

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery  
clause with generating performance incentive  
factor.

DOCKET NO. 20180001-EI  
ORDER NO. PSC-2018-0610-FOF-EI  
ISSUED: December 26, 2018

The following Commissioners participated in the disposition of this matter:

ART GRAHAM, Chairman  
JULIE I. BROWN  
DONALD J. POLMANN  
GARY F. CLARK  
ANDREW GILES FAY

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

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**BY THE COMMISSION:**

As part of the continuing fuel and purchased power adjustment and generating performance incentive clause proceedings, an administrative hearing was held on November 5-6, 2018, in this docket.

At the hearing, we voted to approve stipulated issues 1B, 2B-2L, 2O, 2T, 3A, 6, 7, 8, 9, 10, 11, 15A, 15B, 16, 17, 18, 19, 20, 21, 22, 23A, 24A-24E, and 27-36 as set forth in Attachment

A.<sup>1</sup> We also approved Issues 1A, 2A, 4A and 5A, hedging issues contested by FRF, by bench decision as set forth in Attachment B. As a result of our bench decisions on these issues, we approved all issues associated with DEF, TECO, FPUC, and Gulf. The remaining FPL issues, Issues 2M, 2N, 2P, 2Q, 2R, and 2S, concern FPL's 2018 and 2019 Solar Base Rate Adjustments (SoBRA). FIPUG waived cross examination of FPL's SoBRA witnesses but asked to brief these issues. FIPUG and FPL filed briefs on the SoBRA issues on November 16, 2018. FIPUG filed a notice of correction of its post-hearing brief for Issues 2O<sup>2</sup> and 2P on November 19, 2018.

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

### **SoBRA PROJECTS**

Issues 2M, 2N, 2P, 2Q, 2R, and 2S, are company-specific issues pertaining to solar generation base rate adjustment (SoBRA) considerations. Issues 2M and 2N address the recovery of construction costs for solar generation facilities that were recently constructed, and are currently operating. Issues 2P, 2Q, 2R, and 2S pertain to FPL's Miami-Dade, Interstate, Pioneer Trail, and Sunshine Gateway solar generation facilities which are currently being constructed and scheduled to be operational on March 1, 2019 (2019 SoBRA projects). Collectively, all of the SoBRA-related issues relate to FPL's 2016 rate case Stipulation and Settlement Agreement approved by Order No. PSC-2016-0560-AS-EI (the 2016 Agreement).<sup>3</sup>

With regard to all of the SoBR issues, Issues 2M, 2N, 2Q, 2R and 2S, FIPUG has made several arguments in its brief. First, that the Commission is specifically required by statute to make findings that the 2018 and 2019 solar projects for which cost recovery is sought are both prudent and needed. Second, that Commission approval of a negotiated settlement agreement executed by a limited number of parties cannot substitute for the required findings of prudence and need. Third, that the use of projected carbon dioxide (CO<sub>2</sub>) tax costs in FPL's cost effectiveness analysis is improper for two reasons: no carbon dioxide tax is currently imposed, nor likely to be imposed in the future, and the carbon dioxide tax amount is based on uncorroborated hearsay. Fourth, that recovery of capital costs through the fuel cost recovery docket is improper.

FIPUG's first and second arguments are essentially attempts to revive two issues previously raised by FIPUG and excluded by the Prehearing Officer at the Prehearing Conference.<sup>4</sup> We find that nothing has changed since the Prehearing Conference and the determination that the terms of FPL's 2016 Agreement, approved by Order No. PSC-2016-0560-

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<sup>1</sup>DEF's witness Jeffrey Swartz testified on the first day of the hearing on Issue No. 1B, the February 2017 forced outage at DEF's Bartow plant. However, on the second day of the hearing OPC and PCS Phosphate were able to reach a stipulation with DEF, approved by the Commission, which defers consideration of this issue until next year.

<sup>2</sup>Although FIPUG filed a corrected position for Issue 2O, this issue had been previously voted on at the final hearing.

<sup>3</sup>Order No. PSC-2016-0560-AS-EI, issued on December 15, 2016, in Docket No. 20160021-EI, In re: Petition for rate increase by Florida Power & Light Company.

<sup>4</sup>Issue A: "Are FPL's proposed solar projects prudent?" and Issue B: "Are FPL's proposed solar projects needed?"

AS-EI,<sup>5</sup> control and limit the issues regarding FPL's solar generation projects to the cost-effectiveness issues stated in Issues 2P, 2Q, 2R and 2S, continues to be valid.<sup>6</sup> One could also conclude that FIPUG's arguments are an attempt to collaterally attack Order No. PSC-2016-0560-AS-EI's approval of the SoBRA process outlined therein. However, FIPUG, as a party to the 2016 rate case, had an opportunity to appeal Order No. PSC-2016-0560-AS-EI and failed to do so. Thus, we find that FIPUG's right to contest the 2016 Agreement, and any of its terms and conditions, has passed. FIPUG's third argument will be addressed below.

FIPUG's fourth argument appears to be that use of the fuel cost recovery clause factors to recover FPL's proposed solar generation capital costs is improper. However, FPL is not seeking to recover its proposed solar generation capital costs through fuel charge factors. As the 2016 Agreement clearly states, the capital costs associated with the proposed solar generation projects are rate base adjustments which are made to FPL's books at the time the solar projects are placed into service.<sup>7</sup> We agree with FPL that the fuel cost recovery docket was simply used for administrative and procedural efficiency since it is an annual proceeding with a relatively fixed filing schedule. Further, we note that if the filing schedule for the fuel cost recovery docket is used, increases in base rates as a result of the approval of SoBRA projects can be coordinated with projected fuel costs which include those units.

#### 2017 SoBRA Projects

With regard to Issue 2M, calculation of a revised SoBRA factor for the 2017 projects that reflect their actual construction costs, FPL testified that final construction costs for the 2017 SoBRA Project are not yet known, and, therefore, cannot be resolved in this hearing cycle. FPL further testified that the calculation and resulting factor could be addressed in 2019. FPL stated that although not final, preliminary information indicates that final costs will be lower than the cost estimates that were used to develop the projected revenue requirements and cost recovery factors for these projects. Pursuant to Paragraph 10(g) of the 2016 Agreement, if actual capital expenditures are less than the projected costs used to develop the initial SoBRA factor, the lower figure will be the basis for the full revenue requirements, and a one-time credit will be made through the Capacity Cost Clause. FIPUG neither sponsored a witness on this issue nor specifically addressed this issue in its post-hearing brief. Due to the fact that it is uncontroverted that the information needed is not yet available to calculate a final SoBRA factor for the 2017 projects, we find that this issue is not ripe for consideration at this time and shall be addressed in the 20190001-EI docket.

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

<sup>6</sup>Order No. PSC-2018-0520-PHO-EI, issued November 1, 2018, in Docket No. 20180001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor, at 65-66.

<sup>7</sup>2016 Agreement at ¶¶ 10(c), 10(e), 10(i).

### 2018 SoBRA Projects

Issue 2N concerns the calculation of a revised SoBRA factor for the 2018 projects that reflect their actual construction costs. Like the 2017 SoBRA projects, FPL testified that the construction costs for the 2018 SoBRA projects are also not yet final. FIPUG also did not sponsor a witness on this issue or specifically address this issue in its post-hearing brief. That being the case, we find that the calculation of a final SoBRA factor for the 2018 projects is not ripe for consideration at this time and shall also be addressed in the 20190001-EI docket.

### 2019 SoBRA projects

#### 2016 Settlement Agreement

The 2019 solar generation projects for which FPL is seeking approval for cost recovery are specifically provided for in the 2016 Agreement approved by Order No. PSC-16-0560-AS-EI.<sup>8</sup> The 2016 Agreement allows FPL to construct up to 300 MW per calendar year of solar capacity during the period 2017-2021 and to recover through base rates the incremental annualized base revenue requirement for those facilities for the first 12 months of operation commencing when the facilities are placed into service.<sup>9</sup> There are several conditions that must be met for recovery in this case. First, FPL must request recovery for these projects during the term of the 2016 Agreement, or prior to December 31, 2020. Second, the cost of the components, engineering, and construction for any solar project is capped at \$1,750 kW<sub>ac</sub>. Third, for projects less than 75 MW (as are all of the projects proposed in this case): 1) the request for base rate recovery must be filed in the Fuel Clause docket as part of its final true-up filing; and 2) the issues are “limited to the cost effectiveness of each such project (i.e., will the project lower the projected system CPVRR as compared to each CPVRR without the solar project) and the amount of revenue requirements and appropriate percentage in base rates needed to collect the estimated revenue requirements.”<sup>10</sup> If the project meets these requirements, the terms of the 2016 Agreement have been met.

#### Project Descriptions

FPL witnesses Brannen and Enjamio provided testimony and exhibits concerning FPL’s proposed 2019 SoBRA projects, including cost effectiveness and the ability to meet the \$1,750 per kW<sub>ac</sub> cost cap. As described in the testimony of witness Enjamio, FPL is proposing to construct and operate four solar generation centers with a total nameplate capacity of 298 MW<sub>ac</sub> (each project is 74.5 MW<sub>ac</sub>) with an in-service date of March 1, 2019. Construction of the 2019 SoBRA projects began on September 29, 2017. The proposed 2019 SoBRA projects are fixed-tilt systems with an average projected first year net capacity factor of 26.5 percent. There are no

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<sup>8</sup>Order No. PSC-16-0560-AS-EI, issued December 15, 2016, in Docket No. 20160021-EI, In re: Petition for rate increase by Florida Power & Light Company.

<sup>9</sup>2016 Agreement at ¶ 10(a).

<sup>10</sup>2016 Agreement at ¶ 10(c).

upgrades to existing transmission infrastructure required as part of the construction of the 2019 SoBRA projects.

The four proposed construction sites for the 2019 SoBRA projects are Miami-Dade in Miami-Dade County, Interstate in St. Lucie County, Pioneer Trail in Volusia County and Sunshine Gateway in Columbia County. All parcels are new purchases, and the land costs are included in the cost of the 2019 SoBRA projects. Not all land for the four newly purchased sites was being used for the 2019 solar generation projects. In response to Commission staff discovery requests, it was disclosed that unused areas could include both usable and unusable areas for future solar development. To develop a better understanding of the ratio of land that could be used for future development, Commission staff requested a more detailed breakdown of each site. This breakdown included four categories: total acreage, acreage used by the projects (Site Acreage), non-usable land, and usable land. Usable land consists of property that could possibly be used for future solar developments on the site, and for sites with adequate amounts of usable land, FPL will consider leasing land to third parties. Any revenue from the usable land leased to third parties will be credited to FPL ratepayers via an offset to the revenue requirement associated with the 2019 solar generation projects. The land usage of each site is illustrated in Table 1:

Table 1  
Land Usage

<b>Site Name</b>	<b>Total Acreage (acres)</b>	<b>Site Acreage (acres)</b>	<b>Non-Usable Land (acres)</b>	<b>Usable Land (acres)</b>
Miami-Dade	465.1	425.1	0	40.0
Interstate	539.0	522.8	16.2	0
Pioneer Trail	1,189.6	438.6	398.0	353.0
Sunshine	954.4	547.2	407.2	0

Source: EXH 76, 77

## 2019 Solar Generation Projects Evaluation

### Economic Assumptions

The resource planning document filed with FPL's petition included FPL's three reliability criteria: 20 percent total reserve margin, 10 percent generation-only reserve margin (GRM), and loss of load probability. Because FPL's GRM criterion has not been relied upon by us in previous proceedings, a revised resource planning document that did not incorporate the GRM criterion in the 2019 SoBRA project resource planning was requested by Commission staff. FPL's revised resource planning document includes two resource plans that form the basis of the cost effectiveness analysis that the Company performed. These two resource plans are called the No Solar Plan and 2019 Solar Plan. The No Solar Plan includes the 2017 and 2018 SoBRA projects and assumes that further resource needs will be met by combined cycle (CC) units and short term purchase power agreements (PPAs) through the year 2031. The 2019 Solar Plan includes the 2017 and 2018 SoBRA projects and takes into account the four 2019 SoBRA projects, which initially defer the 2028 CC unit and reduces the size of the CC unit projected for 2031. This resource plan is shown in Table 2:

Table 2  
Resource Plan (w/o GRM)

<b>Year</b>	<b>No Solar Resource Plan</b>	<b>2019 Solar Resource Plan</b>
2018	2017/2018 596 MW SoBRA	2017/2018 596 MW SoBRA
2019	Okeechobee Energy Center; 1-year 476 MW PPA	2019 298 MW SoBRA; Okeechobee Energy Center; 1- year 311 MW PPA
2020	1- year 470 MW PPA	1- year 305 MW PPA
2021	1- year 717 MW PPA	1- year 553 MW PPA
2022	Dania Beach Energy Center	Dania Beach Energy Center
2023	1- year 215 MW PPA	1- year 52 MW PPA
2024	1 Greenfield 3x1 CC Unit	1 Greenfield 3x1 CC Unit
2025		
2026		
2027	1- year 75 MW PPA	
2028	1 Greenfield 3x1 CC Unit	1- year 337 MW PPA
2029		1 Greenfield 3x1 CC Unit
2030		
2031	Equalizing 578 MW CC Unit	Equalizing 419 MW CC Unit

Source: EXH 77

In completing the analysis, FPL considered multiple components to determine cost effectiveness: solar revenue requirements, avoided generation costs, and avoided system costs. For the proposed solar facilities, the revenue requirements included fixed operation and maintenance (O&M), equipment, installation, land cost, and transmission interconnection cost. The avoided generation cost component considered avoided generation capital, avoided fixed O&M, avoided transmission interconnection, avoided capital replacement, incremental gas transport, and short-term purchases. The avoided system cost component considers the factors of fuel savings, avoided variable O&M, and emission cost savings.

FPL witness Enjamio stated that the emission cost savings consideration did not incorporate CO<sub>2</sub> pricing until 2028. FPL witness Enjamio identified ICF International's (ICF) CO<sub>2</sub> emissions cost forecast as a major assumption in FPL's economic analysis of its proposed 2019 solar generation projects. The CO<sub>2</sub> cost projections used in FPL's cost-effectiveness analyses are based on ICF's CO<sub>2</sub> emission cost forecast dated January 31, 2018. ICF is a consulting firm with extensive experience in forecasting the cost of air emissions and is recognized as one of the industry leaders in this field. No intervenor offered testimony rebutting FPL's CO<sub>2</sub> emission cost forecast or provided any alternative emission cost forecast. Based on the evidence of record, we find that the CO<sub>2</sub> cost projections FPL used in this docket are reasonable.

Hearsay

We do not find FIPUG's argument, that carbon dioxide tax projections prepared by ICF and used by FPL in its CPVRR analysis is based on uncorroborated hearsay, to be persuasive.

Section 120.57(1)(c), F.S., states that “[h]earsay evidence may be used for the purpose of supplementing or explaining other evidence, but it shall not be sufficient in itself to support a finding unless it would be admissible over objection in civil actions.” Section 90.704, F.S., allows the use by an expert of “facts or data [that] are of a type reasonably relied upon by experts in the subject to support the opinion expressed” even if the facts or data are not admissible in evidence. Smith v. State, 7 So. 3d 473, 501 (Fla. 2009); Geralds v. State, 674 So. 2d 96, 100 (Fla. 1996)(expert allowed to base opinion on cause of death on materials prepared by another doctor).

FPL identified witness Enjamio as an expert in the field of resource planning and the cost-effectiveness of FPL’s 2019 Solar Project.<sup>11</sup> FIPUG objected to any witness being considered an expert witness unless the witness states the subject matter areas in which he or she claims expertise, and voir dire, if requested, is permitted. However, FIPUG failed to comply with the requirements of Section VI.A(8) of Order No. PSC-2018-0079-PCO-EI, that a party identify each witness the party wishes to voir dire and specify the portions of the witness’ testimony to which it objects. For that reason, FIPUG was prevented from challenging the expertise of any witness at the final hearing.<sup>12</sup>

Witness Enjamio’s testimony is that ICF is recognized as an industry leader in the field of forecasting the cost of air emissions and that its cost projections have been used for many years in FPL’s resource plans and economic analyses, i.e., FPL’s 2018 Ten Year Site Plan. It is important to note that it is witness Enjamio’s expert opinion that ICF’s projection of carbon dioxide costs should be included in FPL’s cost effectiveness analysis for the 2019 SoBRA projects. FIPUG did not present any evidence to support the exclusion of these costs or to refute ICF’s expertise in projecting air emission costs. Based on this record, we find that ICF’s carbon dioxide tax costs do not constitute uncorroborated hearsay and can be used in FPL’s cost effectiveness calculation.

#### CPVRR Analysis

FPL’s CPVRR analysis assumed that each project had an actual life of 33 years, with the analysis ending in 2050. FPL’s CPVRR for the 2019 SoBRA projects produced savings of \$40 million for the base fuel and environmental forecasts. This calculation included the previously mentioned CO<sub>2</sub> pricing in 2028. FPL’s CPVRR analysis in support of its 2019 Solar Plan included assumptions related to future fuel prices. The Company employed its standard fuel forecasting methodology to produce its long-term fuel price forecast. Based on the evidence of record, we find that the forecasted fuel prices used in the Company’s CPVRR analysis associated with its current proposal are reasonable.

FPL’s CPVRR calculation for the 2019 SoBRA projects includes the FPL GRM criteria, which has not been relied upon by us in previous proceedings. FPL has provided a CPVRR analysis that excludes this GRM criterion and economically evaluates the solar projects based

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<sup>11</sup>DN 06651-2018.

<sup>12</sup>Order No. PSC-2018-0520-PHO-EI, issued November 1, 2018, in Docket No. 20180001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.



upon FPL's remaining reliability criteria. The resulting CPVRR produced a savings of \$39.9 million for the base fuel and environmental forecasts, a slight decrease from the \$40 million savings that included the GRM criterion. Since we did not rely upon FPL's GRM criterion in previous proceedings, we find that this criterion is not a critical component of the overall cost-effectiveness of the 2019 SoBRA projects.

FPL has provided a CPVRR analysis with both fuel and environmental compliance sensitivities. In FPL's analysis, a Low, Medium, and High Fuel Forecast and ENV I, ENV II, and ENV III compliance costs were considered. ENV I assumes an annual \$0/ton cost for CO<sub>2</sub> pricing and low environmental compliance costs, ENV II assumes a most likely cost, and ENV III assumes high environmental compliance costs. While this analysis includes FPL's GRM criterion, it is assumed there would be a similar negligible effect on the other sensitivities as it did on FPL's base case forecast. The range of savings is illustrated in Table 3:

Table 3  
CPVRR Analysis including GRM

	<b>Environmental Compliance Cost Forecast</b>			
		<b>ENV I</b>	<b>ENV II</b>	<b>ENV III</b>
Fuel Cost Forecast	<b>High</b>	(\$62)	(\$81)	(\$130)
	<b>Medium</b>	(\$19)	(\$40)	(\$89)
	<b>Low</b>	\$24	\$4	(\$46)

Source: EXH 77

Table 3 shows that in seven of the nine scenarios, the 2019 SoBRA projects are cost effective. Notably the base fuel case (medium), ENV I scenario contains no cost for CO<sub>2</sub>, but is also cost effective. Examining the forecasted scenarios, in all scenarios avoided fuel costs are the major driving force in producing overall savings for the projects. This fact is present in even the "worst" case scenario of Low Fuel Cost, ENV I, where there are projected fuel savings in every forecasted year. These cost forecast scenarios are identical to the ones present in the 2017 and 2018 solar generation projects in previous proceedings. When reviewing the overall cost effectiveness of the projects, the first cumulative benefit occurred in 2028 in all scenarios. This benefit seems to be driven by the avoided capital that would be required for the Greenfield 3x1 CC Unit. Therefore, we find the CPVRR assumptions discussed above to be reasonable.

#### 2016 Agreement Threshold

As stated previously, the 2016 Agreement requires the FPL 2019 SoBRA projects to meet a \$1,750 per kW<sub>ac</sub> cost cap. The estimated total cost to build all of the 2019 solar generation projects is \$1,386 per kW<sub>ac</sub>, falling below the cost cap. Each of the 2019 solar generation projects also fall under this threshold when considered individually. The cost per kW<sub>ac</sub> for the 2019 solar generation projects is illustrated in Table 4:

Table 4  
\$/kW<sub>ac</sub> Cost Cap

<b>2019 Solar Generation Projects Cost per \$/kW<sub>ac</sub></b>				
<b>Site Name</b>	<b>Miami Dade</b>	<b>Interstate</b>	<b>Pioneer Trail</b>	<b>Sunshine Gateway</b>
<b>Cost (\$/kW<sub>ac</sub>)</b>	\$1,460	\$1,289	\$1,422	\$1,374

Source: EXH 76

Based on the evidence contained in the record, we find that FPL’s proposed 2019 SoBRA projects are projected to produce savings under multiple scenarios. The 2019 SoBRA projects have also met the terms of the 2016 Agreement in regards to keeping construction cost under the \$1,750 per kW<sub>ac</sub> cost cap. These two criteria having been met, we find that the projects are cost effective.

Revenue requirements

FPL’s witness Castaneda testified that the annualized jurisdictional revenue requirements for the first 12 months of operations related to the 2019 SoBRA projects are \$51,685,454. Witness Castaneda further stated that the revenue requirement value was calculated by following the methodologies approved by this Commission for FPL’s 2017 and 2018 solar base rate projects, which is the same methodology used for the generation base rate adjustments (GBRA) for Turkey Point Unit 5 and West County Energy Center Units 1 and 2 in Order No. PSC-2005-0902-S-EI,<sup>13</sup> West County Energy Center Unit 3 in Order No. PSC-2011-0089-S-EI,<sup>14</sup> and the modernization projects at Canaveral, Riviera Beach, and Port Everglades in Order No. PSC-2013-0023-S-EI.<sup>15</sup> The jurisdictional annualized revenue requirement calculation for the 2019 SoBRA projects used several inputs, including the most current estimated capital expenditures presented by FPL witness Brannen. FIPUG did not sponsor a witness to address this issue or specifically address this issue in its post-hearing brief.

Having reviewed the testimony, exhibits, and calculations used by FPL witness Castaneda for determining the amount of revenue requirements associated with the 2019 SoBRA projects, we find them to be reasonable. Therefore, we find that the jurisdictional annualized revenue requirements associated with the 2019 SoBRA projects are \$51,685,454.

<sup>13</sup>Order No. PSC-2005-0902-S-EI, issued September 14, 2005, in Docket No. 20050045-EI, In re: Petition for rate increase by Florida Power & Light Company, and in Docket No. 20050188-EI, In re: 2005 comprehensive depreciation study by Florida Power & Light Company.

<sup>14</sup>Order No. PSC-2011-0089-S-EI, issued February 1, 2011, in Docket No. 20080677-EI, In re: Petition for increase in rates by Florida Power & Light Company, and in Docket No. 20090130-EI, In re: 2009 depreciation and dismantlement study by Florida Power & Light Company.

<sup>15</sup>Order No. PSC-2013-0023-S-EI, issued January 14, 2013, in Docket No. 20120015-EI, In re: Petition for increase in rates by Florida Power & Light Company.

Base Rate Percentage Increase

The SoBRA factors are incremental cost recovery factors that will be applied to base rate charges in order for the Company to collect the revenue necessary to recover the costs associated with building and operating the 2019 SoBRA projects. The SoBRA factor is equal to the ratio of (1) the Company's jurisdictional revenue requirements for the Project and (2) the forecasted retail base revenue from electricity sales for the first twelve months of operations, expected to begin March 1, 2019. FPL's witness Cohen sponsored an exhibit to demonstrate the inputs and calculations performed to determine the resulting incremental cost recovery factor of 0.795 percent for the 2019 SoBRA projects. FIPUG did not sponsor a witness to address this issue or specifically address this issue in its post-hearing brief.

Having reviewed the testimony, exhibits, and calculations used by FPL witness Cohen for determining the appropriate incremental cost recovery factor associated with the 2019 SoBRA projects, we find that the appropriate base rate percentage increase (SoBRA Factor) for the 2019 SoBRA projects is 0.795 percent.

SoBRA tariffs for 2019 Projects

FPL witness Cohen sponsored exhibits that summarize the tariff changes for the 2019 SoBRA projects, which are scheduled to enter into commercial service on March 1, 2019. Witness Cohen testified that the Company will formally notify the Commission by letter of the specific in-service dates for each set of projects, and the base rate changes will become effective on or after that date.

Upon approval of the proposed stipulations in this proceeding, FPL proposes that new cost recovery factors be implemented in the first billing cycle of January 2019. Witness Deaton provided testimony and schedules that reflect the three billing changes that customers can anticipate in 2019. Billing changes summarized below are for a residential customer using 1,000 kWh of electricity per month:

1. For the January and February 2019 billing cycles, changes to various cost recovery factors will increase customer bills by a total of \$1.81 per month.
2. The changes attributable to the 2019 SoBRA projects begin in the March 2019 billing cycle will increase customer bills by a total of \$0.31 per month.
3. A third change is anticipated for bills in the June 2019 billing cycle, when the proposed Okeechobee Clean Energy Center enters into commercial service.<sup>16</sup> This change will increase customer bills by a total of \$0.44 per month.

All of these billing change impacts are shown in Table 5 below:

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<sup>16</sup>Paragraph 9 of the 2016 Agreement describes the Okeechobee Unit and the Limited Scope Adjustment for FPL's generating station now known as the Okeechobee Clean Energy Center.

Table 5  
FPL's Residential Bill Impact for the period January-December, 2019

Bill Components	Present (2018)	Proposed in Projection filing (Jan and Feb, 2019)	Change from 2018	Proposed in Projection filing (March-May, 2019), incl. 2019 SoBRAs	Proposed in Projection filing (June-Dec, 2019), incl. SoBRAs and new power plant
Base Rate Charges	\$66.88	\$66.88	\$0.00	\$67.41	\$69.46
Fuel Cost Recovery	\$22.93	\$24.12	\$1.19	\$23.89	\$22.27
Capacity Cost recovery	\$2.34	\$2.58	\$0.24	\$2.58	\$2.58
Energy Conservation	\$1.53	\$1.50	-\$0.03	\$1.50	\$1.50
Environmental	\$1.22	\$1.59	\$0.37	\$1.59	\$1.59
Storm Restoration	<u>\$1.24</u>	<u>\$1.24</u>	<u>\$0.00</u>	<u>\$1.24</u>	<u>\$1.24</u>
Sub-Total	\$96.14	\$97.91	\$1.77	\$98.21	\$98.64
Gross Receipts Tax	\$2.47	\$2.51	\$0.04	\$2.52	\$2.53
<b>TOTAL</b>	<b><u>\$98.61</u></b>	<b><u>\$100.42</u></b>	<b>\$1.81</b>	<b><u>\$100.73</u></b>	<b><u>\$101.17</u></b>

Source: EXH 19 (f/k/a, Exhibit RBD-7 (Appendix IV – 2019 FCR Projections), Page 7 of 7)

FIPUG did not sponsor a witness to address this issue or specifically address this issue in its post-hearing brief.

FPL's 2016 Agreement outlines three principle considerations for the approval of the 2019 SoBRA projects: 1) the cost effectiveness of the 2019 Projects; 2) the amount of revenue requirements for the 2019 Projects; and 3) the appropriate percentage increase in base rates needed to recover the revenue requirement amounts for the 2019 Projects. These percentage increases are reflected as recovery factors, as discussed above.

Based on our approval of the 2019 SoBRA Projects, we hereby approve tariff sheets which reflect our decisions with an effective date on or after the date that the 2019 SoBRA projects are placed into service upon written notice being filed with the Clerk. Further, we hereby give our staff administrative authority to approve revised tariff sheets for FPL reflecting the base rate percentage increases for the 2019 SoBRA projects as stated herein.

## OTHER MATTERS

Per stipulation of the parties, the new fuel adjustment and capacity factors shall become effective beginning with the first billing cycle for January 2019 through the last billing cycle for December 2019. The first billing cycle may start before January 1, 2019, and the last cycle may be read after December 31, 2019, so that each customer is billed for twelve months regardless of

when the recovery factors became effective. The new factors shall continue in effect until modified by us.

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

Based on the foregoing, it is

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

ORDERED that Florida Power & Light Company, Florida Public Utilities Company, Gulf Power Company, Duke Energy Florida, LLC, and Tampa Electric Company are hereby authorized to apply the fuel cost recovery factors set forth herein during the period January 2019 through December 2019. It is further

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

ORDERED that Florida Power & Light Company, Florida Public Utilities Company, Gulf Power Company, Duke Energy Florida, LLC, and Tampa Electric Company are hereby authorized to apply the capacity cost recovery factors set forth herein during the period January 2019 through December 2019. It is further

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

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

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

By ORDER of the Florida Public Service Commission this 26th day of December, 2018.



CARLOTTA S. STAUFFER  
Commission Clerk  
Florida Public Service Commission  
2540 Shumard Oak Boulevard  
Tallahassee, Florida 32399  
(850) 413-6770  
www.floridapsc.com

Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

SBr

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

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

Any party adversely affected by the Commission's final action in this matter may request:

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

**APPROVED TYPE 2 STIPULATIONS<sup>17</sup>**

**ISSUE 1B:** Has DEF made appropriate adjustments, if any are needed, to account for replacement costs associated with the February 2017 forced outage at the Bartow plant? If appropriate adjustments are needed and have not been made, what adjustment(s) should be made?

**STIPULATION:**

The parties agree:

- A. To allow recovery of replacement power costs of \$11.1 million subject to final true-up in a subsequent fuel docket, based on availability of essential information.
- B. DEF will file a revised request for confidentiality for the Root Cause Analysis attached to Jeffery Swartz's Exhibit JS-1.
- C. This stipulation will resolve Issue 1B and fall-out Issues 8, 10, 18, 20 and 22.
- D. No briefs will be filed on Issues 1B, 8, 10, 18, 20 and 22.

**ISSUE 2B:** 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 2017 through December 2017, 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 2017 through December 2017 was \$43,861,831, 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 \$2,317,099, as reflected in Column 9 of Table 2, Total Gains Schedule (Exhibit GJY-1, Page 1 of 4).

**ISSUE 2C:** 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,

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<sup>17</sup>A Type 2 Stipulation is one in which all parties either agree with, do not object to, or take no position on, the stipulation presented.

**Software, and Hardware costs for the period January 2017 through December 2017?**

**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 2017 through December 2017 is \$703,923, as reflected in Columns 2 and 3 of the Incremental Optimization Costs Schedule (Exhibit GJY-1, Page 4 of 4), and also on Line 14 of Schedule E1-B (2017 FCR Final True Up, Exhibit RBD-1, Page 2 of 3).

**ISSUE 2D: 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 2017 through December 2017?**

**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 2017 through December 2017 is \$1,275,624, as reflected in Column 6 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 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 2017 through December 2017?**

**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 2017 through December 2017 is (\$403,935), as reflected in Column 7 of the Incremental Optimization Costs Schedule (Exhibit GJY-1, page 4 of 4).



**ISSUE 2F:** What is the appropriate amount of actual/estimated 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 actual/estimated 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 \$519,261, as reflected on Line 15 of Schedule E1-B (2018 FCR Actual Estimated, Exhibit RBD-3, Page 1 of 40).

**ISSUE 2G:** What is the appropriate amount of actual/estimated 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 actual/estimated 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 \$1,375,890, as reflected on Line 16 of Schedule E1-B (2018 FCR Actual Estimated, Exhibit RBD-3, Page 1 of 40).

**ISSUE 2H:** What is the appropriate amount of actual/estimated 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 actual/estimated 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 (\$417,954), as

reflected on Line 17 of Schedule E1-B (2018 FCR Actual Estimated, Exhibit RBD-3, Page 1 of 40).

**ISSUE 2I:** What is the appropriate amount of projected 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 2019 through December 2019?

**STIPULATION:**

The appropriate amount of projected 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 2019 through December 2019 is \$509,164, as reflected on Line 17 of Schedule E1 (Appendix II - 2019 FCR Projections, Exhibit RBD-5, Page 1 of 91).

**ISSUE 2J:** What is the appropriate amount of projected 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 2019 through December 2019?

**STIPULATION:**

The appropriate amount of projected 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 2019 through December 2019 is \$1,424,563, as reflected on Line 18 (Appendix II - 2019 FCR Projections, Exhibit RBD-5, Page 1 of 91).

**ISSUE 2K:** What is the appropriate amount of projected 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 2019 through December 2019?

**STIPULATION:**

The appropriate amount of projected 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 2019 through December 2019 is (\$357,809), as reflected on Line 19 of Schedule E1 (Appendix II - 2019 FCR Projections, Exhibit RBD-5, Page 1 of 91).

**ISSUE 2L:** Has FPL properly reflected in the fuel and purchased power cost recovery clause the effects of the St. John's River Power Park transaction approved by Order No. PSC-2017-0415-AS-EI?

**STIPULATION:**

Yes, as reflected on Line 4 of Schedule E1-B (2018 FCR Actual/Estimated, Exhibit RBD-3, Page 1 of 40).

**ISSUE 2O:** Should the Commission approve revised tariffs for FPL reflecting the revised SoBRA factors for the 2017 and 2018 projects determined to be appropriate in this proceeding, effective January 1, 2019?

**STIPULATION:**

This issue is not ripe for consideration during the hearing cycle for 2018, and will be addressed in Docket No. 20190001-EI.

**ISSUE 2T:** Should the Commission approve FPL's proposed generation base rate adjustment (GBRA) factor of 3.040% percent for the Okeechobee Clean Energy Center expected to go in-service on June 1, 2019?

**STIPULATION:**

Yes. FPL's proposed GBRA factor of 3.040% percent for the Okeechobee Clean Energy Center is reflected in the 2019 GBRA Factor Calculation Schedule (Attachment TCC-1, Page 1 of 1).

**ISSUE 3A:** Has FPUC properly refunded \$221,415 to customers through the Fuel Clause in accordance with Order No. PSC-2018-0028-FOF-EI?

**STIPULATION:**

Yes. \$221,415 was refunded through the Fuel Clause to customers as a result of the Florida Supreme Court's March 16, 2017 decision on the FPL Interconnection Line project, and in accordance with Order No. PSC-2018-0028-FOF-EI. This amount included all actual/estimated costs associated with the FPL Interconnection Line project.

**ISSUE 6:**     **What are the appropriate actual benchmark levels for calendar year 2018 for gains on non-separated wholesale energy sales eligible for a shareholder incentive?**

**STIPULATION:**

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

DEF:           \$1,817,289.

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 2018 for gains on non-separated wholesale energy sales eligible for a shareholder incentive is not applicable to FPL as part of its revised Incentive Mechanism.

GULF:          \$1,095,264.

TECO:         The Company did not set a benchmark level for calendar year 2018. 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 2019 for gains on non-separated wholesale energy sales eligible for a shareholder incentive?**

**STIPULATION:**

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

DEF: \$1,303,502.

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 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: \$976,386.

TECO: The Company did not set an estimated 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 8: What are the appropriate final fuel adjustment true-up amounts for the period January 2017 through December 2017?**

**STIPULATION:**

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

DEF: \$16,096,208, under-recovery, as reflected on Line 12 of the Summary of Actual True-Up Amount Schedule (Exhibit CAM-1T, Sheet 1 of 6).

FPL: \$23,632,267, under-recovery, as reflected on Line 3 of the Summary Of Net True Up Schedule (2017 FCR Final True Up, Exhibit RBD-1, Page 1 of 3).

FPUC: \$2,245,979, under-recovery as reflected on Line 10 of Schedule A (Exhibit CDY-1, Page 1 of 3).

GULF: \$10,213,781 over-recovery, as reflected on Line C9, Schedule 2, 2017 Final True-Up Schedules (Exhibit CSB-1, Page 2 of 7).

TECO: \$7,199,907, over-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 2018 through December 2018?**

**STIPULATION:**

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

DEF: \$34,602,826, under-recovery, as reflected on Line 8 of Schedule E1-B (Exhibit CAM-3, Part 2, Page 2 of 2).

FPL: \$88,108,249, under-recovery, as reflected on Lines 41 plus Line 42 of Schedule E1-B (2018 FCR Actual Estimated, Exhibit RBD-3, Page 1 of 40).

FPUC: \$3,176,245, under-recovery, as reflected on Lines 83 and 84 of Schedule E-1b (Exhibit MC-1, Page 2 of 3).

GULF: \$13,195,558, over-recovery, as reflected on Line C9, Schedule E-1B, Page 2 of 2 (Exhibit CSB-5, 2019 Projection Filing, Page 4 of 41).

TECO: \$184,422, under-recovery, as reflected on Schedule E1-B, Line C9 (Exhibit PAR-2, Calculation of Estimated True-Up, Document No. 1, Page 2 of 30).

**ISSUE 10: What are the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2019 through December 2019?**

**STIPULATION:**

The appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2019 through December 2019 are as follows:

DEF: \$148,450,915, to be collected (under-recovery), as reflected on Line 13 of Schedule E1-B (Exhibit CAM-3, Part 2, Page 2 of 2).

FPL: \$111,740,516 to be collected (under-recovery), as reflected on Line 46 of Schedule E1-B (2018 FCR Actual/Estimated, Exhibit RBD-3, Page 1 of 40).

FPUC: On October 18, 2018, FPUC and OPC jointly proposed a stipulation to resolve all issues in Docket No. 20180048-EI. If approved, that proposal that impacts this issue.

If that stipulation is approved, the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2019 through December 2019 is \$3,957,772 to be collected (under-recovery), as reflected on Line 88 of Alternate Schedule E-1b (Alternate Exhibit MC-1, Page 2 of 3).

If that stipulation is not approved, the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2019 through December 2019 is \$5,422,224, to be collected (under-recovery), as reflected Line 87 of Schedule E-1b (Exhibit MC-1, Page 2 of 3).

Gulf: \$23,409,339, to be refunded (over-recovery), as reflected on Line 23, Schedule E-1 (Exhibit CSB-5, 2019 Projection Filing, Page 1 of 41).

TECO: \$7,015,485 to be refunded (over-recovery), as reflected on Line 28, Schedule E1 (Exhibit PAR-3, Document No. 2, Page 2 of 30).

**ISSUE 11:** **What are the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2019 through December 2019?**

**STIPULATION:**

The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2019 through December 2019 are as follows:

DEF: \$1,412,413,746, 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 (Exhibit CAM-3, Part 2, Page 1 of 1).

FPL: \$2,706,845,783, which is adjusted for jurisdictional losses, but excludes prior period true-up amounts, revenue taxes, GPIF amounts, and FPL's portion of Incentive Mechanism gains, as reflected on Line 27 of Schedule E1 (Appendix V – 2019 FCR Projections Schedule, Exhibit RBD-8, Page 1 of 6). The jurisdictional savings amounts from the 2019 SoBRAs and the Okeechobee Clean Energy Center are incorporated in this amount, and the spread across the entire year.

FPUC: \$61,162,693, as reflected on Line 27, Schedule E1 (Exhibit MC-2, Page 1 of 8).

GULF: \$359,681,325, which is adjusted for line losses, but excluding prior period true-up amounts, revenue taxes, GPIF amounts, and the estimated tax credit savings, as

reflected on Line 22, Schedule E1 (Exhibit CSB-5, 2019 Projection Filing, Page 1 of 41).

TECO: \$537,871,753, which is adjusted for jurisdictional losses, but excluding prior period true-up amounts, revenue taxes, and GPIF amounts, as reflected on Line 27, Schedule E1 (Exhibit PAR-3, Document No. 2, Page 2 of 30).

### **Tampa Electric Company**

**ISSUE 15A: What adjustments, if any, should be made to correct Tampa Electric's calculations of its GPIF rewards or penalties for the years 2014, 2015, and 2016?**

### **STIPULATION:**

The Bayside Station is one of the generating stations in Tampa Electric's GPIF program. Tampa Electric recently discovered inaccuracies in the performance data it recorded for Bayside Station that impacted the GPIF calculations for the years 2014, 2015, and 2016.

Exhibit BSB-2 reflects corrections to the previously-reported performance data and re-calculated GPIF results for the years 2014, 2015, and 2016. The adjustments that should be made to correct Tampa Electric's calculations of its GPIF rewards or penalties for the years 2014, 2015, and 2016 are shown in Table 15A-1 below:

**Table 15A-1  
Adjustments in GPIF Calculations for TECO for 2014-2016**

Year	Original Calculation of GPIF Reward / (Penalty)	Corrected Calculation of GPIF Reward / (Penalty)	Difference between the Corrected and Original Calculations
2014	\$1,258,599	\$1,990,038	\$731,439
2015	969,593	1,711,713	742,120
2016	47,392	1,024,743	<u>977,351</u>
		Total	<u>\$2,450,910</u>

Source: Corrected Actual GPIF Incentive Points Calculations (Exhibit BSB-2, Page 32 of 39 of Document 2 (for 2014), Page 32 of 39 of Document 4 (for 2015), and Page 32 of 39 of Document 6 (for 2016)).

**ISSUE 15B: Should the Commission approve Tampa Electric's proposed corrections to its GPIF 2017 and 2018 targets?**



**STIPULATION:**

Yes. The appropriate proposed corrections to Tampa Electric’s GPIF 2017 and 2018 targets/ranges are shown in Table 15B-1 for 2017, and Table 15B-2 for 2018, as shown below:

**Table 15B-1  
Corrected GPIF Targets/Ranges for the period January-December, 2017**

	Plant/Unit	Target	Maximum		Target	Maximum		
		EAF (%)	EAF (%)	Savings (\$000's)	ANOHR BTU/KWH	ANOHR BTU/KWH	Savings (\$000's)	
TECO	Big Bend 1	80.5	83.4	1,202.8	10,698	10,987	1,677.5	
	Big Bend 2	69.6	74.7	1,583	10,545	10,992	2,294.1	
	Big Bend 3	61.4	65.8	1,008.9	10,588	10,852	1,136.4	
	Big Bend 4	79.1	82.3	1,422.8	10,447	10,652	1,309.3	
	Polk 1	82.1	84.6	779.9	10,048	10,568	1,275.5	
	Bayside 1	75.3	77.5	498.6	7,357	7,435	985.1	
	Bayside 2	76.1	78.0	113.7	7,526	7,665	1698.7	
	Total				6,609.7			10,376.6

Source: Corrected GPIF Target and Range Summary (Exh. BSB-2, Document 7, Page 4 of 40).

**Table 15B-2  
Corrected GPIF Targets/Ranges for the period January-December, 2018**

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

Source: Corrected GPIF Target and Range Summary (Exh. BSB-2, Document 8, Page 4 of 40).

**ISSUE 16:** What is the appropriate generation performance incentive factor (GPIF) reward or penalty for performance achieved during the period January 2017 through December 2017 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 2017 through December 2017 for each investor-owned electric utility subject to the GPIF is as follows:

- DEF \$2,301,526 penalty, as reflected on Original Sheet No. 6.101.1, GPIF Reward/Penalty Table (Exhibit MJJ-1T, Page 2 of 24), and also on Line 26 of Schedule E1 (Exhibit CAM-3, Part 2, Page 1 of 1).
- FPL \$5,857,941 reward, as reflected in Reward/Penalty Table (Actual) For the Period January through December, 2017 (Exhibit CRR-1, Page 2 of 20), and also on Line 32 of Schedule E1, Appendix II – 2019 FCR Projections Schedule (Exhibit RBD-5, Page 1 of 91).
- GULF \$256,872 penalty, as reflected in GPIF 2017 Results Filing (Exhibit CLN-1, Page 28 of 51, Schedule 4, Page 2 of 2), and also on Line 27, Schedule E1 (Exhibit CSB-5, 2019 Projection Filing, Page 1 of 41).
- TECO \$4,711,929 penalty, 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 2019 through December 2019 for each investor-owned electric utility subject to the GPIF?**

**STIPULATION:**

The appropriate GPIF targets/ranges be for the period January 2019 through December 2019 for each investor-owned electric utility subject to the GPIF are shown in Tables 17-1 through 17-4 below:

- DEF: See Table 17-1 below:
- FPL: See Table 17-2 below:
- Gulf: See Table 17-3 below:
- TECO: See Table 17-4 below:

**Table 17-1**  
**GPIF Targets/Ranges for the period January-December, 2019**

	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	77.28	81.18	684	8,075	8,724	10,278
	Crystal River 4	88.12	92.48	1,399	10,237	10,773	6,743
	Crystal River 5	78.10	80.15	741	10,206	10,764	5,939
	Hines 1	91.96	92.78	279	7,337	7,754	2,750
	Hines 2	92.15	92.88	82	7,501	7,777	1,811
	Hines 3	88.09	89.19	370	7,354	7,599	1,789
	Hines 4	88.17	85.53	1,026	7,050	7,262	1,756
	Total			4,580			31,066

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

**Table 17-2**  
**GPIF Targets/Ranges for the period January-December, 2019**

	Plant/Unit	EAF			ANOHR		
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings (\$000's)	ANOHR BTU/KWH	ANOHR BTU/KWH	Savings (\$000's)
FPL	Cape Canaveral 3	77.7	80.7	1,375	6,644	6,771	2,283
	Manatee 3	91.2	93.7	1,044	6,924	7,058	2,010
	Ft. Myers 2	81.5	84.0	1,195	7,298	7,429	3,052
	Martin 8	90.8	93.3	1,047	6,977	7,129	2,286
	Riviera 5	86.7	89.2	1,270	6,661	6,754	1,856
	St. Lucie 1	84.6	87.6	4,157	10,404	10,503	393
	St. Lucie 2	93.6	96.6	3,848	10,268	10,358	344
	Turkey Point 3	93.6	96.6	3,597	11,021	11,176	674
	Turkey Point 4	81.3	84.3	3,263	10,954	11,126	612
	West County 1	87.4	90.4	1,913	7,012	7,144	2,691
	West County 2	84.5	87.0	1,186	6,946	7,085	2,626
	West County 3	86.8	89.8	1,972	6,982	7,121	2,943
Total			25,867			21,770	

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

**Table 17-3**  
**GPIF Targets/Ranges for the period January-December, 2019**

	Plant/Unit	EAF			ANOHR		
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings (\$000's)	ANOHR BTU/KWH	ANOHR BTU/KWH	Savings (\$000's)
GULF	Scherer 3	79.5	80.4	11	10,617	10,936	1,205
	Crist 7	90.2	93.2	10	10,585	10,903	559
	Daniel 1	93.5	95.6	0	11,976	12,335	25
	Daniel 2	86.5	88.2	0	11,673	12,023	37
	Smith 3	93.6	94	57	6,882	7,088	2,923
	Total			78			4,749

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

**Table 17-4**  
**GPIF Targets/Ranges for the period January-December, 2019**

	Plant/Unit	Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings (\$000's)	ANOHR BTU/KWH	ANOHR BTU/KWH	Savings (\$000's)
		TECO	Polk 1	83.3	85.4	549.8	10,170
Polk 2	90.9		91.7	205.7	6,930	7,103	3,998.7
Bayside 1	91.0		91.7	120.0	7,400	7,516	1,517.1
Bayside 2	87.4		88.8	337.7	7,561	7,789	2,964.0
Total			1,213.2			9,625.6	

Source: GPIF Target and Range Summary (Exhibit BSB-3, Document 1, Page 4 of 27).

**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 2019 through December 2019?

**STIPULATION:**

The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2019 through December 2019 are as follows:

DEF: \$1,559,686,958, as reflected on Line 27 of Schedule E1 (Exhibit CAM-3, Part 2, Page 1 of 1).

FPL: \$2,828,678,170, which includes prior period true-up amounts, revenue taxes, the GPIF reward, FPL's portion of Incentive Mechanism gains, and the jurisdictional savings amounts from the 2019 SoBRAs and the Okeechobee Clean Energy

Center, as reflected on Line 34 of Schedule E1 (Appendix V – 2019 FCR Projections Schedule, Exhibit RBD-8, Page 1 of 6).

FPUC: On October 18, 2018, FPUC and OPC jointly proposed a stipulation to resolve all issues in Docket No. 20180048-EI. If approved, that proposal that impacts this issue.

If that stipulation is approved, the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2019 through December 2019 is \$64,370,465, which includes prior period true-up amounts, as reflected on Line 31, Alternate Schedule E1 (Alternate Exhibit MC-2, Page 1 of 8).

If that stipulation is not approved, the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2019 through December 2019 is \$65,834,917, which includes prior period true-up amounts, as reflected on Line 31, Schedule E1 (Exhibit MC-2, Page 1 of 8).

GULF: \$326,311,230, which is adjusted for line losses, and includes prior period true-up amounts, revenue taxes, GPIF amounts, and the estimated tax credit savings, as reflected on Line 30, Schedule E1 (Exhibit CSB-5, 2019 Projection Filing, Page 1 of 41).

TECO: \$528,977,466, which is adjusted for jurisdictional losses, and includes prior period true-up amounts, revenue taxes, and GPIF amounts, 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 2019 through December 2019?**

**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 2019 through December 2019 is 1.00072.

**ISSUE 20: What are the appropriate levelized fuel cost recovery factors for the period January 2019 through December 2019?**

**STIPULATION:**

The appropriate levelized fuel cost recovery factors for the period January 2019 through December 2019 are as follows:

DEF: The appropriate levelized factor is 3.969 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. 2.735 cents per kWh (adjusted for jurisdictional losses and revenue taxes), for the period January 1, 2019 through the day prior to the in-service date of the 2019 SoBRA (projected to be February 28, 2019), as reflected on Line 37 of Schedule E1 (Appendix II – 2019 FCR Projections Schedule, Exhibit RBD-5, Page 1 of 91).
- B. 2.712 cents per kWh (adjusted for jurisdictional losses and revenue taxes), for the period March 1, 2019 through the day prior to the in-service date of the Okeechobee Clean Energy Center (projected to be May 31, 2019), as reflected on Line 38 of Schedule E1 (Appendix III – 2019 FCR Projections Schedule, Exhibit RBD-6, Page 1 of 7).
- C. 2.551 cents per kWh (adjusted for jurisdictional losses and revenue taxes), for the period June 1, 2019 through December, 31, 2019, as reflected on Line 39 of Schedule E1 (Appendix IV – 2019 FCR Projections Schedule, Exhibit RBD-7, Page 1 of 7).

FPUC: On October 18, 2018, FPUC and OPC jointly proposed a stipulation to resolve all issues in Docket No. 20180048-EI. If approved, that proposal that impacts this issue.

If that stipulation is approved, the appropriate levelized factor is 6.212 cents per kWh, as reflected on Line 43, Alternate Schedule E1 (Alternate Exhibit MC-2, Page 2 of 8).

If that stipulation is not approved, the appropriate levelized factor is 6.433 cents per kWh, as reflected on Line 43, Schedule E1 (Exhibit MC-2, Page 2 of 8).

GULF: The appropriate levelized factor is 3.030 cents/kWh., as reflected on Line 31, Schedule E-1 (Exhibit CSB-5, 2019 Projection Filing, Page 1 of 41).

TECO: The appropriate factor is 2.715 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, 2019**

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 August 24, 2018 (Pages 2-3).

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

FPUC: The appropriate fuel recovery line loss multiplier to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class is 1.0000, as reflected on Line 26a, Schedule E1 (Exhibit MC-2, Page 1 of 8).

GULF: See Table 21-2 below:

**Table 21-2  
 GULF Fuel Recovery Line Loss Multipliers  
 for the period January-December, 2019**

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, 2019 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, 2019**

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

Source: Schedule E1-E, 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 22-13 below:

DEF: DEF's appropriate fuel cost recovery factors for each rate class/delivery voltage level class, adjusted for line losses, are as provided below. In recognition of the decreasing spread between on-peak and off-peak time of use fuel cost factors, DEF will evaluate, what, if any adjustments to the calculation of on- and off-peak



time of use fuel cost factors are appropriate. DEF will provide its findings in Docket No. 20190001-EI.

**Table 22-1**  
**DEF Fuel Cost Recovery Factors**

Fuel Cost Factors (cents/kWh)						
Group	Delivery Voltage Level	First Tier Factor	Second Tier Factors	Levelized Factors	Time of Use	
					On-Peak	Off-Peak
A	Transmission	--	--	3.895	4.857	3.470
B	Distribution Primary	--	--	3.934	4.906	3.505
C	Distribution Secondary	3.698	4.698	3.974	4.956	3.541
D	Lighting Secondary	--	--	3.805	--	--

Source: Schedule E1-E (Exhibit CAM-3, Part II, 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. The factors for January and February, 2019 are shown in Tables 22-2 and 22-3 below. The factors for March through May, 2019 are shown in Tables 22-4 and 22-5 below. The factors for June through December, 2019 are shown in Tables 22-6 and 22-7 below:

**Table 22-2**  
**FPL Fuel Cost Recovery Factors for the period January-February, 2019**

Fuel Recovery Factors – By Rate Group (Adjusted for Line Losses)				
For the Period January through February, 2019				
Group	Rate Schedule	Avg. Factor	Loss Multiplier	Fuel Recovery Factor
A	RS-1 first 1,000 kWh	2.735	1.00487	2.412
	RS-1, all addl. kWh	2.735	1.00487	3.412
	GS-1, SL-2, GSCU-1, WIES-1	2.735	1.00487	2.748
A-1	SL-1, OL-1, PL-1	2.591	1.00487	2.604
B	GSD-1	2.735	1.00482	2.748
C	GSLD-1, CS-1	2.735	1.00412	2.746
D	GSLD-2, CS-2, OS-2, MET	2.735	0.99638	2.725
E	GSLD-3, CS-3	2.735	0.97324	2.662
A	GST-1 On-Peak	3.457	1.00487	3.474
	GST-1 Off Peak	2.426	1.00487	2.438
	RTR-1 On-Peak	-	-	0.726
	RTR-1 Off-Peak	-	-	(0.310)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On Peak	3.457	1.00481	3.474
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off Peak	2.426	1.00481	2.438
C	GSDLT-1, CST-1, HLFT-2 (500-1,9999 kW) On Peak	3.457	1.00412	3.471
	GSDLT-1, CST-1, HLFT-2 (500-1,9999 kW) Off Peak	2.426	1.00412	2.436

D	GSDLT-2, CST-2, HLFT-3 (2,000+ kW) On Peak	3.457	0.99690	3.446
	GSDLT-2, CST-2, HLFT-3 (2,000+ kW) On Peak	2.426	0.99690	2.418
E	GSDLT-3, CST-3, CILC-1(T), ISST-1(T) On Peak	3.457	0.97324	3.364
	GSDLT-3, CST-3, CILC-1(T), ISST-1(T) Off Peak	2.426	0.97324	2.361
F	CILC-1(D), ISST-1(D) On Peak	3.457	0.99646	3.445
	CILC-1(D), ISST-1(D) Off Peak	2.426	0.99646	2.417

Source: Schedule E1-E, Page 1 of 2 (Exh. RBD-5, Appendix II – 2019 FCR Projections, Page 7 of 91).

**Table 22-3**  
**FPL Fuel Cost Recovery Factors for the period January-February, 2019**

Seasonal Demand Time of Use Rider (SDTR) Fuel Recovery Factors				
For the Period June - September, 2019				
Group	Rate Schedule	Avg. Factor	Loss Multiplier	Fuel Recovery Factor
B	GSD(T)-1 On-Peak	4.611	1.00482	4.633
	GSD(T)-1 Off-Peak	2.494	1.00482	2.506
C	GSLD(T)-1 On-Peak	4.611	1.00412	4.630
	GSLD(T)-1 Off-Peak	2.494	1.00412	2.504
D	GSLD(T)-2 On-Peak	4.611	0.99690	4.597
	GSLD(T)-2 Off-Peak	2.494	0.99690	2.486

Source: Schedule E1- E, Page 2 of 2 (Exh. RBD-5, Appendix II – 2019 FCR Projections, Page 8 of 91).

**Table 22-4**  
**FPL Fuel Cost Recovery Factors for the period March-May, 2019**

Fuel Recovery Factors – By Rate Group (Adjusted for Line Losses)				
For the Period March through May, 2019				
Group	Rate Schedule	Avg. Factor	Loss Multiplier	Fuel Recovery Factor
A	RS-1 first 1,000 kWh	2.712	1.00487	2.389
	RS-1, all addl. kWh	2.712	1.00487	3.389
	GS-1, SL-2, GSCU-1, WIES-1	2.712	1.00487	2.725
A-1	SL-1, OL-1, PL-1	2.569	1.00487	2.582
B	GSD-1	2.712	1.00482	2.725
C	GSLD-1, CS-1	2.712	1.00412	2.723
D	GSLD-2, CS-2, OS-2, MET	2.712	0.99638	2.702
E	GSLD-3, CS-3	2.712	0.97324	2.639
A	GST-1 On-Peak	3.428	1.00487	3.445
	GST-1 Off Peak	2.406	1.00487	2.418
	RTR-1 On-Peak	-	-	0.720
	RTR-1 Off-Peak	-	-	(0.307)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On Peak	3.428	1.00481	3.445
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off Peak	2.406	1.00481	2.418

C	GSDLT-1, CST-1, HLFT-2 (500-1,9999 kW) On Peak	3.428	1.00412	3.442
	GSDLT-1, CST-1, HLFT-2 (500-1,9999 kW) Off Peak	2.406	1.00412	2.416
D	GSDLT-2, CST-2, HLFT-3 (2,000+ kW) On Peak	3.428	0.99690	3.417
	GSDLT-2, CST-2, HLFT-3 (2,000+ kW) Off Peak	2.406	0.99690	2.399
E	GSDLT-3, CST-3, CILC-1(T), ISST-1(T) On Peak	3.428	0.97324	3.336
	GSDLT-3, CST-3, CILC-1(T), ISST-1(T) Off Peak	2.406	0.97324	2.342
F	CILC-1(D), ISST-1(D) On Peak	3.428	0.99646	3.416
	CILC-1(D), ISST-1(D) Off Peak	2.406	0.99646	2.397

Source: Schedule E1-E, Page 1 of 2 (Exh. RBD-6, Appendix III – 2019 FCR Projections, Page 3 of 7).

**Table 22-5**  
**FPL Fuel Cost Recovery Factors for the period March-May, 2019**

Seasonal Demand Time of Use Rider (SDTR) Fuel Recovery Factors				
For the Period June - September, 2019				
Group	Rate Schedule	Avg. Factor	Loss Multiplier	Fuel Recovery Factor
B	GSD(T)-1 On-Peak	4.572	1.00482	4.594
	GSD(T)-1 Off-Peak	2.473	1.00482	2.485
C	GSLD(T)-1 On-Peak	4.572	1.00412	4.591
	GSLD(T)-1 Off-Peak	2.473	1.00412	2.483
D	GSLD(T)-2 On-Peak	4.572	0.99690	4.558
	GSLD(T)-2 Off-Peak	2.473	0.99690	2.465

Source: Schedule E1- E, Page 2 of 2 (Exh. RBD-6, Appendix III – 2019 FCR Projections, Page 4 of 7).

**Table 22-6**  
**FPL Fuel Cost Recovery Factors for the period June-December, 2019**

Fuel Recovery Factors – By Rate Group (Adjusted for Line Losses)				
For the Period June through December, 2019				
Group	Rate Schedule	Avg. Factor	Loss Multiplier	Fuel Recovery Factor
A	RS-1 first 1,000 kWh	2.551	1.00487	2.227
	RS-1, all addl. kWh	2.551	1.00487	3.227
	GS-1, SL-2, GSCU-1, WIES-1	2.551	1.00487	2.563
A-1	SL-1, OL-1, PL-1	2.417	1.00487	2.428
B	GSD-1	2.551	1.00482	2.563
C	GSLD-1, CS-1	2.551	1.00412	2.562
D	GSLD-2, CS-2, OS-2, MET	2.551	0.99638	2.542
E	GSLD-3, CS-3	2.551	0.97324	2.483
A	GST-1 On-Peak	3.224	1.00487	3.240
	GST-1 Off Peak	2.263	1.00487	2.274
	RTR-1 On-Peak	-	-	0.677
	RTR-1 Off-Peak	-	-	(0.289)

B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On Peak	3.224	1.00481	3.240
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off Peak	2.263	1.00481	2.274
C	GSDLT-1, CST-1, HLFT-2 (500-1,9999 kW) On Peak	3.224	1.00412	3.237
	GSDLT-1, CST-1, HLFT-2 (500-1,9999 kW) Off Peak	2.263	1.00412	2.272
D	GSDLT-2, CST-2, HLFT-3 (2,000+ kW) On Peak	3.224	0.99690	3.214
	GSDLT-2, CST-2, HLFT-3 (2,000+ kW) Off Peak	2.263	0.99690	2.256
E	GSDLT-3, CST-3, CILC-1(T), ISST-1(T) On Peak	3.224	0.97324	3.138
	GSDLT-3, CST-3, CILC-1(T), ISST-1(T) Off Peak	2.263	0.97324	2.202
F	CILC-1(D), ISST-1(D) On Peak	3.224	0.99646	3.213
	CILC-1(D), ISST-1(D) Off Peak	2.263	0.99646	2.255

Source: Schedule E1-E, Page 1 of 2 (Exh. RBD-7, Appendix IV – 2019 FCR Projections, Page 3 of 7).

**Table 22-7**  
**FPL Fuel Cost Recovery Factors for the period June-December, 2019**

Seasonal Demand Time of Use Rider (SDTR) Fuel Recovery Factors				
For the Period June - September, 2019				
Group	Rate Schedule	Avg. Factor	Loss Multiplier	Fuel Recovery Factor
B	GSD(T)-1 On-Peak	4.301	1.00482	4.322
	GSD(T)-1 Off-Peak	2.327	1.00482	2.338
C	GSLD(T)-1 On-Peak	4.301	1.00412	4.319
	GSLD(T)-1 Off-Peak	2.327	1.00412	2.337
D	GSLD(T)-2 On-Peak	4.301	0.99690	4.288
	GSLD(T)-2 Off-Peak	2.327	0.99690	2.320

Source: Schedule E1- E, Page 2 of 2 (Exh. RBD-7, Appendix IV – 2019 FCR Projections, Page 4 of 7).

FPUC: On October 18, 2018, FPUC and OPC jointly proposed a stipulation to resolve all issues in Docket No. 20180048-EI. If approved, that proposal that impacts this issue.

If that stipulation is approved, the appropriate levelized fuel adjustment and purchased power cost recovery factors for the period January 2019 through December 2019 for the Consolidated Electric Division, adjusted for line loss multipliers and including taxes, are shown in Alternate Tables 22-8 through 22-10 below:

If that stipulation is not approved, the appropriate levelized fuel adjustment and purchased power cost recovery factors for the period January 2019 through December 2019 for the Consolidated Electric Division, adjusted for line loss multipliers and including taxes, are shown in Tables 22-8 through 22-10 below:

**Alternate Table 22-8  
FPUC Fuel Cost Recovery Factors for the period January-December, 2019**

Fuel Recovery Factors – By Rate Schedule	
For the Period January through December, 2019	
Rate Schedule	Levelized Adjustment (cents/kWh)
RS	9.885
GS	9.564
GSD	9.141
GSLD	8.842
LS	6.952

Source: Alternate Schedule E1, Page 3 of 3 (Alternate Exhibit MC-2, Cost Recovery Clause Calculation, Page 3 of 8).

**Alternative Table 22-9  
FPUC Fuel Cost Recovery Factors for the period January-December, 2019**

Step Rate Allocation For Residential Customers (RS Rate Schedule)	
For the Period January through December, 2019	
Rate Schedule and Allocation	Levelized Adjustment (cents/kWh)
RS Rate Schedule – Sales Allocation	9.885
RS Rate Schedule with less than or equal to 1,000 kWh/month	9.562
RS Rate Schedule with more than 1,000 kWh/month	10.776

Source: Alternative Schedule E1, Page 3 of 3 (Alternative Exhibit MC-2, Cost Recovery Clause Calculation, Page 3 of 8)

**Alternate Table 22-10  
FPUC Fuel Cost Recovery Factors for the period January-December, 2019**

Fuel Recovery Factors for Time Of Use – By Rate Schedule		
For the Period January through December, 2019		
Rate Schedule	Levelized Adjustment On Peak (cents/kWh)	Levelized Adjustment Off Peak (cents/kWh)
RS	17.926	5.626
GS	13.564	4.564
GSD	13.141	5.891
GSLD	14.842	5.842
Interruptible	7.342	8.842

Source: Alternate Schedule E1, Page 3 of 3 (Alternate Exhibit MC-2, Cost Recovery Clause Calculation, Page 3 of 8).

**Table 22-8  
FPUC Fuel Cost Recovery Factors for the period January-December, 2019**

Fuel Recovery Factors – By Rate Schedule	
For the Period January through December, 2019	
Rate Schedule	Levelized Adjustment (cents/kWh)
RS	10.106
GS	9.785
GSD	9.362
GSLD	9.063
LS	7.173

Source: Schedule E1, Page 3 of 3 (Exhibit MC-2, Cost Recovery Clause Calculation, Page 3 of 8).

**Table 22-9  
FPUC Fuel Cost Recovery Factors for the period January-December, 2019**

Step Rate Allocation For Residential Customers (RS Rate Schedule)	
For the Period January through December, 2019	
Rate Schedule and Allocation	Levelized Adjustment (cents/kWh)
RS Rate Schedule – Sales Allocation	10.106
RS Rate Schedule with less than or equal to 1,000 kWh/month	9.747
RS Rate Schedule with more than 1,000 kWh/month	10.997

Source: Schedule E1, Page 3 of 3 (Exhibit MC-2, Cost Recovery Clause Calculation, Page 3 of 8).

**Table 22-10**  
**FPUC Fuel Cost Recovery Factors for the period January-December, 2019**

Fuel Recovery Factors for Time Of Use – By Rate Schedule		
For the Period January through December, 2019		
Rate Schedule	Levelized Adjustment On Peak (cents/kWh)	Levelized Adjustment Off Peak (cents/kWh)
RS	18.147	5.847
GS	13.785	4.785
GSD	13.362	6.112
GSLD	15.063	6.063
Interruptible	7.563	9.063

Source: Schedule E1, Page 3 of 3 (Exhibit MC-2, 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 2019 through December 2019, are shown in Tables 22-11 and 22-12 below:

**Table 22-11**  
**Gulf Standard Fuel Cost Recovery Factors**  
**for the period January-December, 2019**

Group	Rate Schedules	Fuel Cost Recovery Factors ¢/KWH
A	RS, RSVP, RSTOU, GS, GSD, GSDD, GSTOU, OSIII	3.047
B	LP	3.005
C	PX, RTP	2.959
D	OSI/II	3.008

Source: Schedule E1-E (Exhibit CSB-5, 2019 Projection Filing, Page 8 of 41).

**Table 22-12**  
**Gulf Time-of-Use Fuel Cost Recovery Factors**  
**for the period January-December, 2019**

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	3.681	2.782
B	LPT, SBS(2)	0.99188	3.631	2.745
C	PXT, SBS(3)	0.97668	3.576	2.702
(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, 2019 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 2019 through December 2019, are shown in Table 22-13 below:

**Table 22-13**  
**TECO Fuel Cost Recovery Factors for the period January-December, 2019**

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)
<b>STANDARD</b>			
Distribution Secondary (RS only)	--	2.405	3.405
Distribution Secondary	2.719		
Distribution Primary	2.692		
Transmission	2.665		
Lighting Service	2.691		
<b>TIME OF USE</b>			
Distribution Secondary- On-Peak	2.874		
Distribution Secondary- Off-Peak	2.653		
Distribution Primary- On-Peak	2.845		
Distribution Primary- Off-Peak	2.626		
Transmission – On-Peak	2.817		
Transmission – Off-Peak	2.600		

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 \$43,858,854 in the capacity cost recovery clause for nuclear cost recovery, as reflected on Line 35, Schedule E12-A (Exhibit CAM-2, Part 3, Page 1 of 2).

**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: Has FPL properly reflected in the capacity cost recovery clause the effects of the St. John's River Power Park transaction approved by Order No. PSC-2017-0415-AS-EI?**

**STIPULATION:**

Yes, as reflected in 2018 CCR Actual Estimated Schedule (Exhibit RDB-4, Page 14 of 18).

**ISSUE 24C: What are the appropriate Indiantown non-fuel base revenue requirements to be recovered through the Capacity Clause pursuant to the Commission's approval of the Indiantown transaction in Docket No. 160154-EI for 2018 and 2019?**

**STIPULATION:**

For 2019, the appropriate projected 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 is \$3,304,628, as reflected on Line 15 of the Indiantown 2019 Revenue Requirements Schedule (Exhibit RDB-9, Appendix VI - 2019 CCR Projections Schedule, Page 20 of 31).

**ISSUE 24D: 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 2019?**

**STIPULATION:**

This issue is not ripe for consideration during the hearing cycle for 2018, and will be addressed in Docket No. 20190001-EI.

**ISSUE 24E: 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 2019?**

**STIPULATION:**

This issue is not ripe for consideration during the hearing cycle for 2018, and will be addressed in Docket No. 20190001-EI.

**GENERIC CAPACITY COST RECOVERY FACTOR ISSUES**

**ISSUE 27: What are the appropriate final capacity cost recovery true-up amounts for the period January 2017 through December 2017?**

**STIPULATION:**

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

DEF: \$346,154, over-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: \$2,212,807, under-recovery, as reflected on Line 3 of Capacity Cost Recovery Clause Final True Up Summary Schedule (Exhibit RBD-2, 2017 CCR Final True Up, Page 1 of 12).

GULF: \$846,417, over-recovery, as reflected on Line 2, Schedule CCE-1A, 2018 Est/Actual Schedules (Exhibit CSB-3, Page 29 of 33).

TECO: \$1,952,049, under-recovery, as reflected on Line 3, CCR 2017 Final True-Up (Exhibit PAR-1, Document No. 1, Page 1 of 4).

**ISSUE 28:** What are the appropriate capacity cost recovery actual/estimated true-up amounts for the period January 2018 through December 2018?

**STIPULATION:**

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

DEF: \$16,264,319, over-recovery, as reflected on Line 42, Schedule E12-B (Exhibit CAM-2, Part 2, Page 1 of 2).

FPL: \$6,415,909, over-recovery, as reflected on Lines 9 plus Line 10, Capacity Cost Recovery Calculation of Actual/Estimated True-Up Amount (Exhibit RBD-4, 2018 CCR Actual Estimated, Page 3 of 18).

GULF: \$1,187,593, over-recovery, as reflected on Line 1, Schedule CCE-1A, 2018 Est/Actual Schedules (Exhibit CSB-3, Page 29 of 33).

TECO: \$832,939, under-recovery, as reflected on Line 2, Capacity Cost Recovery Calculation of the Current Period True-Up (Exhibit PAR-2, Document No. 2, Page 1 of 4).

**ISSUE 29:** What are the appropriate total capacity cost recovery true-up amounts to be collected/refunded during the period January 2019 through December 2019?

**STIPULATION:**

The appropriate total capacity cost recovery true-up amounts to be collected/refunded during the period January 2019 through December 2019 are as follows:

DEF: \$16,610,473, over-recovery, as reflected on Line 46, Schedule E12-B (Exhibit CAM-2, Part 2, Page 1 of 2).

FPL: \$4,203,102, over-recovery, as reflected on Line 15, Capacity Cost Recovery Calculation of Actual/Estimated True-Up Amount (Exhibit RBD-4, 2018 CCR Actual Estimated, Page 3 of 18).

GULF: \$2,034,010, over-recovery, as reflected on Line 3, Schedule CCE-1A, 2018 Est/Actual Schedules (Exhibit CSB-3, Page 29 of 33).

TECO: \$2,784,988, under-recovery, as reflected on Line 3, Capacity Cost Recovery Calculation of the Current Period True-Up (Exhibit PAR-2, Document No. 2, Page 1 of 4).

**ISSUE 30: What are the appropriate projected total capacity cost recovery amounts for the period January 2019 through December 2019?**

**STIPULATION:**

The appropriate projected total capacity cost recovery amounts for the period January 2019 through December 2019 are as follows:

DEF: \$395,724,869, as reflected on Line 28, Schedule E12-A (Exhibit CAM-2, Part 3, Page 1 of 2).

FPL: \$260,414,750, which excludes prior period true-up amounts, revenue taxes and the Indiantown non-fuel base revenue requirement, as reflected on Line 27, Appendix VI - 2019 CCR Projections Schedule (Exhibit RBD-9, Page 2 of 31).

GULF: \$74,394,162, which is adjusted for jurisdictional losses, but excludes prior period true-up amounts, and revenue taxes, as reflected on Line 7 of Schedule CCE-1, 2019 Projection Filing (Exhibit CSB-5, Page 36 of 41).

TECO: \$14,327,487, 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).

**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 2019 through December 2019?**

**STIPULATION:**

The appropriate projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January 2019 through December 2019 are as follows:

DEF: \$430,136,347, as reflected on Line 39, Schedule E12-A (Exhibit CAM-2, Part 3, Page 1 of 2).

FPL: \$259,700,749, which includes prior period true-up amounts, revenue taxes and the Indiantown non-fuel based revenue requirement, as reflected Line 39, Appendix

VI - 2019 CCR Projections Schedule (Exhibit RBD-9, Page 2 of 31) plus Line 15, Appendix VI – 2019 CCR Projections Schedule (Exhibit RBD-9, Page 17 of 31).

GULF: \$72,412,251, which is adjusted for jurisdictional losses, and includes prior period true-up amounts and revenue taxes, as reflected on Line 11 of Schedule CCE-1, 2019 Projection Filing (Exhibit CSB-5, Page 36 of 41).

TECO: \$17,124,796, 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).

**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 2019 through December 2019?**

**STIPULATION:**

The appropriate jurisdictional separation factors for capacity revenues and costs to be included in the recovery factor for the period January 2019 through December 2019 are as follows:

DEF: Base – 92.885%, Intermediate – 72.703%, and Peaking – 95.924%, as reflected on Lines 10, 16, and 23, respectively, on Schedule E12-A (Exhibit CAM-3, Part 3, Page 1 of 2).

FPL:

<b>Demand</b>	<b>Separation Factors</b>
Transmission	0.892071
System Average Production Demand (base and solar)	0.957589
Contract Adjusted Demand – Intermediate	0.942474
Contract Adjusted Demand – Peaking	0.953443
<b>Energy</b>	
System Average Production Demand (base and solar)	0.959309
Contract Adjusted Demand – Intermediate	0.944167
Contract Adjusted Demand - Peaking	0.955155
<b>General Plant</b>	0.969214
<b>Distribution</b>	1.00000

Source: Appendix VI- 2019 CCR Projections Schedule (Exhibit RBD-9, Page 22 of 31).

GULF: FPSC - 97.18277%, and FERC - 2.81723%, as reflected on Schedule CCE-1, 2019 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 2019 through December 2019?

**STIPULATION:**

The appropriate capacity cost recovery factors for the period January 2019 through December 2019 are shown in Tables 33-1 through 33-6 below.

DEF: The appropriate capacity cost recovery factors for the period January 2019 through December 2019 are shown in Table 33-1 below.

**Table 33-1  
DEF Capacity Cost Recovery Factors for the period January-December, 2019**

Rate Class	2019 Capacity and Nuclear Cost Recovery Factors	
	Cents / kWh	Dollars / kW-month
Residential (RS-1, RST-1, RSL-1, RSL-2, RSS-1) At Secondary Voltage	1.248	
General Service Non-Demand (GS-1, GST-1)		
At Secondary Voltage	1.192	
At Primary Voltage	1.180	
At Transmission Voltage	1.168	
General Service (GS-2)	0.718	
Lighting (LS-1)	0.154	
General Service Demand (GSD-1, GSDDT-1, SS-1)		
At Secondary Voltage		3.72
At Primary Voltage		3.68
At Transmission Voltage		3.65
Curtable (CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3)		
At Secondary Voltage		1.47
At Primary Voltage		1.46
At Transmission Voltage		1.44
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		0.360

	At Primary Voltage		0.356
	At Transmission Voltage		0.353
Standby Daily (SS-1, 2, 3)			
	At Secondary Voltage		0.171
	At Primary Voltage		0.169
	At Transmission Voltage		0.168

Source: Schedule E12-E (Exhibit CAM-3, Part 3, Pages 1 of 2 and 2 of 2).

FPL: The appropriate capacity cost recovery factors for the period January 2019 through December 2019 are shown in Tables 33-2 through 33-4 below:

**Table 33-2**  
**FPL Capacity Cost Recovery Factors for the period January-December, 2019**

Rate Schedule	2019 Capacity Cost Recovery Factors			
	\$/kW	\$/kWh	Reservation Demand Charge (RDC) \$/kW	Sum of Daily Demand Charge (SDD) \$/kW
RS1/RTR1	-	0.00255	-	-
GS1/GST1	-	0.00251	-	-
GSD1/GSDT1/HLFT1	0.82	-	-	-
OS2	-	0.00102	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	0.94	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	0.89	-	-	-
GSLD3/GSLDT3/CS3/CST3	0.87	-	-	-
SST1T	-	-	\$0.11	\$0.05
SST1D1/SST1D2/SST1D3	-	-	\$0.11	\$0.05
CILC D/CILC G	0.96	-	-	-
CILC T	0.92	-	-	-
MET	0.82	-	-	-
OL1/SL1/SL1M/PL1	-	0.00018	-	-
SL2/SL2M/GSCU1	-	0.00170	-	-

Source: Appendix VI – 2019 CCR Projections (Exhibit RBD-9, Page 19 of 31).

**Table 33-3**  
**FPL Capacity Cost Recovery Factors for the period January-December, 2019**

Rate Schedule	2019 Indiantown Capacity Cost Recovery Factors			
	\$/kW	\$/kWh	Reservation Demand Charge (RDC) \$/kW	Sum of Daily Demand Charge (SDD) \$/kW
RS1/RTR1	-	0.00003	-	-
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 VI – 2019 CCR Projections (Exhibit RBD-9, Page 19 of 31).

**Table 33-4**  
**FPL Capacity Cost Recovery Factors for the period January-December, 2019**

Rate Schedule	2019 Total Capacity Cost Recovery Factors			
	\$/kW	\$/kWh	Reservation Demand Charge (RDC) \$/kW	Sum of Daily Demand Charge (SDD) \$/kW
RS1/RTR1	-	0.00258	-	-
GS1/GST1	-	0.00254	-	-
GSD1/GSDT1/HLFT1	0.83	-	-	-
OS2	-	0.00104	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	0.95	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	0.90	-	-	-
GSLD3/GSLDT3/CS3/CST3	0.88	-	-	-
SST1T	-	-	\$0.11	\$0.05
SST1D1/SST1D2/SST1D3	-	-	\$0.11	\$0.05
CILC D/CILC G	0.97	-	-	-
CILC T	0.93	-	-	-
MET	0.83	-	-	-
OL1/SL1/SL1M/PL1	-	0.00019	-	-
SL2/SL2M/GSCU1	-	0.00172	-	-

Source: Appendix VI – 2019 CCR Projections (Exhibit RBD-9, Page 19 of 31).



GULF: The appropriate capacity cost recovery factors for the period January 2019 through December 2019 are shown in Table 33-5 below:

**Table 33-5**  
**GULF Capacity Cost Recovery Factors for the period January-December, 2019**

Rate Class	2019 Capacity Cost Recovery Factors	
	Cents / kWh	Dollars / kW-month
RS, RSVP, RSTOU	0.776	-
GS	0.708	
GSD, GSDT, GSTOU	0.618	
LP, LPT	-	2.51
PX, PXT, RTP, SBS	0.520	-
OS-I/II	0.152	
OSIII	0.469	

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 2019 through December 2019 are shown in Table 33-6 below:

**Table 33-6**  
**TECO Capacity Cost Recovery Factors for the period January-December, 2019**

Rate Class and Metering Voltage	2019 Capacity Cost Recovery Factors	
	Cents / kWh	Dollars / kW
RS Secondary	0.103	-
GS and CS Secondary	0.086	
GSD, SBF Standard		
Secondary	-	0.32
Primary		0.32
Transmission		0.31
GSD Optional		
Secondary	0.075	-
Primary	0.074	
Transmission	0.074	
IS, SBI		
Primary	-	0.24
Transmission		0.24
LS1 Secondary	0.024	-

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 2019 through the last billing cycle for December 2019. The first billing cycle may start before January 1, 2019, and the last cycle may be read after December 31, 2019, 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 this docket be closed?**

**STIPULATION:**

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

HEDGING ISSUE STIPULATIONS

**ISSUE 1A: Should the Commission approve as prudent DEF's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in DEF's April 2018 and August 2018 hedging reports?**

**STIPULATION:**

Yes, the Commission should approve DEF's actions to mitigate fuel price volatility because those activities were taken pursuant to, and were consistent with, previously approved risk management plans. Pursuant to the 2017 RRSSA, DEF has agreed not to enter into any additional hedges during the term of the Agreement, however, the hedges at issue in this docket were entered into prior to the hedging moratorium. Over the period of August 2017 through July 2018, DEF's hedging activities resulted in a cost of approximately \$24.9 M. As indicated in Tampa Electric's Motion to Close Docket No. 20170057-EI, DEF supported the Motion and believes that docket can be closed.

**ISSUE 2A: Should the Commission approve as prudent FPL's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in FPL's April 2018 and August 2018 hedging reports?**

**STIPULATION:**

Yes, the Commission should approve FPL's actions to mitigate fuel price volatility because those activities were taken pursuant to, and were consistent with, previously approved risk management plans. Pursuant to Paragraph 16 of FPL's settlement agreement approved in Order No. PSC-16-0560-AS-EI dated December 15, 2016, FPL's fuel hedging program is under a moratorium. FPL has agreed not to enter into any additional hedges during the terms of the Agreement. However, the hedges at issue in this docket were entered prior to the hedging moratorium. FPL's hedging activities for the period January 1, 2017 through December 31, 2017 as reported in April 2018 in Docket No. 20180001-EI resulted in savings of \$37,833,753. FPL had no hedging activity to report for 2018 in the August 2018 hedging report. Upon review of these filings, FPL has complied with its Risk Management Plan as approved by this Commission and, therefore, its actions are found to be reasonable and prudent. As indicated in Tampa Electric's Motion to Close Docket No. 20170057-EI, FPL supported the Motion and believes that docket can be closed.

**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 2018 and August 2018 hedging reports?

**STIPULATION:**

Yes, the Commission should approve Gulf's actions to mitigate fuel price volatility because those activities were taken pursuant to, and were consistent with, previously approved risk management plans. Pursuant to the 2017 Stipulation and Settlement Agreement, Gulf has agreed not to enter into any additional hedges during the terms of the Agreement, however, the hedges at issue in this docket were entered prior to the hedging moratorium. Gulf's hedging activities for the period August 1, 2017 through July 31, 2018 are reported in April 2018 and August 2018 filings in Docket No. 20180001-EI and resulted in hedging net expense of \$20,129,290. Upon review of these filings, Gulf has complied with its Risk Management Plan as approved by this Commission and, therefore, its actions are found to be reasonable and prudent.

**ISSUE 5A:** Should the Commission approve as prudent TECO's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in TECO's April 2018 and August 2018 hedging reports?

**STIPULATION:**

Yes, the Commission should approve Tampa Electric's actions to mitigate fuel price volatility because those activities were taken pursuant to, and were consistent with, previously approved risk management plans. Pursuant to the 2017 Amended and Restated Stipulation and Settlement Agreement, Tampa Electric has agreed not to enter into any additional hedges during the term of the Agreement, however, the hedges at issue in this docket were entered prior to the hedging moratorium. Over the period of August 2017 through July 2018, Tampa Electric's hedging activities resulted in a cost of approximately \$0.58 million. Upon review of these filings, Tampa Electric has complied with its Risk Management Plan as approved by this Commission and, therefore, its actions are found to be reasonable and prudent. As indicated in Tampa Electric's unopposed Motion to Close Docket No. 20170057-EI, the generic hedging docket, Tampa Electric believes that docket should be closed.