FILED 10/31/2019
DOCUMENT NO. 10625-2019
FPSC - COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 20190001-EI ORDER NO. PSC-2019-0466-PHO-EI ISSUED: October 31, 2019

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 22, 2019, in Tallahassee, Florida, before Commissioner Gary F. Clark, 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)

MARIA J. MONCADA, WILLIAM P. COX and JOEL BAKER, 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)

RUSSELL A. BADDERS, Gulf Power Company, One Energy Place, Pensacola, Florida 32520 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, MALCOM N. MEANS, 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, STEPHANIE MORSE, and THOMAS A. DAVID, 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)

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, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Florida Public Service Commission (Staff)

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

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

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 November 5-7, 2019. 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, 1C, 6-11, 18-23, 27-37
Jeffrey Swartz	DEF	1B, 1C
*Arnold Garcia	DEF	1B
*James McClay	DEF	1A
*James B. Daniel	DEF	16, 17

Witness	Proffered By	Issues #
*R. B. Deaton	FPL	2G, 6-11, 18-22, 24A, 24D, 27-33, 34, 35, 36, 37
*G. J. Yupp	FPL	2C-2F, 6-11, 18
*R. Coffey	FPL	6-11, 18
*C. R. Rote	FPL	16, 17
*L. Fuentes	FPL	2I, 24B
*W. F. Brannen	FPL	2H, 24B
*J. E. Enjamio	FPL	2H
*E. J. Anderson	FPL	2A, 2J, 2K, 2M, 2N, 24B
*Curtis D. Young	FPUC	8, 9
*Michelle Napier	FPUC	10, 11, 18, 19, 20-22, 34-36
*P. Mark Cutshaw	FPUC	10, 11
*C. S. Boyett	Gulf	4A, 6-11, 18-22, 27-37
*C. L. Nicholson	Gulf	16, 17
*Penelope A. Rusk	TECO	6-11, 18-22, 27-35
*Brian S. Buckley	TECO	16, 18
*J. Brent Caldwell	TECO	5A
*Jeremy B. Cain	TECO	17
*Benjamin F. Smith	TECO	18, 31
*John C. Heisey	TECO	5B, 18

Witness	Proffered By	Issues #
Richard A. Polich, P.E.	OPC	1B, 1C
*Intesar Terkawi	Staff	5A
*Simon O. Ojada	Staff	1A
*Debra N. Dobiac	Staff	4A
Rebuttal		
Jeffrey Swartz	DEF	1B, 1C

***** 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 2020 Fuel and Purchased Power Cost Recovery factors and Capacity Cost Recovery factors, including its prior period true-ups, are appropriate and reasonable and should be approved.

FPL's proposed 2020 Solar Project should be approved. The costs of the 2020 Solar Project are reasonable, and the Project is cost effective. The associated revenue requirement of $50.5 million and solar base rate adjustment ("SoBRA") factor of 0.732% were calculated in accordance with the terms approved in Order No. PSC-16-0560-AS-EI, and should therefore be approved here. The revised tariffs for FPL reflecting the requested base rate percentage increase for the 2020 SoBRA also were calculated in accordance with the terms approved in Order No. PSC-16-0560-AS-EI and should be approved. In addition, FPL's refund, including interest, of $6.7 million and base rate decrease of 0.045% associated with the true-up of the 2017 SoBRA should be approved.

Finally, the Joint Motion to Modify Order No. PSC-2012-0425-PAA-EU Regarding Weighted Average Cost of Capital Methodology is consistent with Internal Revenue Service requirements and should therefore be approved.

FPUC: The Commission should approve Florida Public Utilities Company's final net true-up for the period January through December, 2018, the estimated true-up for the period January through December, 2019, and the purchase power cost recovery factor for the period January through December, 2020.

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 2020 through December 2020 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 3.012 cents 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 2020; a GPIF reward of $4,141,330 for performance during 2018 and the company’s proposed GPIF targets and ranges for 2020.

OPC: The utilities have the burden of proof to justify and support the recovery of costs and their proposal(s) seeking the Commission's adoption of policy statements (whether new or changed) or other affirmative relief sought, regardless of whether the Interveners provide evidence to the contrary. Regardless of whether the Commission has previously approved a program as meeting the Commission’s requirements, the utilities must still meet their burden of demonstrating that the costs submitted for final recovery meet the statutory test(s) and are reasonable in amount and prudently incurred.

The OPC specifically contests the recovery of approximately $16.1 million in replacement power costs resulting from DEF’s imprudent actions and decisions in operating the Bartow Combined Cycle Unite steam Generator

FIPUG: Only reasonable and prudent costs legally authorized and reviewed for prudence 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.

PCS Phosphate: Florida electric utilities, including in particular Duke Energy Florida, Inc. (“DEF”), carry the burden of proving the reasonableness of any expenditures for which recovery or other relief is sought in this proceeding. In this case, PCS agrees with the Office of Public Counsel (“OPC”) that Duke has not demonstrated the reasonableness of replacement power costs associated with the outage and prolonged de-rating of its Bartow gas combined cycle unit.

In Docket No. 20180001-EI, Duke acknowledged that the differential between on and off-peak fuel factors has been shrinking. This softens the price signals intended to help control the growth in peak demands, which is a key FEECA[1] objective. In this docket, DEF presented an assessment of alternative approaches (i.e., maintaining its marginal cost-based calculation, performing a calculation based on average peak and off-peak fuel costs, and establishing a minimum peak/ off-peak pricing differential comparable to its Residential 1st tier rate)[2]. Duke proposes continuing the current use of marginal costs for TOU fuel factors. In brief, where the essential goal is to sustain or enhance price signals concerning peak period energy consumption, PCS agrees that an average cost-based approach is not suitable. Duke's presentation, however, does not adequately address the potential benefits of maintaining a threshold differential price signal as its generation fleet becomes heavily gas-fired and DEF continues to expect sustained retail peak load growth.[3]

Finally, PCS Phosphate is a signatory to the 2017 Second Revised and Restated Settlement Agreement, approved by the Commission in Docket No. 20170183, *Application for Limited Proceeding to Approve 2017 Second Revised and Restated Settlement Agreement* in Order No. PSC-2017-0451-AS-EU on November 20, 2017. That 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 that are consistent with that 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 stated herein.

VIII. ISSUES AND POSITIONS

I. FUEL ISSUES

Duke Energy Florida, LLC

ISSUE 1A: Should the Commission approve as prudent DEF's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in DEF's April 2019 and August 2019 hedging reports?

Proposed stipulation – see Section X.

---

[1] Florida Energy Efficiency and Conservation Act, F.S. § 366.82.
[2] Direct testimony of Christopher A. Menendez at 8-11 (Mar. 1, 2019).
[3] *See* Duke Energy Florida, LLC 2019 Ten Year Site Plan, schs. 3.1 and 3.2.

ISSUE 1B: **Was DEF prudent in its actions and decisions leading up to and in restoring the unit to service after the February 2017 forced outage at the Bartow plant and, if not, what action should the Commission take with respect to replacement power costs?**

POSITIONS:

DEF: Yes. DEF's actions leading up to, and in restoring the unit to service after, the Bartow outage were prudent. DEF operated the Bartow unit within the known operating parameters set by the Original Equipment Manufacturer, as further explained in the confidential testimony and exhibits of Mr. Jeff Swartz. DEF included the replacement power costs from the Bartow outage in the 2017 final true-up balance, filed on March 2, 2018 and consistent with the stipulation in Order No. PSC-2018-0610-FOF-EI, the 2019 fuel factors; no further Commission action is needed with respect to replacement power costs. (Swartz, Menendez, Garcia)

FPL: No position.

FPUC: No position.

Gulf: No position.

TECO: No position.

OPC: No. DEF was not prudent in its actions and decisions leading up to and restoring the unit to service after the February 2017 forced outage at the Bartow plant, and the Commission should reduce the requested fuel cost recovery by $11.1 million. This figure represents the replacement power costs incurred during the 2017 forced outage resulting from DEF's imprudent actions or decisions that resulted in the need for replacement power costs. The imprudent actions led to the need to install a pressure plate to allow the steam turbine to return to service without the damaged blades and resulted in a de-rating of the Bartow plant to approximately 380 MW resulting in an additional $5.01 million in replacement power costs as demonstrated by OPC witness Richard A. Polich. If DEF had been prudent in those actions or decisions, such replacement power costs would not have been necessary. Therefore, those costs should not be recovered from the ratepayers through the fuel cost recover clause.

FIPUG: No.

PCS Phosphate: Agree with OPC.

Staff: Staff has no position at this time.

<u>ISSUE 1C</u>: Has DEF made prudent adjustments, if any are needed, to account for replacement power costs associated with any impacts related to the de-rating of the Bartow plant? If adjustments are needed and have not been made, what adjustment(s) should be made?

<u>POSITIONS</u>:

DEF: No adjustments are needed. DEF's actions leading up to, and in restoring the unit to service after, the Bartow outage were prudent, therefore DEF should be permitted to recover its prudently incurred fuel and purchased power costs. Specifically, DEF does not agree that the Bartow Plant was "de-rated" as a result of the installation of the pressure plate. To the contrary, the pressure plate has ensured reliable operation of the plant until the long-term solution can be implemented. (Swartz, Menendez)

FPL: No position.

FPUC: No position.

Gulf: No position.

TECO: No position.

OPC: No. DEF was not prudent in its actions and decisions leading up to and restoring the unit to service after the February 2017 forced outage at the Bartow plant, and the Commission should reduce the requested fuel cost recovery by $11.1 million. This figure represents the replacement power costs incurred during the 2017 forced outage resulting from DEF's imprudent actions or decisions that resulted in the need for replacement power costs. The imprudent actions led to the need to install a pressure plate to allow the steam turbine to return to service without the damaged blades and resulted in a de-rating of the Bartow plant to approximately 380 MW resulting in an additional $5.01 million in replacement power costs as demonstrated by OPC witness Richard A. Polich. If DEF had been prudent in those actions or decisions, such replacement power costs would not have been necessary. Therefore, those costs should not be recovered from the ratepayers through the fuel cost recover clause.

FIPUG: No.

PCS Phosphate: Agree with OPC.

Staff: Staff has no position at this time.

Florida Power & Light Company

<u>ISSUE 2A</u>: **What is the appropriate revised SoBRA factor for the 2017 projects to reflect actual construction costs that are less than the projected costs used to develop the initial SoBRA factor?**

Proposed stipulation – see Section X.

<u>ISSUE 2B</u>: **What is the appropriate revised SoBRA factor for the 2018 projects to reflect actual construction costs that are less than the projected costs used to develop the initial SoBRA factor? (DEFERRED)**

Proposed stipulation – see Section X.

<u>ISSUE 2C</u>: **What is the appropriate_total gain under FPL's Incentive Mechanism approved by Order No. PSC-2016-0560-AS-EI that FPL may recover for the period January 2018 through December 2018, and how should that gain to be shared between FPL and customers?**

Proposed stipulation – see Section X.

<u>ISSUE 2D:</u> **What is the appropriate amount of Incremental Optimization Costs under FPL's Incentive Mechanism approved by Order No. PSC-2016-0560-AS-EI that FPL should be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2018 through December 2018?**

Proposed stipulation – see Section X.

<u>ISSUE 2E:</u> **What is the appropriate amount of Variable Power Plant O&M Attributable to Off-System Sales under FPL's Incentive Mechanism approved by Order No. PSC-2016-0560-AS-EI that FPL should be allowed to recover through the fuel clause for the period January 2018 through December 2018?**

Proposed stipulation – see Section X.

<u>ISSUE 2F:</u> **What is the appropriate amount of Variable Power Plant O&M Avoided due to Economy Purchases under FPL's Incentive Mechanism approved by**

Order No. PSC-2016-0560-AS-EI that FPL should be allowed to recover through the fuel clause for the period January 2018 through December 2018?

Proposed stipulation – see Section X.

ISSUE 2G: **If the Commission approves the FPL Solar Together Program and Tariff, what is the appropriate total FPL SolarTogether Credit amount to be recovered through the fuel cost recovery clause for the period January 2020 through December 2020?**

Proposed stipulation – see Section X.

ISSUE 2H: **Are the 2020 SoBRA projects (Hibiscus, Okeechobee, Southfork, and Echo River) proposed by FPL cost effective?**

POSITIONS:

DEF: No position.

FPL: Yes. The 2020 projects are projected to result in $26 million (CPVRR) of customer savings. (Enjamio, Brannen)

FPUC: No position.

Gulf: No position.

TECO: No position.

OPC: No position.

FIPUG: No.

PCS Phosphate: No position.

Staff: Staff has no position at this time.

ISSUE 2I: **What are the revenue requirements associated with the 2020 SoBRA projects?**

Proposed stipulation – see Section X.

ISSUE 2J: **What is the appropriate base rate percentage increase to be effective when all of the 2020 SoBRA projects are in service, currently projected to be May 1, 2020?**

Proposed stipulation – see Section X.

ISSUE 2K: **Should the Commission approve revised tariffs for FPL, reflecting the base rate percentage increase for the 2020 SoBRA projects, determined to be reasonable in this proceeding?**

Proposed stipulation – see Section X.

ISSUE 2L: **Has FPL made prudent adjustments, if any are needed, to account for replacement costs associated with the April 2019 forced outage at Saint Lucie Unit 1 generating station? If adjustments are needed and have not been made, what adjustment(s) should be made?**

Proposed stipulation – see Section X.

ISSUE 2M: **What is the appropriate base rate percentage decrease associated with the true-up of the 2017 SoBRA projects approved by Order No. PSC-2018-0028-FOF-EI to be effective January 1, 2020?**

Proposed stipulation – see Section X.

ISSUE 2N: **Should the Commission approve revised tariffs for FPL to be effective January 1, 2020, reflecting the base rate percentage decrease for the true-up of the 2017 SoBRA projects determined to be reasonable in this proceeding?**

Proposed stipulation – see Section X.

Florida Public Utilities Company

No company-specific fuel issues for Florida Public Utilities Company have been identified at this time. If such issues are identified, they shall be numbered 3A, 3B, 3C, and so forth, as appropriate.

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 2019 and August 2019 hedging reports?**

Proposed stipulation – see Section X.

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 2019 hedging report?**

Proposed stipulation – see Section X.

ISSUE 5B **What was the total gain under TECO's Optimization Mechanism approved by Order No. PSC-2017-0456-S-EI that TECO may recover for the period January 2018 through December 2018, and how should that gain be shared between TECO and customers?**

Proposed stipulation – see Section X.

GENERIC FUEL ADJUSTMENT ISSUES

ISSUE 6: **What are the appropriate actual benchmark levels for calendar year 2019 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 2020 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 2018 through December 2018?**

Proposed stipulation – see Section X.

ISSUE 9: **What are the appropriate fuel adjustment actual/estimated true-up amounts for the period January 2019 through December 2019?**

Proposed stipulation – see Section X.

ISSUE 10: **What are the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2020 through December 2020?**

Proposed stipulation – see Section X.

ISSUE 11: **What are the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2020 through December 2020?**

Proposed stipulation – see Section X.

COMPANY-SPECIFIC GENERATING PERFORMANCE INCENTIVE FACTOR (GPIF) ISSUES

Duke Energy Florida, LLC.

No company-specific GPIF issues for Duke Energy Florida, LLC 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

No company-specific GPIF issues for Florida Power & Light Company have been identified at this time. If such issues are identified, they shall be numbered 13A, 13B, 13C, and so forth, as appropriate.

Gulf Power Company

No company-specific GPIF 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 GPIF 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 GPIF ISSUES

ISSUE 16: **What is the appropriate generation performance incentive factor (GPIF) reward or penalty for performance achieved during the period January 2018 through December 2018 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 2020 through December 2020 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 2020 through December 2020?**

Proposed stipulation – see Section X.

ISSUE 19: **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 2020 through December 2020?**

Proposed stipulation – see Section X.

ISSUE 20: **What are the appropriate levelized fuel cost recovery factors for the period January 2020 through December 2020?**

Proposed stipulation – see Section X.

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?**

Proposed stipulation – see Section X.

ISSUE 22: **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. CAPACITY ISSUES

COMPANY-SPECIFIC CAPACITY COST RECOVERY FACTOR ISSUES

Duke Energy Florida, LLC

ISSUE 23A: **What amount has DEF included in the capacity cost recovery clause for nuclear cost recovery?**

Proposed stipulation – see Section X.

ISSUE 23B: What is the appropriate true-up adjustment amount associated with the Hamilton SoBRA project approved by Order No. PSC-2019-0159-FOF-EI to be refunded through the capacity clause in 2020?

Proposed stipulation – see Section X.

Florida Power & Light Company

ISSUE 24A: What amount has FPL included in the capacity cost recovery clause for nuclear cost recovery?

Proposed stipulation – see Section X.

ISSUE 24B: What is the appropriate true-up adjustment amount associated with the 2017 SOBRA projects approved by Order No. PSC-2018-0028-FOF-EI to be refunded through the capacity clause in 2020?

Proposed stipulation – see Section X.

ISSUE 24C: What is the appropriate_true-up amount associated with the 2018 SOBRA projects approved by Order No. PSC-2018-0028-FOF-EI to be refunded through the capacity clause in 2020? (Deferred)

Proposed stipulation – see Section X.

ISSUE 24D: What are the appropriate Indiantown non-fuel based 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 2020?

Proposed stipulation – see Section X.

Gulf Power Company

No company-specific capacity cost recovery factor 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 capacity cost recovery factor 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 2018 through December 2018?**

Proposed stipulation – see Section X.

ISSUE 28: **What are the appropriate capacity cost recovery actual/estimated true-up amounts for the period January 2019 through December 2019?**

Proposed stipulation – see Section X.

ISSUE 29: **What are the appropriate total capacity cost recovery true-up amounts to be collected/refunded during the period January 2020 through December 2020?**

Proposed stipulation – see Section X.

ISSUE 30: **What are the appropriate projected total capacity cost recovery amounts for the period January 2020 through December 2020?**

Proposed stipulation – see Section X.

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 2020 through December 2020?**

Proposed stipulation – see Section X.

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 2020 through December 2020?**

Proposed stipulation – see Section X.

ISSUE 33: **What are the appropriate capacity cost recovery factors for the period January 2020 through December 2020?**

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 reasonable in this proceeding?**

Proposed stipulation – see Section X.

IV. <u>MISCELLANEOUS ISSUES</u>

<u>ISSUE 36</u>: **Should the Joint Motion to Modify Order No. PSC-2012-0425-PAA-EU Regarding Weighted Average Cost of Capital Methodology be approved?**

Proposed stipulation – see Section X.

<u>ISSUE 37</u>: **Should this docket be closed?**

<u>POSITIONS</u>:

DEF: Yes. (Menendez)

FPL: No. While a separate docket number is assigned to each year for administrative convenience, this is a continuing docket and should remain open. (Deaton)

FPUC: Yes.

Gulf: No, this is a continuing docket and should remain open. (Boyett)

TECO: Yes.

OPC: No position at this time.

FIPUG: No position at this time.

PCS Phosphate: No position.

Staff: Staff has no position at this time.

IX. EXHIBIT LIST

Witness	Proffered By		Description
Direct			
Christopher A. Menendez	DEF	CAM-1T	Fuel Cost Recovery True-Up (Jan – Dec. 2018).
Christopher A. Menendez	DEF	CAM-2T	Capacity Cost Recovery True-Up (Jan – Dec. 2018). **CONFIDENTIAL DN. 01320-2019**
Christopher A. Menendez	DEF	CAM-3T	Schedule A12 for Jan-Dec 2018.
Christopher A. Menendez	DEF	CAM-4T	2018 Capital Structure and Cost Rates Applied to Capital Projects.
Christopher A. Menendez	DEF	CAM-2	Actual/Estimated True-up Schedules for period January – December 2019.
Christopher A. Menendez	DEF	CAM-3	Projection Factors for January - December 2020.
Jeffrey Swartz	DEF	(JS-1)[4]	Bartow Plant Root Cause Analysis. **CONFIDENTIAL DN. 02031-2018**

[4] Filed in Docket No. 20180001-EI, incorporated by reference in Mr. Jeffrey Swartz's Direct Testimony filed in this docket on March 2, 2019.

Witness	Proffered By		Description
Arnold Garcia	DEF	AG-1	Bartow CC Insurance Policy in effect on February 9, 2017. **CONFIDENTIAL DN. 01320-2019**
James McClay	DEF	JM-1T	Hedging True-Up August - December 2018. **CONFIDENTIAL DN. 03493-2019**
James McClay	DEF	JM-1P	Hedging Report (January – July 2019). **CONFIDENTIAL DN. 07514-2019**
James B. Daniel	DEF	JBD-1T	Calculation of GPIF Reward for January - December 2018.
James B. Daniel	DEF	JBD-1P	GPIF Targets/Ranges Schedules for January – December 2020).
R. B. Deaton	FPL	RBD-1	2018 FCR Final True Up Calculation.
R. B. Deaton	FPL	RBD-2	2018 CCR Final True Up Calculation. **CONFIDENTIAL DN. 01324-2019**
R. B. Deaton	FPL	RBD-3	2019 FCR Actual/Estimated True Up Calculation.

Witness	Proffered By		Description	
R. B. Deaton	FPL	RBD-4	2019 CCR Actual/Estimated True Up Calculation.	
R. B. Deaton	FPL	RBD-5 (Revised)	2018 FCR Final True Up Calculation.	
R. B. Deaton	FPL	RBD-6 (Revised)	2018 CCR Final True Up Calculation.	
R. B. Deaton	FPL	RBD-7	Appendix II 2020 FCR Projection (Jan-Apr).	
R. B. Deaton	FPL	RBD-8	Appendix III 2020 FCR Projection (May-Dec).	
R. B. Deaton	FPL	RBD-9	Appendix IV 2020 FCR Projection (Jan-Dec).	
R. B. Deaton	FPL	RBD-10	Appendix V 2020 CCR Projection (Jan-Dec). **CONFIDENTIAL DN. 08579-2019**	
G. J. Yupp	FPL	GJY-1	2018 Incentive Mechanism Results. **CONFIDENTIAL DN. 01324-2019**	
G. J. Yupp	FPL	GJY-2	Appendix I Fuel Cost Recovery.	FPL
C. R. Rote	FPL	CRR-1	Generating Performance Incentive Factor Performance Results for January 2018 through December 2018.	

Witness	Proffered By		Description
C. R. Rote	FPL	CRR-2	Generating Performance Incentive Factor Performance Targets for January 2020 through December 2020.
L. Fuentes	FPL	LF-1	2020 SoBRA Revenue Requirement Calculation.
L. Fuentes	FPL	LF-2	2017 SoBRA Final Revenue Requirement Calculation.
W. F. Brannen	FPL	WFB-1	List of FPL Universal PV Solar Energy Centers in Service.
W. F. Brannen	FPL	WFB-2	Typical Solar Energy Center Block Diagram.
W. F. Brannen	FPL	WFB-3	Renderings of 2020 Solar Energy Centers.
W. F. Brannen	FPL	WFB-4	Specifications for 2020 Solar Energy Centers.
W. F. Brannen	FPL	WFB-5	Property Delineations, Features and Land Use of 2020 Solar Energy Centers.
W. F. Brannen	FPL	WFB-6	Construction Schedule for 2020 Solar Energy Centers
J. E. Enjamio	FPL	JE-1	Load Forecast.
J. E. Enjamio	FPL	JE-2	FPL Fuel Price Forecast.

Witness	Proffered By		Description
J. E. Enjamio	FPL	JE-3	FPL Resource Plans.
J. E. Enjamio	FPL	JE-4	CPVRR – Costs and (Benefits).
E. J. Anderson	FPL	EJA-1	2020 SoBRA Factor Calculation.
E. J. Anderson	FPL	EJA-2	Projected Retail Base Revenues for May 1, 2020.
E. J. Anderson	FPL	EJA-3	Summary of Tariff Changes for May 1, 2020.
E. J. Anderson	FPL	EJA-4	Revised 2017 SoBRA Factor.
E. J. Anderson	FPL	EJA-5	2017 Project Refund Calculation.
E. J. Anderson	FPL	EJA-6	2017 SoBRA Prospective Adjustment for January 1, 2020.
E. J. Anderson	FPL	EJA-7	Projected Retail Base Revenues for January 1, 2020.
E. J. Anderson	FPL	EJA-8	Summary of Tariff Changes for January 1, 2020.
E. J. Anderson	FPL	EJA-9	Typical Bill Projections.
Curtis D. Young	FPUC	CDY-1 (Composite)	Final True Up Schedules (Schedules A, C1 and E1-B for FPUC's Divisions).

Witness	Proffered By		Description
Curtis D. Young	FPUC	CDY-2 (Composite)	Estimated/Actual (Schedules El-A, El-B, and El-B1).
Michelle Napier	FPUC	MDN-1 (Composite) (Revised)	Schedules E1, E1A, E2, E7, E8, E10 and Schedule A.
C.S. Boyett	Gulf	CSB-1	Calculation of Final True-Up January 2018 – December 2018.
C.S. Boyett	Gulf	CSB-2	A-Schedules December 2018.
C.S. Boyett	Gulf	CSB-3	Estimated True-Up January 2019 – December 2019.
C.S. Boyett	Gulf	CSB-4	Estimated PPCC Scherer/Flint Credit Calculation January 2019 – December 2019.
C.S. Boyett	Gulf	CSB-5	Projection January 2020 – December 2020.
C.S. Boyett	Gulf	CSB-6	Hedging Information Report August 2018 – December 2018.
C.S. Boyett	Gulf	CSB-7	Hedging Information Report January 2019– July 2019.

Witness	Proffered By		Description
C. L. Nicholson	Gulf	CLN-1	Gulf Power Company GPIF Results January 2018 – December 2018.
C. L. Nicholson	Gulf	CLN-2	Gulf Power Company GPIF Targets and Ranges January 2020 – December 2020.
Penelope A. Rusk	TECO	PAR-1	Final True-up Capacity Cost Recovery January 2018 - December 2018. Final True-up Fuel Cost Recovery January 2018-December 2018. Actual Fuel True-up Compared to Original Estimates January 2018 – December 2018. Schedules A-1, A-2 and A-6 through A-9 and A-12 January 2018 – December 2018. Capital Projects Approved for Fuel Clause Recovery January 2018 – December 2018.
Penelope A. Rusk	TECO	PAR-2	Actual/Estimated True-Up Fuel Cost Recovery January 2019 – December 2019. Actual/Estimated True-Up Fuel Capacity Cost Recovery January 2019-December 2019. Capital Projects Approved for Fuel Clause Recovery January 2019 – December 2019.

Witness	Proffered By		Description
Penelope A. Rusk	TECO	PAR-3	Projected Capacity Cost Recovery January 2020 – December 2020. Projected Fuel Cost Recovery January 2010 – December 2010. Levelized and Tiered Fuel Rate January 2020– December 2020. Capital Projects Approved for Fuel Clause Recovery January 2020 – December 2020.
Brian S. Buckley	TECO	BSB-1	Final True-Up Generating Performance Incentive Factor January 2018 – December 2018. Actual Unit Performance Data January 2018 – December 2018.
J. Brent Caldwell	TECO	JBC-1	Final True-Up Hedging Activity Report January 2018 – December 2018.
Jeremy B. Cain	TECO	JC-1	Generating Performance Incentive Factor January 2020 – December 2020. Summary of Generating Performance Incentive Factor Targets January 2020 – December 2020.
John C. Heisey	TECO	JCH-1	Optimization Mechanism Results January 2018 – December 2018
Richard A. Polich, P.E.	OPC	RAP-1	Resume.
Richard A. Polich, P.E.	OPC	RAP-2	Regulatory testimony list.

Witness	Proffered By		Description
Richard A. Polich, P.E.	OPC	RAP-3	Bartow Combined Cycle Thermal Cycle. **CONFIDENTIAL DN. 09202-2019, x-ref. 08773-2019**
Richard A. Polich, P.E.	OPC	RAP-4	Turbine generator output curve.
Richard A. Polich, P.E.	OPC	RAP-5	BCC ST Operation greater than 420 MW.
Richard A. Polich, P.E.	OPC	RAP-6	Bartow ST#1 LO blade upgrade to achieve 450 MW, dated Sept. 18, 2013. **CONFIDENTIAL DN. 09202-2019, x-ref. 08773-2019**
Richard A. Polich, P.E.	OPC	RAP-7	Bartow RCA review, dated March 15, 2017. **CONFIDENTIAL DN. 09202-2019, x-ref. 08773-2019**
Richard A. Polich, P.E.	OPC	RAP-8	Update on 40” last stage blade, dated 2015. **CONFIDENTIAL DN. 09202-2019, x-ref. 08773-2019**
Richard A. Polich, P.E.	OPC	RAP-9	Bartow combined cycle replacement power costs.
Intesar Terkawi	Staff	IT-1	Auditor’s Report Gulf Hedging Activities.

Witness	Proffered By		Description
Simon O. Ojada	Staff	SOO-1	Auditor's Report-TECO Hedging Activities.
Debra N. Dobiac	Staff	DMD-1	Auditor's Report DEF Hedging Activities.
Rebuttal			
Jeffrey Swartz	DEF	JS-2	Bartow Plant Root Cause Analysis. **CONFIDENTIAL DN. 09061-2019**
Jeffrey Swartz	DEF	JS-3	Bartow ST 40" Blade Test. **CONFIDENTIAL DN. 09061-2019**
Jeffrey Swartz	DEF	JS-4	Bartow RCA Summary. **CONFIDENTIAL DN. 09061-2019**

Parties and Commission 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:

I. FUEL ISSUES

ISSUE 1A: Should the Commission approve as prudent DEF's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in DEF's April 2019 and August 2019 hedging reports?

STIPULATION:

Yes, the Commission should approve as prudent DEF's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices that are reported in the August 2019 filing in Docket No. 20190001-EI. For the period reported in the April report, DEF's hedging activities resulted in a net savings of $588,460. For the period reported in the August report, DEF's hedging activities resulted in a net savings of $100,700, and the activities in these reports were pursuant to, and were consistent with, previously approved risk management plans. Pursuant to the 2017 RRSSA, DEF agreed not to enter into any additional hedges during the term of the Agreement.

ISSUE 2A: What is the appropriate revised SoBRA factor for the 2017 projects to reflect actual construction costs that are less than the projected costs used to develop the initial SoBRA factor?

STIPULATION:

The appropriate revised SoBRA factor for the 2017 projects is 0.888%, as reflected in Line E of Exhibit EJA-4, Page 1 of 1.

ISSUE 2B: What is the appropriate revised SoBRA factor for the 2018 projects to reflect actual construction costs that are less than the projected costs used to develop the initial SoBRA factor?

STIPULATION:

By agreement of the parties this matter will be addressed during the 2020 Fuel Clause cycle.

ISSUE 2C: What was the total gain under FPL's Incentive Mechanism approved by Order No. PSC-2016-0560-AS-EI that FPL may recover for the period January 2018 through December 2018, and how should that gain to be shared between FPL and customers?

STIPULATION:

The total gain under FPL's Incentive Mechanism approved by Order No. PSC-2016-0560-AS-EI that FPL may recover for the period January 2018 through December 2018 was $62,404,332, as reflected in Column 5 of Table 1, Total Gains Schedule, (Exhibit GJY-1, Page 1 of 4). This amount exceeded the sharing threshold of $40 million, and therefore the incremental gain above that amount should be shared between FPL and customers (60% and 40%, respectively), with FPL retaining $13,442,599, as reflected in Column 9 of Table 2, Total Gains Schedule (Exhibit GJY-1, Page 1 of 4).

ISSUE 2D: What is the appropriate amount of Incremental Optimization Costs under FPL's Incentive Mechanism approved by Order No. PSC-2016-0560-AS-EI that FPL should be allowed to recover through the fuel clause for Personnel,

Software, and Hardware costs for the period January 2018 through December 2018?

STIPULATION:

The appropriate amount of Incremental Optimization Costs under FPL's Incentive Mechanism approved by Order No. PSC-2016-0560-AS-EI that FPL should be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2018 through December 2018 is $516,451, as reflected in Columns 2 and 3 of the Incremental Optimization Costs Schedule (Exhibit GJY-1, Page 4 of 4).

ISSUE 2E: **What is the appropriate amount of Variable Power Plant O&M Attributable to Off-System Sales under FPL's Incentive Mechanism approved by Order No. PSC-2016-0560-AS-EI that FPL should be allowed to recover through the fuel clause for the period January 2018 through December 2018?**

STIPULATION:

The appropriate amount of Variable Power Plant O&M Attributable to Off-System Sales under FPL's Incentive Mechanism approved by Order No. PSC-2016-0560-AS-EI that FPL should be allowed to recover through the fuel clause for the period January 2018 through December 2018 is $1,611,119, as reflected in Column 6 of the Incremental Optimization Costs Schedule (Exhibit GJY-1, Page 4 of 4).

ISSUE 2F: **What is the appropriate amount of Variable Power Plant O&M Avoided due to Economy Purchases under FPL's Incentive Mechanism approved by Order No. PSC-2016-0560-AS-EI that FPL should be allowed to recover through the fuel clause for the period January 2018 through December 2018?**

STIPULATION:

The appropriate amount of Variable Power Plant O&M Avoided due to Economy Purchases under FPL's Incentive Mechanism approved by Order No. PSC-2016-0560-AS-EI that FPL should be allowed to recover through the fuel clause for the period January 2018 through December 2018 is ($151,215), as reflected in Column 7 of the Incremental Optimization Costs Schedule (Exhibit GJY-1, Page 4 of 4).

ISSUE 2G: **If the Commission approves the FPL SolarTogether Program and Tariff, what is the appropriate total FPL SolarTogether Credit amount to be recovered through the fuel cost recovery clause for the period January 2020 through December 2020?**

STIPULATION:

$0. Removal of the FPL SolarTogether Program costs from the cost recovery factors for 2020 is appropriate until a decision is made in FPL's SolarTogether Program docket (Docket No. 20190061-EI), for which the hearing is currently scheduled to begin on January 14, 2020. If the Program is approved, the actual FPL SolarTogether Credit amount for the 2020 calendar year will be reflected in FPL's True-Up filing to be submitted in 2021.

ISSUE 2H: Are the 2020 SoBRA projects (Hibiscus, Okeechobee, Southfork, and Echo River) proposed by FPL cost effective?

STIPULATION:

Yes.

ISSUE 2I: What are the revenue requirements associated with the 2020 SoBRA projects?

STIPULATION:

The appropriate revenue requirements associated with the 2020 SoBRA projects is $50,491,000, as reflected on Line 7 of the 2020 SoBRA Revenue Requirement Calculation Schedule (Exhibit LF-1, Page 1 of 5).

ISSUE 2J: What is the appropriate base rate percentage increase to be effective when all of the 2020 SoBRA projects are in service, currently projected to be May 1, 2020?

STIPULATION:

The appropriate base rate percentage increase to be effective when all of the 2020 SoBRA projects are in service, currently projected to be May 1, 2020, is 0.732%, as reflected on Line C of the 2020 SoBRA Factor Calculation Schedule (Exhibit EJA-1, Page 1 of 1).

ISSUE 2K: Should the Commission approve revised tariffs for FPL reflecting the base rate percentage increase for the 2020 SoBRA projects determined to be appropriate in this proceeding?

STIPULATION:

Yes.

ISSUE 2L: Has the Commission made prudent adjustments, if any are needed, to account for replacement power costs associated with the April 2019 forced outage at Saint Lucie Unit 1 generating station? If adjustments are needed and have not been made, what adjustment(s) should be made?

STIPULATION:

The parties have agreed to defer this issue to the 2020 Fuel Cost Recovery Clause docket. It is understood that any amounts associated with the April 2019 St. Lucie outage included in this docket are subject to true-up in the subsequent proceeding in which this issue is heard and that no presumption of prudence attaches.

ISSUE 2M: What is the appropriate base rate percentage decrease associated with the true-up of the 2017 SoBRA?

STIPULATION:

The appropriate base rate percentage decrease associated with the true-up of the 2017 SoBRA is 0.045%, as reflected on Line C of the 2017 SoBRA Prospective Adjustment Schedule (Exhibit EJA-6, Page 1 of 1).

ISSUE 2N: Should the Commission approve revised tariffs for FPL reflecting the base rate percentage decrease for the true-up of the 2017 SoBRA projects determined to be reasonable in this proceeding?

STIPULATION:

Yes.

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 2019 and August 2019 hedging reports?

STIPULATION:

Yes, the Commission should approve as prudent Gulf's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices that are reported in April 2019 and August 2019 filings in Docket No. 20190001-EI. For the period reported in the April report, Gulf's hedging activities resulted in a net cost of $3,049,820. For the period reported in the August report, Gulf's hedging activities resulted in a net cost of $3,629,330. and the activities in these reports were pursuant to, and were consistent with, previously approved risk management plans. Pursuant to the 2017 Stipulation and Settlement Agreement, Gulf agreed not to enter into any additional hedges during the term of the Agreement.

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 2019 and August 2019 hedging reports?

STIPULATION:

Yes, the Commission should approve as prudent TECO's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices that are reported in the April 2019 filing in Docket No. 20190001-EI. For the period August 1, 2018 through November 30, 2018, TECO's hedging activities resulted in a net gain of $106,110, and these activities were pursuant to, and were consistent with, previously approved risk management plans. Pursuant to the 2017 Amended and Restated Stipulation and Settlement Agreement, TECO agreed not to enter into any additional hedges through December 31, 2022. TECO did not file an August 2019 hedging report.

ISSUE 5B: What was the total gain under TECO's Optimization Mechanism approved by Order No. PSC-2017-0456-S-EI that TECO may recover for the period January 2018 through December 2018, and how should that gain to be shared between TECO and customers?

STIPULATION:

The total gain under TECO's Optimization Mechanism approved by Order No. PSC-2017-0456-S-EI for the period January 2018 through December 2018 was $6,367,256, as reflected in Column 5 of Table 1, Total Gains Threshold Schedule (Exhibit JCH-1, Page 1 of 3). This amount should be shared between TECO and customers (60% and 40%, respectively), with TECO customers receiving $5,246,902, and TECO retaining $1,120,353, as reflected in Columns 7 and 8 of Table 2, Total Gains Threshold Schedule (Exhibit JCH-1, Page 1 of 3).

ISSUE 6: What are the appropriate actual benchmark levels for calendar year 2019 for gains on non-separated wholesale energy sales eligible for a shareholder incentive?

STIPULATION:

The appropriate actual benchmark levels for calendar year 2019 for gains on non-separated wholesale energy sales eligible for a shareholder incentive are as follows:

DEF: $1,333,709.

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 2019 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: $1,092,804.

TECO: The Company did not set a benchmark level for calendar year 2019. Pursuant to the Stipulation and Settlement that was approved in Order No. PSC-2017-0456-S-EI, the Company's Optimization Mechanism replaces the incentive program that used benchmark levels for gains on non-separated wholesale energy sales eligible for a shareholder incentive.

ISSUE 7: **What are the appropriate estimated benchmark levels for calendar year 2020 for gains on non-separated wholesale energy sales eligible for a shareholder incentive?**

STIPULATION:

The appropriate estimated benchmark levels for calendar year 2020 for gains on non-separated wholesale energy sales eligible for a shareholder incentive are as follows:

DEF: $1,604,573.

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 2020 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: $900,572.

TECO: The Company did not set an estimated benchmark level for calendar year 2020. Pursuant to the Stipulation and Settlement that was approved in Order No. PSC-2017-0456-S-EI, the Company's Optimization Mechanism replaces the incentive program that used benchmark levels for gains on non-separated wholesale energy sales eligible for a shareholder incentive.

ISSUE 8: **What are the appropriate final fuel adjustment true-up amounts for the period January 2018 through December 2018?**

STIPULATION:

The appropriate final fuel adjustment true-up amounts for the period January 2018 through December 2018 are as follows:

DEF: $54,428,676, under-recovery, as reflected on Line 13 of the Summary of Actual True-Up Amount Schedule (Exhibit CAM-1T, Sheet 1 of 6).

FPL: $70,653,405, under-recovery, as reflected on Line 41 of Schedule E1b, (2019 FCR Actual/Estimated True-up, Exhibit RBD-3, Page 1 of 27).

FPUC: $2,475,441, over-recovery, as reflected on Line 10 of Schedule A (Exhibit CDY-1, Page 1 of 3).

Gulf: $4,512,071, over-recovery, as reflected on Line 3, Schedule 1, 2018 Final True-Up Schedules (Exhibit CSB-1, Page 1 of 8).

TECO: $43,986,397, under-recovery, as reflected on Line 11, Final Fuel and Purchased Power Over/(Under) Recovery Schedule (Exhibit PAR-1, Document No.2, Page 1 of 1).

ISSUE 9: **What are the appropriate fuel adjustment actual/estimated true-up amounts for the period January 2019 through December 2019?**

STIPULATION:

The appropriate fuel adjustment actual/estimated true-up amounts for the period January 2019 through December 2019 are as follows:

DEF: $39,965,991 over-recovery as reflected on Line 8 of Schedule E1-B (Exhibit CAM-2, Part 1, Page 2 of 2).

FPL: $128,735,937 over-recovery as reflected on Lines 38 plus 39 of Schedule E1-B (2019 FCR Actual Estimated, Exhibit RBD-3, Page 1 of 27).

FPUC: $4,409,893 under-recovery as reflected on Lines 83 and 84 of Schedule E-1b (Exhibit CDY-2, Page 2 of 3).

Gulf: $5,178,904, under-recovery, as reflected on Line C9 of Schedule E-1B (Exhibit CSB-3, Page 2 of 32).

TECO: $13,244,371, over-recovery as reflected on Schedule E1-A, Line 4 (Exhibit PAR-2, Document No. 1, Page 2 of 31).

ISSUE 10: What are the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2020 through December 2020?

STIPULATION:

The appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2020 through December 2020 are as follows:

DEF: $14,462,684 under-recovery as reflected on Line 13 of Schedule E1-B (Exhibit CAM-2, Part 1, Page 2 of 2).

FPL: $58,082,532 over-recovery as reflected on Line 43 of Schedule E1-B (2019 FCR Actual Estimated, Exhibit RBD-3, Page 1 of 27).

FPUC: $1,934,452 under-recovery as reflected Line 88 of Schedule E-1b (Exhibit CDY-2, Page 2 of 3).

Gulf: $666,833, under-recovery, as reflected on Line 22, Schedule E-1 (Exhibit CSB-5, 2020 Projection Filing, Page 1 of 41).

TECO: $30,742,026, under-recovery as reflected on Line 6, Schedule E1-A (Exhibit PAR-2, Document No. 1, Page 2 of 31).

ISSUE 11: What are the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2020 through December 2020?

STIPULATION:

The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2020 through December 2020 are as follows:

DEF: $1,303,329,632. which is adjusted for line losses and excludes prior period true-up amounts, revenue taxes and GPIF amounts, as reflected on Line 21 of Schedule E1. This amount is subject to possible adjustments ordered in Issues 1B and C. If any adjustments are ordered by the Commission in relation to Issues 1B and 1C, that amount will be reflected in Duke’s 2020 filing that reports the final true up of fuel costs for the period January through December, 2019.

FPL: $2,488,782,409, which is adjusted for jurisdictional losses, and includes the jurisdictional savings amount associated with the 2020 solar Project, but excludes prior period true-up amounts, revenue taxes, GPIF amounts, and FPL’s portion of

Incentive Mechanism gains, as reflected on Line 28 of Schedule E1 (Discovery Response Version of 2020 FCR Projection Schedule, Page FCR-19-029127).

FPUC: $42,849,420, as reflected on Line 27, Schedule E1 (Revised Exhibit MDN-1, Page 1 of 8).

Gulf: $354,335,230, which is adjusted for line losses, but excluding prior period true-up amounts, revenue taxes and GPIF amounts, as reflected on Line 21, Schedule E1 (Exhibit CSB-5, 2020 Projection Filing, Page 1 of 41).

TECO: $582,744,972, which is adjusted for jurisdictional separation, the results of the optimization program, and prior period true-up amounts, but excludes revenue taxes and GPIF amounts, as reflected on Line 30, Schedule E1 (Exhibit PAR-3, Document No. 2, Page 2 of 30).

GENERIC GPIF ISSUES

ISSUE 16: **What is the appropriate generation performance incentive factor (GPIF) reward or penalty for performance achieved during the period January 2018 through December 2018 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 2018 through December 2018 for each investor-owned electric utility subject to the GPIF is as follows:

DEF: $2,591,697, reward, as reflected on Original Sheet No. 6.101.1, GPIF Reward/Penalty Table (Exhibit JBD, Page 2 of 24).

FPL: $8,577,071 reward, as reflected in Reward/Penalty Table (Actual) For the Period January through December, 2018 (Exhibit CRR-1, Page 2 of 20).

Gulf: $10,384, reward, as reflected in GPIF 2018 Results Filing (Exhibit CLN-1, Page 28 of 51, Schedule 4, Page 2 of 2).

TECO: $4,141,330 reward, as reflected GPIF Reward/Penalty Table (Exhibit BSB-1, Document No. 1, Page 2 of 32).

ISSUE 17: **What should the GPIF targets/ranges be for the period January 2020 through December 2020 for each investor-owned electric utility subject to the GPIF?**

STIPULATION:

The appropriate GPIF targets/ranges be for the period January 2020 through December 2020 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:

Table 17-1
GPIF Targets/Ranges for the period January-December, 2020

	Plant/Unit	EAF			ANOHR		
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings ($000's)	ANOHR BTU/KWH	ANOHR BTU/KWH	Savings ($000's)
DEF	Bartow 4	88.20	92.74	1,617	7,892	8,289	6,774
	Hines 1	87.02	89.01	160	7,261	7,600	2,659
	Hines 2	90.32	91.15	25	7,410	7,660	1,937
	Hines 3	93.73	94.89	159	7,266	7,514	2,089
	Hines 4	83.95	87.02	866	6,982	7,162	1,611
	Osprey 1	88.14	91.02	521	7,291	7,866	3,517
	Total			3,348			18,586

Source: GPIF Target and Range Summary (Exhibit JBD-1P, Page 4 of 67).

FPL: See Table 17-2 below:

Table 17-2
GPIF Targets/Ranges for the period January-December, 2020

	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	83.4	85.9	469	6,615	6,737	2,376
	Manatee 3	91.3	93.8	158	6,880	7,002	1,264
	Ft. Myers 2	90.1	92.6	232	7,342	7,455	2,277
	Port Everglades 5	81.8	84.8	822	6,525	6,695	3,847
	Riviera 5	84.7	87.2	446	6,567	6,684	2,389
	St. Lucie 1	87.4	90.9	3,728	10,421	10,525	413

FPL	Plant/Unit	EAF			ANOHR		
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings ($000's)	ANOHR BTU/KWH	ANOHR BTU/KWH	Savings ($000's)
	St. Lucie 2	85.7	88.7	2,576	10,262	10,355	278
	Turkey Point 3	85.7	88.7	2,403	11,228	11,418	661
	Turkey Point 4	82.7	85.7	2,250	10,865	11,035	561
	West County 1	68.5	71.0	496	7,060	7,218	2,532
	West County 2	90.2	92.7	614	6,918	7,064	3,126
	West County 3	85.3	88.3	608	6,921	7,084	3,274
	Total			14,802			22,998

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

Gulf: See Table 17-3 below:

Table 17-3
GPIF Targets/Ranges for the period January-December, 2020

GULF	Plant/Unit	EAF			ANOHR		
		Target	Maximum		Target	Minimum	Maximum
		EAF (%)	EAF (%)	Savings ($000's)	ANOHR BTU/KWH	ANOHR BTU/KWH	Savings ($000's)
	Scherer 3	96.8	97.8	23	10,616	10,298	1,211
	Crist 7	78.4	80.9	4	10,584	10,266	365
	Daniel 1	70.9	73.8	1	11,404	11,062	64
	Daniel 2	84.7	86.5	3	11,057	10,725	164
	Smith 3	89.9	90.8	66	6,900	6,693	3,011
	Total			97			4,815

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

TECO: See Table 17-4 below:

Table 17-4
GPIF Targets/Ranges for the period January-December, 2020

	Plant/Unit	Target EAF (%)	Maximum EAF (%)	Maximum Savings ($000's)	Target ANOHR BTU/KWH	Maximum ANOHR BTU/KWH	Maximum Savings ($000's)
TECO	Big Bend 4	55.4	61.0	301.8	10,837	11,264	956.4
	Polk 1	75.5	79.1	680.0	10,018	11,429	2,408.6
	Polk 2	84.9	86.1	1,477.8	7,209	7,603	7,768.2
	Bayside 1	91.7	92.4	1,216.3	7,379	7,498	1,649.5
	Bayside 2	88.9	90.1	1,811.8	7,499	7,749	3,332.3
	Total			5487.7			16,115.0

Source: GPIF Target and Range Summary (Exhibit JC-1, Document 1, Page 4 of 31).

FUEL FACTOR CALCULATION ISSUES

<u>**ISSUE 18**</u>: **What are the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2020 through December 2020?**

<u>**STIPULATION**</u>:

The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2020 through December 2020 are as follows:

DEF: **$**1,321,332,823 as reflected on Line 27 of Schedule E1. This amount is subject to possible adjustments ordered in Issues 1B and C. If any adjustments are ordered by the Commission in relation to Issues 1B and 1C, that amount will be reflected in Duke’s 2020 filing that reports the final true up of fuel costs for the period January through December, 2019.

FPL: $2,453,813,512, which includes prior period true-up amounts, revenue taxes, the GPIF reward, FPL’s portion of Incentive Mechanism gains, and the jurisdictional savings amount associated with the 2020 solar Project, as reflected on Line 35 of Schedule E1 (Discovery Response Version of 2020 FCR Projection Schedule, Page FCR-19-029127).

FPUC: $44,783,872 which includes prior period true-up amounts, as reflected on Line 31, Schedule E1 (Revised Exhibit MDN-1, Page 1 of 8).

Gulf: $355,268,048 which is adjusted for line losses, and includes prior period true-up amounts, revenue taxes and GPIF amounts, as reflected on Line 28, Schedule E1 (Exhibit CSB-5, 2020 Projection Filing, Page 1 of 41).

TECO: $587,305,878 which is adjusted for jurisdictional separation, and includes prior period true-up amounts, revenue taxes, and GPIF amounts and optimization mechanism, as reflected on Line 33, Schedule E1 (Exhibit PAR-3, Document No. 2, Page 2 of 30).

ISSUE 19: 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 2020 through December 2020?

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 2020 through December 2020 is 1.00072.

ISSUE 20: **What are the appropriate levelized fuel cost recovery factors for the period January 2020 through December 2020?**

STIPULATION:

The appropriate levelized fuel cost recovery factors for the period January 2020 through December 2020 are as follows:

DEF: The appropriate levelized factor is 3.345 cents per kWh (adjusted for jurisdictional losses), as reflected on Line 6, Schedule E1-D (Exhibit CAM-3, Part 2, Page 1 of 1).

FPL: The appropriate levelized factors are as follows:

A. 2.224 cents per kWh (adjusted for jurisdictional losses), for January 2020 through the day prior to the 2020 Project in-service date (projected to be April 30, 2020), as reflected on Line 37 of Schedule E1 (Discovery Response Version of 2020 FCR Projection Schedule, Page FCR-19-029115).

B. 2.211 cents per kWh (adjusted for jurisdictional losses), from the 2020 Project in-service date (projected to be May 1, 2020) until the fuel factor is reset by the Commission, as reflected on Line 38 of Schedule E1 (Discovery Response Version of 2020 FCR Projection Schedule, Page FCR-19-029121).

FPUC: The appropriate levelized factor is 5.109 cents per kWh, as reflected on Line 43, Schedule E1 (Revised Exhibit MDN-1, Page 2 of 8).

Gulf: The appropriate levelized factor is 3.244 per kWh, as reflected on Line 31, Schedule E-1 (Exhibit CSB-5, 2020 Projection Filing, Page 1 of 41).

TECO: The appropriate factor is 3.012 cents per kWh before any application of time of use multipliers for on-peak or off-peak usage, as reflected on Line 34, Schedule E1 (Exhibit PAR-3, Document No. 2, Page 2 of 30).

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, 2020

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 Testimony, dated September 3, 2019 (Page 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, as reflected on Line 26a, Schedule E1 (Revised Exhibit MDN-1, Page 1 of 8).

Gulf: See Table 21-2 below:

Table 21-2
GULF Fuel Recovery Line Loss Multipliers
for the period January-December, 2020

Group	Rate Schedules	Fuel Recovery Loss Multipliers
A	RS, RSVP, RSTOU, GS, GSD, GSDT, GSTOU, OSIII, SBS(1)	1.00555
B	LP, LPT, SBS(2)	0.99188
C	PX, PXT, RTP, SBS(3)	0.97668
D	OSI/II	1.00560
(1) Includes SBS customers with a contract demand in the range of 100 to 499 kW (2) Includes SBS customers with a contract demand in the range of 500 to 7,499 kW (3) Includes SBS customers with a contract demand over 7,499 kW		

Source: Schedule E1-E (Exhibit CSB-5, 2020 Projection Filing, Page 8 of 41).

TECO: See Table 21-3 below**:**

Table 21-3
TECO Fuel Recovery Line Loss Multipliers
for the period January-December, 2020

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

Source: Schedule E1-D, BSP 23 (Exhibit PAR-3, Document Number 2, Page 6 of 30).

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 22-8 below:

DEF: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses for the period January 2020 through December

2020, are shown Table 22-1 below. DEF agrees in its next base rate case to consult with PCS Phosphate concerning DEF's on and off peak rate design.

Table 22-1
Fuel Cost Recovery Factors for the period January-December, 2020

Fuel Cost Recovery Factors For the Period January-December, 2020						
Group	Delivery Voltage Level	Fuel Cost Recovery Factors (cents/kWh)			Time of Use	
		First Tier	Second Tier	Levelized	On-Peak Multiplier 1.286	Off-Peak Multiplier 0.872
A	Transmission	--	--	3.350	4.308	2.921
B	Distribution Primary	--	--	3.317	4.266	2.892
C	Distribution Secondary	3.067	4.067	3.283	4.222	2.863
D	Lighting Service	--	--	3.181	--	--

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

FPL: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown below in Tables 22-2 through 22-5. The factors for January and April, 2020 are shown in Tables 22-2 and 22-3, and the factors for May through December, 2020 are shown in Tables 22-4 and 22-5:

Table 22-2
FPL Fuel Cost Recovery Factors for the period January-April, 2020

Fuel Recovery Factors – By Rate Group (Adjusted for Line Losses)				
For the Period January through April, 2020				
Group	Rate Schedule	Avg. Factor	Loss Multiplier	Fuel Recovery Factor
A	RS-1 first 1,000 kWh	2.224	1.00212	1.897
	RS-1, all addl. kWh	2.224	1.00212	2.897
	GS-1, SL-2, GSCU-1, WIES-1	2.224	1.00212	2.229
A-1	SL-1, OL-1, PL-1	2.158	1.00212	2.163
B	GSD-1	2.224	1.00207	2.229
C	GSLD-1, CS-1	2.224	1.00157	2.227
D	GSLD-2, CS-2, OS-2, MET	2.224	0.99555	2.214
E	GSLD-3, CS-3	2.224	0.97529	2.169
A	GST-1 On-Peak	2.555	1.00212	2.560
	GST-1 Off Peak	2.082	1.00212	2.086
	RTR-1 On-Peak	-	-	0.331
	RTR-1 Off-Peak	-	-	(0.143)

B	GSLDT-1, CILC-1(G), HLFT-1 (21-499 kW) On Peak	2.555	1.00207	2.560
	GSLDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off Peak	2.082	1.00207	2.086
C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On Peak	2.555	1.00157	2.559
	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off Peak	2.082	1.00157	2.085
D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On Peak	2.555	0.99588	2.544
	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off Peak	2.082	0.99588	2.073
E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On Peak	2.555	0.97529	2.492
	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off Peak	2.082	0.97529	2.031
F	CILC-1(D), ISST-1(D) On Peak	2.555	0.99566	2.544
	CILC-1(D), ISST-1(D) Off Peak	2.082	0.99566	2.073

Source: Schedule E1-E, Page 1 of 2 (Discovery Response Version of 2020 FCR Projection Schedule, Page FCR-19-029116).

Table 22-3
FPL Fuel Cost Recovery Factors for the period January- April, 2020

Seasonal Demand Time of Use Rider (SDTR) Fuel Recovery Factors				
For the Period June through September, 2020				
Group	Rate Schedule	Avg. Factor	Loss Multiplier	Fuel Recovery Factor
B	GSD(T)-1 On-Peak	3.051	1.00207	3.057
	GSD(T)-1 Off-Peak	2.115	1.00207	2.119
C	GSLD(T)-1 On-Peak	3.051	1.00157	3.056
	GSLD(T)-1 Off-Peak	2.115	1.00157	2.118
D	GSLD(T)-2 On-Peak	3.051	0.99588	3.038
	GSLD(T)-2 Off-Peak	2.115	0.99588	2.106

Source: Schedule E1- E, Page 2 of 2 (Discovery Response Version of 2020 FCR Projection Schedule, Page FCR-19-029117).

Table 22-4
FPL Fuel Cost Recovery Factors for the period May through December, 2020

Fuel Recovery Factors – By Rate Group (Adjusted for Line Losses)				
For the Period May through December, 2020				
Group	Rate Schedule	Avg. Factor	Loss Multiplier	Fuel Recovery Factor
A	RS-1 first 1,000 kWh	2.211	1.00212	1.884
	RS-1, all addl. kWh	2.211	1.00212	2.884
	GS-1, SL-2, GSCU-1, WIES-1	2.211	1.00212	2.216
A-1	SL-1, OL-1, PL-1	2.144	1.00212	2.149
B	GSD-1	2.211	1.00207	2.216
C	GSLD-1, CS-1	2.211	1.00157	2.214
D	GSLD-2, CS-2, OS-2, MET	2.211	0.99555	2.201
E	GSLD-3, CS-3	2.211	0.97529	2.156
A	GST-1 On-Peak	2.540	1.00212	2.545
	GST-1 Off Peak	2.069	1.00212	2.073
	RTR-1 On-Peak	-	-	0.329
	RTR-1 Off-Peak	-	-	(0.143)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On Peak	2.540	1.00207	2.545
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off Peak	2.069	1.00207	2.073
C	GSLDT-1, CST-1, HLFT-2 (500-1,9999 kW) On Peak	2.540	1.00157	2.544
	GSLDT-1, CST-1, HLFT-2 (500-1,9999 kW) Off Peak	2.069	1.00157	2.072
D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On Peak	2.540	0.99588	2.530
	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off Peak	2.069	0.99588	2.060
E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On Peak	2.540	0.97529	2.477
	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off Peak	2.069	0.97529	2.018
F	CILC-1(D), ISST-1(D) On Peak	2.540	0.99566	2.529
	CILC-1(D), ISST-1(D) Off Peak	2.069	0.99566	2.060

Source: Schedule E1-E, Page 1 of 2 (Discovery Response Version of 2020 FCR Projection Schedule, Page FCR-19-029122).

Table 22-5
FPL Fuel Cost Recovery Factors for the period May through December, 2020

Seasonal Demand Time of Use Rider (SDTR) Fuel Recovery Factors				
For the Period June through September, 2020				
Group	Rate Schedule	Avg. Factor	Loss Multiplier	Fuel Recovery Factor
B	GSD(T)-1 On-Peak	3.033	1.00207	3.039
	GSD(T)-1 Off-Peak	2.103	1.00207	2.107
C	GSLD(T)-1 On-Peak	3.033	1.00157	3.038
	GSLD(T)-1 Off-Peak	2.103	1.00157	2.106
D	GSLD(T)-2 On-Peak	3.033	0.99588	3.021
	GSLD(T)-2 Off-Peak	2.103	0.99588	2.094

Source: Schedule E1- E, Page 2 of 2 (Discovery Response Version of 2020 FCR Projection Schedule, Page FCR-19-029123).

FPUC: The appropriate levelized fuel adjustment and purchased power cost recovery factors for the period January 2020 through December 2020 for the Consolidated Electric Division, adjusted for line loss multipliers and including taxes, are shown in Tables 22-8 through 22-10 below:

Table 22-8
FPUC Fuel Cost Recovery Factors for the period January-December, 2020

Fuel Recovery Factors – By Rate Schedule	
For the Period January through December, 2020	
Rate Schedule	Levelized Adjustment (cents/kWh)
RS	7.766
GS	7.535
GSD	7.228
GSLD	7.009
LS	5.621

Source: Schedule E1, Page 3 of 3 (Revised Exhibit MDN-1, Cost Recovery Clause Calculation, Page 3 of 8).

Table 22-9
FPUC Fuel Cost Recovery Factors for the period January-December, 2020

Step Rate Allocation For Residential Customers (RS Rate Schedule)	
For the Period January through December, 2020	
Rate Schedule and Allocation	Levelized Adjustment (cents/kWh)
RS Rate Schedule – Sales Allocation	7.766
RS Rate Schedule with less than or equal to 1,000 kWh/month	7.459
RS Rate Schedule with more than 1,000 kWh/month	8.709

Source: Schedule E1, Page 3 of 3 (Revised Exhibit MDN-1, Cost Recovery Clause Calculation, Page 3 of 8).

Table 22-10
FPUC Fuel Cost Recovery Factors for the period January-December, 2020

Fuel Recovery Factors for Time Of Use – By Rate Schedule		
For the Period January through December, 2020		
Rate Schedule	Levelized Adjustment On Peak (cents/kWh)	Levelized Adjustment Off Peak (cents/kWh)
RS	15.859	3.559
GS	11.535	2.535
GSD	11.228	3.978
GSLD	13.009	4.009
Interruptible	5.509	7.009

Source: Schedule E1, Page 3 of 3 (Revised Exhibit MDN-1, Cost Recovery Clause Calculation, Page 3 of 8).

Gulf: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses for the period January 2020 through December 2020, are shown in Tables 22-11 and 22-12 below:

Table 22-11
Gulf Standard Fuel Cost Recovery Factors
for the period January-December, 2020

Group	Rate Schedules	Fuel Cost Recovery Factors ¢/KWH
A	RS, RSVP, RSTOU, GS, GSD, GSDT, GSTOU, OSIII	3.262
B	LP	3.218
C	PX, RTP	3.168
D	OSI/II	3.236

Source: Schedule E1-E (Exhibit CSB-5, 2020 Projection Filing, Page 7 of 41).

Table 22-12
Gulf Time-of-Use Fuel Cost Recovery Factors
for the period January-December, 2020

Group	Time-of-Use Rate Schedules	Fuel Recovery Loss Multipliers	Fuel Cost Recovery Factors ¢/KWH	
			On-Peak	Off-Peak
A	GSDT, SBS(1)	1.00555	3.762	3.059
B	LPT, SBS(2)	0.99188	3.711	3.017
C	PXT, SBS(3)	0.97668	3.654	2.971

(1) Includes SBS customers with a contract demand in the range of 100 to 499 kW
(2) Includes SBS customers with a contract demand in the range of 500 to 7,499 kW
(3) Includes SBS customers with a contract demand over 7,499 kW

Source: Schedule E1-E (Exhibit CSB-5, 2020 Projection Filing, Page 8 of 41).

TECO: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses for the period January 2020 through December 2020, are shown in Table 22-13 below:

Table 22-13
TECO Fuel Cost Recovery Factors for the period January-December, 2020

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)	--	2.702	3.702
	Distribution Secondary	3.016		
	Distribution Primary	2.986		
	Transmission	2.956		
	Lighting Service	2.989		
TIME OF USE				
	Distribution Secondary- On-Peak	3.162		
	Distribution Secondary- Off-Peak	2.953		
	Distribution Primary- On-Peak	3.130		
	Distribution Primary- Off-Peak	2.923		
	Transmission – On-Peak	3.099		
	Transmission – Off-Peak	2.894		

Source: Schedule E1-E, Bates Stamped Page 23 (Exhibit PAR-3, Document Number 2, Page 6 of 30).

II. CAPACITY ISSUES

COMPANY-SPECIFIC CAPACITY COST RECOVERY FACTOR ISSUES

Duke Energy Florida, LLC

ISSUE 23A: What amount has DEF included in the capacity cost recovery clause for nuclear cost recovery?

STIPULATION:

Duke has included $0 in the capacity cost recovery clause for nuclear cost recovery.

ISSUE 23B: What is the appropriate true-up adjustment amount associated with the Hamilton SoBRA project approved by Order No. PSC-2019-0159-FOF-EI to be refunded through the capacity clause in 2020?

STIPULATION:

The appropriate true-up adjustment amount associated with the Hamilton SoBRA project approved by Order No. PSC-2019-015-FOF-EI to be refunded through the capacity clause in 2020 is $478,334, as reflected on Schedule E-12A, Line 26, in Exhibit CAM-3, Part 3.

Florida Power & Light Company

ISSUE 24A: What amount has FPL included in the capacity cost recovery clause for nuclear cost recovery?

STIPULATION:

$0.

ISSUE 24B: What is the appropriate true-up adjustment amount associated with the 2017 SOBRA projects approved by Order No. PSC-2018-0028-FOF-EI to be refunded through the capacity clause in 2020?

STIPULATION:

$6,657,892, as reflected in the 2017 Project Refund Calculation Schedule (EJA-5, Page 2 of 2).

ISSUE 24C: What is the appropriate true-up amount associated with the 2018 SOBRA projects approved by Order No. PSC-2018-0028-FOF-EI to be refunded through the capacity clause in 2020?

STIPULATION:

The parties have agreed to address this matter in the 2020 Fuel Clause cycle.

ISSUE 24D: 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 2020?

STIPULATION:

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 2020 are $3,687,779, as reflected on Line 15 of Rate Case Allocation of Indiantown Revenue Requirement Schedule in Appendix V – 2020 CCR Projections (Exhibit RBD-10, Page 18 of 32).

GENERIC CAPACITY COST RECOVERY FACTOR ISSUES

ISSUE 27: **What are the appropriate final capacity cost recovery true-up amounts for the period January 2018 through December 2018?**

STIPULATION:

The appropriate final capacity cost recovery true-up amounts for the period January 2018 through December 2018 are as follows:

DEF: $845,393, under-recovery, as reflected on Line 9 of Capacity Cost Recovery Clause Summary of Actual True-Up Amount (Exhibit CAM-2T, Sheet 1 of 3).

FPL: $7,161,719, over-recovery, as reflected on Line 32 of Capacity Cost Recovery Clause Summary Schedule (Exhibit RBD-10, 2020 CCR Projections, Page 2 of 32).

Gulf: $384,798, over-recovery, as reflected on Line 3, Schedule CCA-1, 2018 Final True-Up Schedule (Exhibit CSB-1, Page 5 of 8).

TECO: $0, as reflected on Line 3, CCR 2018 Final True-Up (Exhibit PAR-1, Document No. 1, Page 1 of 4). The appropriate final capacity cost recovery true-up amounts for the period January 2018 through December 2018, was addressed in Order No. PSC-2019-0109-PCO-EI, Order Approving TECO's Petition for Mid-Course Correction, issued March 22, 2019.

ISSUE 28: What are the appropriate capacity cost recovery actual/estimated true-up amounts for the period January 2019 through December 2019?

STIPULATION:

The appropriate capacity cost recovery actual/estimated true-up amounts for the period January 2019 through December 2019 are as follows:

DEF: $2,693,901, over-recovery as reflected on Line 41, Schedule E12-B (Exhibit CAM-2, Part 2, Page 1 of 2).

FPL: $9,002,615 over-recovery, as reflected on Lines 8 plus 9, Capacity Cost Recovery Calculation of Actual/Estimated True-Up Amount (Exhibit RBD-4, 2019 CCR Actual Estimated, Page 3 of 17).

Gulf: $622,746, under-recovery, as reflected on Line 1, Schedule CCE-1A, 2020 Projection Filing (Exhibit CSB-5, Page 37 of 41).

TECO: $2,179,217, under-recovery, as reflected on Line 15, Capacity Cost Recovery Calculation of the Actual/Estimated True-Up Amount (Exhibit PAR-2, Document No. 2, Page 2 of 4).

<u>ISSUE 29</u>: What are the appropriate total capacity cost recovery true-up amounts to be collected/refunded during the period January 2020 through December 2020?

<u>STIPULATION</u>:

The appropriate total capacity cost recovery true-up amounts to be collected/refunded during the period January 2020 through December 2020 are as follows:

DEF: $1,848,509, over-recovery as reflected on Line 45, Schedule E12-B (Exhibit CAM-2, Part 2, Page 1 of 2).

.

FPL: $16,164,334, over-recovery as reflected on Line 13, Capacity Cost Recovery Calculation of Actual/Estimated True-Up Amount (Exhibit RBD-4, 2019 CCR Actual Estimated, Page 3 of 17).

Gulf: $237,948, under-recovery , as reflected on Line 3, Schedule CCE-1A, 2019 Est/Actual Schedules (Exhibit CSB-3, Page 28 of 32).

TECO: $2,179,217, under-recovery, as reflected on Line 6, Capacity Cost Recovery Calculation of the Current Period True-Up (Exhibit PAR-2, Document No. 2, Page 1 of 4).

<u>ISSUE 30</u>: What are the appropriate projected total capacity cost recovery amounts for the period January 2020 through December 2020?

<u>STIPULATION</u>:

The appropriate projected total capacity cost recovery amounts for the period January 2020 through December 2020 are as follows:

DEF: $409,624,753, as reflected on Line 28, Schedule E12-A (Exhibit CAM-2, Part 3, Page 1 of 2).

FPL: $256,597,002, which excludes prior period true-up amounts, revenue taxes, and the Indiantown non-fuel base revenue requirement, as reflected on Line 30, Appendix VI - 2020 CCR Projections Schedule (Exhibit RBD-10, Page 2 of 32).

Gulf: $83,486,772, which is adjusted for jurisdictional separation, but excludes prior period true-up amounts, and revenue taxes, as reflected on Line 7 of Schedule CCE-1, 2020 Projection Filing (Exhibit CSB-5, Page 36 of 41).

TECO: ($560,376), which excludes prior period true-up amounts and revenue taxes, as reflected on Line 6, Capacity Cost Recovery Clause Calculation of Energy and Demand Allocation By Rate Class (Exhibit PAR-3, Document No. 1, Page 2 of 4).

<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 2020 through December 2020?

<u>STIPULATION</u>:

The appropriate projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January 2020 through December 2020 are as follows:

DEF: $414,954,634, as reflected on Line 39, Schedule E12-A (Exhibit CAM-3, Part 3, Page 1 of 2).

FPL: $237,630,783, which includes the net total recoverable capacity costs of $233,943,004, as reflected on Line 37, Appendix V - 2020 CCR Projections Schedule (Exhibit RBD-10, Page 2 of 32), plus $3,687,779, the Indiantown non-fuel base revenue requirement, as reflected on Line 15, Appendix V - 2020 CCR Projections Schedule (Exhibit RBD-10, Page 18 of 32). The net total recoverable capacity costs includes the 2017 SoBRA true-up credit, the final true up from 2018, and the actual/estimated true up from 2019, and revenue taxes.

Gulf: $83,785,002, which is adjusted for jurisdictional separation, and includes prior period true-up amounts and revenue taxes, as reflected on Line 11 of Schedule CCE-1, 2020 Projection Filing (Exhibit CSB-5, Page 36 of 41).

TECO: $1,620,007, which includes prior period true-up amounts and revenue taxes, as reflected on Line 10, Capacity Cost Recovery Clause Calculation of Energy and Demand Allocation By Rate Class (Exhibit PAR-3, Document No. 1, Page 2 of 4).

<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 2020 through December 2020?

<u>STIPULATION</u>

The appropriate jurisdictional separation factors for capacity revenues and costs to be included in the recovery factor for the period January 2020 through December 2020 are as follows:

DEF: Base – 92.885%, Intermediate – 72.703%, and Peaking – 95.924%, as reflected on Lines 8, 14, and 21, respectively, on Schedule E12-A (Exhibit CAM-3, Part 3, Page 1 of 2).

FPL:

2020 Projected Separation Factors	
	SUMMARY
DEMAND	
FPL101 - Transmission	0.899387
FPL102 – Non-Stratified Production	0.957922
FPL103INT – Intermediate Strata Production	0.941569
FPL103PEAK – Peaking Strata Production	0.950455
ENERGY	
FPL201 – Total Sales	0.950640
FPL202 – Non-Stratified Sales	0.958799
FPL203INT – Intermediate Strata Sales	0.942430
FPL203PEAK – Peaking Strata Sales	0.951325
GENERAL PLANT	
I900 - LABOR	0.969124

Source: Appendix V – 2020 CCR Projections (Exhibit RBD-10, Page 23 of 32).

Gulf: FPSC – 97.23427%, and FERC – 2.76573%, as reflected on Schedule CCE-1, 2020 Projection Filing (Exhibit CSB-5, Page 36 of 41).

TECO: The appropriate jurisdictional separation factor is 1.00, as reflected on Line 5, Capacity Cost Recovery Clause Calculation of Energy and Demand Allocation By Rate Class (Exhibit PAR-3, Document No. 1, Page 2 of 4).

ISSUE 33: **What are the appropriate capacity cost recovery factors for the period January 2020 through December 2020?**

STIPULATION

The appropriate capacity cost recovery factors for the period January 2020 through December 2020 are shown in Tables 33-1 through 33-6 below.

DEF: The appropriate capacity cost recovery factors for the period January 2020 through December 2020 are shown in Table 33-1 below.

Table 33-1
DEF Capacity Cost Recovery Factors for the period January-December, 2020

Rate Class		2020 Capacity Cost Recovery Factors Cents / kWh	2020 Capacity Cost Recovery Factors Dollars / kW-month
Residential (RS-1, RST-1, RSL-1, RSL-2, RSS-1) At Secondary Voltage		1.200	
General Service Non-Demand (GS-1, GST-1)			
	At Secondary Voltage	1.147	
	At Primary Voltage	1.136	
	At Transmission Voltage	1.124	
General Service (GS-2)		0.690	
Lighting (LS-1)		0.147	
General Service Demand (GSD-1, GSDT-1, SS-1)			
	At Secondary Voltage		3.60
	At Primary Voltage		3.56
	At Transmission Voltage		3.53
Curtailable (CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3)			
	At Secondary Voltage		1.38
	At Primary Voltage		1.37
	At Transmission Voltage		1.35
Interruptible (IS-1, IST-1, IS-2, IST-2, SS-2)			
	At Secondary Voltage		3.00
	At Primary Voltage		2.97
	At Transmission Voltage		2.94
Standby Monthly (SS-1, 2, 3)			
	At Secondary Voltage		0.349
	At Primary Voltage		0.346
	At Transmission Voltage		0.342
Standby Daily (SS-1, 2, 3)			
	At Secondary Voltage		0.166
	At Primary Voltage		0.164
	At Transmission Voltage		0.163

Source: Schedule E12-E (Exhibit CAM-3, Part 3).

FPL: The appropriate capacity cost recovery factors for the period January 2020 through December 2020 are shown in Tables 33-2 through 33-4 below:

Table 33-2
FPL Capacity Cost Recovery Factors for the period January-December, 2020

Rate Schedule	2020 Capacity Cost Recovery Factors, Excluding Indiantown			
	$/kW	$/kWh	Reservation Demand Charge (RDC) $/kW	Sum of Daily Demand Charge (SDD) $/kW
RS1/RTR1	-	0.00226	-	-
GS1/GST1	-	0.00222	-	-
GSD1/GSDT1/HLFT1	0.74	-	-	-
OS2	-	0.00093	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	0.84	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	0.80	-	-	-
GSLD3/GSLDT3/CS3/CST3	0.83	-	-	-
SST1T	-	-	0.10	0.05
SST1D1/SST1D2/SST1D3	-	-	0.10	0.05
CILC D/CILC G	0.86	-	-	-
CILC T	0.83	-	-	-
MET	0.74	-	-	-
OL1/SL1/SL1M/PL1	-	0.00017	-	-
SL2/SL2M/GSCU1	-	0.00151	-	-

Source: Appendix V – 2020 CCR Projections (Exhibit RBD-10, Page 4 of 32).

Table 33-3
FPL Capacity Cost Recovery Factors for the period January-December, 2020

Rate Schedule	2020 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	-	0.00003	-	-
GSD1/GSDT1/HLFT1	0.01	-	-	-
OS2	-	0.00002	-	-
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	0.01	-	-	-
CILC T	0.01	-	-	-

MET	0.01	-	-	-
OL1/SL1/SL1M/PL1	-	0.00001	-	-
SL2/SL2M/GSCU1	-	0.00002	-	-

Source: Appendix V – 2020 CCR Projections (Exhibit RBD-10, Page 19 of 32).

Table 33-4
FPL Capacity Cost Recovery Factors for the period January-December, 2020

Rate Schedule	2020 Total Capacity Cost Recovery Factors			
	$/kW	$/kWh	Reservation Demand Charge (RDC) $/kW	Sum of Daily Demand Charge (SDD) $/kW
RS1/RTR1	-	0.00230	-	-
GS1/GST1	-	0.00225	-	-
GSD1/GSDT1/HLFT1	0.75	-	-	-
OS2	-	0.00095	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	0.85	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	0.81	-	-	-
GSLD3/GSLDT3/CS3/CST3	0.84	-	-	-
SST1T	-	-	0.10	0.05
SST1D1/SST1D2/SST1D3	-	-	0.10	0.05
CILC D/CILC G	0.87	-	-	-
CILC T	0.84	-	-	-
MET	0.75	-	-	-
OL1/SL1/SL1M/PL1	-	0.00018	-	-
SL2/SL2M/GSCU1	-	0.00153	-	-

Source: Appendix V – 2020 CCR Projections (Exhibit RBD-10, Page 20 of 32).

Gulf: The appropriate capacity cost recovery factors for the period January 2020 through December 2020 are shown in Table 33-5 below:

Table 33-5
GULF Capacity Cost Recovery Factors for the period January-December, 2020

Rate Class	2019 Capacity Cost Recovery Factors	
	Cents / kWh	Dollars / kW-month
RS, RSVP, RSTOU	0.878	-
GS	0.893	
GSD, GSDT, GSTOU	0.703	
LP, LPT	-	2.92
PX, PXT, RTP, SBS	0.598	-
OS-I/II	0.121	
OSIII	0.543	

Source: Schedule CCE-2, Page 2 of 2 (Exhibit CSB-5, Columns G and I, Page 40 of 41).

TECO: The appropriate capacity cost recovery factors for the period January 2020 through December 2020 are shown in Table 33-6 below**:**

Table 33-6
TECO Capacity Cost Recovery Factors for the period January-December, 2020

Rate Class and Metering Voltage	**2020 Capacity Cost Recovery Factors**	
	Cents / kWh	Dollars / kW
RS Secondary	0.010	-
GS and CS	0.008	
GSD, SBF Standard		
Secondary	-	0.03
Primary		0.03
Transmission		0.03
GSD Optional		
Secondary	0.007	-
Primary	0.007	
Transmission	0.007	
IS, SBI		
Primary	-	0.03
Transmission		0.03
LS1 Secondary	0.002	-

Source: Exhibit PAR-3, Document Number 1, Columns 10 and 11, Page 3 of 4.

III. EFFECTIVE DATE

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

STIPULATION

The new factors should be effective begin with the first billing cycle for January 2020 through the last billing cycle for December 2020. The first billing cycle may start before January 1, 2020, and the last cycle may be read after December 31, 2020, so that each customer is billed for twelve months regardless of when the recovery factors became effective. The new factors shall continue in effect until modified by this Commission.

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

STIPULATION

Yes.

ISSUE 36: **Should the Joint Motion to Modify Order No. PSC-2012-0425-PAA-EU regarding Weighted Average Cost of Capital Methodology be approved?**

STIPULATION

No. The normalization provisions of the Internal Revenue Code (IRC) Treasury Regulation Section 1.167(1)-1(h)(6) shall be applied to the Weighted Average Cost of Capital (WACC) in this docket subject to true-up. The determination of the WACC to be applied in future clause dockets shall be the subject of a workshop to be held by Commission staff.

XI. PENDING MOTIONS

On August 21, 2019, DEF, Gulf, TECO, and FPUC filed a Joint Motion to Modify Order No. PSC-2012-0425-PAA-EI Regarding Weighted Average Cost of Capital Methodology. This motion is the subject of Issue 36 and a stipulation of the issue as stated above has been reached.

XII. PENDING CONFIDENTIALITY MATTERS

There are no pending confidentiality matters.

XIII. POST-HEARING PROCEDURES

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 50 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 50 words, it must be reduced to no more than 50 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.

XIV. RULINGS

Opening statements, if any, shall not exceed ten minutes per party unless a party chooses to waive its opening statement. Each witness shall be given five minutes for a summary of their testimony.

At this time all parties have stipulated to the entry of the pre-filed testimony and exhibits of all witnesses into the record with the exception of witnesses Swartz and Polich who are addressing Issues 1B and 1C, replacement power costs for the Bartow Unit 4 power plant and its de-rating. Issues 1B and 1C have been referred by Chairman Graham to the Division of

Administrative Hearings (DOAH) for hearing in order to maintain the confidentiality of the materials necessary to be discussed to resolve these issues.

Contested Issue 1E was raised by OPC and states as follows: "Should the Commission hold a separate "spin-off" hearing to determine a cause of the Bartow outage and the prudence of DEF's decisions on all factors related to the cause(s) and duration of any outages and the de-rating of the Bartow plant?" At the Prehearing Conference the parties all agreed that they were prepared to try the issue and no longer wished to spin it off into a separate docket. Subsequent to the Prehearing Conference, Issues 1B and 1C have been referred by Chairman Graham to the Division of Administrative Hearings in order to protect the confidentiality of the materials relevant to the resolution of those issues. For this reason, I find that this issue is now moot.

FIPUG has 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-2019-0059-PCO-EI (OEP), issued on February 13, 2019, 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 FIPUG has not 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 FIPUG shall not be allowed to voir dire or challenge the expertise of any witness at the final hearing.

It is therefore,

ORDERED by Commissioner Gary F. Clark, 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 Gary F. Clark, as Prehearing Officer, this 31th day of October, 2019.

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

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

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