FPL

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March 1, 2019

-VIA ELECTRONIC FILING -

Adam Teitzman
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket No. 20190001-EI

Dear Mr. Teitzman:

I attach for electronic filing in the above docket (i) Florida Power & Light Company's Petition for Approval of Fuel Cost Recovery and Capacity Cost Recovery Net Final True-Ups for the Period Ending December 2018 and (ii) the prepared testimony and exhibits of FPL witnesses Renae B. Deaton and Gerard J. Yupp in support of the final true-ups.

Exhibit RBD-2 to Ms. Deaton's testimony and Exhibit GJY-1 to Mr. Yupp's testimony contain confidential information. This electronic filing includes only the redacted version of Exhibits RBD-2 and GJY-1. Contemporaneous herewith, FPL will file via hand-delivery a Request for Confidential Classification.

Please contact me if you have or your Staff has any questions regarding this filing.

Sincerely,

s/ Maria J. Moncada
Maria J. Moncada

Attachments
cc: Counsel for Parties of Record (w/attachments)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	Docket No: 20190001-EI Filed: March 1, 2019

PETITION FOR APPROVAL OF FUEL COST RECOVERY AND CAPACITY COST RECOVERY NET FINAL TRUE-UPS FOR THE PERIOD ENDING DECEMBER 2018, AND 2018 INCENTIVE MECHANISM RESULTS

Florida Power & Light Company ("FPL") hereby petitions this Commission for approval of (1) FPL's net Fuel and Purchased Power Cost Recovery ("FCR") final true-up amount of $70,653,875 under-recovery, (2) net Capacity Cost Recovery ("CCR") final true-up amount of $7,161,574 over-recovery, both for the period ending December 2018, and (3) FPL's retention and recovery of $13,442,599 of the $62,404,332 total 2018 Incentive Mechanism gains, representing 60% of the gains above $40 million threshold established in Order Nos. PSC-13-0023-S-EI and PSC-16-0560-AS-EI. FPL incorporates the prepared testimony and exhibits of FPL witnesses Renae B. Deaton and Gerard J. Yupp, and states as follows:

1. The $70,653,875 net FCR final true-up under-recovery for the period January 2018 through December 2018 was calculated in accordance with the methodology set forth in Schedule 1, page 2 of 2, attached to Order No. 10093, dated June 19, 1981. This calculation and the supporting documentation are contained in the prepared testimony and exhibits of Ms. Deaton.

2. By Order No. PSC-2018-0610-FOF-EI ("Order 2018-0610"), the Commission approved FCR Factors for the period commencing January 2019. These factors reflected an actual/estimated true-up under-recovery, including interest, for the period January 2018 through December 2018 of $88,108,249, which was also approved in Order 2018-0610. The actual

under-recovery, including interest, for the period January 2018 through December 2018 is $158,762,124. The $158,762,124 actual under-recovery, less the actual/estimated under-recovery of $88,108,249, results in a net FCR final true-up under-recovery of $70,653,875 that is to be included in the calculation of the FCR Factors for the period beginning January 2020.

3. The $7,161,574 net CCR final true-up over-recovery for the period January 2018 through December 2018 was calculated in accordance with the methodology set forth in Order No. 25773, dated February 24, 1992. This calculation and the supporting documentation are contained in the prepared testimony and exhibits of Ms. Deaton.

4. By Order 2018-0610, the Commission approved CCR Factors for the period commencing January 2019. These factors reflected an actual/estimated true-up over-recovery, including interest, for the period January 2018 through December 2018 of $6,415,909, which was also approved in Order 2018-0610. The actual over-recovery, including interest, for the period January 2018 through December 2018 is $13,577,483. The $13,577,483 actual over-recovery, less the actual/estimated over-recovery of $6,415,909, results in a net CCR final true-up over-recovery of $7,161,574 that is to be included in the calculation of the CCR Factors for the period beginning January 2020.

5. By Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 120015-EI, the Commission ordered that, as part of the fuel cost recovery clause, FPL annually file a final true-up schedule showing its gains in the prior calendar year on short-term wholesale sales, short-term wholesale purchases, and all forms of asset optimization ("Incentive Mechanism") it undertook in that calendar year. Additionally, Order No. PSC-16-0560-AS-EI, issued December 15, 2016, in Docket No. 160021-EI, approved the continuation of the Incentive Mechanism with certain modifications as discussed in the testimony of Mr. Yupp. Consistent with the orders, the results of its Incentive Mechanism for the period January 2018 through

December 2018 are provided in the testimony and exhibit of Mr. Yupp. The total gains for the Incentive Mechanism during that period were $62,404,332. This exceeded the sharing threshold of $40 million. Therefore, the incremental gains above $40 million are to be shared between customers and FPL, 40% and 60%, respectively. FPL's 60% share of the incremental gains above $40 million is $13,442,599, which is to be included in the calculation of the FCR Factors for the period beginning January 2020.

WHEREFORE, Florida Power & Light Company respectfully requests the Commission to approve for the period ending December 2018: (1) FPL's net FCR final true-up amount of $70,653,875 under-recovery and authorize the inclusion of this amount in the calculation of the FCR Factors for the period beginning January 2020, (2) FPL's net CCR final true-up amount of $7,161,574 over-recovery and authorize the inclusion of this amount in the calculation of the CCR Factors for the period beginning January 2020, and (3) FPL's retention and recovery of $13,442,599 of the $62,404,332 total 2018 Incentive Mechanism gains, representing 60% of the gains above $40 million, and authorize the inclusion of this amount in the calculation of the FCR Factors for the period beginning January 2020.

Respectfully submitted,

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By: *s/ Maria J. Moncada*
Maria J. Moncada
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CERTIFICATE OF SERVICE
Docket No. 20190001-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic service on this 1st day of March 2019 to the following:

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By: *s/ Maria J. Moncada*
Maria J. Moncada

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20190001-EI

MARCH 1, 2019

Q. Please state your name, business address, employer and position.

A. My name is Renae B. Deaton. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "the Company") as the Director of Clause Recovery and Wholesale Rates, in the Regulatory & State Governmental Affairs Department.

Q. Please state your education and business experience.

A. I hold a Bachelor of Science in Business Administration and a Master of Business Administration from Charleston Southern University. Since joining FPL in 1998, I have held various positions in the rates and regulatory areas. Prior to my current position, I held the positions of Senior Manager of Cost of Service and Load Research and Senior Manager of Rate Design in the Rates and Tariffs Department. I have previously testified before this Commission in base rate and clause recovery proceedings. I am a member of the Edison Electric Institute ("EEI") Rates and Regulatory Affairs Committee, and I have completed the EEI Advanced Rate Design Course. I have been a guest speaker at Public Utility Research Center/World Bank International Training Programs on Utility Regulation and Strategy. In 2016, I assumed my current position, where my duties include providing direction as to appropriateness of inclusion of costs through a cost recovery clause and the overall preparation and filing of all cost recovery clause documents including testimony and discovery.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the schedules necessary to support the actual Fuel Cost Recovery ("FCR") Clause and Capacity Cost Recovery ("CCR") Clause net true-up amounts for the period January 2018 through December 2018.

The 2018 net true-up for the FCR Clause is an under-recovery, including interest, of $70,653,875. FPL is requesting Commission approval to include this 2018 FCR Clause true-up under-recovery of $70,653,875 in the calculation of the FCR factors for the period January 2020 through December 2020.

The 2018 net true-up for the CCR Clause is an over-recovery, including interest, of $7,161,574. FPL is requesting Commission approval to include this 2018 CCR Clause true-up over-recovery of $7,161,574 in the calculation of the CCR factors for the period January 2020 through December 2020.

Finally, FPL is requesting Commission approval to include $13,442,599 in the calculation of the FCR factors for the period January 2020 through December 2020, which represents FPL's share of the 2018 Incentive Mechanism gain described in the testimony of FPL witness Yupp.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits in this proceeding?

A. Yes, I have. Exhibit RBD-1 contains the FCR-related schedules and Exhibit RBD-2 contains the CCR-related schedules. In addition, FCR Schedules A1 through A12 for the January 2018 through December 2018 period have been filed monthly with the Commission and served on all parties of record in this docket. Those schedules are incorporated herein by reference.

Q. What is the source of the data you present?

A. Unless otherwise indicated, the data are taken from the books and records of FPL. The books and records are kept in the regular course of the Company's business in accordance with generally accepted accounting principles and practices, and with the applicable provisions of the Uniform System of Accounts as prescribed by the Commission.

FUEL COST RECOVERY CLAUSE

Q. Please explain the calculation of the 2018 FCR net true-up amount.

A. Exhibit RBD-1, page 1, titled "Summary of Net True-Up," shows the calculation of the FCR net true-up for the period January 2018 through December 2018, an under-recovery of $70,653,875.

The summary of the FCR net true-up amount shows the actual end-of-period true-up under-recovery for the period January 2018 through December 2018 of

$158,762,124 on line 1. The actual/estimated true-up under-recovery for the same period of $88,108,249 is shown on line 2. Line 1 less line 2 results in the net final true-up under-recovery for the period January 2018 through December 2018 of $70,653,875 shown on line 3.

The calculation of the FCR true-up amount for the period follows the procedures established by this Commission as set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision."

Q. Have you provided a schedule showing the calculation of the 2018 FCR actual true-up by month?

A. Yes. Exhibit RBD-1, page 2, titled "Calculation of Final True-Up Amount," shows the calculation of the FCR actual true-up by month for January 2018 through December 2018.

Q. Have you provided schedules showing the variances between actual and actual/estimated FCR costs and applicable revenues for 2018?

A. Yes. Exhibit RBD-1, page 3, (sum of lines 40 and 41) compares the actual end-of-period true-up under-recovery of $158,762,124 (column 4) to the actual/estimated end-of-period true-up under-recovery of $88,108,249 (column 5) resulting in a net under-recovery of $70,653,875 (column 6). Exhibit RBD-1, page 3 lines 39 and 30, shows that the variance consists of an increase in jurisdictional fuel costs of $136.1 million partially offset by an increase in revenues of $65.5 million.

Q. Please summarize the variance schedule on page 3 of Exhibit RBD-1.

A. FPL previously projected jurisdictional total fuel costs and net power transactions to be $2.89 billion for 2018 (Exhibit RBD-1, page 3, line 39, column 5). The actual jurisdictional total fuel costs and net power transactions for that period is $3.02 billion (Exhibit RBD-1, page 3, line 39, column 4). Jurisdictional total fuel costs and net power transactions are $136.1 million, or 4.7% higher than previously projected (Exhibit RBD-1, page 3, line 39, column 6) and jurisdictional fuel revenues, net of revenue taxes for 2018, are $65.5 million, or 2.3% higher than previously projected (Exhibit RBD-1, page 3, line 30, column 6).

Q. Please explain the variances in jurisdictional total fuel costs and net power transactions.

A. Below are the primary reasons for the $136.1 million variance.

<u>Fuel Cost of System Net Generation: $184.6 million increase (Exhibit RBD-1, page 3, line 1, column 6)</u>

The table below provides the detail of this variance.

FUEL VARIANCE	**2018 FINAL TRUE-UP**	**2018 ACTUAL/ ESTIMATED**	**DIFFERENCE**
<u>Heavy Oil</u>			
Total Dollar	$33,336,536	$18,081,040	$15,255,496
Units (MMBTU)	2,817,296	1,540,386	1,276,910
$ per Units	11.8328	11.7380	0.0948
Variance Due to Consumption			$14,988,357
Variance Due to Cost			$267,139

FUEL VARIANCE	2018 FINAL TRUE-UP	2018 ACTUAL/ ESTIMATED	DIFFERENCE
Total Variance			$15,255,496
Light Oil			
Total Dollar	$17,471,205	$23,252,266	($5,781,061)
Units (MMBTU)	1,091,030	1,564,774	(473,744)
$ per Units	16.0135	14.8598	1.1537
Variance Due to Consumption			($7,039,757)
Variance Due to Cost			$1,258,697
Total Variance			($5,781,061)
Coal			
Total Dollar	$70,954,592	$61,474,973	$9,479,619
Units (MMBTU)	28,818,876	25,345,757	3,473,119
$ per Units	2.4621	2.4255	0.0366
Variance Due to Consumption			$8,423,891
Variance Due to Cost			$1,055,728
Total Variance			$9,479,619
Gas			
Total Dollar	$2,938,221,234	$2,773,198,972	$165,022,262
Units (MMBTU)	660,577,429	631,814,389	28,763,040
$ per Units	4.4480	4.3893	0.0587
Variance Due to Consumption			$126,248,522
Variance Due to Cost			$38,773,740
Total Variance			$165,022,262
Nuclear			
Total Dollar	$175,457,637	$174,817,401	$640,236
Units (MMBTU)	308,786,317	302,463,140	6,323,177
$ per Units	0.5682	0.5780	(0.0098)
Variance Due to Consumption			$3,654,665
Variance Due to Cost			($3,014,429)
Total Variance			$640,236
Total			
Variance Due to Consumption			$124,737,240

FUEL VARIANCE	2018 FINAL TRUE-UP	2018 ACTUAL/ ESTIMATED	DIFFERENCE
Variance Due to Cost			$59,879,312
Total Variance			$184,616,552
Note: Fuel Cost of System Net Generation reflected above does not tie to amounts provided on the 2018 final true-up schedule due to a reduction to nuclear fuel expense in the amount of $1.1 million. In 2018, an overstatement of nuclear fuel amortization and other adjustments occurred, which were included and footnoted on the impacted monthly A-Schedule.			

<u>Rail Car Lease (Cedar Bay/ICL/SJRPP): $0.7 million increase (Exhibit RBD-1, page 3, line 4, column 6)</u>

The variance for rail car lease (Cedar Bay/ICL/SJRPP) is primarily attributable to higher than projected rail car lease costs for SJRPP.

<u>Variable Power Plant O&M Avoided due to Economy Purchases: $0.3 million decrease (Exhibit RBD-1, page 3, line 15, column 6)</u>

The variance for variable power plant O&M avoided due to economy purchases is attributable to lower than projected economy power purchases.

<u>Variable Power Plant O&M Attributable to Off-System Sales: $0.2 million increase (Exhibit RBD-1, page 3, line 14, column 6)</u>

The variance for variable power plant O&M attributable to off-system sales is attributable to higher than projected economy power sales.

<u>Energy Cost of Economy Purchases: $13.4 million decrease (Exhibit RBD-1, page 3, line 10, column 6)</u>

The variance for the energy cost of economy purchases is primarily attributable to lower than projected economy purchases. FPL purchased 232,638 MWh, or 410,368 MWh less of economy power resulting in a volume decrease of $15.3 million. This volume variance is partially offset by higher than projected costs for economy power. The average cost of economy power purchases was $8.41/MWh higher than projected, resulting in a cost increase of $1.9 million. The combination of lower economy power purchases coupled with higher costs for economy power purchases results in a net decrease of $13.4 million.

Fuel Cost of Power Sold: $8.5 million increase (Exhibit RBD-1, page 3, line 6, column 6)

The variance for the fuel cost of power sold is primarily attributable to higher than projected economy power sales. FPL sold 2,478,644 MWh, or 361,890 MWh more of economy power, resulting in a volume increase of $8.2 million. The average unit fuel cost on economy power sales was $0.10/MWh higher than projected, resulting in a cost increase of $0.2 million. The combination of higher economy power sales and higher fuel costs attributable to economy power sales results in a net increase for economy power sales of $8.4 million. The remaining variance of $0.1 million is attributable to higher than projected St. Lucie Plant Reliability Exchange sales and higher than projected fuel costs on St. Lucie Plant Reliability Exchange sales.

Gains from Off-System Sales: $2.6 million increase (Exhibit RBD-1, page 3, line 7, column 6)

The variance for gains from off-system sales is attributable to higher than projected economy power sales and lower than projected margins on economy power sales. FPL sold 2,478,644 MWh, or 361,890 MWh more of economy power, resulting in an increase of $4.9 million. This variance is partially offset by lower than projected margins on economy power sales. Margins on economy power sales averaged $0.93/MWh lower than projected, resulting in a decrease of $2.3 million. The combination of higher economy power sales and lower margins on economy power sales results in a net increase for gains from off-system sales of $2.6 million.

<u>Fuel Cost of Stratified Sales: $2.3 million increase (Exhibit RBD-1, page 3, line 5, column 6)</u>

The variance for the fuel cost of stratified sales is primarily attributable to higher than projected MWh sales from stratified contracts due to variations in weather.

<u>Fuel Cost of Purchased Power: $1.4 million decrease (Exhibit RBD-1, page 3, line 8, column 6)</u>

The variance for the fuel cost of purchased power is primarily attributable to lower than projected purchases under agreements with Exelon Generation Company, LLC ("ExGen") and the Orlando Utilities Commission ("OUC") and higher than projected purchases under contracts with the Solid Waste Authority of Palm Beach County ("SWA"). For ExGen, the combination of slightly lower average fuel costs coupled with 50,556 MWh less in purchases resulted in a decrease of $2.3 million. For OUC, FPL had projected $0.7 million in purchased power costs from October through December. The firm capacity and energy agreement with OUC did not begin until the latter half of December and FPL did not purchase power from OUC under the agreement, resulting in a decrease of $0.7 million. This combined variance of $3.0 million for ExGen and OUC is partially offset by higher than projected purchases from SWA. FPL purchased 861,682 MWh, or 72,833 MWh more from SWA at an average cost that was $0.88/MWh lower than projected. The combination of higher purchases and lower fuel costs for SWA resulted in an increase of $1.4 million. The remaining variance of $0.2 million is primarily attributable to higher than projected fuel costs related to St. Lucie Reliability Exchange purchases.

<u>Energy Payments to Qualifying Facilities: $0.4 million decrease (Exhibit RBD-1, page 3, line 9, column 6)</u>

The variance for energy payments to qualifying facilities is primarily attributable to lower than projected purchases and costs from As-Available Co-Gen facilities. In total, FPL purchased 214,427 MWh, or 17,847 MWh less than projected from As-Available Co-Gen facilities at an average unit fuel cost that was $0.44/MWh lower than projected. The combination of lower purchases and fuel costs for As-Available purchases resulted in a decrease of $0.5 million. This variance is partially offset by higher than projected purchases and fuel costs from FPL's Firm Co-Gen facility. FPL purchased 34,403 MWh, or 275 MWh more of Firm Co-Gen power at an average cost that was $3.20/MWh higher than projected, resulting in an increase for Firm Co-Gen power of $0.1 million.

Q. What is the variance in retail (jurisdictional) FCR revenues?

A. As shown on Exhibit RBD-1, page 3, line 30, actual 2018 jurisdictional FCR revenues, net of revenue taxes, are approximately $65.5 million higher than the actual/estimated projection. This is primarily due to jurisdictional sales that are 2,231,289 MWh higher than the actual/estimated projection.

Q. FPL witness Yupp calculates in his testimony that FPL is entitled to retain $13,442,599 as its 60% share of 2018 Incentive Mechanism gains over the $40 million threshold. When is FPL requesting to recover its share of the gains, and how will this be reflected in the FCR schedules?

A. FPL is requesting recovery of its share of the 2018 Incentive Mechanism gains through the 2020 FCR factors, consistent with how gains have been recovered in prior years. FPL will include the approved jurisdictionalized Incentive Mechanism gains amount in the calculation of the 2020 FCR factors and will reflect recovery of one-twelfth of the approved amount, net of revenue taxes, in each month's Schedule A2 for the period January 2020 through December 2020 as a reduction to jurisdictional fuel revenues applicable to each period.

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the calculation of the 2018 CCR net true-up amount.

A. Exhibit RBD-2, page 1, titled "Final True-Up Summary" shows the calculation of the CCR net true-up for the period January 2018 through December 2018, an over-recovery of $7,161,574, which FPL is requesting to be included in the calculation of the CCR factors for the January 2020 through December 2020 period.

The actual end-of-period over-recovery for the period January 2018 through December 2018 of $13,577,483 shown on line 1 less the actual/estimated end-of-period over-recovery for the same period of $6,415,909 shown on line 2 that was approved by the Commission in Order No. PSC-2018-0610-FOF-EI, results in the net true-up over-recovery for the period January 2018 through December 2018 of $7,161,574 shown on line 3.

Q. Have you provided a schedule showing the calculation of the 2018 CCR actual true-up by month?

A. Yes. Exhibit RBD-2, pages 2 through 4, titled “Calculation of Final True-Up Amount” shows the calculation of the CCR end-of-period true-up for the period January 2018 through December 2018 by month.

Q. Is this true-up calculation consistent with the true-up methodology used for the FCR Clause?

A. Yes, it is. The calculation of the true-up amount follows the procedures established by this Commission set forth on Commission Schedule A2 “Calculation of True-Up and Interest Provision” for the FCR Clause.

Q. Have you provided a schedule showing the variances between actual and actual/estimated capacity costs and applicable revenues for 2018?

A. Yes. Exhibit RBD-2, pages 5 and 6, titled "Calculation of Final True-Up Variances," shows the actual capacity costs and applicable revenues compared to actual/estimated capacity costs and applicable revenues for the period January 2018 through December 2018.

Q. Please explain the variances related to capacity costs.

A. As shown in Exhibit RBD-2, page 6, line 27, column 5, the variance related to jurisdictional capacity costs is a decrease of $3.7 million, or 1.5%, from the actual/estimated projection. The primary reason for this variance is a $3.9 million or 1.5% decrease in total system capacity costs (page 5, line 13, column 5).

Below are the primary reasons for the $3.9 million decrease in total system capacity costs.

<u>Transmission Revenues from Capacity Sales: $1.9 million increase (Exhibit RBD-2, page 5, line 12, column 5)</u>

The variance for transmission revenues from capacity sales is primarily attributable to higher revenues from capacity premiums associated with power capacity sales of $1.0 million. The remaining variance of $0.9 million is primarily due to higher than projected transmission revenues from higher than projected economy power sales.

Payments to Non-Cogenerators: $1.9 million decrease (Exhibit RBD-2, page 5, line 1, column 5)

The variance for payments to non-cogenerators (SJRPP, SWA, Exelon and OUC) is primarily attributable to lower than projected costs of approximately $1.9 million associated with the OUC agreement, and adjustments associated with SJRPP in the second half of the year. Due to the timing of Commission approval, OUC capacity payments originally expected during October and November did not occur and December costs were less than projected.

Transmission of Electricity by Others: $0.6 million decrease (Exhibit RBD-2, page 5, line 11, column 5)

The variance for transmission of electricity by others is primarily attributable to true-up adjustments of approximately $0.7 million received from Southern Company for transmission service costs related to the expired Southern Company UPS agreements. This variance is partially offset by approximately $0.1 million due to the purchase of third party transmission utilized to facilitate wholesale power sales.

Incremental Nuclear NRC Compliance Costs (Fukushima): O&M - $0.3 million increase (Exhibit RBD-2, page 5, line 9, column 5)

The variance for incremental NRC compliance O&M costs is primarily attributable to an increase in fees for FPL’s share in costs to support the Regional Response Centers (a warehouse of off-site portable equipment shared by the industry).

<u>Nuclear Cost Recovery Costs: $0.3 million decrease (Exhibit RBD-2, page 6, line 29, column 5)</u>

The variance for nuclear cost recovery costs is attributable to a refund from the Nuclear Regulatory Commission for incorrectly billed work on contested hearings for the Turkey Point Unit 6 application. The refund amount relates to costs incurred on hearings prior to 2017.

Q. Please describe the variance in 2018 CCR revenues.

A. As shown on page 6, line 36, column 5, actual 2018 CCR revenues (net of revenue taxes), are $3.1 million higher than projected in the actual/estimated true-up filing. This is primarily due to higher than projected jurisdictional sales, which are 2,231,289 MWh higher than the actual/estimated projection.

Q. Have you provided a schedule showing the actual monthly capacity payments by contract?

A. Yes. Schedule A12 consists of two pages that are included in Exhibit RBD-2 as pages 7 and 8. Page 7 shows the actual capacity payments for FPL's Purchase Power Agreements for the period January 2018 through December 2018. Page 8 provides the Short Term Capacity Payments for the period January 2018 through December 2018.

Q. Have you provided a schedule showing the capital structure components and cost rates relied upon by FPL to calculate the rate of return applied to all capital projects recovered through the FCR and CCR Clauses?

A. Yes. The capital structure components and cost rates used to calculate the rate of return on the capital investments for the period January 2018 through December 2018 are included on pages 18 and 19 of Exhibit RBD-2.

Q. Does this conclude your testimony?

A. Yes, it does.

SCHEDULE: E1-A

FLORIDA POWER & LIGHT COMPANY
SUMMARY OF NET TRUE-UP
FOR THE PERIOD: JANUARY 2018 THROUGH DECEMBER 2018

E1-A True-Up Summary	Total
1. End of Period True-Up [1]	($158,762,124)
2. Less: Actual Estimated True-up for the same period [2]	($88,108,249)
3. Net True-up for the period	($70,653,875)

[1] Page 2, Column 15, Lines 40 & 41
[2] Approved in FPSC Final Order PSC-2018-0610-FOF-EI

Note: Totals may not add due to rounding.

( ) Reflects Underrecovery

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD: JANUARY 2018 THROUGH DECEMBER 2018

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	True-up	True Up Line	a-Jan - 2018	a-Feb - 2018	a-Mar - 2018	a-Apr - 2018	a-May - 2018	a-Jun - 2018	a-Jul - 2018	a-Aug - 2018	a-Sep - 2018	a-Oct - 2018	a-Nov - 2018	a-Dec - 2018	a-2018
1	**Fuel Costs & Net Power Transactions**	Fuel Cost of System Net Generation [1]	$243,085,192	$233,591,015	$214,637,822	$232,227,371	$249,785,380	$278,196,301	$296,181,995	$302,312,660	$313,118,581	$307,140,535	$269,491,495	$294,578,787	$3,234,347,133
2		SJRPP Fuel Inventory Expense	$4,996,469												$4,996,469
3		Scherer Coal Cars Depreciation & Return			($2,311)	($52,651)									($54,962)
4		Rail Car Lease (Cedar Bay/ICL/SJRPP)	$649,217	$402,076	($182,761)	$463,585	$234,001	$1,034,482	$1,914,506	($66,155)	$797,743	$286,914	$519,804	$690,876	$6,744,289
5		Fuel Cost of Stratified Sales	($826,924)	($2,635,194)	($1,242,878)	($2,454,710)	($896,866)	($2,451,517)	($3,316,610)	($3,092,829)	($2,998,708)	($3,219,174)	($3,081,166)	($2,370,828)	($28,587,406)
6		Fuel Cost of Power Sold (Per A6)	($11,254,619)	($6,322,850)	($6,543,614)	($2,113,385)	($5,410,548)	($2,909,968)	($3,050,183)	($2,924,894)	($1,970,471)	($2,613,083)	($6,344,058)	($8,473,622)	($59,931,294)
7		Gains from Off-System Sales (Per A6)	($12,786,865)	($2,885,156)	($2,843,784)	($806,000)	($2,408,061)	($1,211,737)	($1,326,065)	($634,240)	($1,230,189)	($1,107,285)	($1,645,142)	($2,446,754)	($31,331,278)
8		Fuel Cost of Purchased Power (Per A7)	$3,007,258	$1,463,004	$2,541,679	$2,565,137	$1,240,528	$4,359,681	$1,535,914	$3,072,905	$3,179,060	$1,782,418	$3,759,500	$2,418,183	$30,925,266
9		Energy Payments to Qualifying Facilities (Per A8)	$443,260	$350,206	$284,154	$216,279	$316,743	$474,881	$317,094	$386,056	$546,027	$819,311	$711,947	$603,375	$5,469,331
10		Energy Cost of Economy Purchases (Per A9)	$14,131	$12,615	$8,391	$892,096	$116,832	$1,833,085	$491,910	$1,370,715	$2,542,261	$3,179,247	$55,507	$129,606	$10,646,395
11		Total Fuel Costs & Net Power Transactions	227,327,118	223,975,715	206,656,698	230,937,722	242,978,008	279,325,207	292,748,561	300,424,218	313,984,305	306,268,881	263,467,886	285,129,624	3,173,223,943
12															
13	**Incremental Optimization Costs**	Incremental Personnel, Software, and Hardware Costs	$42,272	$37,555	$42,032	$44,237	$49,641	$44,511	$42,505	$44,173	$39,617	$45,255	$43,306	$41,345	$516,451
14		Variable Power Plant O&M Attributable to Off-System Sales (Per A6)	$264,122	$190,332	$227,335	$62,122	$165,868	$71,172	$69,326	$53,599	$53,191	$61,857	$169,175	$223,022	$1,611,119
15		Variable Power Plant O&M Avoided due to Economy Purchases (Per A9)	($224)	($632)	($140)	($14,803)	($1,565)	($27,905)	($7,095)	($18,615)	($37,304)	($39,380)	($976)	($2,575)	($151,215)
16		Total Incremental Optimization Costs	306,170	227,255	269,228	91,555	213,943	87,778	104,736	79,157	55,504	67,732	211,505	261,791	1,976,355
17															
18	**Adjustments to Fuel Cost**	Energy Imbalance Fuel Revenues	($40,028)	($104,158)	($31,590)	($38,401)	($67,894)	($107,952)	($147,312)	($79,676)	($107,584)	($170,067)	($166,283)	($89,787)	($1,150,732)
19		Inventory Adjustments	$120,176	$130,505	$3,814	$41,771	$1,035,106	($701,824)	($319,763)	$449,050	$276,930	$30,926	$54,104	($64,411)	$1,056,384
20		Non Recoverable Oil/Tank Bottoms						$222,715							$222,715
21		Other O&M Expense		$1,530				$199,751		$349,662	$20,428	($0)			$571,371
22		Adjusted Total Fuel Costs & Net Power Transactions	227,713,437	224,230,846	206,898,150	231,032,646	244,159,164	279,025,675	292,386,222	301,222,410	314,229,583	306,197,473	263,567,213	285,237,217	3,175,900,036
23															
24	**kWh Sales**	Jurisdictional kWh Sales	8,262,961,939	7,655,562,391	7,658,691,776	8,020,344,013	8,908,457,763	9,630,385,468	10,669,863,413	11,037,589,280	10,444,184,942	10,554,149,683	9,185,318,934	8,025,631,481	110,053,141,083
25		Sales for Resale (excluding Stratified Sales)	401,044,771	440,593,709	406,083,666	407,540,643	449,608,712	461,042,727	544,159,311	580,072,443	556,073,813	544,201,229	514,143,681	426,135,345	5,730,700,050
26		Sub-Total Sales	8,664,006,710	8,096,156,100	8,064,775,442	8,427,884,656	9,358,066,475	10,091,428,195	11,214,022,724	11,617,661,723	11,000,258,755	11,098,350,912	9,699,462,615	8,451,766,826	115,783,841,133
27															
28		**Jurisdictional % of Total Sales (Line 24/26)**	95.37114%	94.55799%	94.96472%	95.16438%	95.19550%	95.43134%	95.14751%	95.00698%	94.94490%	95.09656%	94.69926%	94.95803%	95.05052%
29															
30	**True-Up Calculation**	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$215,083,204	$198,105,794	$194,179,392	$204,602,796	$229,930,394	$250,662,270	$281,327,173	$292,069,109	$276,639,549	$279,679,927	$239,212,570	$206,106,538	$2,867,598,717
31															
32	**Fuel Adjustment Revenues Not Applicable to Period**														
33		Prior Period True-Up (Collected)/Refunded This Period [2]	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$1,399,365	$16,792,378
34		GPIF, Net of Revenue Taxes [3]	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($804,090)	($9,649,084)
35		Incentive Mechanism, Net of Revenue Taxes [5]	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($793,849)	($9,526,193)
36		Jurisdictional Fuel Revenues Applicable to Period	214,884,629	197,907,219	193,980,817	204,404,221	229,731,820	250,463,695	281,128,598	291,870,534	276,440,974	279,481,352	239,013,995	205,907,963	2,865,215,818
37		Adjusted Total Fuel Costs & Net Power Transactions	227,713,437	224,230,846	206,898,150	231,032,646	244,159,164	279,025,675	292,386,222	301,222,410	314,229,583	306,197,473	263,567,213	285,237,217	3,175,900,036
38		Jurisdictional Sales % of Total kWh Sales (Line 28)	95.37114%	94.55799%	94.96472%	95.16438%	95.19550%	95.43134%	95.14751%	95.00698%	94.94490%	95.09656%	94.69926%	94.95803%	95.05052%
39		Juris. Total Fuel Costs & Net Power Trans. (Line 37xLine38x1.00133)	217,461,740	212,310,178	196,741,567	220,153,200	232,737,667	266,632,090	278,568,213	286,562,937	298,741,763	291,570,537	249,928,163	271,215,880	3,022,623,937
40		True-Up Provision for the Month-Over/(Under) Recovery (Line 36-Line 39)	($2,577,111)	($14,402,959)	($2,760,750)	($15,748,980)	($3,005,847)	($16,168,395)	$2,560,385	$5,307,597	($22,300,788)	($12,089,185)	($10,914,168)	($65,307,917)	($157,408,119)
41		Interest Provision for the Month	($11,182)	($24,035)	($41,664)	($60,952)	($77,915)	($98,387)	($114,896)	($110,903)	($134,815)	($179,107)	($207,612)	($292,538)	($1,354,005)
42		True-Up & Interest Prov. Beg of Period-Over/(Under) Recovery	$16,792,378	$12,804,720	($3,021,640)	($7,223,419)	($24,432,716)	($28,915,842)	($46,581,989)	($45,535,864)	($41,738,535)	($65,573,504)	($79,241,160)	($91,762,304)	$16,792,378
43		Deferred True-up Beginning of Period - Over/(Under) Recovery [6]	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)	($23,632,267)
44		Prior Period True-Up Collected/(Refunded) This Period	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($1,399,365)	($16,792,378)
45		End of Period Net True-up Amount Over/(Under) Recovery (Line 40 - 44)	($10,827,547)	($26,653,907)	($30,855,686)	($48,064,983)	($52,548,109)	($70,214,256)	($69,168,131)	($65,370,802)	($89,205,771)	($102,873,427)	($115,394,571)	($182,394,391)	($182,394,391)

46
47
48 [1] Actuals include various adjustments as noted on the A-Schedules
49 [2] Prior Period 2017 Actual/Estimated True-up
50 [3] Generating Performance Incentive Factor is (($9,656,036/12) x 99.9280%) - See Order No. PSC-2018-0028-FOF-EI
51 [4] Other Fuel Expense consists of nuclear fuel design software maintenance costs
52 [5] Jurisdictionalized Incentive Mechanism - FPL Portion is (($9,533,057/12) x 99.9280%) - See Order No. PSC-2018-0028-FOF-EI
53 [6] 2017 Final True-up
54
55 Note: Totals may not add due to rounding
56
57 ( ) Reflects Underrecovery

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF VARIANCE
FOR THE PERIOD: JANUARY 2018 THROUGH DECEMBER 2018

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	True-up	True Up Line	2018 FCR - Final True-up	2018 FCR - Actual/Estimated	2018 $ Dif. FCR - Actual/Estimated	2018 % Dif. FCR - Actual/Estimated
1	**Fuel Costs & Net Power Transactions**	Fuel Cost of System Net Generation [1]	$3,234,347,133	$3,049,738,951	$184,608,182	6.05%
2		SJRPP Fuel Inventory Expense	$4,996,469	$4,996,469	$0	0.00%
3		Scherer Coal Cars Depreciation & Return	($54,962)	($54,962)	$0	0.00%
4		Rail Car Lease (Cedar Bay/ICL/SJRPP)	$6,744,289	$6,035,632	$708,657	11.74%
5		Fuel Cost of Stratified Sales	($28,587,406)	($26,276,574)	($2,310,832)	8.79%
6		Fuel Cost of Power Sold (Per A6)	($59,931,294)	($51,392,408)	($8,538,886)	16.62%
7		Gains from Off-System Sales (Per A6)	($31,331,278)	($28,731,438)	($2,599,840)	9.05%
8		Fuel Cost of Purchased Power (Per A7)	$30,925,266	$32,322,589	($1,397,323)	(4.32%)
9		Energy Payments to Qualifying Facilities (Per A8)	$5,469,331	$5,851,938	($382,607)	(6.54%)
10		Energy Cost of Economy Purchases (Per A9)	$10,646,395	$24,020,472	($13,374,077)	(55.68%)
11		Total Fuel Costs & Net Power Transactions	$3,173,223,943	$3,016,510,670	$156,713,273	5.20%
12						
13	**Incremental Optimization Costs**	Incremental Personnel, Software, and Hardware Costs	$516,451	$519,261	($2,810)	(0.54%)
14		Variable Power Plant O&M Attributable to Off-System Sales (Per A6)	$1,611,119	$1,375,890	$235,229	17.10%
15		Variable Power Plant O&M Avoided due to Economy Purchases (Per A9)	($151,215)	($417,954)	$266,739	(63.82%)
16		Total Incremental Optimization Costs	$1,976,355	$1,477,197	$499,158	33.79%
17						
18	**Adjustments to Fuel Cost**	Energy Imbalance Fuel Revenues	($1,150,732)	($390,023)	($760,709)	195.04%
19		Inventory Adjustments	$1,056,384	$629,547	$426,836	67.80%
20		Non Recoverable Oil/Tank Bottoms	$222,715	$222,715	$0	0.00%
21		Other O&M Expense	$571,371	$551,034	$20,337	3.69%
22		Adjusted Total Fuel Costs & Net Power Transactions	$3,175,900,036	$3,019,001,140	$156,898,896	5.20%
23						
24	**kWh Sales**	Jurisdictional kWh Sales	110,053,141,083	107,821,851,507	2,231,289,576	2.07%
25		Sales for Resale (excluding Stratified Sales)	5,730,700,050	5,100,512,972	630,187,078	12.36%
26		Sub-Total Sales	115,783,841,133	112,922,364,479	2,861,476,654	2.53%
27						
28		**Jurisdictional % of Total Sales (Line 24/26)**	95.05052%	95.48317%	77.97686%	81.67%
29						
30	**True-Up Calculation**	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$2,867,598,717	$2,802,084,630	$65,514,087	2.34%
31						
32	**Fuel Adjustment Revenues Not Applicable to Period**					
33		Prior Period True-Up (Collected)/Refunded This Period [3]	$16,792,378	$16,792,378	$0	0.00%
34		GPIF, Net of Revenue Taxes [4]	($9,649,084)	($9,649,086)	$3	(0.00%)
35		Incentive Mechanism, Net of Revenue Taxes [5]	($9,526,193)	($9,526,193)	$0	0.00%
36		Jurisdictional Fuel Revenues Applicable to Period	$2,865,215,818	$2,799,701,728	$65,514,090	2.34%
37		Adjusted Total Fuel Costs & Net Power Transactions	$3,175,900,036	$3,019,001,140	$156,898,896	5.20%
38		Jurisdictional Sales % of Total kWh Sales (Line 28)	95.05%	95.48%	77.98%	81.67%
39		Juris. Total Fuel Costs & Net Power Trans. (Line 37xLine38x1.00133)	$3,022,623,937	$2,886,505,885	$136,118,052	4.72%
40		True-Up Provision for the Month-Over/(Under) Recovery (Line 36-Line 39)	($157,408,119)	($86,804,157)	($70,603,962)	81.34%
41		Interest Provision for the Month	($1,354,005)	($1,304,092)	($49,913)	3.83%
42		True-Up & Interest Prov. Beg of Period-Over/(Under) Recovery	$16,792,378	$16,792,378	$0	0.00%
43		Deferred True-up Beginning of Period - Over/(Under) Recovery [6]	($23,632,267)	($23,632,267)	$0	0.00%
44		Prior Period True-Up Collected/(Refunded) This Period	($16,792,378)	($16,792,378)	$0	0.00%
45		End of Period Net True-up Amount Over/(Under) Recovery (Line 40 - Line 44)	($182,394,391)	($111,740,516)	($70,653,875)	63.23%
46						
47						
48	[1] Actuals include various adjustments as noted on the A-Schedules					
49	[2] Other Fuel Expense consists of nuclear fuel design software maintenance costs					
50	[3] Prior Period 2017 Actual/Estimated True-up					
51	[4] Generating Performance Incentive Factor is (($9,656,036/12) x 99.9280%) - See Order No. PSC-2018-0028-FOF-EI					
52	[5] Jurisdictionalized Incentive Mechanism - FPL Portion is (($9,533,057/12) x 99.9280%) - See Order No. PSC-2018-0028-FOF-EI					
53	[6] 2017 Final True-up					

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
FINAL TRUE-UP SUMMARY
FOR THE PERIOD: JANUARY 2018 THROUGH DECEMBER 2018

Line No.	Line	Total
1	End of Period True-Up (1)	$13,577,483
2	Less: Actual/Estimated True-Up for the same period (2)	$6,415,909
3	Net True-Up for the Period	$7,161,574
4		
5	(1) From Page 4, Column (15), Lines 9 & 10.	
6	(2) Approved in FPSC Final Order PSC-2018-0610-FOF-EI.	
7		
8	Note: Totals may not add due to rounding	
9		
10	( ) Reflects Under-recovery	
11		
12		
13		
14		
15		

Docket No. 20190001-EI
2018 CCR Final True Up
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD OF: JANUARY 2018 THROUGH DECEMBER 2018

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Capacity Costs	a-Jan - 2018	a-Feb - 2018	a-Mar - 2018	a-Apr - 2018	a-May - 2018	a-Jun - 2018	a-Jul - 2018	a-Aug - 2018	a-Sep - 2018	a-Oct - 2018	a-Nov - 2018	a-Dec - 2018	Total
1	**Base**													
2	Payments to Non-cogenerators	$901,301	($6,606,934)	$1,442,911	$1,195,029	$1,410,102	$1,030,047	$1,530,800	$1,530,800	$1,486,549	$1,221,016	$1,230,546	$1,822,519	$8,194,687
3	Payments to Co-generators	$813,328	($586,738)	$113,295	$113,295	$210,228	$13,908	$105,358	$123,686	$113,295	$113,295	$113,295	$113,295	$1,359,540
4	Cedar Bay Transaction-Regulatory Asset-Amortization and Return	$10,089,646	$10,059,421	$10,029,196	$9,998,971	$9,968,746	$9,938,520	$9,860,803	$9,831,191	$9,801,578	$9,771,966	$9,742,354	$9,712,741	$118,805,132
5	Cedar Bay Transaction-Regulatory Liability-Amortization and Return	($93,924)	($93,528)	($93,132)	($92,736)	($92,340)	($91,944)	($90,926)	($90,538)	($90,151)	($89,763)	($89,375)	($88,987)	($1,097,343)
6	Indiantown Transaction-Regulatory Asset-Amortization and Return	$6,777,143	$6,749,953	$6,722,764	$6,695,575	$6,668,385	$6,641,196	$6,564,669	$6,538,031	$6,511,393	$6,484,755	$6,458,116	$6,431,478	$79,243,457
7	SJRPP Revenue Requirements	$1,130,656	$1,119,275	$1,107,892	$1,096,511	$1,085,130	$1,073,749	$1,053,254	$1,042,104	$1,030,954	$1,019,803	$1,008,653	$997,503	$12,765,484
8	Incremental Plant Security Costs O&M	$2,422,840	$2,028,451	$2,104,429	$2,375,596	$2,020,784	$2,143,832	$2,241,615	$2,528,416	$2,125,567	$1,978,287	$2,223,730	$2,824,341	$27,017,888
9	Incremental Plant Security Costs Capital	$235,139	$238,990	$244,524	$251,374	$255,953	$259,239	$259,365	$254,303	$258,390	$270,418	$275,066	$282,759	$3,085,521
10	Incremental Nuclear NRC Compliance Costs O&M	$85,624	$285,960	$75,293	$135,846	$115,687	$188,256	$238,245	$177,111	$90,114	$66,389	$239,709	$210,187	$1,908,420
11	Incremental Nuclear NRC Compliance Costs Capital	$916,397	$926,618	$935,812	$935,279	$934,622	$932,512	$921,519	$925,829	$930,636	$943,971	$958,930	$967,372	$11,229,497
12	Transmission of Electricity by Others	$354,669	$22,654	$9,929	$1,303	$15,873	$34,071	($26,894)	$24		$21,154	($509,804)	($73,925)	($150,946)
13	Transmission Revenues from Capacity Sales	($1,504,513)	($971,822)	($1,192,732)	($526,107)	($1,114,919)	($426,142)	($570,975)	($316,283)	($522,375)	($556,476)	($827,736)	($900,414)	($9,430,493)
14	Total Base	$22,128,305	$13,172,301	$21,500,182	$22,179,936	$21,478,251	$21,737,246	$22,086,833	$22,544,673	$21,735,950	$21,244,816	$20,823,484	$22,298,868	$252,930,845
15														
16	**Intermediate**													
17	Incremental Plant Security Costs O&M	$40,553	$259,024	$227,888	$105,840	$97,773	$132,703	$133,730	$59,285	$76,059	$164,205	$128,266	$174,713	$1,600,039
18	Incremental Plant Security Costs Capital	$47,332	$47,232	$47,133	$47,034	$46,893	$46,751	$46,014	$45,918	$45,821	$45,725	$45,628	$45,531	$557,012
19	Total Intermediate	$87,885	$306,257	$275,021	$152,874	$144,665	$179,455	$179,744	$105,203	$121,880	$209,930	$173,894	$220,245	$2,157,052
20														
21	**Peaking**													
22	Incremental Plant Security Costs O&M	$22,301	$123,516	$57,732	$25,718	$22,861	$19,185	$21,583	$23,739	$16,513	$59,561	$51,362	$79,262	$523,334
23	Incremental Plant Security Costs Capital	$6,803	$6,784	$6,765	$6,746	$6,726	$6,707	$6,612	$6,594	$6,575	$6,556	$6,538	$6,519	$79,923
24	Total Peaking	$29,104	$130,300	$64,496	$32,464	$29,588	$25,892	$28,195	$30,333	$23,088	$66,117	$57,900	$85,781	$603,257
25														
26	**General**													
27	Incremental Plant Security Costs Capital	$2,971	$2,956	$2,940	$2,924	$2,908	$2,893	$2,868	$11,186	$11,117	$2,715	$2,699	$2,684	$50,861
28	Total General	$2,971	$2,956	$2,940	$2,924	$2,908	$2,893	$2,868	$11,186	$11,117	$2,715	$2,699	$2,684	$50,861
29														
30	**Total**	$22,248,265	$13,611,813	$21,842,639	$22,368,198	$21,655,413	$21,945,485	$22,297,639	$22,691,395	$21,892,035	$21,523,577	$21,057,977	$22,607,577	$255,742,014
31														
32	Totals may not add due to rounding													

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD OF: JANUARY 2018 THROUGH DECEMBER 2018

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	a-Jan - 2018	a-Feb - 2018	a-Mar - 2018	a-Apr - 2018	a-May - 2018	a-Jun - 2018	a-Jul - 2018	a-Aug - 2018	a-Sep - 2018	a-Oct - 2018	a-Nov - 2018	a-Dec - 2018	Total
1														
2	Total Capacity Costs (Page 2, Line 30)	$22,248,265	$13,611,813	$21,842,639	$22,368,198	$21,655,413	$21,945,485	$22,297,639	$22,691,395	$21,892,035	$21,523,577	$21,057,977	$22,607,577	$255,742,014
3														
4	Total Base Capacity Costs	$22,128,305	$13,172,301	$21,500,182	$22,179,936	$21,478,251	$21,737,246	$22,086,833	$22,544,673	$21,735,950	$21,244,816	$20,823,484	$22,298,868	$252,930,845
5	Base Jurisdictional Factor [(a)]	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%
6	Total Base Jurisdictional Capacity Costs	$21,169,088	$12,601,309	$20,568,192	$21,218,480	$20,547,212	$20,794,979	$21,129,413	$21,567,407	$20,793,740	$20,323,896	$19,920,827	$21,332,257	$241,966,798
7														
8	Total Intermediate Capacity Costs	$87,885	$306,257	$275,021	$152,874	$144,665	$179,455	$179,744	$105,203	$121,880	$209,930	$173,894	$220,245	$2,157,052
9	Intermediate Jurisdictional Factor [(a)]	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%
10	Total Intermediate Jurisdictional Capacity Costs	$82,737	$288,319	$258,914	$143,920	$136,193	$168,944	$169,217	$99,041	$114,741	$197,635	$163,709	$207,345	$2,030,715
11														
12	Total Peaking Capacity Costs	$29,104	$130,300	$64,496	$32,464	$29,588	$25,892	$28,195	$30,333	$23,088	$66,117	$57,900	$85,781	$603,257
13	Peaking Jurisdictional Factor [(a)]	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%
14	Total Peaking Jurisdictional Capacity Costs	$27,573	$123,444	$61,103	$30,756	$28,031	$24,530	$26,711	$28,737	$21,873	$62,638	$54,854	$81,267	$571,518
15														
16	Solar Jurisdictional Factor [(a)]	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%
17														
18	Transmission Jurisdictional Factor [(a)]	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%
19														
20	Total General Capacity Costs	$2,971	$2,956	$2,940	$2,924	$2,908	$2,893	$2,868	$11,186	$11,117	$2,715	$2,699	$2,684	$50,861
21	General Jurisdictional Factor [(a)]	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%
22	Total General Jurisdictional Capacity Costs	$2,881	$2,865	$2,850	$2,835	$2,819	$2,804	$2,780	$10,844	$10,778	$2,632	$2,617	$2,602	$49,307
23														
24	Jurisdictional Capacity Costs	$21,282,278	$13,015,938	$20,891,058	$21,395,991	$20,714,255	$20,991,258	$21,328,121	$21,706,029	$20,941,132	$20,586,800	$20,142,007	$21,623,471	$244,618,338
25														
26	Nuclear Cost Recovery Costs	($665,337)	($669,748)	($674,209)	($678,722)	($683,296)	($687,940)	($692,666)	($697,499)	($702,476)	($707,674)	($713,284)	($985,444)	($8,558,295)
27														
28	Net Jurisdictional Capacity Costs	$20,616,942	$12,346,189	$20,216,850	$20,717,268	$20,030,959	$20,303,318	$20,635,454	$21,008,530	$20,238,656	$19,879,126	$19,428,723	$20,638,027	$236,060,043
29														
30														
31														
32	[(a)] As approved in Order No. PSC-2018-0610-FOF-EI.													
33														
34	Totals may not add due to rounding													

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD OF: JANUARY 2018 THROUGH DECEMBER 2018

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	a-Jan - 2018	a-Feb - 2018	a-Mar - 2018	a-Apr - 2018	a-May - 2018	a-Jun - 2018	a-Jul - 2018	a-Aug - 2018	a-Sep - 2018	a-Oct - 2018	a-Nov - 2018	a-Dec - 2018	Total
1														
2	Net Jurisdictional CCR Costs (Page 3, Line 28)	$20,616,942	$12,346,189	$20,216,850	$20,717,268	$20,030,959	$20,303,318	$20,635,454	$21,008,530	$20,238,656	$19,879,126	$19,428,723	$20,638,027	$236,060,043
3														
4	CCR Revenues (Net of Revenue Taxes)	$20,939,641	$19,614,735	$17,854,813	$18,654,560	$20,286,676	$21,810,960	$21,952,605	$22,617,217	$21,584,076	$21,879,317	$19,159,809	$16,986,220	$243,340,629
5	Prior Period True-up Provision	$78,102	$78,102	$78,102	$78,102	$78,102	$78,102	$78,102	$78,102	$78,102	$78,102	$78,102	$78,102	$937,222
6	Cape Canaveral GBRA Refund	$429,660	$429,660	$429,660	$429,660	$429,660	$429,660	$429,660	$429,660	$429,660	$429,660	$429,660	$429,660	$5,155,918
7	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	21,447,403	20,122,496	18,362,575	19,162,322	20,794,437	22,318,722	22,460,366	23,124,979	22,091,838	22,387,078	19,667,571	17,493,982	249,433,769
8														
9	True-up Provision - Over/(Under) Recovery (Line 7 - Line 2)	$830,461	$7,776,307	($1,854,275)	($1,554,946)	$763,478	$2,015,404	$1,824,912	$2,116,448	$1,853,182	$2,507,952	$238,848	($3,144,045)	$13,373,726
10	Interest Provision	$5,120	$10,064	$14,943	$12,534	$11,187	$13,010	$15,734	$18,174	$21,839	$26,515	$28,746	$25,891	$203,757
11	True-up & Interest Provision Beginning of Year - Over/(Under) Recovery	$6,093,140	$6,420,959	$13,699,569	$11,352,476	$9,302,302	$9,569,205	$11,089,857	$12,422,741	$14,049,602	$15,416,861	$17,443,566	$17,203,399	$6,093,140
12	Deferred True-up - Over/(Under) Recovery	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)	($2,212,807)
13	GBRA Refund Cape Canaveral	($429,660)	($429,660)	($429,660)	($429,660)	($429,660)	($429,660)	($429,660)	($429,660)	($429,660)	($429,660)	($429,660)	($429,660)	($5,155,918)
14	Prior Period True-up Provision - Collected/(Refunded)	($78,102)	($78,102)	($78,102)	($78,102)	($78,102)	($78,102)	($78,102)	($78,102)	($78,102)	($78,102)	($78,102)	($78,102)	($937,222)
15	End of Period True-up - Over/(Under) Recovery (Lines 9 through 14)	$4,208,153	$11,486,762	$9,139,669	$7,089,495	$7,356,398	$8,877,050	$10,209,934	$11,836,795	$13,204,054	$15,230,759	$14,990,592	$11,364,676	$11,364,676
16														
17	Totals may not add due to rounding													

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-IP VARIANCES
FOR THE PERIOD OF: JANUARY 2018 THROUGH DECEMBER 2018

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Capacity Costs	CCR 2018 Final True-up	CCR 2018 Actual/Estimated	Dif. CCR - 2018 Actual/Estimated	% Dif. CCR - 2018 Actual/Estimated
1	Payments to Non-cogenerators	$8,194,687	$10,123,256	($1,928,569)	(19.1%)
2	Payments to Co-generators	$1,359,540	$1,357,086	$2,454	0.2%
3	Cedar Bay Transaction - Reg Asset - Amort & Return	$118,805,132	$118,805,132	$0	0%
4	Cedar Bay Transaction - Reg Liability - Amort & Return	($1,097,343)	($1,097,343)	$0	0%
5	Indiantown Transaction - Regulatory Asset - Amortization and Return	$79,243,457	$79,243,457	$0	0%
6	SJRPP Transaction Revenue Requirements	$12,765,484	$12,765,484	$0	0.0%
7	Incremental Plant Security Costs-Order No. PSC-02-1761 (O&M)	$29,141,261	$28,839,868	$301,393	1.0%
8	Incremental Plant Security Costs-Order No. PSC-02-1761 (Capital)	$3,773,317	$3,823,692	($50,374)	(1.3%)
9	Incremental Nuclear NRC Compliance Costs O&M	$1,908,420	$1,581,250	$327,170	20.7%
10	Incremental Nuclear NRC Compliance Costs Capital	$11,229,497	$11,264,475	($34,978)	(0.3%)
11	Transmission of Electricity by Others	($150,946)	$438,500	($589,446)	(134.4%)
12	Transmission Revenues from Capacity Sales	($9,430,493)	($7,500,714)	($1,929,779)	25.7%
13	Total Capacity Costs	$255,742,014	$259,644,143	($3,902,129)	(1.5%)
14					
15					
16	Totals may not add due to rounding				

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED VARIANCES
FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2018 THROUGH DECEMBER 2018

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Line	CCR 2018 Final True-up	CCR 2018 Actual/Estimated	Dif. CCR - 2018 Actual/Estimated	% Dif. CCR - 2018 Actual/Estimated
1	Total Capacity Costs	$255,742,014	$259,644,143	($3,902,129)	(1.50%)
2					
3	Total Base Capacity Costs	$252,930,845	$257,240,683	($4,309,839)	(1.68%)
4	Base Jurisdictional Factor	95.66520%	95.66520%	0.00%	0.00%
5	Total Base Jurisdictionalized Capacity Costs	$241,966,798	$246,089,814	($4,123,016)	(1.68%)
6					
7	Total Intermediate Capacity Costs	$2,157,052	$1,829,989	$327,063	17.87%
8	Intermediate Jurisdictional Factor	94.14310%	94.14310%	0.00%	0.00%
9	Total Intermediate Jurisdictionalized Capacity Costs	$2,030,715	$1,722,808	$307,907	17.87%
10					
11	Total Peaking Capacity Costs	$603,257	$538,905	$64,352	11.94%
12	Peaking Jurisdictional Factor	94.73860%	94.73860%	0.00%	0.00%
13	Total Peaking Jurisidictionalized Capacity Costs	$571,518	$510,551	$60,966	11.94%
14					
15	Total Solar Capacity Costs	$0	$0	$0	N/A
16	Solar Jurisdictional Factor	95.66520%	95.66520%	0.00%	0.00%
17	Total Solar Jurisdictionalized Capacity Costs	$0	$0	$0	0.00%
18					
19	Total General Capacity Costs	$50,861	$34,566	$16,295	47.14%
20	General Jurisdictional Factor	96.94490%	96.94490%	0.00%	0.00%
21	Total General Jurisdictionalized Capacity Costs	$49,307	$33,510	$15,797	47.14%
22					
23	Total Transmission Capacity Costs	$0	$0	$0	N/A
24	Transmission Jurisdictional Factor	88.79740%	88.79740%	0.00%	0.00%
25	Total Transmission Jurisdictionalized Costs	$0	$0	$0	0.00%
26					
27	Jurisdictional Capacity Costs	$244,618,338	$248,356,683	($3,738,345)	(1.51%)
28					
29	Nuclear Cost Recovery Costs	($8,558,295)	($8,295,198)	($263,097)	3.17%
30					
31	Net Jurisdictional Capacity Costs	$236,060,043	$240,061,486	($4,001,443)	1.67%
32					
33	CCR Revenues	$243,340,629	$240,213,606	$3,127,023	1.3%
34	Prior Period True-up Provision	$937,222	$937,222	$0	N/A
35	Cape Canaveral GBRA Refund	$5,155,918	$5,155,918	$0	N/A
36	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$249,433,769	$246,306,746	$3,127,023	1.3%
37					
38	True-up Provision for Month - Over/(Under) Recovery	$13,373,726	$6,245,260	$7,128,466	114.14%
39	Interest Provision for the Month	$203,757	$170,648	$33,108	19.40%
40	True-Up & Interest Provision - Beginning of Year	$6,093,140	$6,093,140	$0	N/A
41	Deferred True-up - Over/(Under) Recovery	($2,212,807)	($2,212,807)	($0)	0.0%
42	GBRA Refund Cape Canaveral	($5,155,918)	($5,155,918)	$0	N/A
43	Prior Period True-up Provision - Collected/(Refunded) this Month	($937,222)	($937,222)	$0	N/A
44	End of Period True-up - Over/(Under) Recovery	$11,364,676	$4,203,102	$7,161,574	170.4%
45					
46	Totals may not add due to rounding				

Florida Power & Light Company
Schedule A12 - Capacity Costs: Payments to Co-generators
Page 1 of 2

For the Month of **Dec-18**

Contract	Capacity MW	Term Start	Term End	Contract Type
Indiantown [1]	330	12/22/1995	3/31/2020	QF
Broward South - 1991 Agreement	3.5	1/1/1993	12/31/2026	QF

QF = Qualifying Facility

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
ICL [2]	8,298,756	6,919,342	7,465,879	8,486,653	6,844,979	8,456,553	7,672,441	-54,144,603					0
BS-NEG '91	113,295	113,295	113,295	113,295	210,228	13,908	105,358	123,686	113,295	113,295	113,295	113,295	1,359,540
Total	8,412,051	7,032,637	7,579,174	8,599,948	7,055,207	8,470,461	7,777,799	-54,020,917	113,295	113,295	113,295	113,295	1,359,540

Notes:
[1] Consistent with Commission Order No. PSC-2016-0506-FOF-EI, issued in Docket No. 20160154-EI on November 2, 2016, energy and capacity costs associated with the Indiantown Cogeneration, LP (ICL) purchased power agreement (PPA) are no longer being recovered through the Fuel or Capacity Clauses, respectively. FPL, through its ownership, which began on January 5, 2017, now has dispatch control of the ICL facility and will administer the PPA internally.
[2] The amount reflected in August 2018 for ICL reflects a reversal of costs incorrectly reported for January through July 2018.

Florida Power & Light Company
Schedule A12 - Capacity Costs: Payments to Non-cogenerators
Page 2 of 2

For the Month of **Dec-18**

Contract	Counterparty	Identification	Contract Start Date	Contract End Date
1	JEA - SJRPP	Other Entity	April, 1982	January 4, 2018
2	Solid Waste Authority - 40 MW	Other Entity	January, 2012	March 31, 2032
3	Solid Waste Authority - 70 MW	Other Entity	July, 2015	May 31, 2034
4	Exelon Generation Company, LLC	Other Entity	May, 2018	September 30, 2018
5	Orlando Utilities Commission OP-CAP	Other Entity	December 17, 2018	December 31, 2020

2018 Capacity in MW

Contract	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	375	-	-	-	-	-	-	-	-	-	-	-
2	40	40	40	40	40	40	40	40	40	40	40	40
3	70	70	70	70	70	70	70	70	70	70	70	70
4	-	-	-	-	200	200	200	200	200	-	-	-
5												118
Total	485	110	110	110	310	310	310	310	310	110	110	228

2018 Capacity in Dollars

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total	901,301	(6,606,934)	1,442,911	1,195,029	1,410,102	1,029,989	1,530,800	1,530,800	1,486,549	1,220,762	1,230,800	1,822,519

Year-to-date Short Term Capacity Payments	8,194,628 (1)

Contract	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	[redacted]	[redacted]										[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3												
4					[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
5												[redacted]

True ups												
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
2		[redacted]										
3												
4												
5												

(1) Total capacity costs do not include payments for the Solid Waste Authority - 70 MW unit. Capacity costs for this unit were recovered through the Energy Conservation Cost Recovery Clause in 2014, consistent with Commission Order No. PSC-11-0293-FOF-EU issued in Docket No. 110018-EU on July 6, 2011.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY-BASE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

Line No.	Strata	Line	Beginning of Period	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
1	**Base**	Investments														
2		a.Expenditures/Additions		$543,088	$636,293	($1,851,701)	($42,249)	$400,554	$653,721	$519,658	$618,648	$757,403	$518,920	$1,106,460	$1,459,719	$5,320,512
3		b.Clearings to Plant		$44,524	$54,376	$2,134,361	$349,738	$29,205	$25,602	$19,816	$29,445	$19,567	$11,044	($8,393)	$17,062	$2,726,348
4		c.Retirements														
5		d.Other		$156	$9,265	($523)	($554)	($865)	($5,447)	($4,723)	$794	$811	($4,991)	($10,436)	($12,408)	($28,923)
6																
7		Plant-In-Service/Depreciation Base	$16,498,724	$16,543,248	$16,597,624	$18,731,985	$19,081,723	$19,110,928	$19,136,530	$19,156,346	$19,185,792	$19,205,358	$19,216,403	$19,208,010	$19,225,071	N/A
8		Less: Accumulated Depreciation	$617,968	$699,344	$790,084	$873,972	$963,323	$1,055,134	$1,142,625	$1,231,016	$1,316,633	$1,402,360	$1,490,703	$1,573,607	$1,654,551	N/A
9		CWIP - Non Interest Bearing	$7,532,118	$8,075,206	$8,711,499	$6,859,797	$6,817,549	$7,218,102	$7,871,824	$8,391,481	$9,010,130	$9,767,532	$10,286,452	$11,392,912	$12,852,631	N/A
10																
11		Net Investment (Lines 7 - 8 + 9)	$23,412,874	$23,919,110	$24,519,039	$24,717,810	$24,935,949	$25,273,897	$25,865,729	$26,316,811	$26,879,288	$27,570,531	$28,012,152	$29,027,314	$30,423,151	N/A
12																
13		Average Net Investment		$23,665,992	$24,219,074	$24,618,425	$24,826,880	$25,104,923	$25,569,813	$26,091,270	$26,598,050	$27,224,909	$27,791,342	$28,519,733	$29,725,233	N/A
14																
15		Return on Average Net Investment														
16		a.Equity Component grossed up for taxes		$127,464	$130,443	$132,594	$133,717	$135,214	$137,718	$137,340	$140,007	$143,307	$146,288	$150,123	$156,468	$1,670,685
17		b.Debt Component (Line 13 x debt rate x 1/12)		$26,454	$27,072	$27,518	$27,751	$28,062	$28,582	$28,912	$29,473	$30,168	$30,796	$31,603	$32,939	$349,330
18																
19		Investment Expenses														
20		a.Depreciation		$81,221	$81,475	$84,411	$89,905	$92,676	$92,939	$93,114	$84,822	$84,915	$93,334	$93,341	$93,352	$1,065,506
21		b.Amortization														
22		c.Other														
23																
24		Total System Recoverable Costs (Lines 15 & 19)		$235,139	$238,990	$244,524	$251,374	$255,953	$259,239	$259,365	$254,303	$258,390	$270,418	$275,066	$282,759	$3,085,521

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28 [(a)] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2018 period is 4.8251%, based on May 2017 ROR Surveillance Report
29 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 ROR Surveillance Report and reflects a 10.55% return on equity.
30 [(b)] The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earnings Surveillance Report.
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33 Totals may not add due to rounding

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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY-GENERAL
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

Line No.	Strata	Line	Beginning of Period	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
1	**General**	Investments														
2		a.Expenditures/Additions														
3		b.Clearings to Plant														
4		c.Retirements														
5		d.Other														
6																
7		Plant-In-Service/Depreciation Base	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	N/A
8		Less: Accumulated Depreciation	$59,518	$61,940	$64,361	$66,782	$69,204	$71,625	$74,047	$76,468	$87,250	$98,032	$100,453	$102,875	$105,296	N/A
9		CWIP - Non Interest Bearing														N/A
10																
11		Net Investment (Lines 7 - 8 + 9)	$85,766	$83,344	$80,923	$78,501	$76,080	$73,659	$71,237	$68,816	$58,034	$47,252	$44,831	$42,409	$39,988	N/A
12																
13		Average Net Investment		$84,555	$82,134	$79,712	$77,291	$74,869	$72,448	$70,027	$63,425	$52,643	$46,041	$43,620	$41,199	N/A
14																
15		Return on Average Net Investment														
16		a.Equity Component grossed up for taxes		$455	$442	$429	$416	$403	$390	$369	$334	$277	$242	$230	$217	$4,205
17		b.Debt Component (Line 13 x debt rate x 1/12)		$95	$92	$89	$86	$84	$81	$78	$70	$58	$51	$48	$46	$878
18																
19		Investment Expenses														
20		a.Depreciation		$2,421	$2,421	$2,421	$2,421	$2,421	$2,421	$2,421	$10,782	$10,782	$2,421	$2,421	$2,421	$45,778
21		b.Amortization														
22		c.Other														
23																
24		Total System Recoverable Costs (Lines 15 & 19)		$2,971	$2,956	$2,940	$2,924	$2,908	$2,893	$2,868	$11,186	$11,117	$2,715	$2,699	$2,684	$50,861

28 [(a)] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2018 period is 4.8251%, based on May 2017 ROR Surveillance Report
29 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 ROR Surveillance Report and reflects a 10.55% return on equity.
30 [(b)] The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earnings Surveillance Report.

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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY-INTERMEDIATE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

Line No.	Strata	Line	Beginning of Period	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
1	**Intermediate**	Investments														
2		a.Expenditures/Additions														
3		b.Clearings to Plant														
4		c.Retirements														
5		d.Other														
6																
7		Plant-In-Service/Depreciation Base	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	N/A
8		Less: Accumulated Depreciation	$399,817	$415,062	$430,307	$445,551	$460,796	$475,999	$491,159	$506,319	$521,479	$536,639	$551,799	$566,958	$582,118	N/A
9		CWIP - Non Interest Bearing														N/A
10																
11		Net Investment (Lines 7 - 8 + 9)	$4,941,168	$4,925,923	$4,910,678	$4,895,433	$4,880,188	$4,864,985	$4,849,825	$4,834,665	$4,819,506	$4,804,346	$4,789,186	$4,774,026	$4,758,866	N/A
12																
13		Average Net Investment		$4,933,545	$4,918,300	$4,903,055	$4,887,810	$4,872,587	$4,857,405	$4,842,245	$4,827,086	$4,811,926	$4,796,766	$4,781,606	$4,766,446	N/A
14																
15		Return on Average Net Investment														
16		a.Equity Component grossed up for taxes		$26,572	$26,490	$26,408	$26,326	$26,244	$26,162	$25,489	$25,409	$25,329	$25,249	$25,169	$25,090	$309,936
17		b.Debt Component (Line 13 x debt rate x 1/12)		$5,515	$5,498	$5,481	$5,464	$5,447	$5,430	$5,366	$5,349	$5,332	$5,315	$5,298	$5,282	$64,775
18																
19		Investment Expenses														
20		a.Depreciation		$15,245	$15,245	$15,245	$15,245	$15,202	$15,160	$15,160	$15,160	$15,160	$15,160	$15,160	$15,160	$182,302
21		b.Amortization														
22		c.Other														
23																
24		Total System Recoverable Costs (Lines 15 & 19)		$47,332	$47,232	$47,133	$47,034	$46,893	$46,751	$46,014	$45,918	$45,821	$45,725	$45,628	$45,531	$557,012

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28 [(a)] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2018 period is 4.8251%, based on May 2017 ROR Surveillance Report

29 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 ROR Surveillance Report and reflects a 10.55% return on equity.

30 [(b)] The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earnings Surveillance Report.

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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY-PEAKING
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

Line No.	Strata	Line	Beginning of Period	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
1	**Peaking**	Investments														
2		a.Expenditures/Additions														
3		b.Clearings to Plant														
4		c.Retirements														
5		d.Other														
6																
7		Plant-In-Service/Depreciation Base	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	N/A
8		Less: Accumulated Depreciation	$75,740	$78,670	$81,599	$84,528	$87,457	$90,386	$93,316	$96,245	$99,174	$102,103	$105,032	$107,961	$110,891	N/A
9		CWIP - Non Interest Bearing														N/A
10																
11		Net Investment (Lines 7 - 8 + 9)	$597,043	$594,113	$591,184	$588,255	$585,326	$582,397	$579,467	$576,538	$573,609	$570,680	$567,751	$564,821	$561,892	N/A
12																
13		Average Net Investment		$595,578	$592,649	$589,720	$586,790	$583,861	$580,932	$578,003	$575,074	$572,144	$569,215	$566,286	$563,357	N/A
14																
15		Return on Average Net Investment														
16		a.Equity Component grossed up for taxes		$3,208	$3,192	$3,176	$3,160	$3,145	$3,129	$3,042	$3,027	$3,012	$2,996	$2,981	$2,965	$37,034
17		b.Debt Component (Line 13 x debt rate x 1/12)		$666	$662	$659	$656	$653	$649	$640	$637	$634	$631	$628	$624	$7,740
18																
19		Investment Expenses														
20		a.Depreciation		$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$35,150
21		b.Amortization														
22		c.Other														
23																
24		Total System Recoverable Costs (Lines 15 & 19)		$6,803	$6,784	$6,765	$6,746	$6,726	$6,707	$6,612	$6,594	$6,575	$6,556	$6,538	$6,519	$79,923
25																
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27																

28 [(a)] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2018 period is 4.8251%, based on May 2017 ROR Surveillance Report
29 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 ROR Surveillance Report and reflects a 10.55% return on equity.
30 [(b)] The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earnings Surveillance Report.
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL NUCLEAR NRC COMPLIANCE -BASE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

Line No.	Line	Beginning of Period	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
1	Investments														
2	a.Expenditures/Additions		$729,181	($105,023)	$5,069	$100,311	$60,967	$251,189	$639,702	$1,800,534	$455,467	($3,064,573)	($1,681,025)	$82,959	($725,240)
3	b.Clearings to Plant		$68,688	$2,088,860	$53,917	$485,838	$72	$0	$15,356	($12,411)		$1,777,914	$1,548,025	$1,530,094	$7,556,353
4	c.Retirements											($4,541,804)			($4,541,804)
5	d.Other		($5,300)	($6,557)	($5,857)	$467,457	($20)	$0	$0	$15,700		$36		$270,320	$735,779
6															
7	Plant-In-Service/Depreciation Base	$92,095,957	$92,164,645	$94,253,504	$94,307,421	$94,793,259	$94,793,332	$94,793,332	$94,808,688	$94,796,277	$94,796,277	$96,574,191	$98,122,216	$99,652,310	N/A
8	Less: Accumulated Depreciation	$6,897,009	$7,241,209	$7,587,573	$7,939,457	$8,765,857	$9,125,877	$9,485,130	$9,844,415	$10,218,262	$10,576,399	$6,396,577	$6,765,864	$7,412,434	N/A
9	CWIP - Non Interest Bearing	$1,738,561	$2,467,743	$2,362,720	$2,367,789	$2,468,100	$2,529,067	$2,780,257	$3,419,959	$5,220,494	$5,675,961	$2,611,387	$930,363	$1,013,321	N/A
10															
11	Net Investment (Lines 7 - 8 + 9)	$86,937,509	$87,391,178	$89,028,651	$88,735,753	$88,495,502	$88,196,522	$88,088,458	$88,384,232	$89,798,509	$89,895,838	$92,789,002	$92,286,714	$93,253,198	N/A
12															
13	Average Net Investment		$87,164,343	$88,209,915	$88,882,202	$88,615,627	$88,346,012	$88,142,490	$88,236,345	$89,091,370	$89,847,173	$91,342,420	$92,537,858	$92,769,956	N/A
14															
15	Return on Average Net Investment														
16	a.Equity Component grossed up for taxes [(a)]		$469,465	$475,096	$478,717	$477,282	$475,829	$474,733	$464,460	$468,960	$472,939	$480,809	$487,102	$488,324	$5,713,717
17	b.Debt Component (Line 13 x debt rate x 1/12) [(b)]		$97,432	$98,601	$99,353	$99,055	$98,753	$98,526	$97,775	$98,722	$99,560	$101,217	$102,541	$102,798	$1,194,332
18															
19	Investment Expenses														
20	a.Depreciation		$349,499	$352,921	$357,742	$358,943	$360,040	$359,253	$359,285	$358,147	$358,137	$361,945	$369,287	$376,249	$4,321,448
21	b.Amortization														
22	c.Other														
23															
24	Total System Recoverable Costs (Lines 15 & 19)		$916,397	$926,618	$935,812	$935,279	$934,622	$932,512	$921,519	$925,829	$930,636	$943,971	$958,930	$967,372	$11,229,497
25															
26															
27															

28 [(a)] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2018 period is 4.8251%, based on May 2017 ROR Surveillance Report
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30 [(b)] The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earnings Surveillance Report.
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CEDAR BAY TRANSACTION
REGULATORY ASSET RELATED TO THE LOSS OF THE PPA AND INCOME TAX GROSS-UP (AMORTIZATION)
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

Line No.	Line	Beginning of Period	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
1	Regulatory Asset - Loss of PPA		$390,375,045	$385,727,723	$381,080,401	$376,433,079	$371,785,757	$367,138,435	$362,491,113	$357,843,791	$353,196,469	$348,549,147	$343,901,825	$339,254,503	N/A
2															
3	Regulatory Asset - Loss of PPA Amort		$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$55,767,864
4															
5	Unamortized Regulatory Asset - Loss of PPA	$390,375,045	$385,727,723	$381,080,401	$376,433,079	$371,785,757	$367,138,435	$362,491,113	$357,843,791	$353,196,469	$348,549,147	$343,901,825	$339,254,503	$334,607,181	N/A
6															
7	Average Unamortized Regulatory Asset - Loss of PPA		$388,051,384	$383,404,062	$378,756,740	$374,109,418	$369,462,096	$364,814,774	$360,167,452	$355,520,130	$350,872,808	$346,225,486	$341,578,164	$336,930,842	N/A
8															
9	Regulatory Asset - Income Tax Gross Up	$248,074,626	$245,156,101	$242,237,576	$239,319,051	$236,400,526	$233,482,001	$230,563,476	$227,644,951	$224,726,426	$221,807,901	$218,889,376	$215,970,851	$213,052,326	N/A
10															
11	Regulatory Asset Amortization - Income Tax Gross-Up		$2,918,525	$2,918,525	$2,918,525	$2,918,525	$2,918,525	$2,918,525	$2,918,525	$2,918,525	$2,918,525	$2,918,525	$2,918,525	$2,918,525	$35,022,300
12															
13	Unamortized Regulatory Asset - Income Tax Gross Up		$242,237,576	$239,319,051	$236,400,526	$233,482,001	$230,563,476	$227,644,951	$224,726,426	$221,807,901	$218,889,376	$215,970,851	$213,052,326	$210,133,801	N/A
14															
15	Return on Unamortized Regulatory Asset - Loss of PPA only														
16	a. Equity Component [(a)]		$1,560,316	$1,541,629	$1,522,943	$1,504,257	$1,485,570	$1,466,884	$1,415,350	$1,397,087	$1,378,825	$1,360,562	$1,342,300	$1,324,037	$17,299,760
17															
18	b. Equity Comp. grossed up for taxes (Line 16 / 0.61425) [(a)]		$2,090,035	$2,065,005	$2,039,975	$2,014,944	$1,989,914	$1,964,883	$1,895,854	$1,871,392	$1,846,929	$1,822,466	$1,798,004	$1,773,541	$23,172,942
19															
20	c. Debt Component (Line 7 * debt rate / 12) [(b)]		$433,764	$428,569	$423,374	$418,180	$412,985	$407,790	$399,102	$393,952	$388,802	$383,652	$378,503	$373,353	$4,842,025
21															
22	Total Return Requirements (Line 18 + 20)		$2,523,799	$2,493,574	$2,463,349	$2,433,124	$2,402,899	$2,372,673	$2,294,956	$2,265,344	$2,235,731	$2,206,119	$2,176,507	$2,146,894	$28,014,968
23	Total Recoverable Costs (Line 3 + 11 + 22)		$10,089,646	$10,059,421	$10,029,196	$9,998,971	$9,968,746	$9,938,520	$9,860,803	$9,831,191	$9,801,578	$9,771,966	$9,742,354	$9,712,741	$118,805,132
24															
25															

26 [(a)] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2018 period is 4.8251%, based on May 2017 ROR Surveillance Report
27 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 ROR Surveillance Report and reflects a 10.55% return on equity.
28 [(b)] The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earnings Surveillance Report.
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CEDAR BAY TRANSACTION
REGULATORY LIABILITY - BOOK/TAX TIMING DIFFERENCE ASSOCIATED TO PLANT ASSET - AMORTIZATION
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

Line No.	Line	Beginning of Period	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
1	Regulatory Liability - Book/Tax Timing Difference [c]		($5,112,949)	($5,052,081)	($4,991,213)	($4,930,345)	($4,869,477)	($4,808,609)	($4,747,741)	($4,686,873)	($4,626,005)	($4,565,137)	($4,504,269)	($4,443,401)	N/A
2															
3	Regulatory Liability Amortization		$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$730,416
4															
5	Unamortized Regulatory Liability - Book/Tax Timing Diff	($5,112,949)	($5,052,081)	($4,991,213)	($4,930,345)	($4,869,477)	($4,808,609)	($4,747,741)	($4,686,873)	($4,626,005)	($4,565,137)	($4,504,269)	($4,443,401)	($4,382,533)	N/A
6															
7	Average Unamortized Regulatory Liability-Book/Tax Timing Difference		($5,082,515)	($5,021,647)	($4,960,779)	($4,899,911)	($4,839,043)	($4,778,175)	($4,717,307)	($4,656,439)	($4,595,571)	($4,534,703)	($4,473,835)	($4,412,967)	N/A
8															
9	Return on Unamortized Regulatory Liability-Book/Tax Timing Difference														
10															
11	a. Equity Component [a]		($20,436)	($20,192)	($19,947)	($19,702)	($19,457)	($19,213)	($18,538)	($18,298)	($18,059)	($17,820)	($17,581)	($17,342)	($226,584)
12															
13	b. Equity Comp. grossed up for taxes (Line 11 / 0.61425) [a]		($27,374)	($27,046)	($26,719)	($26,391)	($26,063)	($25,735)	($24,831)	($24,511)	($24,190)	($23,870)	($23,549)	($23,229)	($303,508)
14															
15	c. Debt Component (Line 7 * 1.4904% / 12) [b]		($5,681)	($5,613)	($5,545)	($5,477)	($5,409)	($5,341)	($5,227)	($5,160)	($5,092)	($5,025)	($4,957)	($4,890)	($63,419)
16															
17	Total Return Requirements (Line 13 + 15)		($33,056)	($32,660)	($32,264)	($31,868)	($31,472)	($31,076)	($30,058)	($29,670)	($29,283)	($28,895)	($28,507)	($28,119)	($366,927)
18	Total Recoverable Costs (Line -3 + 17)		($93,924)	($93,528)	($93,132)	($92,736)	($92,340)	($91,944)	($90,926)	($90,538)	($90,151)	($89,763)	($89,375)	($88,987)	($1,097,343)

19
20
21 [a] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2018 period is 4.8251%, based on May 2017 ROR Surveillance Report
22 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 ROR Surveillance Report and reflects a 10.55% return on equity.
23 [b] The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earnings Surveillance Report.
24 [c] Recovery of the Cedar Bay Transaction is based on the settlement agreement approved by the FPSC in Docket No. 150075-EI, Order No. PSC-15-0401-AS-EI.
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27
28 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INDIANTOWN TRANSACTION
REGULATORY ASSET RELATED TO THE LOSS OF THE PPA AND INCOME TAX GROSS-UP
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

Line No.	Line	Beginning of Period	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
1	Regulatory Asset - Loss of PPA [c]		$401,333,333	$397,152,777	$392,972,222	$388,791,666	$384,611,111	$380,430,555	$376,250,000	$372,069,444	$367,888,889	$363,708,333	$359,527,777	$355,347,222	N/A
2															
3	Regulatory Asset - Loss of PPA Amort		$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$50,166,667
4															
5	Unamortized Regulatory Asset - Loss of PPA	$401,333,333	$397,152,777	$392,972,222	$388,791,666	$384,611,111	$380,430,555	$376,250,000	$372,069,444	$367,888,889	$363,708,333	$359,527,777	$355,347,222	$351,166,666	N/A
6															
7	Average Unamortized Regulatory Asset - Loss of PPA		$399,243,055	$395,062,500	$390,881,944	$386,701,389	$382,520,833	$378,340,277	$374,159,722	$369,979,166	$365,798,611	$361,618,055	$357,437,500	$353,256,944	N/A
8															
9	Return on Unamortized Regulatory Asset - Loss of PPA only														
10	a. Equity Component [a]		$1,605,316	$1,588,507	$1,571,697	$1,554,888	$1,538,078	$1,521,268	$1,470,335	$1,453,907	$1,437,479	$1,421,050	$1,404,622	$1,388,194	$17,955,342
11															
12	b. Equity Comp. grossed up for taxes (Line 9a / 0.61425) [a]		$2,150,313	$2,127,797	$2,105,281	$2,082,764	$2,060,248	$2,037,731	$1,969,507	$1,947,501	$1,925,496	$1,903,490	$1,881,484	$1,859,479	$24,051,091
13															
14	c. Debt Component (Line 7 * debt rate / 12) [b]		$446,274	$441,601	$436,928	$432,255	$427,582	$422,909	$414,606	$409,974	$405,341	$400,709	$396,076	$391,444	$5,025,699
15															
16	Total Return Requirements (Line 12 + 14)		$2,596,587	$2,569,398	$2,542,208	$2,515,019	$2,487,830	$2,460,640	$2,384,113	$2,357,475	$2,330,837	$2,304,199	$2,277,561	$2,250,923	$29,076,791
17	Total Recoverable Costs (Line 3 + 16)		$6,777,143	$6,749,953	$6,722,764	$6,695,575	$6,668,385	$6,641,196	$6,564,669	$6,538,031	$6,511,393	$6,484,755	$6,458,116	$6,431,478	$79,243,457
18															
19															

20 [a] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2018 period is 4.8251%, based on May 2017 ROR Surveillance Report
21 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 ROR Surveillance Report and reflects a 10.55% return on equity.
22 [b] The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297%
23 based on the May 2018 Earnings Surveillance Report.
24 [c] Recovery of the Indiantown Transaction is based on the settlement agreement approved by the FPSC in Docket No. 160154-EI, Order No. PSC-16-0506-FOF-EI.
25
26
27 Totals may not add due to rounding

Docket No. 20190001-EI
2018 CCR Final True Up
Exhibit RBD-2, Page 16 of 19

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
SJRPP TRANSACTION
REGULATORY ASSETS AND LIABILITIES RELATED TO THE SJRPP TRANSACTION
FOR THE PERIOD JANUARY 2018 THROUGH DECEMBER 2018

Line No.	Line	Beginning Balance	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	Total
1															
2	Regulatory Asset - SJRPP Transaction Shutdown Payment [c]		$90,400,000	$88,434,783	$86,469,565	$84,504,348	$82,539,130	$80,573,913	$78,608,696	$76,643,478	$74,678,261	$72,713,043	$70,747,826	$68,782,609	
3	Regulatory Asset - SJRPP Transaction Shutdown Payment Amortization		$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$23,582,609
4	Unamortized Regulatory Asset - SJRPP Transaction Shutdown Payment	$90,400,000	$88,434,783	$86,469,565	$84,504,348	$82,539,130	$80,573,913	$78,608,696	$76,643,478	$74,678,261	$72,713,043	$70,747,826	$68,782,609	$66,817,391	
5															
6	Other regulatory liability - SJRPP Suspension Liability		($9,904,593)	($9,689,276)	($9,473,959)	($9,258,641)	($9,043,324)	($8,828,007)	($8,612,690)	($8,397,372)	($8,182,055)	($7,966,738)	($7,751,421)	($7,536,103)	
7	Other regulatory liability - SJRPP Suspension Liability Amortization (Refund)		($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($2,583,807)
8	Unamortized Regulatory Liability - SJRPP Suspension Liability	($9,904,593)	($9,689,276)	($9,473,959)	($9,258,641)	($9,043,324)	($8,828,007)	($8,612,690)	($8,397,372)	($8,182,055)	($7,966,738)	($7,751,421)	($7,536,103)	($7,320,786)	
9															
10	Average Net Unamortized Regulatory Asset/Liab (Lines 4 + 8)		$79,620,457	$77,870,557	$76,120,657	$74,370,756	$72,620,856	$70,870,956	$69,121,056	$67,371,156	$65,621,256	$63,871,356	$62,121,455	$60,371,555	
11															
12	Equity Component [a]		$320,146	$313,110	$306,074	$299,037	$292,001	$284,965	$271,625	$264,748	$257,872	$250,995	$244,119	$237,242	$3,341,934
13	Equity Comp. grossed up for taxes [a]		$428,834	$419,409	$409,984	$400,559	$391,134	$381,709	$363,840	$354,629	$345,418	$336,207	$326,996	$317,785	$4,476,504
14	Debt Component (Line 10 x debt rate x 1/12) [b]		$89,000	$87,044	$85,088	$83,132	$81,176	$79,220	$76,593	$74,654	$72,715	$70,776	$68,837	$66,898	$935,130
15															
16	Total Return Requirements (Line 13 + 14)		$517,834	$506,453	$495,072	$483,691	$472,310	$460,929	$440,433	$429,283	$418,133	$406,983	$395,833	$384,682	$5,411,634
17															
18	Other SJRPP Transaction Items [d]														
19	SJRPP Deferred Interest Amortization (Refund)		($269,181)	($269,181)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($3,230,180)
20	SJRPP Article 8 PPA Dismantlement Accrual Amortization (Refund)		($867,897)	($867,897)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($10,414,772)
21															
22	Total Recoverable Expenses (Lines 3 + 7 + 16 + 19 + 20)		$1,130,656	$1,119,275	$1,107,892	$1,096,511	$1,085,130	$1,073,749	$1,053,254	$1,042,104	$1,030,954	$1,019,803	$1,008,653	$997,503	$12,765,484
23															
24															
25															

26 [a] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2018 period is 4.8251%, based on May 2017 ROR Surveillance Report

27 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 ROR Surveillance Report and reflects a 10.55% return on equity.

28 [b] The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earnings Surveillance Report.

29 [c] Recovery of the SJRPP Transaction over a 46 month period is based on the settlement agreement approved by the FPSC in Docket No. 20170123-EI Order No. PSC-2017-0415-AS-EI.

30 [d] The total amount of SJRPP Deferred Interest and Article 8 PPA Dismantlement Accrual to refund is $12.4M and $39.9M, respectively. The unamortized balances for these regulatory liabilities are reflected in rate base.

31

32 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.55%	CAPITAL STRUCTURE AND COST RATES PER MAY 2017 EARNINGS SURVEILLANCE REPORT				
	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	8,578,170,782	27.773%	4.53%	1.26%	1.26%
SHORT_TERM_DEBT	876,957,343	2.839%	1.76%	0.05%	0.05%
PREFERRED_STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER_DEPOSITS	421,323,778	1.364%	2.09%	0.03%	0.03%
COMMON_EQUITY	14,087,418,183	45.610%	10.55%	4.81%	7.83%
DEFERRED_INCOME_TAX	6,860,621,618	22.212%	0.00%	0.00%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	62,115,684	0.201%	8.27%	0.02%	0.02%
TOTAL	$30,886,607,389	100.00%		6.17%	9.20%

	CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) (a)				
	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$8,578,170,782	37.85%	4.534%	1.716%	1.716%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	14,087,418,183	62.15%	10.550%	6.557%	10.675%
TOTAL	$22,665,588,966	100.00%		8.273%	12.391%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.2592%
SHORT TERM DEBT	0.0501%
CUSTOMER DEPOSITS	0.0285%
TAX CREDITS -WEIGHTED	0.0035%
TOTAL DEBT	**1.3413%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.8119%
TAX CREDITS -WEIGHTED	0.0132%
TOTAL EQUITY	**4.8251%**
TOTAL	6.1663%
PRE-TAX EQUITY	7.8552%
PRE-TAX TOTAL	9.1965%

Note:

(a) This capital structure applies only to Convertible Investment Tax Credit (C-ITC)

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.55%

CAPITAL STRUCTURE AND COST RATES PER MAY 2018 EARNINGS SURVEILLANCE REPORT

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	9,493,721,402	27.894%	4.33%	1.21%	1.21%
SHORT_TERM_DEBT	1,266,291,093	3.721%	2.42%	0.09%	0.09%
PREFERRED_STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER_DEPOSITS	403,315,602	1.185%	2.08%	0.02%	0.02%
COMMON_EQUITY	15,115,086,261	44.410%	10.55%	4.69%	6.28%
DEFERRED_INCOME_TAX	7,597,792,885	22.323%	0.00%	0.00%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	159,231,867	0.468%	8.15%	0.04%	0.05%
TOTAL	$34,035,439,111	100.00%		6.05%	7.65%

CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) (a)

	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$9,493,721,402	38.58%	4.328%	1.670%	1.670%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	15,115,086,261	61.42%	10.550%	6.480%	8.680%
TOTAL	$24,608,807,663	100.00%		8.150%	10.350%
RATIO					

DEBT COMPONENTS:

LONG TERM DEBT	1.2073%
SHORT TERM DEBT	0.0900%
CUSTOMER DEPOSITS	0.0246%
TAX CREDITS -WEIGHTED	0.0078%
TOTAL DEBT	**1.3297%**

EQUITY COMPONENTS:

PREFERRED STOCK	0.0000%
COMMON EQUITY	4.6852%
TAX CREDITS -WEIGHTED	0.0303%
TOTAL EQUITY	**4.7156%**
TOTAL	6.0452%
PRE-TAX EQUITY	6.3165%
PRE-TAX TOTAL	7.6461%

Note:

(a) This capital structure applies only to Convertible Investment Tax Credit (C-ITC)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 20190001-EI

MARCH 1, 2019

Q. Please state your name and address.

A. My name is Gerard J. Yupp. My business address is 700 Universe Boulevard, Juno Beach, Florida, 33408.

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

A. I am employed by Florida Power and Light Company ("FPL") as Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Please summarize your educational background and professional experience.

A. I graduated from Drexel University with a Bachelor of Science Degree in Electrical Engineering in 1989. I joined the Protection and Control Department of FPL in 1989 as a Field Engineer where I was responsible for the installation, maintenance, and troubleshooting of protective relay equipment for generation, transmission and distribution facilities. While employed by FPL, I earned a Masters of Business Administration degree from Florida Atlantic University in 1994. In 1996, I joined the Energy Marketing and Trading Division ("EMT") of FPL as a real-time power trader. I progressed through several power trading positions and assumed the lead role for power trading in 2002. In 2004, I became the Director of Wholesale Operations and natural gas and fuel oil procurement and operations were added to my responsibilities. I have been in my current role since 2008. On the operations side, I am responsible for the procurement and management of all natural gas and fuel oil for FPL, as well as all short-term power trading activity. Finally, I am responsible for the oversight of FPL's optimization activities associated with the Incentive Mechanism.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the 2018 results of FPL's activities under the Incentive Mechanism that was originally approved by Order No. PSC-13-0023-S-EI, dated January 14, 2013, in Docket No. 120015-EI and approved for continuation, with certain modifications, by Order No. PSC-16-0560-AS-EI, dated December 15, 2016, in Docket No. 160021-EI.

Q. Have you prepared or caused to be prepared under your supervision, direction and control any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

- GJY-1, consisting of 4 pages:
    - Page 1 – Total Gains Schedule
    - Page 2 – Wholesale Power Detail
    - Page 3 – Asset Optimization Detail
    - Page 4 – Incremental Optimization Costs

Q. Please provide an overview of the Incentive Mechanism.

A. The Incentive Mechanism is an expanded optimization program that is designed to create additional value for FPL's customers while also providing an incentive to FPL if certain customer-value thresholds are achieved. The Incentive Mechanism includes gains from wholesale power sales and savings from wholesale power purchases, as well as gains from other forms of asset optimization. These other forms of asset optimization include, but are not limited to, natural gas storage optimization, natural gas sales, capacity releases of natural gas transportation, capacity releases of electric transmission and potentially capturing additional value from a third party in the form of an Asset Management Agreement (AMA). Under the modified Incentive Mechanism, customers receive 100% of the gains up to the sharing threshold of $40 million. Incremental gains above $40 million are shared between FPL and customers as follows: customers receive 40% and FPL receives 60% of the incremental gains between $40 million and $100 million; and customers receive 50% and FPL receives 50% of all incremental gains above $100 million.

In addition, FPL recovers the net amount of variable power plant O&M incurred during the year. This is accomplished by multiplying the per-MWh variable power plant O&M rate times the volume (MWh) of economy sales and then subtracting the per-MWh variable power plant O&M rate times the volume (MWh) of economy purchases. For example, if economy purchases are greater than economy sales, customers will receive a credit for the net variable power plant O&M that has been saved during the year. The per-MWh variable power plant O&M rate that FPL utilizes to calculate these costs, as described in FPL's

2017 Test Year MFRs filed with the 2016 Rate Petition, is $0.65/MWh. Finally, FPL is allowed to recover reasonable and prudent incremental O&M costs incurred in implementing the expanded optimization program under the Incentive Mechanism, including incremental personnel, software and associated hardware costs.

Q. Please summarize the activities and results of the Incentive Mechanism for 2018?

A. FPL's activities under the Incentive Mechanism in 2018 delivered $62,404,332 in total gains. During 2018, FPL's activities under the Incentive Mechanism included wholesale power purchases and sales, natural gas sales in the market and production areas, gas storage utilization, and the capacity release of firm natural gas transportation. Additionally, FPL entered into several Asset Management Agreements related to a small portion of upstream gas transportation during 2018. The total gains of $62,404,332 exceeded the sharing threshold of $40 million. Therefore, the incremental gains above $40 million will be shared between customers and FPL, 40% and 60%, respectively. Exhibit GJY-1, Page 1, shows monthly gain totals, threshold levels and the final gains allocation for 2018.

Q. Please provide the details of FPL's wholesale power activities under the Incentive Mechanism for 2018.

A. The details of FPL's 2018 wholesale power sales and purchases are shown separately on Page 2 of Exhibit GJY-1. FPL had gains of $32,462,909 on wholesale sales and savings of $7,943,114 on wholesale purchases for the year.

Q. Please provide the details of FPL's asset optimization activities under the Incentive Mechanism for 2018.

A. The details of FPL's 2018 asset optimization activities are shown on Page 3 of Exhibit GJY-1. FPL had a total of $21,998,309 of gains that were the result of seven different forms of asset optimization.

Q. Did FPL engage in any new forms of asset optimization during 2018?

A. No. FPL did not engage in any new forms of asset optimization activities during 2018.

Q. Did FPL incur incremental O&M expenses related to the operation of the Incentive Mechanism in 2018?

A. Yes. FPL incurred personnel expenses of $458,689 related to the costs associated with an additional two and one-half personnel required to support FPL's expanded activities under the Incentive Mechanism. FPL also incurred $57,762 in expenses related to licensing fees of OATI WebTrader software. In total, FPL incurred incremental O&M expenses related to the operation of the Incentive Mechanism of $516,451 in 2018.

On the variable power plant O&M side, FPL's actual net economy power sales and purchases totaled 2,246,006 MWh (2,478,644 MWh of economy sales and 232,638 MWh of economy purchases), resulting in net variable power plant O&M costs of $1,459,905 for 2018.

Q. Overall, were FPL's activities under the Incentive Mechanism successful in 2018?

A. Yes. FPL's activities under the Incentive Mechanism were highly successful in 2018. On the wholesale power and natural gas optimization side, suitable market conditions in the winter period helped drive strong wholesale power sales and natural gas optimization activities and high demand during the late summer/early fall peak period provided the opportunity to purchase power from the market to avoid running more expensive generation. Overall, FPL was able to consistently capitalize on power market opportunities throughout the year to deliver slightly more than $40.4 million in customer benefits. Asset optimization activities related to natural gas resulted in significant customer benefits of nearly $22 million. In total, these activities delivered $62,404,332 of gains, which contrast very favorably to the total optimization expenses (personnel and variable power plant O&M) of $1,976,355.

Q. Does this conclude your testimony?

A. Yes it does.

TOTAL GAINS SCHEDULE
Actual for the Period of: January 2018 through December 2018

TABLE 1

(1) Month	(2) Wholesale Sales Gains ($)	(3) Wholesale Purchases Savings ($)	(4) Asset Optimization Gains ($)	(5) Total Monthly Gains ($) (2)+(3)+(4)	(6) **Threshold 1** Gains ≤ $30M ($)	(7) **Threshold 2** $30M > Gains ≤ $40M ($)	(8) **Threshold 3** $40M > Gains ≤ $100M ($)	(9) **Threshold 4** Gains > $100M ($)
January	12,631,703	3,449	6,917,445	19,552,597	19,552,597	0	0	0
February	2,687,794	5,402	1,599,802	4,292,999	4,292,999	0	0	0
March	2,701,593	(1,714)	1,674,495	4,374,374	4,374,374	0	0	0
April	950,556	494,871	1,005,623	2,451,050	1,780,031	671,019	0	0
May	2,614,719	96,675	1,464,993	4,176,387	0	4,176,387	0	0
June	1,396,844	1,172,843	1,362,678	3,932,365	0	3,932,365	0	0
July	1,732,445	92,481	1,310,817	3,135,743	0	1,220,230	1,915,513	0
August	1,178,568	671,957	1,114,406	2,964,931	0	0	2,964,931	0
September	1,321,428	2,384,866	1,335,598	5,041,891	0	0	5,041,891	0
October	1,493,084	2,970,424	1,191,781	5,655,290	0	0	5,655,290	0
November	1,573,680	14,464	1,614,537	3,202,682	0	0	3,202,682	0
December	2,180,496	37,395	1,406,134	3,624,025	0	0	3,624,025	0
Total	**32,462,909**	**7,943,114**	**21,998,309**	**62,404,332**	**30,000,000**	**10,000,000**	**22,404,332**	**0**

TABLE 2

(1) Month	(2) **Threshold 1** Gains ≤ $30M 100% Customer Benefit ($)	(3) **Threshold 2** $30M > Gains ≤ $40M 100% Customer Benefit ($)	(4) **Threshold 3** $40M > Gains ≤ $100M 40% Customer Benefit ($)	(5) **Threshold 3** $40M > Gains ≤ $100M 60% FPL Benefit ($)	(6) **Threshold 4** Gains > $100M 50% Customer Benefit ($)	(7) **Threshold 4** Gains > $100M 50% FPL Benefit ($)	(8) **Total** Customer Benefits ($)	(9) **Total** FPL Benefits ($)
January	19,552,597	0	0	0	0	0	19,552,597	0
February	4,292,999	0	0	0	0	0	4,292,999	0
March	4,374,374	0	0	0	0	0	4,374,374	0
April	1,780,031	671,019	0	0	0	0	2,451,050	0
May	0	4,176,387	0	0	0	0	4,176,387	0
June	0	3,932,365	0	0	0	0	3,932,365	0
July	0	1,220,230	766,205	1,149,308	0	0	1,986,435	1,149,308
August	0	0	1,185,973	1,778,959	0	0	1,185,973	1,778,959
September	0	0	2,016,757	3,025,135	0	0	2,016,757	3,025,135
October	0	0	2,262,116	3,393,174	0	0	2,262,116	3,393,174
November	0	0	1,281,073	1,921,609	0	0	1,281,073	1,921,609
December	0	0	1,449,610	2,174,415	0	0	1,449,610	2,174,415
Total	**30,000,000**	**10,000,000**	**8,961,733**	**13,442,599**	**0**	**0**	**48,961,733**	**13,442,599**

WHOLESALE POWER DETAIL
Actual for the Period of: January 2018 through December 2018

Wholesale Sales - Table 1

(1) Month	(2) Total Wholesale Sales (MWh)	(3) OS Gross Gains ($)	(4) Third-Party Transmission Costs ($)	(5) Variable Power Plant O&M Costs ($)	(6) Power Option Premiums ($)	(7) Total Net Wholesale Sales Gains ($)
	Schedule A6	Schedule A6	Schedule A6	Schedule A6	*CCRC	(3)+(4)+(5)+(6)
January	406,342	12,786,865	(354,669)	(264,122)	463,629	12,631,703
February	292,818	2,885,156	(22,654)	(190,332)	15,624	2,687,794
March	349,446	2,843,784	(9,929)	(227,335)	95,073	2,701,593
April	95,887	806,000	(1,303)	(62,132)	207,990	950,556
May	255,181	2,408,061	(15,873)	(165,868)	388,398	2,614,719
June	109,480	1,211,737	(34,071)	(71,162)	290,340	1,396,844
July	106,655	1,326,063	26,894	(69,326)	448,814	1,732,445
August	82,460	958,591	(24)	(53,599)	273,600	1,178,568
September	81,832	906,139	0	(53,191)	468,480	1,321,428
October	95,165	1,107,285	(21,154)	(61,857)	468,810	1,493,084
November	260,268	1,645,202	(59,337)	(169,175)	156,990	1,573,680
December	343,110	2,446,395	(60,175)	(223,022)	17,298	2,180,496
Total	**2,478,644**	**31,331,279**	**(552,296)**	**(1,611,119)**	**3,295,046**	**32,462,909**

Wholesale Purchases - Table 2

(1) Month	(2) Total Wholesale Purchases (MWh)	(3) OS Savings ($)	(4) Capacity Purchases (MWh)	(5) Net Capacity Purchases Savings ($)	(6) Total Wholesale Purchases Savings ($)
	Schedule A9	Schedule A9	Schedule A7/A12		(3) + (5)
January	345	3,449	0	0	3,449
February	973	5,402	0	0	5,402
March	215	(1,714)	0	0	(1,714)
April	22,774	494,871	0	0	494,871
May	2,408	96,675	0	0	96,675
June	42,931	1,172,843	0	0	1,172,843
July	10,915	92,481	0	0	92,481
August	28,638	671,957	0	0	671,957
September	57,391	2,384,866	0	0	2,384,866
October	60,585	2,970,424	0	0	2,970,424
November	1,501	14,464	0	0	14,464
December	3,962	37,395	0	0	37,395
Total	**232,638**	**7,943,114**	**0**	**0**	**7,943,114**

ASSET OPTIMIZATION DETAIL
Actual for the Period of: January 2018 through December 2018

(1) Month	(2) Natural Gas Delivered City-Gate Sales ($)	(3) Natural Gas Production Area Sales ($)	(4) Natural Gas Capacity Release Firm Transport ($)	(5) Natural Gas Option Premiums ($)	(6) Delivered Natural Gas Savings ($)	(7) Natural Gas Storage Optimization ($)	(8) Natural Gas AMA Gains ($)	(9) Electric Transmission Capacity Release Firm Transmission ($)	(10) NOX Emissions Sales ($)	(10) Total Asset Optimization Gains ($)
January	[redacted]									6,917,445
February	[redacted]									1,599,802
March	[redacted]									1,674,495
April	[redacted]									1,005,623
May	[redacted]									1,464,993
June	[redacted]									1,362,678
July	[redacted]									1,310,817
August	[redacted]									1,114,406
September	[redacted]									1,335,598
October	[redacted]									1,191,781
November	[redacted]									1,614,537
December	[redacted]									1,406,134
Total	**5,752,546**	**959,088**	**1,870,986**	**8,120,859**	**0**	**3,307,897**	**1,986,933**	**0**	**0**	**21,998,309**

INCREMENTAL OPTIMIZATION COSTS
Actual for the Period of: January 2018 through December 2018

(1) Month	(2) Personnel Expenses ($)	(3) Other Expenses* ($)	(4) Wholesale Sales (MWh)	(5) Wholesale Purchases (MWh)	(6) Wholesale Sales VOM ($)	(7) Wholesale Purchases VOM ($)	(8) Net VOM ($)	(9) Total Incremental O&M Expenses ($)
	Schedule A2						Schedule A2	(2) + (3) + (8)
January	37,356	4,917	406,342	345	264,122	(224)	263,898	306,170
February	32,775	4,780	292,818	973	190,332	(632)	189,699	227,255
March	37,252	4,780	349,446	215	227,335	(140)	227,195	269,228
April	39,456	4,780	95,887	22,774	62,132	(14,803)	47,328	91,565
May	44,598	5,043	255,181	2,408	165,868	(1,565)	164,302	213,943
June	39,731	4,780	109,480	42,931	71,162	(27,905)	43,257	87,768
July	37,725	4,780	106,655	10,915	69,326	(7,095)	62,231	104,736
August	39,393	4,780	82,460	28,638	53,599	(18,615)	34,984	79,157
September	34,837	4,780	81,832	57,391	53,191	(37,304)	15,887	55,504
October	40,475	4,780	95,165	60,585	61,857	(39,380)	22,477	67,732
November	38,526	4,780	260,268	1,501	169,175	(976)	168,199	211,505
December	36,565	4,780	343,110	3,962	223,022	(2,575)	220,446	261,791
Total	**458,689**	**57,762**	**2,478,644**	**232,638**	**1,611,119**	**(151,215)**	**1,459,905**	**1,976,355**

*Includes software and hardware expenses