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. 20170001-EI<br>ORDER NO. PSC-2017-0399-PHO-EI<br>ISSUED: October 20, 2017 |

PREHEARING ORDER

Pursuant to Notice and in accordance with Rule 28-106.209, Florida Administrative Code (F.A.C.), a Prehearing Conference was held on October 11, 2017, in Tallahassee, Florida, before Commissioner Ronald A. Brisé, as Prehearing Officer.

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, 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)

JAMES W. BREW, and LAURA A. WYNN, ESQUIRES, Stone Mattheis Xenopoulos & Brew, PC, 1025 Thomas Jefferson St., NW, Eighth Floor, West Tower, Washington, DC 20007
On behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs (PCS Phosphate)

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

## PREHEARING ORDER

## I. CASE BACKGROUND

As part of the continuing fuel and purchased power adjustment and generating performance incentive clause proceedings, an administrative hearing will be held by the Florida Public Service Commission (Commission) on October 25-27, 2017. The purpose of this docket is to review and approve purchased wholesale electric power charges, electric generation facilities' fuel and fuel related costs, and incentives associated with the efficient operation of generation facilities which are passed through to ratepayers through the fuel adjustment factor. The Commission will address those issues listed in this prehearing order. The Commission has the option to render a bench decision with agreement of the parties on any or all of the issues listed below.

## II. CONDUCT OF PROCEEDINGS

Pursuant to Rule 28-106.211, F.A.C., this Prehearing Order is issued to prevent delay and to promote the just, speedy, and inexpensive determination of all aspects of this case.

## III. 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.

## IV. PROCEDURE FOR HANDLING CONFIDENTIAL INFORMATION

Information 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.

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 and with the confidential information highlighted. 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 material is admitted into the evidentiary record at hearing and is not otherwise subject to a request for confidential classification 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.

## V. PREFILED TESTIMONY AND EXHIBITS; WITNESSES

Testimony of all witnesses to be sponsored by the parties has been prefiled and will be inserted into the record as though read after the witness has taken the stand and affirmed the correctness of the testimony and associated exhibits. All testimony remains subject to timely and appropriate objections. Upon insertion of a witness' testimony, exhibits appended thereto may be marked for identification. Each witness will have the opportunity to orally summarize his or her testimony at the time he or she takes the stand. Summaries of testimony shall be limited to five minutes.

Witnesses are reminded that, on cross-examination, responses to questions calling for a simple yes or no answer shall be so answered first, after which the witness may explain his or her answer. After all parties and Staff have had the opportunity to cross-examine the witness, the exhibit may be moved into the record. All other exhibits may be similarly identified and entered into the record at the appropriate time during the hearing.

The Commission frequently administers the testimonial oath to more than one witness at a time. Therefore, when a witness takes the stand to testify, the attorney calling the witness is directed to ask the witness to affirm whether he or she has been sworn.

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.

## VI. ORDER OF WITNESSES

| Witness | Proffered By | Issues # |
|---|---|---|
| Direct | | |
| *Christopher A. Menendez | DEF | 1B, 6-11, 18-23A, 27-36 |
| *Joseph McCallister | DEF | 1A |
| *Matthew J. Jones | DEF | 16, 17 |

| Witness | Proffered By | Issues # |
|---|---|---|
| R. B. Deaton | FPL | 2Q, 2R, 6-11, 18-22, 24A-24D, 27-36 |
| *G. J. Yupp | FPL | 2A-2I, 8-11, 18 |
| *M. Kiley | FPL | 8-11, 18 |
| *C. R. Rote | FPL | 13A, 16, 17 |
| J. Enjamio | FPL | 2J, 2M |
| W. F. Brannen | FPL | 2J, 2M |
| *L. Fuentes | FPL | 2K, 2N |
| *T. C. Cohen | FPL | 2L, 2O-2P |
| *Curtis D. Young | FPUC | 8 |
| *Michael Cassel | FPUC | 3A, 9, 10, 11, 18-22, 34, 35 |
| *P. Mark Cutshaw | FPUC | 10, 11 |
| *C. S. Boyett | Gulf | 4A, 6-11, 18-22, 27-36 |
| *C. L. Nicholson | Gulf | 16, 17 |
| *Penelope A. Rusk | TECO | 6-11, 18-22, 27-36 |
| *Brian S. Buckley | TECO | 16-18 |
| *Benjamin F. Smith | TECO | 18, 31 |
| *J. Brent Caldwell | TECO | 5A, 18 |
| *Simon O. Ojada | Staff | 1A |
| *Donna D. Brown | Staff | 2A |

| Witness | Proffered By | Issues # |
|---|---|---|
| *George Simmons | Staff | 4A |
| *Intesar Terkawi | Staff | 5A |

***** These witnesses have been stipulated to by the parties.

## VII. BASIC POSITIONS

**DEF:** Not applicable. DEF's positions on specific issues are listed below.

**FPL:** FPL's 2018 Fuel and Purchased Power Cost Recovery factors and Capacity Cost Recovery factors, including its prior period true-ups, are reasonable and should be approved. The final true-up of $126,520 related to Woodford completes the removal of all Woodford-related costs from the Fuel Clause. FPL's asset optimization activities in 2016 delivered total gains of $62,835,808. Of these total gains, FPL is allowed to retain $10,101,485. FPL's Incremental Optimization Costs are reasonable and should be approved for recovery. FPL's hedging activities, as reported in the April 2017 and August 2017 hedging reports should be approved as compliant with its Commission-approved 2017 Risk Management Plan. FPL's Generation Base Rate Adjustment ("GBRA") refund true-up amount of $5,155,198 for Port Everglades Energy Center ("PEEC") should be approved. FPL's solar generation that will be placed into service in 2017 and 2018 (the "2017 Solar Project" and "2018 Solar Project," respectively) are projected to save FPL customers approximately $106 million on a cumulative present value of revenue requirements ("CPVRR") basis and their costs are lower than the cap prescribed by FPL's Base Rate Settlement Agreement. FPL's proposed 2017 and 2018 Solar Projects are cost effective and should be approved. FPL's solar base rate adjustment ("SoBRA") factors of 0.937% and 0.919% and revenue requirements of $60,523,000 and $59,890,000 associated with the 2017 and 2018 Solar Projects, respectively, should be approved, and the revised tariffs for FPL reflecting the requested base rate percentage increases for the 2017 and 2018 SoBRA projects should be approved.

**FPUC:** The Commission should approve Florida Public Utilities Company's final net true-up for the period January through December 2016, the estimated true-up for the period January through December, 2017, and the purchase power cost recovery factor for the period January through December, 2018, as well as the Company's calculation of the amount to be refunded to customers as a result of the Florida Supreme Court's March 16, 2017 decision on the FPL Interconnection Line project.

**Gulf:** It is the basic position of Gulf Power Company that the fuel and capacity cost recovery factors proposed by the Company present the best estimate of Gulf's fuel and capacity expense for the period January 2018 through December 2018 including the true-up calculations, GPIF and other adjustments allowed by the Commission.

**TECO:** The Commission should approve Tampa Electric's calculation of its fuel adjustment, capacity cost recovery and GPIF true-up and projection calculations, including the proposed fuel adjustment factor of 3.127cents per kWh before any application of time of use multipliers for on-peak or off-peak usage; the company's proposed capacity factor for the period January through December 2018; a GPIF reward of $47,392 for performance during 2016; and approval of the company’s proposed GPIF targets and ranges for 2018. Tampa Electric also requests approval of its calculated wholesale incentive benchmark of $881,855 for calendar year 2018.

**OPC:** Following the approval of a joint stipulation by the parties in last year’s Fuel and Purchased Power Cost Recovery Clause docket by Order No. PSC-2016-0547-FOF-EI, issued December 5, 2016, the Commission initiated Docket No. 20170057-EI to review the hedging practices of the four investor owned utilities (IOUs) which financially hedged natural gas. Pursuant to Order No. PSC-2017-0134-PCO-EI, issued April 13, 2017, revising the order establishing procedure, the IOUs did not file 2018 Risk Management Plans for the Commission’s review and approval. In the last 12 months, the four IOUs have each entered into settlements to cease the financial hedging of natural gas pursuant to the terms of their respective settlement agreements. Two of the settlements have been approved and two are pending review and approval by the Commission. OPC continues to believe that financial hedging should be discontinued as a result of the substantial changes in the natural gas markets in recent years which have increased natural gas supply and decreased price volatility experienced by customers. If circumstances change substantially, then volatility mitigation mechanisms, like hedging, can be visited again in the future.

As a result of the Supreme Court’s decision, the total amount collected for the Interconnection Line project should be refunded to FPUC’s customers through the Fuel Clause.

To the extent that DEF has removed from this 2017 filing the estimated replacement power costs associate with the 2017 Bartow outage, no adjustment is needed. Once the root cause analysis is completed, DEF will not be precluded from submitting any replacement power costs for recovery if it meets its burden of proof to demonstrate that it acted prudently in the actions and inactions that led to the outage as well as its role in procuring replacement power.

With regard to the August 2016 and January 2017 unplanned outages at St. Lucie Unit 1, lasting 27 and 7 days respectively, and the March 2017 unplanned outage at Turkey Point Unit 3 lasting 9 days, OPC does not object to the recovery of the replacement power costs including other related costs subject to refund. OPC reserves the right to challenge the prudence of FPL's actions or inactions related to the cause(s) of the three unplanned outages and seek refunds of the corresponding replacement power costs and any other related costs in a subsequent Fuel and Purchased Power Cost Recovery Clause docket.

**FIPUG:** Only reasonable and prudent costs legally authorized should be recovered through the fuel clause. FIPUG maintains that the respective utilities must satisfy their burden of proof for any and all monies or other relief sought in this proceeding.

**FRF:** **Fuel Cost Hedging Issues**

The Florida Retail Federation believes that the investor-owned utilities' ("IOUs") financial hedging activities have been contrary to the best interests of all customers, and accordingly, the FRF continues to oppose those activities. Through approval of settlement agreements between Florida Power & Light Company ("FPL") and Gulf Power Company ("Gulf") and customer parties in their most recent respective rate cases, both of which settlements included the Office of Public Counsel and the Florida Retail Federation and other consumer parties, the Commission has approved the suspension and cessation of financial hedging activities by these two IOUs, through 2021 in FPL's case and through at least 2020 for Gulf Power. Additionally, pending settlements between customer representatives, again including the Office of Public Counsel and the FRF as well as other consumer parties, and Duke Energy Florida and Tampa Electric Company, include similar hedging suspension provisions: Duke has agreed not to enter into new natural gas financial gas hedging contracts through at least 2021, and Tampa Electric has agreed not to enter into new natural gas financial hedging contracts through December 31, 2022. All four IOUs are permitted by the respective settlement agreements to perform existing hedging contracts. For reasons stated many times by the FRF, the Office of Public Counsel, and other Consumer Parties, the FRF does not agree that the IOUs' hedging activities have been prudent. However, consistent with the settlement agreements, the FRF does not oppose the IOUs' recovery of costs pursuant to approved, existing hedging contracts.

**Other Issues**

All of the investor-owned electric utilities bear the burden of proving the reasonableness and prudence of their expenditures for which they seek recovery through their Fuel and Purchased Power Cost Recovery Charges.

**PCS Phosphate:** Only costs prudently incurred and legally authorized should be recovered through the fuel clause. Florida electric utilities, including in particular Duke Energy Florida, Inc. ("DEF"), must satisfy the burden of proving the reasonableness of any expenditures for which recovery or other relief is sought in this proceeding.

Additionally, PCS Phosphate is a signatory to the pending 2017 Second Revised and Restated Settlement Agreement, filed with the Commission in Docket No. 20170183, *Application for Limited Proceeding to Approve 2017 Second Revised and Restated Settlement Agreement*. That proposed agreement contains provisions that pertain to prior period fuel cost under-recoveries that are included in DEF's filing in this docket. PCS Phosphate supports the recovery of prudently incurred Duke Energy Florida fuel costs in the manner proposed in that pending rate settlement agreement.

**Staff:** Staff's positions are preliminary and based on materials filed by the parties and on discovery. The preliminary positions are offered to assist the parties in preparing for the hearing. Staff's final positions will be based upon all the evidence in the record and may differ from the preliminary positions.

## VIII. <u>ISSUES AND POSITIONS</u>

## I. <u>FUEL ISSUES</u>

### COMPANY-SPECIFIC FUEL ADJUSTMENT ISSUES

### Duke Energy Florida, LLC.

<u>ISSUE 1A</u>: **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?**

**POSITIONS:**

**DEF:** 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 the Commission and, therefore, its actions are found to be reasonable and prudent. (McCallister)

**FPL:** No position provided.

**FPUC:** No position.

**Gulf:** No position provided.

**TECO:** No position provided.

**OPC:** No. Hedging should be discontinued.

**FIPUG:** No. Hedging should be discontinued.

**FRF:** No.

**PCS Phosphate:** 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 Agreement). PCS Phosphate is a party to, and fully supports Commission approval of the 2017 RRSSA Agreement. If that Agreement is approved by the Commission, PCS Phosphate takes no position. If the Agreement is not approved, PCS Phosphate maintains that DEF's historically implemented hedging approach is not reasonable and that more appropriate fuel hedging strategies should be developed and implemented in Docket No. 20170057-EI.

**Staff:** Staff has no position at this time.

**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?**

***Proposed Stipulation – see Section X.***

**Florida Power & Light Company**

**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?**

**POSITIONS:**

**DEF:** No position.

**FPL:** 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 the Commission and, therefore, its actions are found to be reasonable and prudent. (Yupp)

**FPUC:** No position.

**Gulf:** No position provided.

**TECO:** No position provided.

**OPC:** No. Hedging should be discontinued.

**FIPUG:** No. Hedging should be discontinued.

**FRF:** No.

**PCS Phosphate:** No position.

**Staff:** Staff has no position at this time.

**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?**

***Proposed Stipulation – see Section X.***

**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?**

***Proposed Stipulation – see Section X.***

**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?**

***Proposed Stipulation – see Section X.***

**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?**

***Proposed Stipulation – see Section X.***

**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?**

***Proposed Stipulation – see Section X.***

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

***Proposed Stipulation – see Section X.***

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

***Proposed Stipulation – see Section X.***

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

***Proposed Stipulation – see Section X.***

**ISSUE 2J:** **Are the 2017 SOBRA projects proposed by FPL (Horizon, Wildflower, Indian River, and Coral Farms) cost effective?**

**POSITIONS:**

**DEF:** No position.

**FPL:** Yes. The 2017 and 2018 SOBRA projects are projected to result in $106 million (CPVRR) of customer savings. (Enjamio, Brannen)

**FPUC:** No position.

**Gulf:** No position provided.

**TECO:** No position provided.

**OPC:** No position

**FIPUG:** No.

**FRF:** No position.

**PCS Phosphate:** No position.

**Staff:** Staff has no position at this time.

**ISSUE 2K: What are the revenue requirements associated with the 2017 SOBRA projects?**

**POSITIONS:**

**DEF:** No position.

**FPL:** $60,523,000. (Fuentes)

**FPUC:** No position.

**Gulf:** No position provided.

**TECO:** No position provided.

**OPC:** No position.

**FIPUG:** Less than $60.52 million.

**FRF:** No position.

**PCS Phosphate:** No position.

**Staff:** Staff has no position at this time.

**ISSUE 2L: What is the appropriate base rate percentage increase for the 2017 SOBRA projects to be effective when all 2017 projects are in service, currently projected to be January 1, 2018?**

**POSITIONS:**

**DEF:** No position.

**FPL:** 0.937%. (Cohen)

**FPUC:** No position.

**Gulf:** No position provided.

**TECO:** No position provided.
**OPC:** No position.

**FIPUG:** Less than 0.937%.

**FRF:** No position.

**PCS Phosphate:** No position.

**Staff:** Staff has no position at this time.

**ISSUE 2M: Are the 2018 SOBRA projects proposed by FPL (Hammock, Barefoot Bay, Blue Cypress and Loggerhead) cost effective?**

**POSITIONS:**

**DEF:** No position.

**FPL:** Yes. The 2017 and 2018 SOBRA projects are projected to result in $106 million (CPVRR) of customer savings. (Enjamio, Brannen)

**FPUC:** No position.

**Gulf:** No position provided.

**TECO:** No position provided.

**OPC:** No position.

**FIPUG:** No.

**FRF:** No position.

**PCS Phosphate:** No position.

**Staff:** Staff has no position at this time.

**<u>ISSUE 2N</u>: What are the revenue requirements associated with the 2018 SOBRA projects?**

**POSITIONS:**

**DEF:** No position.

**FPL:** $59,890,000. (Fuentes)

**FPUC:** No position.

**Gulf:** No position provided.

**TECO:** No position provided.

**OPC:** No position.

**FIPUG:** Less than $59.89 million.

**FRF:** No position.

**PCS Phosphate:** No position.

**Staff:** Staff has no position at this time.

**<u>ISSUE 2O</u>: What is the appropriate base rate percentage increase for the 2018 SOBRA projects to be effective when all 2018 projects are in service, currently projected to be March 1, 2018?**

**POSITIONS:**

**DEF:** No position.

**FPL:** 0.919%. (Cohen)

**FPUC:** No position.

**Gulf:** No position provided.

**TECO:** No position provided.

**OPC:** No position.

**FIPUG:** Less than 0.919%.

**FRF:** No position.

**PCS Phosphate:** No position.

**Staff:** Staff has no position at this time.

**ISSUE 2P: Should the Commission approve revised tariffs for FPL reflecting the base rate percentage increases for the 2017 and 2018 SoBRA projects determined to be appropriate in this proceeding?**

**POSITIONS:**

**DEF:** No position.

**FPL:** Yes. (Cohen)

**FPUC:** No position.

**Gulf:** No position provided.

**TECO:** No position provided.

**OPC:** No position.

**FIPUG:** No.

**FRF:** No position.

**PCS Phosphate:** No position.

**Staff:** Staff has no position at this time.

**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?**

***Proposed Stipulation – see Section X.***

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

***Proposed Stipulation – see Section X.*****Florida Public Utilities Company**

**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?**

***Proposed Stipulation – see Section X.***

**Gulf Power Company**

**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?**

**POSITIONS:**

**DEF:** No position.

**FPL:** No position provided.

**FPUC:** No position.

**Gulf:** 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 the Commission and, therefore, its actions are found to be reasonable and prudent. (Boyett)

**TECO:** No position provided.

**OPC:** No. Hedging should be discontinued.

**FIPUG:** No. Hedging should be discontinued.

**FRF:** No.

**PCS Phosphate:** No position.

**Staff:** Staff has no position at this time.

**Tampa Electric Company**

**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?**

**POSITIONS:**

**DEF:** No position.

**FPL:** No position provided.

**FPUC:** No position.

**Gulf:** No position provided.

**TECO:** 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 the Commission and, therefore, its actions are found to be reasonable and prudent. (Witness: Caldwell)

**OPC:** No. Hedging should be discontinued.

**FIPUG:** No. Hedging should be discontinued.

**FRF:** No.

**PCS Phosphate:** No position.

**Staff:** Staff has no position at this time.

**GENERIC FUEL ADJUSTMENT ISSUES**

**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?**

***Proposed Stipulation – see Section X.***

**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?**

***Proposed Stipulation – see Section X.***

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

***Proposed Stipulation – see Section X.***

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

***Proposed Stipulation – see Section X.***

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

***Proposed Stipulation – see Section X.***

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

***Proposed Stipulation – see Section X.***

**COMPANY-SPECIFIC GENERATING PERFORMANCE INCENTIVE FACTOR ISSUES**

**Duke Energy Florida, LLC.**

No company-specific issues for Duke Energy Florida, Inc. have been identified at this time. If such issues are identified, they shall be numbered 12A, 12B, 12C, and so forth, as appropriate.

**Florida Power & Light Company**

**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?**

***Proposed Stipulation – see Section X.***

**Gulf Power Company**

No company-specific issues for Gulf Power Company have been identified at this time. If such issues are identified, they shall be numbered 14A, 14B, 14C, and so forth, as appropriate.

**Tampa Electric Company**

No company-specific issues for Tampa Electric Company have been identified at this time. If such issues are identified, they shall be numbered 15A, 15B, 15C, and so forth, as appropriate.

**GENERIC GENERATING PERFORMANCE INCENTIVE FACTOR ISSUES**

**ISSUE 16: 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?**

***Proposed Stipulation – see Section X.***

**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?**

***Proposed Stipulation – see Section X.***

**FUEL FACTOR CALCULATION ISSUES**

**ISSUE 18: 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?**

***Proposed Stipulation – see Section X.***.

**<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?**

***Proposed Stipulation – see Section X.***

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

***Proposed Stipulation – see Section X.***

**<u>ISSUE 21</u>: 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?**

***Proposed Stipulation – see Section X.***

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

***Proposed Stipulation – see Section X.***

## II. <u>CAPACITY ISSUES</u>

**COMPANY-SPECIFIC CAPACITY COST RECOVERY FACTOR ISSUES**

**Duke Energy Florida, LLC.**

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

***Proposed Stipulation – see Section X.***

**Florida Power & Light Company**

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

***Proposed Stipulation – see Section X.***

**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?**

***Proposed Stipulation – see Section X.***

**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?**

***Proposed Stipulation – see Section X.***

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

***Proposed Stipulation – see Section X.***

**Gulf Power Company**

No company-specific issues for Gulf Power Company have been identified at this time. If such issues are identified, they shall be numbered 25A, 25B, 25C, and so forth, as appropriate.

**Tampa Electric Company**

No company-specific issues for Tampa Electric Company have been identified at this time. If such issues are identified, they shall be numbered 26A, 26B, 26C, and so forth, as appropriate.

**GENERIC CAPACITY COST RECOVERY FACTOR ISSUES**

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

***Proposed Stipulation – see Section X.***

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

***Proposed Stipulation – see Section X.***

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

***Proposed Stipulation – see Section X.***

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

***Proposed Stipulation – see Section X.***

**<u>ISSUE 31</u>: 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?**

***Proposed Stipulation – see Section X.***

**<u>ISSUE 32</u>: 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?**

***Proposed Stipulation – see Section X.***

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

***Proposed Stipulation – see Section X.***

## III. <u>EFFECTIVE DATE</u>

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

***Proposed Stipulation – see Section X.***

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

***Proposed Stipulation – see Section X.***

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

***Proposed Stipulation – see Section X.***

## IX. EXHIBIT LIST

| Witness | Proffered By | | Description |
|---|---|---|---|
| Direct | | | |
| Christopher Menendez | DEF | CAM-1T | Fuel Cost Recovery True-Up Jan – Dec. 2016 |
| Christopher Menendez | DEF | CAM-2T | Capacity Cost Recovery True-Up Jan – Dec. 2016 **CONFIDENTIAL** |
| Christopher Menendez | DEF | CAM-3T | Schedules A1 through A3, A6 and A12 for Dec 2016 **CONFIDENTIAL** |
| Christopher Menendez | DEF | CAM-4T | 2016 Capital Structure and Cost Rates Applied to Capital Projects |
| Christopher Menendez | DEF | CAM-2 | Actual/Estimated True-up Schedules for period January – December 2017 **CONFIDENTIAL** |
| Christopher Menendez | DEF | CAM-3 (Composite) | Original Projection Factors for January - December 2018 **CONFIDENTIAL**<br><br>Alternative Fuel and Capacity Cost Recovery Factors for January - December 2018 **CONFIDENTIAL** |
| Joseph McCallister | DEF | JM-1T | Hedging True-Up August - December 2016- **CONFIDENTIAL** |

| Witness | Proffered By | | Description |
|---|---|---|---|
| Joseph McCallister | DEF | JM-1P | Hedging Report January – July 2017 – **CONFIDENTIAL** |
| Matthew Jones | DEF | Revised MJJ-1T | GPIF Reward/Penalty Schedules for 2016 submitted on 8/24/17 |
| Matthew Jones | DEF | MJJ-1P | GPIF Targets/Ranges Schedules for January – December 2018 |
| R. B. Deaton | FPL | RBD-1 | 2016 FCR Final True Up Calculation |
| R. B. Deaton | FPL | RBD-2 | 2016 CCR Final True Up Calculation (Confidential) |
| R. B. Deaton | FPL | RBD-3 | 2017 FCR Actual/Estimated True Up Calculation |
| R. B. Deaton | FPL | RBD-4 | 2017 CCR Actual/Estimated True Up Calculation |
| R. B. Deaton | FPL | RBD-5 | Appendix II 2018 FCR Projection (Jan-Feb) |
| R. B. Deaton | FPL | RBD-6 | Appendix III 2018 FCR Projection (Mar-Dec) |
| R. B. Deaton | FPL | RBD-7 | Appendix IV 2018 FCR Projection (Jan-Dec) |
| R. B. Deaton | FPL | RBD-8 | Appendix V 2018 CCR Projection (Jan-Dec) |
| G. J. Yupp | FPL | GJY-1 | Woodford Refund Calculations and Final True-up Summary |
| G. J. Yupp | FPL | GJY-2 | 2016 Incentive Mechanism Results (Confidential) |
| G. J. Yupp | FPL | GJY-3 | 2016 Hedging Activity True-up (Confidential) |
| G. J. Yupp | FPL | GJY-4 (Supplemental) | 2017 Hedging Activity Supplemental Report (Confidential) |
| G. J. Yupp | FPL | GJY-5 | Appendix I Fuel Cost Recovery |

| Witness | Proffered By | | Description |
|---|---|---|---|
| C. R. Rote | FPL | CRR-1 | Generating Performance Incentive Factor Performance Results for January 2016 through December 2016 |
| C. R. Rote | FPL | CRR-2 | Generating Performance Incentive Factor Performance Targets for January 2018 through December 2018 |
| C. R. Rote | FPL | CRR-3 (Revised) | Revised Generating Performance Incentive Factor Performance Targets for January 2017 through December 2017 |
| J. Enjamio | FPL | JE-1 | Solar Energy Center Assumptions |
| J. Enjamio | FPL | JE-2 | Load Forecast |
| J. Enjamio | FPL | JE-3 | FPL Fuel Price Forecast |
| J. Enjamio | FPL | JE-4 | FPL Resource Plans |
| J. Enjamio | FPL | JE-5 | CPVRR – Costs and Benefits |
| J. Enjamio | FPL | JE-6 (Corrected) | Avoided Fossil Fuel |
| J. Enjamio | FPL | JE-7 | Avoided Air Emissions |
| J. Enjamio | FPL | JE-8 | Updated Project Assumptions |
| J. Enjamio | FPL | JE-9 | Updated CPVRR – Costs and Benefits |
| W. F. Brannen | FPL | WFB-1 | Typical Solar Facility Block Diagram |
| W. F. Brannen | FPL | WFB-2 | List of FPL Universal Solar Energy Centers in Service |
| W. F. Brannen | FPL | WFB-3 | Maps, Property Delineations, and Aerial Photos of Proposed Solar Energy Centers |

| Witness | Proffered By | | Description |
|---|---|---|---|
| W. F. Brannen | FPL | WFB-4 | Renderings of Proposed Solar Energy Centers |
| W. F. Brannen | FPL | WFB-5 | Specifications for Proposed Solar Energy Centers |
| W. F. Brannen | FPL | WFB-6 | Construction Schedule for Proposed Solar Energy Centers |
| W. F. Brannen | FPL | WFB-7 | Construction Cost Components for Proposed Solar Energy Centers |
| W. F. Brannen | FPL | WFB-8 (Supplemental) | Updated Construction Costs for Proposed Solar Energy Center |
| L. Fuentes | FPL | LF-1 | SoBRA Revenue Requirement Calculation Effective date January 1, 2018 |
| L. Fuentes | FPL | LF-2 | SoBRA Revenue Requirement Calculation Effective date March 1, 2018 |
| T. C. Cohen | FPL | TCC-1 | SoBRA Factor Calculation |
| T. C. Cohen | FPL | TCC-2 | Projected Retail Base Revenues |
| T. C. Cohen | FPL | TCC-3 | Summary of Tariff Changes for January 1, 2018 |
| T. C. Cohen | FPL | TCC-4 | Summary of Tariff Changes for March 1, 2018 |
| T. C. Cohen | FPL | TCC-5 | Typical Bill Estimates |
| Curtis D. Young | FPUC | CDY-1 (Composite) | Final True Up Schedules (Schedules A, C1 and E1-B for FPUC's Divisions) |
| Michael Cassel | FPUC | MC-1 (Composite) | Estimated/Actual (Schedules El-A, El-B, and El-B1) |
| Michael Cassel | FPUC | MC-2 (Composite) | Schedules E1, E1A, E2, E7, E8, E10 and Schedule A |

| Witness | Proffered By | | Description |
|---|---|---|---|
| C. S. Boyett | Gulf | CSB-1 | Calculation of Final True-Up January 2016 – December 2016 |
| C. S. Boyett | Gulf | CSB-2 | A-Schedules December 2016 |
| C. S. Boyett | Gulf | CSB-3 | 2016 Coal Purchases and Gas Hedging (Coal Suppliers, Natural Gas Price Variance, Hedging Effectiveness) |
| C. S. Boyett | Gulf | CSB-4 | Estimated True-Up January 2017 – December 2017 |
| C. S. Boyett | Gulf | CSB-5 | Projected PPCC Scherer/Flint Credit Calculation July 2017 – December 2017 |
| C. S. Boyett | Gulf | CSB-6 | Projection January 2018 – December 2018 |
| C. S. Boyett | Gulf | CSB-7 | 2018 Projected PPCC Scherer/Flint Credit Calculation |
| C. S. Boyett | Gulf | CSB-8 | Projected vs. Actual Fuel Cost of System Generation Comparison 2007 – 2018 |
| C. S. Boyett | Gulf | CSB-9 | Hedging Information Report August 2016 – December 2016 |
| C. S. Boyett | Gulf | CSB-10 | Hedging Information Report January 2017– July 2017 |
| C. L. Nicholson | Gulf | CLN-1 | Gulf Power Company GPIF Results January 2016 – December 2016 |

| Witness | Proffered By | | Description |
|---|---|---|---|
| C. L. Nicholson | Gulf | CLN-2 | Gulf Power Company GPIF Targets and Ranges January 2018 – December 2018 |
| Penelope A. Rusk | TECO | PAR-1 | Final True-up Capacity Cost ecovery, January 2016 - December 2016 |
| | | | Final True-up Fuel Cost Recovery, January 2016 – December 2016 |
| | | | Actual Fuel True-up Compared to Original Estimates, January 2016 – December 2016 |
| | | | Schedules A-1, A-2 and A-6 through A-9 and A-12, January 2016 – December 2016 |
| | | | Capital Projects Approved for Fuel Clause Recovery, January 2016 – December 2016 |
| Penelope A. Rusk | TECO | PAR-2 | Actual/Estimated True-Up Fuel Cost Recovery, January 2017 – December 2017 |
| | | | Actual/Estimated True-Up Capacity Cost Recovery, January 2017– December 2017 |
| | | | Capital Projects Approved for Fuel Clause Recovery, January 2017 – December 2017 |

| Witness | Proffered By | | Description |
|---|---|---|---|
| Penelope A. Rusk | TECO | PAR-3 | Projected Capacity Cost Recovery, January 2018 – December 2018<br><br>Projected Fuel Cost Recovery, January 2018 – December 2018<br><br>Levelized and Tiered Fuel Rate, January 2018– December 2018<br><br>Capital Projects Approved for Fuel Clause Recovery, January 2018 – December 2018 |
| Brian S. Buckley | TECO | BSB-1 | Final True-Up Generating Performance Incentive Factor, January 2016 – December 2016<br><br>Actual Unit Performance Data, January 2016 – December 2016 |
| Brian S. Buckley | TECO | BSB-2 | Generating Performance Incentive Factor, January 2018 – December 2018<br><br>Summary of Generating Performance Incentive Factor Targets, January 2018 – December 2018 |
| J. Brent Caldwell | TECO | JBC-1 | Final True-Up Hedging Activity Report for the period of January 2016 – December 2016 |
| J. Brent Caldwell | TECO | JBC-2 | Natural Gas Hedging Activity Report for the period of January 2017 – July 2017 |
| Simon O. Ojada | Staff | SOO-1 | DEF Hedging Audit Report August 1, 2016 to July 31, 2017 |
| Donna D. Brown | Staff | DDB-1 | FPL Hedging Audit Report August 1, 2016 to July 31, 2017 |
| George Simmons | Staff | GS-1 | Gulf Hedging Audit Report August 1, 2016 to July 31, 2017 |

| Witness | Proffered By | | Description |
|---|---|---|---|
| Intesar Terkawi | Staff | IT-1 | TECO Hedging Audit Report August 1, 2016 to July 31, 2017 |

Parties and Staff reserve the right to identify additional exhibits for the purpose of cross-examination.

## X. PROPOSED STIPULATIONS

There are proposed Type 2 stipulations as stated below:

**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 should 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 should 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?**

**STIPULATION**:

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 $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 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, the 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 the 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 Staff and parties to review and conduct discovery, if any, before the mid-course correction is brought to the 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 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. 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.

**<u>ISSUE 6</u>: 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.

**<u>ISSUE 7</u>: 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.

**<u>ISSUE 9</u>:** **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.

**<u>ISSUE 10</u>:** **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.

**<u>ISSUE 13A</u>: 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, the Commission had not yet approved the Indiantown transaction identified in Docket No. 20160154-EI. By Order No. PSC-2016-0506-FOF-EI,[1] the Commission approved the Indiantown transaction. Thereafter,

[1] 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.*

FPL recalculated the **2017 GPIF targets and ranges to reflect the effects of the Indiantown transaction approved by the 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 |
| | 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)

**ISSUE 16: 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)

**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)

**ISSUE 18:** **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.

**ISSUE 20:** **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[2] | 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)

[2]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[3] | 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)

[3]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:

**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, the 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 the 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 the 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.

**ISSUE 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.

**<u>ISSUE 29</u>: 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.

**<u>ISSUE 30</u>: 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 | 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[4] | Sum of Daily Demand Charge (SDD) $/kW[5] |
| 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)

[4] RDC=((Total Capacity Costs )/(Projected Avg 12CP @gen)(.10)(demand loss expansion factor))/12 months
[5] 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**

<table>
<tr><th rowspan="2">Rate Class</th><th colspan="2">Capacity Cost Recovery Factor</th></tr>
<tr><th>Cents / kWh</th><th>Dollars / kW-month</th></tr>
<tr><td>RS, RSVP, RSTOU</td><td>0.835</td><td rowspan="3">-</td></tr>
<tr><td>GS</td><td>0.762</td></tr>
<tr><td>GSD, GSDT, GSTOU</td><td>0.666</td></tr>
<tr><td>LP, LPT</td><td>-</td><td>2.76</td></tr>
<tr><td>PX, PXT, RTP, SBS</td><td>0.560</td><td rowspan="3">-</td></tr>
<tr><td>OS-I/II</td><td>0.164</td></tr>
<tr><td>OSIII</td><td>0.505</td></tr>
</table>

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**

<table>
<tr><th rowspan="2">Rate Class and Metering Voltage</th><th colspan="2">Capacity Cost Recovery Factor</th></tr>
<tr><th>Cents / kWh</th><th>Dollars / kW</th></tr>
<tr><td>RS Secondary</td><td>0.066</td><td rowspan="2">-</td></tr>
<tr><td>GS and CS Secondary</td><td>0.060</td></tr>
<tr><td colspan="2">GSD, SBF Standard</td><td></td></tr>
<tr><td>Secondary</td><td rowspan="3">-</td><td>0.20</td></tr>
<tr><td>Primary</td><td>0.20</td></tr>
<tr><td>Transmission</td><td>0.20</td></tr>
<tr><td colspan="2">GSD Optional</td><td></td></tr>
<tr><td>Secondary</td><td>0.047</td><td rowspan="2">-</td></tr>
<tr><td>Primary</td><td>0.047</td></tr>
<tr><td colspan="2">IS, SBI</td><td></td></tr>
<tr><td>Primary</td><td rowspan="2">-</td><td>0.14</td></tr>
<tr><td>Transmission</td><td>0.14</td></tr>
<tr><td>LS1 Secondary</td><td>0.016</td><td>-</td></tr>
</table>

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

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

**STIPULATION:**

The new factors should 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 the Commission.

**<u>ISSUE 35</u>: 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.

**<u>ISSUE 36</u>: 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 should remain open.

## XI. <u>PENDING MOTIONS</u>

On June 14, 2017, DEF filed a motion requesting that a stipulation be entered for 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. The suggested stipulation is as follows: "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." This language has been agreed to by the parties in the proposed stipulation on this issue listed above. Thus, approval of the proposed stipulation will render this motion moot.

## XII. <u>PENDING CONFIDENTIALITY MATTERS</u>

There are no pending confidentiality matters.

## XIII. <u>POST-HEARING PROCEDURES</u>

If no bench decision is made, each party shall file a post-hearing statement of issues and positions. A summary of each position of no more than 75 words, set off with asterisks, shall be included in that statement. If a party's position has not changed since the issuance of this Prehearing Order, the post-hearing statement may simply restate the prehearing position; however, if the prehearing position is longer than 75 words, it must be reduced to no more than 75 words. If a party fails to file a post-hearing statement, that party shall have waived all issues and may be dismissed from the proceeding.

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. Briefs, if any are required, shall be due on November 13, 2017 for consideration at the December 7, 2017 Agenda Conference.

## XIV. <u>RULINGS</u>

Each party who wishes to do so shall be given 3 minutes for opening statements. FPL shall be given an extra 10 minutes to address the SoBRA issues, Issues 2J through 2P. Parties who have taken a position on Issues 2J through 2P shall have a total of 10 extra minutes to address the SoBRA issues with the additional time divided among the parties as determined by those parties.

Both FRF and FIPUG have objected to a witness being considered an expert witness unless the witness states the subject matter area(s) in which he or she claims expertise, and voir dire, if requested, is permitted. Section VI.A(8) of Order No. PSC-17-0053-PCO-EI (OEP), issued on February 20, 2017, requires that a party identify each witness the party wishes to voir dire and specify the portions of the witness' testimony to which it objects. Since neither FIPUG nor FRF has complied with the OEP by naming witnesses whose expertise it wishes to challenge or identifying the witness testimony to which it objects, I find that neither FRF nor FIPUG shall be allowed to voir dire or challenge the expertise of any witness at the final hearing.

It is therefore,

ORDERED by Commissioner Ronald A. Brisé, as Prehearing Officer, that this Prehearing Order shall govern the conduct of these proceedings as set forth above unless modified by the Commission.

By ORDER of Commissioner Ronald A. Brisé, as Prehearing Officer, this 20th day of October, 2017.

RONALD A. BRISÉ
Commissioner and Prehearing Officer
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 120.5691, 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.