The actual ending balance as of December 31, 2011 for true-up purposes is $324,522,196 under-recovery. When these figures are netted, the final fuel adjustment true-up amount for January through December 2011 is $201,362,994 under-recovery.

We reviewed PEF's testimony, exhibits, and calculations for this issue. We find that the appropriate fuel adjustment true-up amount for the period January 2011 through December 2011 for PEF is a $201,362,994 under-recovery. Based on the testimony and exhibits in the record, we approve the following as the appropriate final fuel adjustment true-up amounts for the period of January 2011 through December 2011:

| | | |
|---|---|---|
| FPL: | $ 51,121,025 under-recovery. | |
| FPUC:[7] | Northwest Division (Marianna) | $1,289,837 under-recovery. |
| | Northeast Division (Fernandina Beach) | $ 360,592 over-recovery. |
| PEF: | $201,362,994 under-recovery | |
| GULF: | $ 13,538,423 over-recovery. | |
| TECO: | $ 11,885,179 over-recovery. | |

Each investor-owned electric utility presented evidence regarding the appropriate estimated/actual fuel adjustment true-up amounts for their company for 2012. No party challenged FPL, FPUC, Gulf and TECO's positions. FIPUG challenged PEF's position as not properly reflected projected NEIL insurance payments. We previously concluded that PEF properly projected the NEIL insurance payments.

[7] The appropriate amounts reflect the current status of FPUC's Generation Services Agreement with Gulf Power. In the event that FPUC and Gulf Power resume operation under Amendment No. 1 to that Generation Services Agreement, FPUC may petition for a mid-course correction to recognize the associated cost reductions and pass the associated savings on to its customers on an expedited basis. The appropriate amounts reflected below also recognize a modification of the demand allocation methodology applied to the Northeast (Fernandina Beach) division such that demand is based upon data from the Gulf Power Company system, instead of the FPL data historically used. The demand allocation used for the Company's Northwest division will remain consistent with that which has been historically applied to the Northwest Division.

PEF witness Olivier asserted that the fuel adjustment actual/estimated true-up amounts for the period January 2012 through December 2012 included a projected $145,366,912 under-recovery. When this figure is netted against the final fuel adjustment true-up amount for January through December 2011, which is a $201,362,994 under-recovery, the appropriate fuel adjustment actual/estimated true-up amount for the period January 2012 through December 2012 is a $55,996,082 over-recovery.

We reviewed PEF's testimony, exhibits, and calculations for this issue. We find that the appropriate fuel adjustment actual/estimated true-up amount for the period January 2012 through December 2012 for PEF is a $55,996,082 over-recovery. Based on the evidence in the record, the appropriate fuel adjustment actual/estimated true-up amounts for the period January 2012 through December 2012 are:

| | | |
|---|---|---|
| FPL: | $99,206,321 over-recovery. | |
| FPUC:[8] | Northwest Division (Marianna) | $187,767 under-recovery. |
| | Northeast Division (Fernandina Beach) | $101,956 under-recovery. |
| GULF: | $26,425,418 over-recovery. | |
| PEF: | $55,996,082 over-recovery | |
| TECO: | $57,434,679 over-recovery. | |

Each investor-owned electric utility presented evidence regarding the appropriate total fuel adjustment true-up amounts to be collected or refunded from January 2013 to December 2013. No party challenged FPL, FPUC, Gulf and TECO's positions. FIPUG challenged PEF's position as not properly reflected projected NEIL insurance payments. We previously concluded that PEF properly projected the NEIL insurance payments.

The appropriate total fuel adjustment true-up amount to be collected/refunded from January 2013 to December 2013 is calculated by summing the fuel adjustment values identified in the prior two issues. PEF witness Olivier asserted that the appropriate total fuel adjustment true-up amount for the period January 2013 through December 2013 is a $145,366,912 under-recovery. We reviewed PEF's testimony, exhibits, and calculations for this issue. We find that the appropriate total fuel adjustment true-up amount for the period January 2013 through December 2013 for PEF is a $145,366,912 under-recovery. Based on the evidence in the record, we approve the following as the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2013 to December 2013.

| | | |
|---|---|---|
| FPL: | $ 48,085,296 over-recovery. | |
| FPUC:[9] | Northwest Division (Marianna) | $1,477,604 under-recovery. |
| | Northeast Division (Fernandina Beach) | $ 258,636 over-recovery. |
| GULF: | Refund of $26,425,418. The net final true-up for the period ending December 2011 has already been included in rates in 2012. Therefore, the proposed fuel | |

[8] Id.
[9] Id.

| | |
|---|---|
| | cost recovery factors reflect only the refund of the estimated fuel cost true-up amount, $26,425,418, during the period of January 2013 through December 2013. |
| PEF: | $145,366,912 under-recovery |
| TECO: | $ 69,319,858 over-recovery. |

Each investor-owned electric utility presented evidence regarding the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2013 through December 2013. No party challenged FPL, FPUC, Gulf and TECO's positions. FIPUG challenged PEF's position as not properly reflected projected NEIL insurance payments. We previously concluded that PEF properly projected the NEIL insurance payments.

Schedule E-1, Line 27 of Exhibit MO-2, Part 2 shows that PEF has projected its total fuel and purchased power cost recovery amount for the period January 2013 through December 2013 to be $1,234,709,629. We reviewed PEF's testimony, exhibits, and calculations for this issue. We find that the appropriate projected total fuel and purchased power cost recovery amount for the period January 2013 through December 2013 is $1,234,709,629. Based on the evidence in the record, the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2013 through December 2013 are:

| | |
|---|---|
| FPL: | $3,097,095,340, including prior period true-ups and revenue taxes and excluding the GPIF reward. |
| FPUC:[10] | Northwest Division (Marianna): $30,935,242.<br>Northeast Division (Fernandina Beach): $36,030,023. |
| GULF: | $ 428,996,843 including prior period true-up amounts and revenue taxes. |
| PEF: | $1,234,709,629 |
| TECO: | The total fuel and purchased power cost recovery amount for the period January 2013 through December 2013, is $745,333,956. The total recoverable fuel and purchased power recovery amount to be collected, adjusted by the jurisdictional separation factor excluding GPIF and revenue tax factor but including the true-up amount, is $676,014,098. |

## GENERATING PERFORMANCE INCENTIVE FACTOR (GPIF) ISSUES

Based on the testimony and evidence submitted in this docket, the appropriate generation performance incentive factor (GPIF) reward or penalty for performance achieved during the period January 2011 through December 2011 for each investor-owned electric utility subject to the GPIF shall be as follows:

| | |
|---|---|
| FPL: | A reward in the amount of $7,703,912. |
| GULF: | A reward in the amount of $1,040,660. |
| PEF: | A reward in the amount of $1,495,572. |
| TECO: | A penalty in the amount of $ 538,019. |

[10] Id.

Based on the testimony and evidence submitted in this docket, the GPIF targets/ranges for the period January 2013 through December 2013 for each investor-owned electric utility subject to the GPIF shall be as follows:

FPL: The GPIF targets and ranges should be as shown in Table 17-1 below:
GULF: The GPIF targets and ranges should be as shown in Table 17-2 below:
PEF: The GPIF targets and ranges should be as shown in Table 17-3 below:
TECO: The GPIF targets and ranges should be as shown in Table 17-4 below:

| **2013 GPIF Targets and Ranges for FPL** | | |
|---|---|---|
| **Plant / Unit** | **EAF Target (%)** | **Heat Rate Target (BTU / KWH)** |
| Ft. Myers 2 | 79.9 | 7,130 |
| Martin 8 | 90.8 | 6,955 |
| Manatee 3 | 91.5 | 6,921 |
| Sanford 4 | 96 | 10,134 |
| Scherer 4 | 81.3 | 10,810 |
| St. Lucie 1 | 90.2 | 10,899 |
| St. Lucie 2 | 83.2 | 11,382 |
| Turkey Point 3 | 73.6 | 11,660 |
| Turkey Point 4 | 91.4 | 7,000 |
| Turkey Point 5 | 79.9 | 7,130 |

Table 17-1

| **2013 GPIF Targets And Ranges For Gulf** | | | | |
|---|---|---|---|---|
| **Unit** | **EAF** | **POF** | **EUOF** | **Heat Rate** |
| Crist 6 | 81.2 | 15.9 | 2.9 | 12,243 |
| Crist 7 | 94.0 | 0.0 | 6.0 | 11,178 |
| Smith 3 | 91.1 | 6.6 | 2.3 | 6,842 |
| Daniel 1 | 94.7 | 0.0 | 5.3 | 10,591 |
| Daniel 2 | 97.1 | 0.0 | 2.9 | 10,611 |
| EAF = Equivalent Availability Factor (%)<br>POF = Planned Outage Factor (%)<br>EUOF = Equivalent Unplanned Outage Factor (%) | | | | |

Table 17-2

**2013 GPIF Targets and Ranges for PEF**

| Plant/ Unit | Weighting Factor (%) | EAF Target (%) | EAF Range Max (%) | EAF Range Min (%) | Max Fuel Savings ($000) | Max Fuel Loss ($000) |
|---|---|---|---|---|---|---|
| Bartow 4 | 8.38 | 89.08 | 92.61 | 81.95 | 4,768 | (10,085) |
| CR 4 | 5.59 | 87.03 | 90.40 | 80.28 | 3.178 | (6,487) |
| CR 5 | 4.57 | 94.57 | 97.12 | 89.38 | 2,597 | (6,007) |
| Hines 1 | 1.86 | 79.35 | 81.83 | 74.36 | 1,057 | (2,504) |
| Hines 2 | 1.85 | 87.70 | 89.50 | 83.97 | 1,054 | (3,815) |
| Hines 3 | 1.62 | 89.17 | 90.66 | 86.10 | 924 | (1,940) |
| Hines 4 | 2.25 | 88.69 | 90.41 | 85.11 | 1,278 | (2,176) |
| GPIF System | 26.12 | | | | 14,856 | (33,014) |

| Plant/ Unit | Weighting Factor (%) | ANOHR Target (BTU/ KWH) | NOF | ANOHR Range Minimum (BTU/ KWH) | ANOHR Range Maximum (BTU/ KWH) | Max Fuel Savings ($000) | Max Fuel Loss ($000) |
|---|---|---|---|---|---|---|---|
| Bartow 4 | 22.21 | 7,323 | 83.3 | 6,947 | 7,699 | 12,632 | (12,632) |
| CR 4 | 13.84 | 10,317 | 73.8 | 9,749 | 10,885 | 7,873 | (7,873) |
| CR 5 | 13.44 | 10,351 | 71.0 | 9,820 | 10,882 | 7,647 | (7,647) |
| Hines 1 | 5.29 | 7,231 | 92.1 | 6,975 | 7,487 | 3,008 | (3,008) |
| Hines 2 | 5.87 | 7,166 | 83.5 | 6,917 | 7,415 | 3,336 | (3,336) |
| Hines 3 | 6.83 | 7,192 | 91.1 | 6,927 | 7,456 | 3,884 | (3,884) |
| Hines 4 | 6.40 | 6,939 | 94.2 | 6,697 | 7,181 | 3,641 | (3,641) |
| GPIF System | 73.88 | | | | | 42,021 | (42,021) |

Table 17-3

**2013 GPIF Targets and Ranges for TECO**

| Unit | EAF | POF | EUOF | Heat Rate |
|---|---|---|---|---|
| Big Bend 1 | 64.2 | 6.6 | 29.2 | 10,530 |
| Big Bend 2 | 74.8 | 6.6 | 18.7 | 10.199 |
| Big Bend 3 | 60.8 | 21.1 | 18.1 | 10,614 |
| Big Bend 4 | 83.6 | 6.6 | 9.8 | 10,536 |
| Polk 1 | 75.1 | 9.6 | 15.3 | 10,437 |
| Bayside 1 | 94.1 | 4.9 | 1.0 | 7,177 |
| Bayside 2 | 93.2 | 5.5 | 1.3 | 7,325 |

EAF = Equivalent Availability Factor (%)
POF = Planned Outage Factor (%)
EUOF = Equivalent Unplanned Outage Factor (%)

Table 17-4

**FUEL FACTOR CALCULATION ISSUES**

Based on the testimony and exhibits presented in this docket, the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2013 through December 2013 shall be as follows:

| | |
|---|---|
| FPL: | $3,104,799,252 including prior period true-ups, revenue taxes and GPIF reward. |
| FPUC:[11] | Northwest Division (Marianna): $30,935,242.<br>Northeast Division (Fernandina Beach): $36,030,023. |
| GULF: | $430,037,503 including prior period true-up amounts and revenue taxes. |
| PEF: | $1,382,565,768. |
| TECO: | The projected net fuel and purchased power cost recovery amount to be included in the recovery factor for the period January 2013 through December 2013, adjusted by the jurisdictional separation factor, is $745,333,956. The total recoverable fuel and purchased power cost recovery amount to be collected, including the true-up and GPIF and adjusted for the revenue tax factor, is $675,962,809. |

Based on the testimony and exhibits presented in this docket, the appropriate revenue tax factor to be applied in calculating each investor-owned electric utility's levelized fuel factor for the projection period January 2013 through December 2013 is:

| | |
|---|---|
| FPL: | 1.00072 |
| FPUC Northwest Division: | 1.00072 |
| FPUC Northeast Division: | 1.00072 |
| GULF: | 1.00072 |
| PEF: | 1.00072 |
| TECO: | 1.00072 |

Based on the testimony and exhibits presented in this docket, The appropriate levelized fuel cost recovery factors for the period January 2013 through December 2013 are:

FPL: The fuel factors shall be reduced as of the in-service date of Cape Canaveral Energy Center (CCEC) to reflect the projected jurisdictional fuel savings for CCEC. The following are the separate factors for January 2013 to May 2013 and for June 2013 through December 2013:

(a) 3.105 cents/kWh for January 2013 through the day prior to the CCEC in-service date (projected to be May 31, 2013);
(b) 2.950 cents/kWh from the CCEC in-service date (projected to be June 1, 2013) through December 2013.

[11] Id.

| | |
|---|---|
| FPUC:[12] | Northwest Division (Marianna): 5.790 ¢ / kwh<br>Northeast Division (Fernandina Beach): 6.420 ¢ /kwh |
| GULF: | 3.803 cents/kWh. |
| PEF: | 3.698 cents per kWh |
| TECO: | The appropriate factor is 3.714 cents per kWh before any application of time of use multipliers for on-peak or off-peak usage. |

Based on the evidence submitted in this docket, the appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class shall be as follows:

| | |
|---|---|
| FPL: | The appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class are shown in Tables 21-1 through 21-3 below: |
| FPUC: | Northwest Division (Marianna): 1.0000 (All rate schedules)<br>Northeast Division (Fernandina Beach): 1.0000 (All rate schedules) |
| GULF: | The appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class are shown in Table 21-4 below: |
| PEF: | The appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class are shown in Table 21-5 below: |
| TECO: | The appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class are shown in Table 21-6 below: |

[12] Id.

| Fuel Recovery Line Loss Multipliers for FPL | | |
|---|---|---|
| **FUEL RECOVERY FACTORS – BY RATE GROUP (Adjusted for Line / Transformation Losses) FOR THE PERIOD JANUARY 2013 – DECEMBER 2013** | | |
| **GROUP** | **RATE SCHEDULE** | **FUEL RECOVERY LOSS MULTIPLIER** |
| A | RS-1 first 1,000kWh | 1.00220 |
| | RS-1 all additional kWh | 1.00220 |
| A | GS-1, SL-2, GSCU-1, WIES-1 | 1.00220 |
| A-1* | SL-1, OL-1, PL-1 | 1.00220 |
| B | GSD-1 | 1.00211 |
| C | GSLD-1 & CS-1 | 1.00109 |
| D | GSLD-2, CS-2, OS-2, MET | 0.99062 |
| E | GSLD-3, CS-3 | 0.96131 |
| * Weighted Average 16 % on-Peak and 84 % off-Peak | | |

Table 21-1

| Fuel Recovery Line Loss Multipliers for FPL<br>SEASONALLY DIFFERENTIATED TIME OF USE<br>FUEL RECOVERY FACTORS – BY RATE GROUP<br>(Adjusted for Line / Transformation Losses)<br>FOR THE PERIOD JANUARY 2013 – DECEMBER 2013 | | | |
|---|---|---|---|
| **GROUP** | **RATE SCHEDULE** | | **FUEL RECOVERY LOSS MULTIPLIERS** |
| A | RST-1, GST-1 | On / Off Peak | 1.00220 |
| B | GSDT-1, CILC-1 (G), HLFT-1 | On / Off Peak | 1.00211 |
| C | GSLDT-1, CST-1, HLFT-2 | On / Off Peak | 1.00109 |
| D | GSLDT-2, CST-2, HLFT-3 | On / Off Peak | 0.99139 |
| E | GSLDT-3, CST-3, CILC1(T), ISST-1(T) | On / Off Peak | 0.96131 |
| F | CILC-1(D), ISST-1(D) | On / Off Peak | 0.99102 |

Table 21-2

| Fuel Recovery Line Loss Multipliers for FPL<br>DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)<br>FUEL RECOVERY FACTORS<br>ON-PEAK: JUNE 2013 THROUGH SEPTEMBER 2013 –<br>WEEKDAYS 3:00 PM TO 6:00 PM<br>OFF-PEAK: ALL OTHER HOURS | | |
|---|---|---|
| **GROUP** | **OTHERWISE APPLICABLE RATE SCHEDULE** | **FUEL RECOVERY LOSS MULTIPLIERS** |
| B | GSD(T)-1 On-Peak | 1.00211 |
| | GSD(T)-1 Off-Peak | 1.00211 |
| C | GSLD(T)-1 On-Peak | 1.00109 |
| | GSLD(T)-1 Off-Peak | 1.00109 |
| D | GSLD(T)-2 On-Peak | 0.99139 |
| | GSLD(T)-2Off-Peak | 0.99139 |

Table 21-3

| Fuel Recovery Line Loss Multipliers for Gulf | | |
|---|---|---|
| **Group** | **Rate Schedules** | **Line Loss Multipliers** |
| A | RS, RSVP,GS, GSD, GSDT, GSTOU, OSIII, SBS(1) | 1.00773 |
| B | LP, LPT, SBS(2) | 0.98353 |
| C | PX, PXT, RTP, SBS(3) | 0.96591 |
| D | OSI/II | 1.00777 |
| (1) Includes SBS customers with a contract demand in the range of 100 to 499 KW<br>(2) Includes SBS customers with a contract demand in the range of 500 to 7,499 KW<br>(3) Includes SBS customers with a contract demand over 7,499 KW | | |

Table 21-4

| Fuel Recovery Line Loss Multipliers for PEF | | |
|---|---|---|
| **Group** | **Delivery Voltage Level** | **Line Loss Multipliers** |
| A | Transmission | 0.9800 |
| B | Distribution Primary | 0.9900 |
| C | Distribution Secondary | 1.000 |
| D | Lighting Service | 1.000 |

Table 21-5

| Fuel Recovery Line Loss Multipliers for TECO | |
|---|---|
| **Metering Voltage Schedule** | **Line Loss Multiplier** |
| Distribution Secondary | 1.0000 |
| Distribution Primary | 0.9900 |
| Transmission | 0.9800 |
| Lighting Service | 1.0000 |

Table 21-6

Based on the evidence in the record, we find that the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses shall be as follows:

FPL: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown in Tables 22-1 through 22-7 below:

FPUC: FPUC Northwest Division: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown in Tables 22-8 through 22-9 below:

FPUC Northeast Division: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown in Tables 22-10:

GULF: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown in Table 22-11 below:

PEF: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown in Table 22-12 below:

TECO: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown in Table 22-13 below:

| FPL - Fuel Cost Recovery Factors By Rate Group (cents/kWh) Adjusted For Line / Transformation Losses | | | | |
|---|---|---|---|---|
| | | January 2013 – May 2013 | | |
| GROUP | RATE SCHEDULE | AVERAGE FACTOR | FUEL RECOVERY LOSS MULTIPLIER | FUEL RECOVERY FACTOR |
| A | RS-1 first 1,000kWh | 3.105 | 1.00220 | 2.789 |
| | RS-1 all additional kWh | 3.105 | 1.00220 | 3.789 |
| A | GS-1, SL-2, GSCU-1, WIES-1 | 3.105 | 1.00220 | 3.112 |
| A-1* | SL-1, OL-1, PL-1 | 2.831 | 1.00220 | 2.837 |
| B | GSD-1 | 3.105 | 1.00211 | 3.112 |
| C | GSLD-1 & CS-1 | 3.105 | 1.00109 | 3.108 |
| D | GSLD-2, CS-2, OS-2, MET | 3.105 | 0.99062 | 3.076 |
| E | GSLD-3, CS-3 | 3.105 | 0.96131 | 2.985 |
| * Weighted Average 16 % on-Peak and 84 % off-Peak | | | | |

Table 22-1

| FPL - Fuel Cost Recovery Factors By Rate Group (cents/kWh) Adjusted For Line / Transformation Losses | | | | |
|---|---|---|---|---|
| | | June 2013 through December 2013 | | |
| **GROUP** | **RATE SCHEDULE** | **AVERAGE FACTOR** | **FUEL RECOVERY LOSS MULTIPLIER** | **FUEL RECOVERY FACTOR** |
| A | RS-1 first 1,000kWh | 2.950 | 1.00220 | 2.633 |
| | RS-1 all additional kWh | 2.950 | 1.00220 | 3.633 |
| | GS-1, SL-2, GSCU-1, WIES-1 | 2.950 | 1.00220 | 2.956 |
| A-1* | SL-1, OL-1, PL-1 | 2.950 | 1.00220 | 2.696 |
| B | GSD-1 | 2.950 | 1.00211 | 2.956 |
| C | GSLD-1 & CS-1 | 2.950 | 1.00109 | 2.953 |
| D | GSLD-2, CS-2, OS-2, MET | 2.950 | 0.99062 | 2.922 |
| E | GSLD-3, CS-3 | 2.950 | 0.96131 | 2.836 |
| * Weighted Average 16 % on-Peak and 84 % off-Peak | | | | |

Table 22-2

| FPL - Seasonally Differentiated Time Of Use Fuel Recovery Factors – By Rate Group for January 2013 through May 2013 (Adjusted for Line / Transformation Losses) | | | | |
|---|---|---|---|---|
| | | JANUARY – MARCH and NOVEMBER - DECEMBER | | |
| **GROUP** | **RATE SCHEDULE** | **AVERAGE FACTOR** | **FUEL RECOVERY LOSS MULTIPLIER** | **FUEL RECOVERY FACTOR** |
| A | RST-1, GST-1 On-Peak | 3.683 | 1.00220 | 3.691 |
| | RST-1, GST-1 Off-Peak | 2.894 | 1.00220 | 2.900 |
| | RTR-1 On-Peak | - | - | 0.579 |
| | RTR-1 Off-Peak | - | - | (0.212) |
| B | GSDT-1, CILC-1 G On-Peak | 3.683 | 1.00211 | 3.691 |
| | HLFT-1 (21-499 kW) Off-Peak | 2.894 | 1.00211 | 2.900 |
| C | GSLDT-1, CST-1 On-Peak | 3.683 | 1.00109 | 3.687 |
| | HLFT-2 (500-1,999 kW) Off-Peak | 2.894 | 1.00109 | 2.897 |
| D | GSLDT-2, CST-2 On-Peak | 3.683 | 0.99139 | 3.651 |
| | HLFT-3 (2,000+ kW) Off-Peak | 2.894 | 0.99139 | 2.869 |
| E | GSLDT-3, CST-3 On-Peak | 3.683 | 0.96131 | 3.540 |
| | CILC-1(T), ISST-1(T) Off-Peak | 2.894 | 0.96131 | 2.782 |
| F | CILC-1(D), ISST-1(D) On-Peak | 3.683 | 0.99102 | 3.650 |
| | Off-Peak | 2.894 | 0.99102 | 2.868 |

Table 22-3

| FPL - Seasonally Differentiated Time Of Use Fuel Recovery Factors – By Rate Group for January 2013 through May 2013 (Adjusted for Line / Transformation Losses) | | | | |
|---|---|---|---|---|
| | | APRIL - OCTOBER | | |
| **GROUP** | **RATE SCHEDULE** | **AVERAGE FACTOR** | **FUEL RECOVERY LOSS MULTIPLIER** | **FUEL RECOVERY FACTOR** |
| A | RST-1, GST-1 On-Peak | 4.698 | 1.00220 | 4.708 |
| | RST-1, GST-1 Off-Peak | 2.288 | 1.00220 | 2.293 |
| | RTR-1 On-Peak | - | - | 1.596 |
| | RTR-1 Off-Peak | - | - | (0.819) |
| B | GSDT-1, CILC-1 G On-Peak | 4.698 | 1.00211 | 4.708 |
| | HLFT-1 (21-499 kW) Off-Peak | 2.288 | 1.00211 | 2.293 |
| C | GSLDT-1, CST-1 On-Peak | 4.698 | 1.00109 | 4.703 |
| | HLFT-2 (500-1,999 kW) Off-Peak | 2.288 | 1.00109 | 2.290 |
| D | GSLDT-2, CST-2 On-Peak | 4.698 | 0.99139 | 4.658 |
| | HLFT-3 (2,000+ kW) Off-Peak | 2.288 | 0.99139 | 2.268 |
| E | GSLDT-3, CST-3 On-Peak | 4.698 | 0.96131 | 4.516 |
| | CILC-1(T), ISST-1(T) Off-Peak | 2.288 | 0.96131 | 2.199 |
| F | CILC-1(D), ISST-1(D) On-Peak | 4.698 | 0.99102 | 4.656 |
| | Off-Peak | 2.288 | 0.99102 | 2.267 |

Table 22-4

| FPL - Seasonally Differentiated Time Of Use Fuel Recovery Factors – By Rate Group for June 2013 through December 2013 (Adjusted for Line / Transformation Losses) | | | | |
|---|---|---|---|---|
| | | JANUARY – MARCH and NOVEMBER - DECEMBER | | |
| **GROUP** | **RATE SCHEDULE** | **AVERAGE FACTOR** | **FUEL RECOVERY LOSS MULTIPLIER** | **FUEL RECOVERY FACTOR** |
| A | RST-1, GST-1 On-Peak | 3.499 | 1.00220 | 3.507 |
| | RST-1, GST-1 Off-Peak | 2.749 | 1.00220 | 2.755 |
| | RTR-1 On-Peak | - | - | 0.551 |
| | RTR-1 Off-Peak | - | - | (0.201) |
| B | GSDT-1, CILC-1 G On-Peak | 3.499 | 1.00211 | 3.506 |
| | HLFT-1 (21-499 kW) Off-Peak | 2.749 | 1.00211 | 2.755 |
| C | GSLDT-1, CST-1 On-Peak | 3.499 | 1.00109 | 3.503 |
| | HLFT-2 (500-1,999 kW) Off-Peak | 2.749 | 1.00109 | 2.752 |
| D | GSLDT-2, CST-2 On-Peak | 3.499 | 0.99139 | 3.469 |
| | HLFT-3 (2,000+ kW) Off-Peak | 2.749 | 0.99139 | 2.725 |
| E | GSLDT-3, CST-3 On-Peak | 3.499 | 0.96131 | 3.364 |
| | CILC-1(T), ISST-1(T) Off-Peak | 2.749 | 0.96131 | 2.643 |
| F | CILC-1(D), ISST-1(D) On-Peak | 3.499 | 0.99102 | 3.468 |
| | Off-Peak | 2.749 | 0.99102 | 2.724 |

Table 22-5

| FPL - Seasonally Differentiated Time Of Use Fuel Recovery Factors – By Rate Group for June 2013 through December 2013 (Adjusted for Line / Transformation Losses) | | | | |
|---|---|---|---|---|
| | | APRIL - OCTOBER | | |
| GROUP | RATE SCHEDULE | AVERAGE FACTOR | FUEL RECOVERY LOSS MULTIPLIER | FUEL RECOVERY FACTOR |
| A | RST-1, GST-1 On-Peak | 4.463 | 1.00220 | 4.473 |
| | RST-1, GST-1 Off-Peak | 2.174 | 1.00220 | 2.179 |
| | RTR-1 On-Peak | - | - | 1.517 |
| | RTR-1 Off-Peak | - | - | (0.777) |
| B | GSDT-1, CILC-1 G On-Peak | 4.463 | 1.00211 | 4.472 |
| | HLFT-1 (21-499 kW) Off-Peak | 2.174 | 1.00211 | 2.179 |
| C | GSLDT-1, CST-1 On-Peak | 4.463 | 1.00109 | 4.468 |
| | HLFT-2 (500-1,999 kW) Off-Peak | 2.174 | 1.00109 | 2.176 |
| D | GSLDT-2, CST-2 On-Peak | 4.463 | 0.99139 | 4.425 |
| | HLFT-3 (2,000+ kW) Off-Peak | 2.174 | 0.99139 | 2.155 |
| E | GSLDT-3, CST-3 On-Peak | 4.463 | 0.96131 | 4.290 |
| | CILC-1(T), ISST-1(T) Off-Peak | 2.174 | 0.96131 | 2.090 |
| F | CILC-1(D), ISST-1(D) On-Peak | 4.463 | 0.99102 | 4.423 |
| | Off-Peak | 2.174 | 0.99102 | 2.154 |

Table 22-6

| FPL - Seasonal Demand Time Of Use Rider (SDTR)<br>Fuel Recovery Factors For January 2013 through May 2013<br>On-Peak: June Through September –<br>Weekdays 3:00 Pm To 6:00 Pm<br>Off-Peak: All Other Hours | | | | |
|---|---|---|---|---|
| | | June - September | | |
| **GROUP** | **OTHERWISE APPLICABLE RATE SCHEDULE** | **AVERAGE FACTOR** | **FUEL RECOVERY LOSS MULTIPLIER** | **FUEL RECOVERY FACTOR** |
| B | GSD(T)-1 On-Peak | 5.344 | 1.00211 | 5.355 |
| | Off-Peak | 2.701 | 1.00211 | 2.707 |
| C | GSLD(T)-1 On-Peak | 5.344 | 1.00109 | 5.350 |
| | Off-Peak | 2.701 | 1.00109 | 2.704 |
| D | GSLD(T)-2 On-Peak | 5.344 | 0.99139 | 5.298 |
| | Off-Peak | 2.701 | 0.99139 | 2.678 |

Table 22-7

| FPL - Seasonal Demand Time Of Use Rider (SDTR)<br>Fuel Recovery Factors For June 2013 through December 2013<br>On-Peak: June Through September –<br>Weekdays 3:00 Pm To 6:00 Pm<br>Off-Peak: All Other Hours | | | | |
|---|---|---|---|---|
| | | June – September | | |
| **GROUP** | **OTHERWISE APPLICABLE RATE SCHEDULE** | **AVERAGE FACTOR** | **FUEL RECOVERY LOSS MULTIPLIER** | **SDTR FUEL RECOVERY FACTOR** |
| B | GSD(T)-1 On-Peak | 5.077 | 1.00211 | 5.088 |
| | Off-Peak | 2.567 | 1.00211 | 2.572 |
| C | GSLD(T)-1 On-Peak | 5.077 | 1.00109 | 5.083 |
| | Off-Peak | 2.567 | 1.00109 | 2.570 |
| D | GSLD(T)-2 On-Peak | 5.077 | 0.99139 | 5.033 |
| | Off-Peak | 2.567 | 0.99139 | 2.545 |

Table 22-7

| FPUC Northwest Division - Fuel Cost Recovery Factors (cents/kWh) Adjusted For Line Losses | |
|---|---|
| **Rate Schedule** | **Fuel Factor** |
| RS | 10.242 |
| GS | 9.854 |
| GSD | 9.308 |
| GSLD | 8.918 |
| OL, OL-2 | 7.410 |
| SL1-2, AND SL-3 | 7.473 |
| Step rate for RS | |
| RS with less than 1,000 kWh/month | 9.883 |
| RS with more than 1,000 kWh/month | 10.883 |

Table 22-8

| FPUC Northwest Division – Time Of Use / Interruptible Fuel Cost Recovery Factors (cents/kWh) Adjusted For Line Losses | | |
|---|---|---|
| **Rate Schedule** | **Fuel Factor On Peak** | **Fuel Factor Off-Peak** |
| RS | 18.283 | 5.983 |
| GS | 13.854 | 4.854 |
| GSD | 13.308 | 6.058 |
| GSLD | 14.918 | 5.918 |
| Interruptible | 7.418 | 8.918 |

Table 22-9

| FPUC Northeast Division - Fuel Cost Recovery Factors (cents/kWh) Adjusted For Line Losses | |
|---|---|
| **Rate Schedule** | **Fuel Factor** |
| RS | 10.158 |
| GS | 9.830 |
| GSD | 9.377 |
| GSLD | 9.052 |
| OL, OL-2 | 6.738 |
| SL1-2, SL-3 | 6.718 |
| Step rate for RS | |
| RS with less than 1,000 kWh/month | 9.786 |
| RS with more than 1,000 kWh/month | 10.786 |

Table 22-10

| **Gulf - Fuel Cost Recovery Factors (cents/kWh) Adjusted For Line Losses** | | | | | |
|---|---|---|---|---|---|
| **Group** | **Rate Schedules** | **Line Loss Multipliers** | **Fuel Factors cents/KWH** | | |
| | | | **Standard** | **TOU (Peak)** | **TOU (Off-Peak)** |
| A | RS, RSVP, GS,GSD,GSDT, GSTOU, OSIII, SBS(1) | 1.00773 | 3.832 | 4.768 | 3.446 |
| B | LP, LPT, SBS(2) | 0.98353 | 3.740 | 4.654 | 3.363 |
| C | PX, PXT,RTP, SBS(3) | 0.96591 | 3.673 | 4.570 | 3.303 |
| D | OS I / II | 1.00777 | 3.776 | N/A | N/A |
| The recovery factor applicable to customers taking service under Rate Schedule SBS is determined as follows: (1) customers with a contract demand in the range of 100 to 499 KW will use the recovery factor applicable to Rate Schedule GSD; (2) customers with a contract demand in the range of 500 to 7,499 KW will use the recovery factor applicable for Rate Schedule LP; and (3) customers with a contract demand over 7,499 KW will use the recovery factor applicable to rate Schedule PX. | | | | | |

Table 22-11

| **PEF - Fuel Cost Recovery Factors (cents/kWh) Adjusted for Line Losses** | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | **Time of Use** | |
| Group | Delivery Voltage Level | First Tier Factor | Second Tier Factors | Levelized Factors | On-Peak | Off-Peak |
| A | Transmission | -- | -- | 3.629 | 5.128 | 2.914 |
| B | Distribution Primary | -- | -- | 3.666 | 5.180 | 2.944 |
| C | Distribution Secondary | 3.393 | 4.393 | 3.703 | 5.232 | 2.974 |
| D | Lighting | -- | -- | 3.396 | -- | -- |

Table 22-12

| **TECO - Fuel Cost Recovery Factors (cents/kWh) Adjusted For Line Losses** | |
|---|---|
| **Metering Voltage Schedule** | **Fuel Factors (cents per kWh)** |
| Secondary | 3.719 |
| Tier I (Up to 1,000 kWh) | 3.369 |
| Tier II (Over 1,000 kWh) | 4.369 |
| Distribution Primary | 3.682 |
| Transmission | 3.645 |
| Lighting Service | 3.697 |
| Distribution Secondary | 3.861 (On-Peak) |
| | 3.664 (Off-Peak) |
| Distribution Primary | 3.822 (On-Peak) |
| | 3.627 (Off-Peak) |
| Transmission | 3.784 (On-Peak) |
| | 3.591 (Off-Peak) |

Table 22-13

## COMPANY-SPECIFIC CAPACITY COST RECOVERY FACTOR ISSUES

Progress Energy Florida, Inc.

Nuclear Cost Recovery

Pursuant to the Nuclear Cost Recovery statute and rule, the amount to included in the Capacity Cost Recovery Clause is based on our vote at the November 26, 2012 special agenda conference in Docket No. 110009-EI. PEF presented evidence in the record to support its nuclear cost recovery amount to be recovered. Pursuant to Order No. PSC-12-0650-FOF-EI,[13] the nuclear cost recovery amount to be recovered in PEF's 2013 capacity cost recovery clause factor is $142,730,579 for both the Levy nuclear project ($102,696,903) and the Crystal River 3 Uprate project ($40,033,676).

Florida Power & Light Company

Nuclear Cost Recovery

Pursuant to the Nuclear Cost Recovery statute and rule, the amount to included in the Capacity Cost Recovery Clause is based on our vote at the November 26, 2012 special agenda conference in Docket No. 110009-EI. FPL presented evidence in the record to support its nuclear cost recovery amount to be recovered. Pursuant to Order No. PSC-12-0650-FOF-EI,[14]

[13] See p. 44, Order No. PSC-12-0650-FOF-EI, issued December 11, 2012, in Docket No. 120009-EI, In Re: Nuclear Cost Recovery.
[14] See p. 78, Order No. PSC-12-0650-FOF-EI, issued December 11, 2012, in Docket No. 120009-EI, In Re: Nuclear Cost Recovery.

the nuclear cost recovery amount to be recovered in FPL's 2013 capacity cost recovery clause factor is $151,491,402.

Incremental Security Costs

FPL, the parties, and our staff raised the issue of whether we should make an adjustment to transfer incremental security costs from the Capacity Cost Recovery Clause to base rates. The parties briefed the issue. Subsequent to the briefing, OPC and FPL submitted a stipulation to address this issue pending the outcome of FPL's rate case in Docket No. 120015-EI. We approve the stipulation as follows.[15]

The issue of the transfer of incremental security costs to base rates is in Issues 67 and 68 in the pending rate case in Docket 120015-EI. Since we will not have reached a decision on this issue in the rate case prior to the decision in Docket 120001-EI, incremental security rates shall be treated per the terms of the Stipulation and Settlement Agreement approved in the prior FPL rate case, Docket No. 080677-EI. Once we have made our decision in Docket No. 120015-EI or in the event FPL implements a base rate increase prior to our decision in 120015-EI (as permitted by Section 366.06(3), F.S.), there is a potential for FPL to recover its incremental security costs in both base rates and in the capacity cost recovery factors. Accordingly, any over recovery resulting from the timing of our decision in Docket No. 120015-EI related to this issue will be handled through the regular true-up process or by mid-course correction.

It is acknowledged that the OPC, FRF and others have objected to the proposed settlement agreement signed by FPL, FIPUG, SFHHA and FEA in Docket No. 120015-EI, and that agreement to the stipulation language on this issue does not constitute waiver by OPC and FRF of those objections to the proposed settlement agreement or orders impacted by our consideration of the proposed settlement agreement.

West County Energy Center Unit 3 Cost Recovery

FPL, the parties, and our staff raised the issue of what amount should be included in the capacity cost recovery clause for recovery of jurisdictional non-fuel revenue requirements associated with West County Energy Center Unit 3 (WCEC-3) for the period January 2013 through December 2013. The parties briefed the issue. Subsequent to the briefing, OPC and FPL submitted a stipulation to address this issue pending the outcome of FPL's rate case in Docket No. 120015-EI. We approve the stipulation as follows.[16]

We will not have addressed or reached a decision in Docket 120015-EI until after the date of our decision in Docket 120001-EI. The costs associated with the WCEC-3 shall be treated in accordance with the terms of the Stipulation and Settlement approved in Docket No. 080677-EI, the prior FPL rate case. The Stipulation and Settlement Agreement approved in Docket No. 080677-EI contemplated the cost recovery of the revenue requirements associated

[15] We approved the Proposed Settlement Agreement, as modified, in Docket 120015-EI on December 13, 2012. However, we have not issued an Order.
[16] Id.

with WCEC-3 would be limited to the fuel savings created by this plant. The recovery through the capacity clause of revenue requirements for WCEC-3 limited by fuel savings shall continue until we render our decision in Docket No. 120015-EI. From the date we render our decision in Docket No. 120015-EI forward, the collection of revenue requirements for WCEC-3 will be as directed by us in Docket No. 120015-EI. No party waives any rights, positions or arguments it might otherwise have, at the time our decision in Docket No. 120015 becomes final and effective, which shall be on the date of our vote, with regard to any alleged retroactive application or the prospective application of the full amount of the WCEC3 revenue requirements. Any over or under recovery resulting from the timing of our decision in Docket No. 120015-EI related to this issue shall be handled through the regular true-up process or by mid-course correction.

It is acknowledged that the OPC, FRF and others have objected to the proposed settlement agreement signed by FPL, FIPUG, SFHHA and FEA in Docket No. 120015-EI and that agreement to the stipulation language on this issue does not constitute waiver by OPC and FRF of those objections to the proposed settlement agreement or orders impacted by the our consideration of the proposed settlement agreement.

Canaveral Modernization Project

FPL, the parties, and our staff raised the issue of what amount should be included in the capacity cost recovery clause for recovery if we approve the Proposed FPL Rate Case Settlement Agreement that was filed in Docket No. 120015-EI on August 15, 2012 (the "Proposed Settlement Agreement"), should we approve FPL's proposed GBRA factor of 3.527 percent for the Canaveral Modernization Project. The parties briefed the issue.[17] Subsequent to the briefing, OPC and FPL submitted a stipulation to address this issue pending the outcome of FPL's rate case in Docket No. 120015-EI. We approve the stipulation as follows.

We will not have addressed or reached a decision in Docket 120015-EI, until after the date of our decision in Docket 120001-EI. Accordingly, we shall reserve ruling on this issue until we have issued our final order in Docket No. 120015-EI at which time we will schedule a decision on this issue for a regular agenda conference that will permit the approved GBRA factor to be implemented when the Canaveral Modernization Project goes into service. The decision on this issue will be made in Docket No. 130001-EI based on the amount, if any, that we approve for GBRA recovery in Docket No. 120015-EI.

It is acknowledged that the OPC, FRF and others have objected to the proposed settlement agreement signed by FPL, FIPUG, SFHHA and FEA in Docket No. 120015-EI, and that agreement to the stipulation language on this issue does not constitute waiver by OPC and FRF of those objections to the proposed settlement agreement or orders impacted by our consideration of the proposed settlement agreement.

[17] Id.

## GENERIC CAPACITY COST RECOVERY FACTOR ISSUES

Based on the testimony and exhibits in the record, the appropriate capacity cost recovery true-up amounts for the period January 2011 through December 2011 are:

| | |
|---|---|
| FPL: | $44,704,575 under-recovery. |
| GULF: | $ 353,030 under-recovery. |
| PEF: | $ 4,389,550 under-recovery. |
| TECO: | $ 1,311,897 under-recovery. |

Based on the testimony and exhibits in the record, the appropriate capacity cost recovery actual/estimated true-up amounts for the period January 2012 through December 2012 are:

| | |
|---|---|
| FPL: | $15,878,460 under-recovery. |
| GULF: | $ 592,654 under recovery. |
| PEF: | $ 6,096,072 under-recovery. |
| TECO: | $ 5,390,608 under-recovery. |

Based on the testimony and exhibits in the record, the appropriate total capacity cost recovery true-up amounts to be collected/refunded during the period January 2013 through December 2013 are:

| | |
|---|---|
| FPL: | $ 60,583,035 under-recovery. |
| GULF: | $ 945,684 under-recovery. |
| PEF: | $ 10,485,622 under-recovery. |
| TECO: | $ 6,702,505 under-recovery. |

The appropriate projected total capacity cost recovery amounts for the period January 2013 through December 2013 are:

| | |
|---|---|
| FPL: | $518,848,705. |
| GULF: | $43,921,106. |
| PEF: | $385,072,136. |
| TECO: | $29,728,488. |

Based on the evidence in the record, the appropriate projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January 2013 through December 2013 are:

| | |
|---|---|
| FPL: | The projected net purchased power capacity cost recovery amount to be recovered over the period January 2013 through December 2013 is $864,438,406 including prior period true-ups, revenue taxes, and the nuclear cost recovery amount.[18] |
| GULF: | $44,899,094 including prior period true-up amounts and revenue taxes. |

[18] Id.

PEF: The appropriate projected net purchased power capacity cost recovery amount, excluding nuclear cost recovery, is $395,842,560. The appropriate nuclear cost recovery amount is $142,730,579.

TECO: The purchased power capacity cost recovery amount to be included in the recovery factor for the period January 2013 through December 2013, adjusted by the jurisdictional separation factor, is $29,728,488. The total recoverable capacity cost recovery amount to be collected, including the true-up amount and adjusted for the revenue tax factor, is $36,457,223.

Based on the evidence in the record, the appropriate jurisdictional separation factors for capacity revenues and costs to be included in the recovery factor for the period January 2013 through December 2013 should be as follows:

| | | |
|---|---|---|
| FPL: | FPSC | 97.97032%. |
| | FERC | 2.02968%. |
| GULF: | | 96.57346% |
| PEF: | Base | 92.885%. |
| | Intermediate | 72.703%. |
| | Peaking | 95.924%. |
| TECO: | | 1.000000%. |

Based on the evidence in the record, the appropriate capacity cost recovery factors for the period January 2013 through December 2013 should be as follows:

FPL: The appropriate capacity cost recovery factors for the period January 2013 through December 2013 are shown in Table 33-1 below:

GULF: The appropriate capacity cost recovery factors for the period January 2013 through December 2013 are shown in Table 33-2 below:

PEF: The appropriate capacity cost recovery factors for the period January 2013 through December 2013 are shown in Table 33-3 below:

TECO: The appropriate capacity cost recovery factors for the period January 2013 through December 2013 are shown in Table 33-4 below:

| FPL – Capacity Cost Recovery Factors | | | | |
|---|---|---|---|---|
| **RATE SCHEDULE** | **Capacity Recovery Factor ($/KW)** | **Capacity Recovery Factor ($/kwh)** | **RDC ($/KW)** | **SDD ($/KW)** |
| RS1/RST1 | - | 0.00938 | - | - |
| GS1/GST1/WIES1 | - | 0.00793 | - | - |
| GSD1/GSDT1/HLFT1 | 2.90 | - | - | - |
| OS2 | - | 0.00811 | - | - |
| GSLD1/GSLDT1/CS1/CST1/HLFT2 | 2.99 | - | - | - |
| GSLD2/GSLDT2/CS2/CST2/HLFT3 | 3.05 | - | - | - |
| GSLD3/GSLDT3/CS3/CST3 | 3.35 | - | - | - |
| SST1T/ISST1T | - | - | $0.40 | $0.19 |
| SST1D1/ SST1D2/SST1D3/ISST1D | - | - | $0.41 | $0.20 |
| CILC D/CILC G | 3.50 | - | - | - |
| CILC T | 3.38 | - | - | - |
| MET | 3.48 | - | - | - |
| OL1/SL1/PL1 | - | 0.00254 | - | - |
| SL2, GSCU1 | - | 0.00591 | - | - |

Table 33-1

| Gulf – Capacity Cost Recovery Factors | |
|---|---|
| **RATE CLASS** | **CAPACITY COST RECOVERY FACTORS ¢/KWH** |
| RS, RSVP | 0.467 |
| GS | 0.426 |
| GSD, GSDT, GSTOU | 0.369 |
| LP, LPT | 0.317 |
| PX, PXT, RTP, SBS | 0.280 |
| OS-I/II | 0.171 |
| OSIII | 0.277 |

Table 33-2

| PEF – Capacity Cost Recovery Factors by Rate Class for January – December, 2013 | | | | | |
|---|---|---|---|---|---|
| RATE CLASS | | Capacity CCR Factor (c/kWh) | Levy CCR Factor (c/kWh) | CR3 CCR Factor (c/kWh) | Capacity & Nuclear CCR Factor (c/kWh) |
| Residential | RS-1, RST-1, RSL-1, RSL-2, RSS-1 Secondary | 1.265 | 0.345 | 0.128 | 1.738 |
| General Service Non-Demand | GS-1, GST-1 Secondary | 1.023 | 0.252 | 0.104 | 1.379 |
| | GS-1, GST-1 Primary | 1.013 | 0.249 | 0.103 | 1.365 |
| | GS-1, GST-1 Transmission | 1.003 | 0.247 | 0.102 | 1.351 |
| General Service | GS-2 Secondary | 0.696 | 0.182 | 0.070 | 0.948 |
| General Service Demand | GSD-1, GSDT-1, SS-1 Secondary | 0.872 | 0.224 | 0.088 | 1.184 |
| | GSD-1, GSDT-1, SS-1 Primary | 0.863 | 0.222 | 0.087 | 1.172 |
| | GSD-1, GSDT-1, SS-1 Transmission | 0.855 | 0.220 | 0.086 | 1.160 |
| Curtailable | CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3 Secondary | 0.623 | 0.207 | 0.063 | 0.893 |
| | CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3 Primary | 0.617 | 0.205 | 0.062 | 0.884 |
| | CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3 Transmission | 0.611 | 0.203 | 0.062 | 0.875 |
| Interruptible | IS-1, IST-1, IS-2, IST-2, SS-2 Secondary | 0.709 | 0.180 | 0.072 | 0.961 |
| | IS-1, IST-1, IS-2, IST-2, SS-2 Primary | 0.702 | 0.178 | 0.071 | 0.951 |
| | IS-1, IST-1, IS-2, IST-2, SS-2 Transmission | 0.695 | 0.176 | 0.071 | 0.942 |
| Lighting | LS-1 Secondary | 0.182 | 0.052 | 0.018 | 0.252 |

Table 33-3

| TECO – Capacity Cost Recovery Factors | | | |
|---|---|---|---|
| Rate Class and Metering Voltage | | Capacity Cost Recovery Factor | |
| | | c/kWh | $/kW |
| RS Secondary | | 0.232 | |
| GS and TS Secondary | | 0.214 | |
| GSD, SBF Standard | Secondary | | 0.73 |
| | Primary | | 0.72 |
| | Transmission | | 0.72 |
| GSD Optional | Secondary | 0.173 | |
| | Primary | 0.171 | |
| IS, SBI | Primary | | 0.60 |
| | Transmission | | 0.60 |
| LS1 Secondary | | 0.060 | |

Table 33-4

Effective Date

FPL: FPL is requesting that the fuel adjustment factors and capacity cost recovery factors become effective with customer bills for January 2013 (cycle day 1) through December 2013 (cycle day 21). This will provide for 12 months of billing for all customers. Thereafter, FPL's fuel adjustment factors and capacity cost recovery factors should remain in effect until modified by us. We approve FPL's requested effective date.

PEF: The new factors shall be effective beginning with the first billing cycle for January 2013 through the last billing cycle for December 2013. The first billing cycle may start before January 1, 2013, and the last billing cycle may end after December 31, 2013, so long as each customer is billed for twelve months regardless of when the factors became effective.

FPUC: The effective date for FPUC's cost recovery factors shall be the first billing cycle for January 1, 2013, which could include some consumption from the prior month. Thereafter, customers shall be billed the approved factors for a full 12 months, unless the factors are otherwise modified by us.

GULF: The new fuel and capacity factors shall be effective beginning with the first billing cycle for January 2013 and thereafter through the last billing cycle for December 2013. Billing cycles may start before January 1, 2013 and the last cycle may be read after December 31, 2013, so that each customer is billed for twelve months regardless of when the adjustment factor became effective.

TECO: The new factors shall be effective beginning with the specified billing cycle and thereafter for the period January 2013 through the last billing cycle for December 2013. The first billing cycle may start before January 1, 2013, and the last billing cycle may end after December 31, 2013, so long as each customer is billed for 12 months regardless of when the fuel factors became effective.

Our staff and the parties discussed two additional issues for our consideration in the next year's fuel proceedings. The first issue is as follows:

> Should the Commission authorize its staff to investigate a change in the annual fuel cost recovery clause effective date of the new factors to begin on or after the first billing cycle in January?"

While the utilities took no position on this issue, the intervenors agreed with our staff that this should be an issue in 2013. We have considered our staff's suggestion and agree. Accordingly, the Commission staff should be instructed to commence an investigation in the 2013 annual fuel cost recovery clause proceedings.

The second issue is as follows:

> Should the Commission authorize it staff to initiate an investigation of the GPIF mechanism in the 2013 annual fuel cost recovery clause proceedings?

While the utilities took no position on this issue, the intervenors agreed with our staff that this should be an issue in 2013. We have considered our staff's suggestion and agree. Accordingly, the Commission staff should be instructed to commence an investigation of the GPIF mechanism in the 2013 annual fuel cost recovery clause proceedings.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the findings set forth in the body of this Order are hereby approved. It is further

ORDERED that Florida Power & Light Company, Florida Public Utilities Company, Gulf Power Company, Progress Energy Florida, Inc., and Tampa Electric Company, are hereby authorized to apply the fuel cost recovery factors set forth herein during the period January 2013 through December 2013. It is further

ORDERED the estimated true-up amounts contained in the fuel cost recovery factors approved herein are hereby authorized subject to final true-up and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that Florida Power & Light Company, Progress Energy Florida, Inc., Gulf Power Company, and Tampa Electric Company are hereby authorized to apply the capacity cost recovery factors as set forth herein during the period January 2013 through December 2013. It is further

ORDERED that the estimated true-up amounts contained in the capacity cost recovery factors approved herein are hereby authorized subject to final true-up and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that the Fuel and Purchased Power Cost Recovery Clause With Generating Performance Incentive Factor docket is an on-going docket and shall remain open.

By ORDER of the Florida Public Service Commission this 21st day of December, 2012.

ANN COLE
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
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Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

MFB

DISSENT BY: COMMISSIONER LISA POLAK EDGAR

COMMISSIONER LISA POLAK EDGAR dissents with the majority on Issue 36 with the following opinion:

Issue 36 in this docket was presented as a Type B Stipulation (the utilities take no position and the intervenors agree with staff on the stipulation).

> Issue: Should the Commission authorize its staff to initiate an investigation of the GPIF mechanism in the 2013 annual fuel cost recovery clause proceedings?
>
> Stipulation: Yes. The Commission staff should be instructed to commence an investigation of the GPIF mechanism in the 2013 annual fuel cost recovery clause proceedings.

A review of the GPIF mechanism may indeed be timely. However, I respectfully disagree with the inclusion of Issue 36 as part of a larger group of "stipulated" issues.

It is my belief that this is an awkward and potentially problematic means for the Commission to consider and vote on whether to authorize an investigation. No background information, analysis, or rationale was provided, putting Commissioners in the uncomfortable position of appearing to direct our staff to take an action because, and only after, that action had been pre-approved by all parties.

This vote should not be a precedent for how to initiate future investigations.

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

## CERTIFICATE OF SERVICE

**I HEREBY CERTIFY** that a true and correct copy of the foregoing has been furnished by electronic mail on this 3rd day of August 2018 to the following:

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