DUKE ENERGY
FLORIDA

Matthew R. Bernier
Associate General Counsel

March 1, 2019

VIA ELECTRONIC FILING

Adam Teitzman, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: *Fuel and Purchased Power Cost recovery clause with Generating Performance Incentive Factor; Docket No. 20190001-EI*

Dear Mr. Teitzman:

On behalf of Duke Energy Florida, LLC ("DEF"), please find enclosed for electronic filing in the above-referenced docket:

- DEF's Petition for Approval of Fuel Cost Recovery and Capacity Cost Recovery Actual True-Ups for the Period ending December 2018;
- Direct Testimony of Christopher Menendez with Exhibit No. ___ (CAM-1T), Redacted Exhibit No. ___ (CAM-2T), and Exhibit No. ___ (CAM-3T) and Exhibit No. ___ (CAM-4T);
- Direct Testimony of Arnold Garcia with Redacted Exhibit No. ___ (AG-1); and
- Direct Testimony of Jeffrey Swartz incorporating Exhibit No. ___ (JS-1)[1].

Thank you for your assistance in this matter. Please feel free to call me at (850) 521-

[1] DEF hereby incorporates Exhibit No. __-(JS-1), filed on March 2, 2018 in Docket No. 20180001-EI as if fully set forth herein.

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1428 should you have any questions concerning this filing.

Respectfully,

s/ Matthew R. Bernier
Matthew R. Bernier

MRB/mw
Enclosures

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchase Power Cost Recovery Clause and Generating Performance Incentive Factor	Docket No. 20190001-EI Filed: March 1, 2019

PETITION FOR APPROVAL OF FUEL COST RECOVERY AND CAPACITY COST RECOVERY WITH GENERATING PERFORMANCE INCENTIVE FACTOR ACTUAL TRUE-UPS FOR THE PERIOD ENDING DECEMBER 2018

Duke Energy Florida, LLC ("DEF"), hereby petitions the Commission for approval of DEF's actual Fuel and Purchased Power Cost Recovery ("FCR") true-up amount of $202,879,590 under-recovery and actual Capacity Cost Recovery ("CCR") true-up amount of $15,765,080 over-recovery for the period ending December 2018. In support of this Petition, DEF states as follows:

1. The actual $202,879,590 FCR 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 DEF witness Christopher A. Menendez, which is being filed together with the Petition and is incorporated herein by reference.

2. Pursuant to the 2017 Second Revised and Restated Stipulation and Settlement Agreement approved by the Commission in Order No. PSC-2017-0451-AS-EU, DEF will recover total 2017 actual/estimated true-up under-recovery of fuel and purchased power costs of $195,503,774 over 2018 and 2019. Accordingly, DEF has included $97,751,887 of the total 2017 actual/estimated under-recovery in 2019

rates. By Order No. PSC-2018-0610-FOF-EI, the Commission approved a levelized FCR Factor of 3.969 cents/kWh for the 12-month period commencing January 2019. This FCR Factor reflects an actual/estimated under-recovery including interest for the period January 2018 through December 2018 of $148,450,915. The actual FAC under-recovery including interest for the period January 2018 through December 2018 is $202,879,590. The $202,879,590 actual under-recovery, less the actual/estimated under-recovery of $148,450,915 results in a total under-recovery of $54,428,676.

3. The actual $15,765,080 CCR 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 DEF witness Christopher A. Menendez.

4. By Order No. PSC-2018-0610-FOF-EI, the Commission approved CCR Factors for the 12-month period commencing January 2019. These factors reflected an actual/estimated over-recovery, including interest, for the period January 2018 through December 2018 of $16,610,473. The actual over-recovery, including interest, for the period January 2018 through December 2018 is $15,765,080. The $15,765,080 actual over-recovery, less the actual/estimated over-recovery of $16,610,473 which is currently reflected in charges for the period beginning January 2019 results in a total under-recovery of $845,393.

WHEREFORE, DEF respectfully requests the Commission to approve the net $54,428,676 FCR under-recovery as the actual true-up amount for the period ending December 2018; and to approve the net $845,393 CCR under-recovery as the actual true-up amount for the period ending December 2018.

Respectfully submitted,

s/Matthew R. Bernier

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Duke Energy Florida, LLC
CERTIFICATE OF SERVICE
Docket No. 20190001-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via email this 1st day of March, 2019 to all parties of record as indicated below.

*s/Matthew R. Bernier*_____
Attorney

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DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20190001-EI

Fuel and Capacity Cost Recovery
Actual True-Up for the Period
January 2018 - December 2018

DIRECT TESTIMONY OF
Christopher A. Menendez

March 1, 2019

Q. Please state your name and business address.

A. My name is Christopher A. Menendez. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

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

A. I am employed by Duke Energy Florida, LLC, as Rates and Regulatory Strategy Manager.

Q. What are your responsibilities in that position?

A. I am responsible for regulatory planning and cost recovery for Duke Energy Florida, LLC ("DEF" or the "Company"). These responsibilities include completion of regulatory financial reports and analysis of state, federal and local regulations and their impacts on DEF. In this capacity, I am responsible for DEF's Final True-Up, Actual/Estimated Projection and Projection Filings in the Fuel Adjustment Clause, Capacity Cost Recovery Clause and Environmental Cost Recovery Clause.

Q. Please describe your educational background and professional experience.

A. I joined the Company on April 7, 2008 as a Senior Financial Specialist in the Florida Planning & Strategy group. In that capacity, I supported the development of long-term financial forecasts and the development of current-year monthly earnings and cash flow projections. In 2011, I accepted a position as a Senior Business Financial Analyst in the Power Generation Florida Finance organization. In that capacity, I provided accounting and financial analysis support to various generation facilities in DEF's Fossil fleet. In 2013, I accepted a position as a Senior Regulatory Specialist. In that capacity, I supported the preparation of testimony and exhibits for the Fuel Docket as well as other Commission Dockets. In October 2014, I was promoted to my current position. Prior to working at DEF, I was the Manager of Inventory Accounting and Control for North American Operations at Cott Beverages. In this role, I was responsible for inventory-related accounting and inventory control functions for Cott-owned manufacturing plants in the United States and Canada. I received a Bachelor of Science degree in Accounting from the University of South Florida, and I am a Certified Public Accountant in the State of Florida.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide DEF's Fuel Adjustment Clause final true-up amount for the period of January 2018 through December 2018, and DEF's Capacity Cost Recovery Clause final true-up amount for the same period.

Q. Have you prepared exhibits to your testimony?

A. Yes, I have prepared and attached to my true-up testimony as Exhibit No. __(CAM-1T), a Fuel Adjustment Clause true-up calculation and related schedules; Exhibit No. __(CAM-2T), a Capacity Cost Recovery Clause true-up calculation and related schedules; Exhibit No. __(CAM-3T), Schedules A1 through A3, A6, and A12 for December 2018, year-to-date; and Exhibit No. __(CAM-4T), with DEF's capital structure and cost rates. Schedules A1 through A9, and A12 for the year ended December 31, 2018, were filed with the Commission on January 29, 2019.

Q. What is the source of the data that you will present by way of testimony or exhibits in this proceeding?

A. Unless otherwise indicated, the actual data is taken from the books and records of the Company. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by this Commission. The Company relies on the information included in this testimony in the conduct of its affairs.

Q. Would you please summarize your testimony?

A. Per Order No. PSC-2018-0610-FOF-EI, the estimated 2018 fuel adjustment true-up amount was an under-recovery of $148.5 million. The actual under-recovery for 2018 was $202.9 million resulting in a final fuel adjustment true-up under-recovery amount of $54.4 million. Exhibit No. __(CAM-1T).

The estimated 2018 capacity cost recovery true-up amount was an over-recovery of $16.6 million. The actual amount for 2018 was an over-recovery of $15.8 million resulting in a final capacity true-up under-recovery amount of $0.8 million. Exhibit No. __(CAM-2T).

FUEL COST RECOVERY

Q. What is DEF's jurisdictional ending balance as of December 31, 2018 for fuel cost recovery?

A. The actual ending balance as of December 31, 2018 for true-up purposes is an under-recovery of $202,879,590.

Q. How does this amount compare to DEF's estimated 2018 ending balance included in the Company's Actual/Estimated Filing?

A. The actual true-up amount attributable to the January 2018 - December 2018 period is an under-recovery of $202,879,590 which is $54,428,676 higher than the re-projected year end under-recovery balance of $148,450,915.

Q. How was the final true-up ending balance determined?

A. The amount was determined in the manner set forth on Schedule A2 of the Commission's standard forms previously submitted by the Company on a monthly basis.

Q. What factors contributed to the period-ending jurisdictional net under-recovery of $54,428,676 shown on your Exhibit No. __(CAM-1T)?

A. The $54.4 million is driven in part by a shift from coal to gas generation resulting in increased gas generation and purchased power costs of approximately $97.6 million partially offset by reduced coal generation expense of $44.7 million.

Q. Please explain the components shown on Exhibit No. __(CAM-1T), sheet 6 of 6, which helps to explain the $52.6 million unfavorable system variance from the projected cost of fuel and net purchased power transactions.

A. Exhibit No. __(CAM-1T), sheet 6 of 6 is an analysis of the system dollar variance for each energy source in terms of three interrelated components; (1) changes in the amount (MWH's) of energy required; (2) changes in the heat rate of generated energy (BTU's per kWh); and (3) changes in the unit price of either fuel consumed for generation ($ per million BTU) or energy purchases and sales (cents per kWh). The $52.6 million unfavorable system variance is mainly attributable to increased natural gas generation and purchased power, in part from a shift from coal to gas, partially offset by reduced coal generation.

Q. Does this period ending true-up balance include any noteworthy adjustments to fuel expense?

A. Yes. Noteworthy adjustments are shown on Exhibit No. __(CAM-3T) in the footnote to line 6b on page 1 of 2, Schedule A2.

Consistent with Order No. PSC-2018-0240-PAA-EQ dated June 8, 2018, DEF included an adjustment of $7,276,033 (grossed up to $7,326,228 from retail to system) for amortization of the Florida Power Development, LLC ("FPD") qualifying facility regulatory asset. This adjustment is shown on

Exhibit No. ___(CAM-3T), in the footnotes to Line 6b on page 1 of 2, Schedule A2, and on line 3, page 1 of 2, Schedule A1. An estimated adjustment of $6,232,811 (grossed up to $6,266,531 from retail to system) for FPD regulatory asset amortization was included on Schedule E1-B (sheet 2), line A5, columns Aug Estimated through Dec Estimated in the 2018 Actual/Estimated Filing on July 27, 2018.

Q. Did DEF make an adjustment for changes in coal inventory based on an Aerial Survey?

A. Yes. DEF included an adjustment of approximately $5.4 million to coal inventory attributable to the semi-annual aerial surveys conducted on June 5, 2018 and November 16, 2018 in accordance with Docket No. 19970001-EI, Order No. PSC-1997-0359-FOF-EI. This adjustment represents 1.96% of the total coal consumed at the Crystal River facility in 2018.

Q. Did DEF exceed the economy sales threshold in 2018?

A. Yes. DEF did exceed the gain on economy sales threshold of $1.8 million in 2018. As reported on Schedule A1-2, Line 11a, the gain for the year-to-date period through December 2018 was approximately $2.3 million. Consistent with Order No. PSC-01-2371-FOF-EI, shareholders retain 20% of the gain in excess of the three-year rolling average. For 2018, that amount is approximately $0.09 million.

Q. Has the three-year rolling average gain on economy sales included in the Company's filing for the November 2018 hearings been updated to incorporate actual data for all of year 2018?

A. Yes. DEF has calculated its three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2016 through 2018, as follows:

Year	Actual Gain
2016	$ 843,842
2017	$ 887,370
2018	$2,269,916
Three-Year Average	$1,333,709

Q. Can you explain DEF's methodology for calculating the Time-of-Use ("TOU") fuel factors?

A. Yes. Commission Order 9661, issued on November 26, 1980, established the current Winter and Summer seasons and applicable on- and off-peak times for each. Within the on- and off-peak periods defined in Order 9661, DEF's uses marginal cost to develop TOU on- and off-peak fuel multipliers ("TOU fuel multipliers"); these are presented each year in Schedule E1-E in DEF's Fuel Projection Filing. The TOU fuel multipliers are then applied to the levelized fuel rate, at secondary metering, to calculate the on- and off-peak fuel factors ("TOU fuel factors"). In Order No. PSC-2011-0216-PAA-EI, the

Commission directed Florida Power & Light ("FPL") to investigate the use of marginal cost in the calculation of the TOU fuel factors; at that time, FPL calculated the TOU fuel factors using projected on- and off-peak average cost. The Commission stated in Order No. PSC-2011-0216-PAA-EI that "[u]sing marginal fuel costs to set TOU fuel factors…increases the on- and off-peak differential, sending a stronger price signal." In Order No. PSC-2011-0579-FOF-EI, the Commission approved FPL's switch from average to marginal cost for the 2012 projected TOU Fuel Factors. DEF follows the Commission's guidance by utilizing marginal cost in to develop the TOU fuel multipliers. Additionally, the Commission has approved DEF's TOU fuel factors each year in the Fuel docket.

Q. Did DEF evaluate the need for adjustments to the on- and off-peak TOU fuel cost factors, as described in the Stipulation to Issue 22 in Order No. PSC-2018-0610-FOF-EI?

A. Yes. DEF evaluated alternative methods of calculating the TOU fuel factors. The first method is the approved marginal cost calculation, as described above. The second was the use of average cost, rather than marginal cost, in the development of the TOU Multipliers. The third method was the implementation of an artificial c/kWh spread between the TOU fuel factors.

Q. Can you please explain the results of the evaluations?

A. Yes. The evaluation of these three methods utilized the same fuel forecast used to develop DEF's 2019 Fuel Projection Filing and 2019 fuel factors. This allows for an apples-to-apples comparison between the various methods.

The first method used marginal cost to develop the TOU multipliers. This is the current method used by DEF.

The Average Cost method utilizes the average on- and off-peak costs to develop the TOU multipliers. This method almost eliminates entirely the spread between the TOU multipliers, resulting in TOU fuel factors that are essentially the same as the levelized rate.

The third method involved the development of an artificial c/kWh spread between the TOU fuel factors. The calculation method is based on the Residential 1st Tier calculation and was developed in a revenue-neutral manner when compared to the current marginal cost TOU process. This method first determines the projected on- and off-peak MWh sales for the non-Residential classes with optional TOU factors (GS-1, GSD, CS, IS and SS). This was done by separating the projected 2019 MWh sales for these rate classes into on- and off-peak based on the most recent full year actual performance. The projected 2019 TOU revenues were determined by multiplying the projected on- and off-peak 2019 MWh sales by the 2019 TOU fuel factors developed under the current marginal cost process. An artificial c/kWh spread is then calculated by applying the Residential 1st Tier formula, whereas the lower first tier becomes the off-peak fuel factor and the higher second tier becomes the on-peak fuel factor. Under this method, the amount of the c/kWh spread would need to be defined and approved by the Commission. A change in the TOU fuel factor calculation, using the artificial c/kWh spread method, will impact the fuel component of customer bills differently. Some customers will experience an increase in the fuel component of their bill, while others will see a reduction as compared to the current marginal cost method. The number of increases versus reductions to customer bills may be asymmetrical under an artificial spread scenario, for example more total customers could experience an increase than those experiencing a reduction.

Q. Based on DEF's evaluation, is DEF recommending an adjustment to the current calculation of the on- and off-peak fuel factors?

A. DEF does not believe any adjustments to the current calculation are necessary. DEF follows Commission guidance by utilizing marginal cost in the TOU fuel factor process. Despite the spread between the on- and off-peak TOU fuel multipliers narrowing in recent years, DEF believes that marginal cost still sends an accurate price signal to customers and aligns the TOU fuel cost incurred with the TOU MWhs causing that cost.

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 2018 for capacity cost recovery?

A. The actual ending balance as of December 31, 2018 for true-up purposes is an over-recovery of $15,765,080.

Q. How does this amount compare to the estimated 2018 ending balance included in the Company's Actual/estimated Filing?

A. When the estimated 2018 over-recovery of $16,610,473 is compared to the $15,765,080 actual over-recovery, the final capacity true-up for the twelve-month period ended December 2018 is an under-recovery of $845,393.

Q. Is this true-up calculation consistent with the true-up methodology used for the other cost recovery clauses?

A. Yes. The calculation of the final net true-up amount follows the procedures established by the Commission in Order No. PSC-1996-1172-FOF-EI. The true-up amount was determined in the manner set forth on the Commission's standard forms previously submitted by the Company on a monthly basis.

Q. What factors contributed to the actual period-end capacity under-recovery of $0.8 million?

A. Exhibit No. __(CAM-2T, sheet 1 of 3) compares actual results to the original projection for the period. The $0.8 million under-recovery is primarily due to higher than estimated costs.

Q. Does this conclude your direct true-up testimony?

A. Yes.

Duke Energy Florida, LLC
Fuel Adjustment Clause
Summary of Actual True-Up Amount
January 2018 - December 2018

Line No.	Description	Contr bution to Over/(Under) Recovery Period to Date
	KWH Sales:	
1	Jurisdictional kWh Sales - Difference	13,609,933
2	Non-Jurisdictional kWh Sales - Difference	31,489,260
3	Total System kWh Sales - Difference Schedule A2, pg 1 of 2, line B3	45,099,193
	System:	
4	Fuel and Net Purchased Power Costs - Difference Schedule A2, page 2 of 2, line C4	$ 55,413,956
	Jurisdictional:	
5	Fuel Revenues - Difference Schedule A2, page 2 of 2, line C3	($167,169)
6	Fuel and Net Purchased Power Costs - Difference Schedule A2, page 2 of 2, line C6 - C12 - C7	84,910,305
7	True-Up Amount for the Period	(85,077,474)
8	True-Up for the Prior Period Schedule A2, page 2 of 2, line C9	(211,599,978)
9	True-Up Collected/(Refunded) in Current Period	97,751,887
10	Interest Provision Schedule A2, page 2 of 2, line C8	(3,954,025)
11	Actual True-Up Ending Balance for the Period January 2018 through December 2018 Schedule A2, page 2 of 2, line C13	(202,879,590)
12	Estimated True-Up Ending Balance for the Period January 2018 through December 2018 as approved in Order No. PSC-2018-0610-FOF-EI	(148,450,915)
13	Total True-Up for the Period January 2018 through December 2018	$ (54,428,676)

Duke Energy Florida, LLC
Fuel Adjustment Clause
Calculation of Actual True-up
January 2018 - December 2018

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 112,913,665	$ 83,401,172	$ 84,812,907	$ 89,220,818	$ 111,294,344	$ 125,529,591	$ 607,172,497
	2	Fuel Cost of Power Sold	(9,605,716)	(3,497,655)	(2,583,535)	(2,055,117)	(2,910,542)	(5,643,807)	(26,296,373)
	3	Fuel Cost of Purchased Power	8,102,839	8,081,727	8,846,730	14,994,550	12,024,468	17,187,681	69,237,994
	3a	Demand and Non-Fuel Cost of Purchased Power	-	-	-	-	-	-	-
	3b	Energy Payments to Qualified Facilities	12,317,998	13,169,787	11,522,091	12,129,406	13,617,807	12,190,979	74,948,069
	4	Energy Cost of Economy Purchases	2,201,782	344,053	853,758	1,336,389	1,331,976	588,120	6,656,077
	5	Adjustments to Fuel Cost	104,607	380	470	560	(98,376)	730	8,370
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	126,035,174	101,499,464	103,452,422	115,626,605	135,259,676	149,853,294	731,726,636
B	1	Jurisdictional MWH Sales	2,806,833	2,986,052	2,939,587	2,788,016	2,885,900	3,475,353	17,881,740
	2	Non-Jurisdictional MWH Sales	18,727	11,367	14,028	15,678	20,520	25,623	105,944
	3	TOTAL SALES (Lines B1 + B2)	2,825,560	2,997,418	2,953,615	2,803,694	2,906,421	3,500,976	17,987,684
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.34%	99.62%	99.53%	99.44%	99.29%	99.27%	99.41%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	114,339,903	121,300,462	118,437,965	112,665,165	117,461,745	143,106,586	727,311,827
	2	True-Up Provision	(8,145,991)	(8,145,991)	(8,145,991)	(8,145,991)	(8,145,991)	(8,145,991)	(48,875,946)
	2a	Incentive Provision	(232,768)	(232,768)	(232,768)	(232,768)	(232,768)	(232,768)	(1,396,608)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	105,961,144	112,921,703	110,059,206	104,286,406	109,082,986	134,727,827	677,039,273
	4	Fuel & Net Power Transactions (Line A6)	126,035,174	101,499,464	103,452,422	115,626,605	135,259,676	149,853,294	731,726,636
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	125,343,570	101,145,111	102,998,115	115,014,740	134,340,965	148,805,481	727,647,982
	6	Over/(Under) Recovery (Line 3 - Line 5)	(19,382,425)	11,776,592	7,061,090	(10,728,334)	(25,257,978)	(14,077,653)	(50,608,709)
	7	Interest Provision	(275,867)	(272,833)	(283,996)	(294,237)	(309,957)	(338,886)	(1,775,776)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(19,658,292)	11,503,759	6,777,095	(11,022,571)	(25,567,935)	(14,416,537)	(52,384,482)
	9	Plus: Prior Period Balance	(211,599,981)	(211,599,981)	(211,599,981)	(211,599,981)	(211,599,981)	(211,599,981)	(211,599,981)
	10	Plus: Cumulative True-Up Provision	8,145,991	16,291,982	24,437,973	32,583,964	40,729,955	48,875,946	48,875,946
	11	Subtotal Prior Period True-up	(203,453,990)	(195,307,999)	(187,162,008)	(179,016,017)	(170,870,026)	(162,724,035)	(162,724,035)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	(223,112,283)	(203,462,533)	($188,539,447)	($191,416,028)	($208,837,972)	($215,108,517)	(215,108,517)

Duke Energy Florida, LLC
Fuel Adjustment Clause
Calculation of Actual True-up
January 2018 - December 2018

			JUL ACTUAL	AUG ACTUAL	SEPT ACTUAL	OCT ACTUAL	NOV ACTUAL	DEC ACTUAL	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 125,129,647	$ 127,721,637	$ 128,558,437	$ 117,580,229	$ 101,587,441	$ 114,722,501	$ 1,322,472,390
	2	Fuel Cost of Power Sold	(3,651,558)	(3,062,643)	(4,398,240)	(4,181,281)	(3,429,695)	(3,142,113)	(48,161,903)
	3	Fuel Cost of Purchased Power	20,739,444	19,697,789	16,251,743	16,835,359	12,901,309	8,196,254	163,859,893
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	10,674,282	10,909,136	9,942,558	9,199,522	10,608,497	11,143,113	137,425,176
	4	Energy Cost of Economy Purchases	2,189,978	1,591,806	253,698	934,906	673,207	866,974	13,166,647
	5	Adjustments to Fuel Cost	2,753,469	1,201,039	386,571	(1,379,660)	1,176,463	4,883,281	9,029,534
	6	TOTAL FUEL & NET POWER TRANSACTIONS	157,835,263	158,058,764	150,994,767	138,989,076	123,517,223	136,670,010	1,597,791,739
		(Sum of Lines A1 Through A5)							
B	1	Jurisdictional MWH Sales	3,831,457	3,745,109	3,868,735	3,712,056	3,226,851	2,878,702	39,144,650
	2	Non-Jurisdictional MWH Sales	26,681	25,468	31,950	27,796	18,979	17,355	254,173
	3	TOTAL SALES (Lines B1 + B2)	3,858,138	3,770,577	3,900,685	3,739,852	3,245,830	2,896,058	39,398,824
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.31%	99.32%	99.18%	99.26%	99.42%	99.40%	99.35%
C	1	Jurisdictional Fuel Recovery Revenue	158,980,145	155,282,574	160,484,582	154,057,122	131,568,741	115,795,394	1,603,480,385
		(Net of Revenue Taxes)							
	2	True-Up Provision	(8,145,991)	(8,145,991)	(8,145,991)	(8,145,991)	(8,145,991)	(8,145,991)	(97,751,887)
	2a	Incentive Provision	(232,768)	(232,768)	(232,768)	(232,768)	(232,768)	(232,768)	(2,793,216)
	3	FUEL REVENUE APPLICABLE TO PERIOD	150,601,386	146,903,816	152,105,824	145,678,363	123,189,983	107,416,635	1,502,935,282
		(Sum of Lines C1 Through C2a)							
	4	Fuel & Net Power Transactions (Line A6)	157,835,263	158,058,764	150,994,767	138,989,076	123,517,223	136,670,010	1,597,791,739
	5	Jurisdictional Total Fuel Costs & Net Power Transactions	156,794,791	157,032,629	149,803,034	138,003,325	122,838,891	135,892,103	1,588,012,756
		(Line A6 * Line B4 * Line Loss Multiplier)							
	6	Over/(Under) Recovery (Line 3 - Line 5)	(6,193,404)	(10,128,814)	2,302,790	7,675,039	351,092	(28,475,468)	(85,077,474)
	7	Interest Provision	(353,318)	(353,926)	(368,588)	(369,989)	(353,526)	(378,902)	(3,954,025)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(6,546,722)	(10,482,740)	1,934,202	7,305,050	(2,434)	(28,854,370)	(89,031,499)
	9	Plus: Prior Period Balance	(211,599,981)	(211,599,981)	(211,599,981)	(211,599,981)	(211,599,981)	(211,599,981)	(211,599,981)
	10	Plus: Cumulative True-Up Provision	57,021,936	65,167,927	73,313,917	81,459,908	89,605,898	97,751,889	97,751,889
	11	Subtotal Prior Period True-up	(154,578,045)	(146,432,054)	(138,286,064)	(130,140,073)	(121,994,083)	(113,848,092)	(113,848,092)
	12	Regulatory Accounting Adjustment	0	0	0	0	0	0	-
	13	TOTAL TRUE-UP BALANCE	($213,509,249)	($215,845,998)	($205,765,805)	($190,314,765)	($182,171,209)	($202,879,590)	(202,879,590)

Docket No. 20190001-EI
Witness: Menendez
Exhibit No. (CAM-1T)
Sheet 4 of 6

Duke Energy Florida, LLC
Fuel Adjustment Clause
Calculation of 2018 Actual/Estimated True-up
January 2018 - December 2018 (Filed July 27, 2018)

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 112,913,665	$ 83,401,172	$ 84,812,907	$ 89,220,818	$ 111,294,344	$ 125,529,591	$ 607,172,497
	2	Fuel Cost of Power Sold	(9,605,716)	(3,497,655)	(2,583,535)	(2,055,117)	(2,910,542)	(5,643,807)	(26,296,373)
	3	Fuel Cost of Purchased Power	8,102,839	8,081,727	8,846,730	14,994,550	12,024,468	17,187,681	69,237,994
	3a	Demand and Non-Fuel Cost of Purchased Power	-	-	-	-	-	-	-
	3b	Energy Payments to Qualified Facilities	12,317,998	13,169,787	11,522,091	12,129,406	13,617,807	12,190,979	74,948,069
	4	Energy Cost of Economy Purchases	2,201,782	344,053	853,758	1,336,389	1,331,976	588,120	6,656,077
	5	Adjustments to Fuel Cost	104,607	380	470	560	(98,376)	730	8,370
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	126,035,174	101,499,464	103,452,422	115,626,605	135,259,676	149,853,294	731,726,636
B	1	Jurisdictional MWH Sales	2,806,833	2,986,052	2,939,587	2,788,016	2,885,900	3,475,353	17,881,740
	2	Non-Jurisdictional MWH Sales	18,727	11,367	14,028	15,678	20,520	25,623	105,944
	3	TOTAL SALES (Lines B1 + B2)	2,825,560	2,997,418	2,953,615	2,803,694	2,906,421	3,500,976	17,987,684
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.34%	99.62%	99.53%	99.44%	99.29%	99.27%	99.41%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	114,339,903	121,300,462	118,437,965	112,665,165	117,461,745	143,106,586	727,311,827
	2	True-Up Provision	(8,145,991)	(8,145,991)	(8,145,991)	(8,145,991)	(8,145,991)	(8,145,991)	(48,875,946)
	2a	Incentive Provision	(232,768)	(232,768)	(232,768)	(232,768)	(232,768)	(232,768)	(1,396,608)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	105,961,144	112,921,703	110,059,206	104,286,406	109,082,986	134,727,827	677,039,273
	4	Fuel & Net Power Transactions (Line A6)	126,035,174	101,499,464	103,452,422	115,626,605	135,259,676	149,853,294	731,726,636
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	125,343,570	101,145,111	102,998,115	115,014,740	134,340,965	148,805,481	727,647,982
	6	Over/(Under) Recovery (Line 3 - Line 5)	(19,382,425)	11,776,592	7,061,090	(10,728,334)	(25,257,978)	(14,077,653)	(50,608,709)
	7	Interest Provision	(275,867)	(272,833)	(283,996)	(294,237)	(309,957)	(338,886)	(1,775,776)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(19,658,292)	11,503,759	6,777,095	(11,022,571)	(25,567,935)	(14,416,537)	(52,384,482)
	9	Plus: Prior Period Balance	(211,599,981)	(211,599,981)	(211,599,981)	(211,599,981)	(211,599,981)	(211,599,981)	(211,599,981)
	10	Plus: Cumulative True-Up Provision	8,145,991	16,291,982	24,437,973	32,583,964	40,729,955	48,875,946	48,875,946
	11	Subtotal Prior Period True-up	(203,453,990)	(195,307,999)	(187,162,008)	(179,016,017)	(170,870,026)	(162,724,035)	(162,724,035)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($223,112,283)	($203,462,533)	($188,539,447)	($191,416,028)	($208,837,972)	($215,108,517)	(215,108,517)

Docket No. 20190001-EI
Witness: Menendez
Exhibit No. (CAM-1T)
Sheet 5 of 6

Duke Energy Florida, LLC
Fuel Adjustment Clause
Calculation of 2017 Actual/Estimated True-up
January 2018 - December 2018 (Filed July 27, 2018)

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 134,146,384	$ 135,566,020	$ 127,685,381	$ 113,036,297	$ 98,793,448	$ 105,646,287	$ 1,322,046,314
	2	Fuel Cost of Power Sold	(2,733,280)	(3,042,758)	(2,389,591)	(1,860,656)	(1,440,801)	(1,898,113)	(39,661,571)
	3	Fuel Cost of Purchased Power	11,454,032	11,066,448	7,669,205	4,622,388	472,290	269,187	104,791,544
	3a	Demand and Non-Fuel Cost of Purchased Power	-	-	-	-	-	-	-
	3b	Energy Payments to Qualified Facilities	14,137,764	11,653,872	10,903,647	7,192,194	10,719,470	11,174,285	140,729,302
	4	Energy Cost of Economy Purchases	314,846	569,569	342,596	204,877	60,855	120,872	8,269,692
	5	Adjustments to Fuel Cost	0	1,261,599	1,257,084	1,252,952	1,248,196	1,246,700	6,274,902
	6	TOTAL FUEL & NET POWER TRANSACTIONS	157,319,747	157,074,751	145,468,322	124,448,053	109,853,458	116,559,218	1,542,450,184
		(Sum of Lines A1 Through A5)							
B	1	Jurisdictional MWH Sales	3,842,941	4,014,062	3,923,616	3,561,556	3,027,388	2,879,737	39,131,041
	2	Non-Jurisdictional MWH Sales	22,368	24,340	21,311	18,093	13,020	17,608	222,684
	3	TOTAL SALES (Lines B1 + B2)	3,865,309	4,038,402	3,944,927	3,579,649	3,040,408	2,897,345	39,353,725
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.42%	99.40%	99.46%	99.49%	99.57%	99.39%	99.43%
C	1	Jurisdictional Fuel Recovery Revenue	158,485,523	165,542,690	161,812,596	146,881,013	124,851,565	118,762,346	1,603,647,559
		(Net of Revenue Taxes)							
	2	True-Up Provision	(8,145,991)	(8,145,991)	(8,145,991)	(8,145,991)	(8,145,991)	(8,145,991)	(97,751,887)
	2a	Incentive Provision	(232,768)	(232,768)	(232,768)	(232,768)	(232,768)	(232,768)	(2,793,216)
	3	FUEL REVENUE APPLICABLE TO PERIOD	150,106,764	157,163,931	153,433,837	138,502,254	116,472,806	110,383,587	1,503,102,456
		(Sum of Lines C1 Through C2a)							
	4	Fuel & Net Power Transactions (Line A6)	157,319,747	157,074,751	145,468,322	124,448,053	109,853,458	116,559,218	1,542,450,184
	5	Jurisdictional Total Fuel Costs & Net Power Transactions	156,455,778	156,180,703	144,727,645	123,851,750	109,414,997	115,884,120	1,534,162,974
		(Line A6 * Line B4 * Line Loss Multiplier)							
	6	Over/(Under) Recovery (Line 3 - Line 5)	(6,349,015)	983,228	8,706,193	14,650,504	7,057,809	(5,500,532)	(31,060,523)
	7	Interest Provision	(342,645)	(334,448)	(314,200)	(282,992)	(253,058)	(239,187)	(3,542,306)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(6,691,660)	648,780	8,391,992	14,367,511	6,804,751	(5,739,719)	(34,602,826)
	9	Plus: Prior Period Balance	(211,599,981)	(211,599,981)	(211,599,981)	(211,599,981)	(211,599,981)	(211,599,981)	(211,599,981)
	10	Plus: Cumulative True-Up Provision	57,021,937	65,167,928	73,313,919	81,459,910	89,605,901	97,751,892	97,751,892
	11	Subtotal Prior Period True-up	(154,578,044)	(146,432,053)	(138,286,062)	(130,140,071)	(121,994,080)	(113,848,089)	(113,848,089)
	12	Regulatory Accounting Adjustment	0	0	0	0	0	0	-
	13	TOTAL TRUE-UP BALANCE	($213,654,186)	($204,859,415)	($188,321,432)	($165,807,929)	($150,857,187)	($148,450,915)	(148,450,915)

Duke Energy Florida, LLC
Fuel Adjustment Clause
Fuel and Net Power Cost Variance Analysis
January 2018 - December 2018

	(A) Energy Source	(B) MWH Variances	(C) Heat Rate Variances	(D) Price Variances	(E) Total
1	Heavy Oil	0	0	0	0
2	Light Oil	7,922,684	(633,350)	(638,252)	6,651,082
3	Coal	(35,676,689)	(3,612,493)	(5,428,702)	(44,717,885)
4	Gas	21,717,477	24,340,695	(7,565,294)	38,492,878
5	Nuclear	0	0	0	0
6	Other Fuel	0	0	0	0
7	Total Generation	(6,036,528)	20,094,852	(13,632,248)	426,075
8	Firm Purchases	45,785,371	0	13,282,978	59,068,349
9	Economy Purchases	4,332,411	0	564,544	4,896,955
10	Schedule E Purchases	0	0	0	0
11	Qualifying Facilities	(4,943,569)	0	1,639,443	(3,304,126)
12	Total Purchases	45,174,213	0	15,486,965	60,661,178
13	Economy Sales	0	0	0	0
14	Other Power Sales	955,395	0	(612,985)	342,410
15	Supplemental Sales	(7,073,312)	0	(1,769,429)	(8,842,741)
16	Total Sales	(6,117,917)	0	(2,382,414)	(8,500,330)
17	Total Fuel and Net Power Cost Variance	33,019,769	20,094,852	(527,697)	52,586,923

Duke Energy Florida, LLC
Capacity Cost Recovery Clause
Summary of Actual True-Up Amount
January 2018 - December 2018

Line No.	Description	Actual	Actual/Estimated Filing	Variance
	Jurisdictional:			
1	Capacity Cost Recovery Revenues Sheet 2 of 3, Line 38	$ 470,397,282	$ 470,752,702	$ (355,420)
2	Capacity Cost Recovery Expenses Sheet 2 of 3, Line 34	454,952,668	454,457,884	494,784
3	Plus/(Minus) Interest Provision Sheet 2 of 3, Line 41	(25,688)	(30,499)	4,811
4	Sub-Total Current Period Over/(Under) Recovery Sheet 2 of 3, Line 42	$ 15,418,926	$ 16,264,319	$ (845,393)
5	Prior Period True-up - January through December 2017 - Over/(Under) Recovery Sheet 2 of 3, Line 43	(4,775,185)	(4,775,185)	0
6	Prior Period True-up - January through December 2017 - (Refunded)/Collected Sheet 2 of 3, Line 44	5,121,339	5,121,339	0
7	Actual True-Up Ending Balance Over/(Under) Recovery for the Period January through December 2018 Sheet 2 of 3, Line 46	$ 15,765,080	$ 16,610,473	$ (845,393)
8	Estimated True-Up Ending Balance for the Period Included in the Filing of Levelized Fuel Cost Factors January through December 2019 per Order No. PSC-2018-0610-FOF-EI (Sheet 3 of 3, Line 46)	16,610,473		
9	Total Over/(Under) Recovery for the Period January through December 2018 (Line 7 - Line 8)	$ (845,393)		

Docket No.	20190001-EI
Witness:	Menendez
Exhibit No.	(CAM-2T)
	Sheet 2 of 3

REDACTED

Duke Energy Florida, LLC
Capacity Cost Recovery Clause
Calculation of Actual True-Up
January 2018 - December 2018

		JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	JUL ACTUAL	AUG ACTUAL	SEPT ACTUAL	OCT ACTUAL	NOV ACTUAL	DEC ACTUAL	Total
1	**<u>Base Production Level Capacity Costs</u>**													
2	Orange Cogen (ORANGECO)	5,071,564	5,590,987	5,331,276	5,331,276	5,331,276	5,331,276	5,331,276	5,331,276	5,331,276	5,331,276	5,331,276	5,331,276	63,975,307
3	Orlando Cogen Limited (ORLACOGL)	5,025,789	5,514,457	5,302,972	5,361,969	5,361,790	5,361,790	5,414,950	5,361,790	5,361,790	5,361,790	5,361,790	5,361,790	64,152,667
4	Pasco County Resource Recovery (PASCOUNT)	1,784,800	2,011,580	1,898,190	1,898,190	1,898,190	1,898,190	1,898,190	1,898,190	1,898,190	1,898,190	1,898,190	1,898,190	22,778,280
5	Pinellas County Resource Recovery (PINCOUNT)	4,248,600	4,788,435	4,518,518	4,518,518	4,518,518	4,518,518	4,518,518	4,518,518	4,518,518	4,518,518	4,518,518	4,518,518	54,222,210
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	6,965,675	7,676,459	7,321,066	7,321,066	7,321,066	7,321,066	7,321,066	7,321,066	7,321,066	7,321,066	7,321,066	7,321,066	87,852,796
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	765,872	790,760	798,927	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	9,564,071
8	US EcoGen	(93,000)	(93,000)	(84,000)	(93,000)	(90,000)	(93,000)	0	0	0	0	0	0	(546,000)
9	Subtotal - Base Level Capacity Costs	23,769,300	26,279,678	25,086,949	25,138,964	25,141,785	25,138,785	25,284,945	25,231,785	25,231,785	25,231,785	25,231,785	25,231,785	301,999,331
10	Base Production Jurisdictional Responsibility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
11	Base Level Jurisdictional Capacity Costs	22,078,114	24,409,879	23,302,013	23,350,326	23,352,947	23,350,161	23,485,921	23,436,544	23,436,544	23,436,544	23,436,544	23,436,544	280,512,080
12	**<u>Intermediate Production Level Capacity Costs</u>**													
13	Southern Franklin	4,609,957	4,467,756	2,685,103	2,663,030	2,934,373	4,811,161	6,285,017	6,268,886	4,634,240	2,701,639	2,384,883	3,505,309	47,951,354
14	Schedule H Capacity Sales - NSB, RCID, Tallahassee & FPL	(208,753)	(31,799)	379,669	270	(27,441)	0	137,852	0	0	(10,758)	191,664	(0)	430,704
15	Subtotal - Intermediate Level Capacity Costs	4,401,204	4,435,957	3,064,772	2,663,300	2,906,932	4,811,161	6,422,869	6,268,886	4,634,240	2,690,881	2,576,547	3,505,309	48,382,058
16	Intermediate Production Jurisdictional Respons bility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
17	Intermediate Level Jurisdictional Capacity Costs	3,199,808	3,225,074	2,228,181	1,936,299	2,113,427	3,497,858	4,669,619	4,557,668	3,369,232	1,956,351	1,873,227	2,548,465	35,175,208
18	**<u>Peaking Production Level Capacity Costs</u>**													
19	Shady Hills	1,984,500	1,984,500	1,417,500	1,371,600	1,920,240	3,904,200	3,904,200	3,904,200	1,821,960	1,371,600	1,371,600	1,976,940	26,933,040
20	Vandolah (NSG)	2,926,756	2,888,311	1,965,274	1,943,845	2,795,467	5,725,022	5,752,286	5,719,859	2,710,954	1,900,501	2,014,083	2,941,953	39,284,311
21	Other	-	-	-	-	-	-	-	-	-	-	-	-	
22	Subtotal - Peaking Level Capacity Costs	4,911,256	4,872,811	3,382,774	3,315,445	4,715,707	9,629,222	9,656,486	9,624,059	4,532,914	3,272,101	3,385,683	4,918,893	66,217,351
23	Peaking Production Jurisdictional Respons bility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
24	Peaking Level Jurisdictional Capacity Costs	4,711,073	4,674,196	3,244,893	3,180,307	4,523,495	9,236,735	9,262,887	9,231,782	4,348,152	3,138,730	3,247,683	4,718,399	63,518,332
25	**<u>Other Capacity Costs</u>**													
26	Retail Wheeling	[redacted]												
27	RRSSA Second Amendment [1]													
28	Total Other Capacity Costs													
29	**Total Capacity Costs (Line 11+17+24+28)**	31,537,913	33,933,287	30,392,188	30,081,704	31,569,791	37,695,859	39,025,569	38,828,605	32,739,268	30,073,141	30,142,053	32,290,733	398,310,113
30	**Nuclear Cost Recovery Clause**													
31	CR3 Uprate Costs	4,290,186	4,261,861	4,233,534	4,205,208	4,176,884	4,148,557	4,120,232	4,091,907	4,063,580	4,035,255	4,006,929	3,978,603	49,612,736
32	**Total Recoverable Nuclear Costs**	4,290,186	4,261,861	4,233,534	4,205,208	4,176,884	4,148,557	4,120,232	4,091,907	4,063,580	4,035,255	4,006,929	3,978,603	49,612,736
33	**ISFSI Revenue Requirement** [2]	677,047	628,287	579,175	555,717	573,770	573,765	573,771	573,769	573,883	573,769	573,545	573,320	7,029,819
34	**Total Recov Capacity & Nuclear Costs (Line 29+32+33)**	36,505,147	38,823,435	35,204,897	34,842,630	36,320,446	42,418,181	43,719,572	43,494,282	37,376,731	34,682,165	34,722,526	36,842,656	454,952,668
35	**<u>Capacity Revenues:</u>**													
36	Capacity Cost Recovery Revenues (net of tax)	35,082,201	37,272,890	35,441,587	33,706,211	34,969,792	41,859,835	46,095,199	45,344,820	46,506,204	44,848,988	39,179,512	35,211,382	475,518,621
37	Prior Period True-Up Provision Over/(Under) Recovery	(426,778)	(426,778)	(426,778)	(426,778)	(426,778)	(426,778)	(426,778)	(426,778)	(426,778)	(426,778)	(426,778)	(426,778)	(5,121,339)
38	Current Period CCR Revenues (net of tax)	34,655,423	36,846,111	35,014,809	33,279,433	34,543,014	41,433,057	45,668,421	44,918,041	46,079,426	44,422,210	38,752,734	34,784,604	470,397,282
39	**<u>True-Up Provision</u>**													
40	True-Up Provision - Over/(Under) Recov (Line 38-34)	(1,849,724)	(1,977,324)	(190,089)	(1,563,197)	(1,777,432)	(985,123)	1,948,849	1,423,759	8,702,695	9,740,045	4,030,208	(2,058,053)	15,444,615
41	Interest Provision for the Month	(6,952)	(8,935)	(11,087)	(12,566)	(14,513)	(16,532)	(15,576)	(12,115)	(3,263)	14,549	28,702	32,600	(25,688)
42	Current Cycle Balance - Over/(Under)	(1,856,676)	(3,842,934)	(4,044,110)	(5,619,874)	(7,411,819)	(8,413,473)	(6,480,201)	(5,068,557)	3,630,875	13,385,468	17,444,379	15,418,926	15,418,926
43	Prior Period Balance - Over/(Under) Recovered	(4,775,185)	(4,348,406)	(3,921,629)	(3,494,850)	(3,068,072)	(2,641,293)	(2,214,516)	(1,787,737)	(1,360,959)	(934,181)	(507,403)	(80,624)	(4,775,185)
44	Prior Period Cumulative True-Up Collected/(Refunded)	426,778	426,778	426,778	426,778	426,778	426,778	426,778	426,778	426,778	426,778	426,778	426,778	5,121,339
45	Prior Period True-up Balance - Over/(Under)	(4,348,407)	(3,921,628)	(3,494,850)	(3,068,072)	(2,641,294)	(2,214,515)	(1,787,737)	(1,360,959)	(934,181)	(507,403)	(80,624)	346,154	346,154
46	**Net Capacity True-up Over/(Under) (Line 42+45)**	(6,205,082)	(7,764,563)	(7,538,961)	(8,687,945)	(10,053,112)	(10,627,989)	(8,267,938)	(6,429,516)	2,696,694	12,878,066	17,363,755	15,765,080	15,765,080

[1] Approved in Commission Order No. PSC-16-0138-FOF-EI

REDACTED

Duke Energy Florida, LLC
Capacity Cost Recovery Clause
Calculation of Actual/Estimated True-Up
January 2018 - December 2018 (Filed July 27, 2018)

		JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	Total
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	5,071,564	5,590,987	5,331,276	5,331,276	5,331,276	5,331,276	5,331,275	5,331,275	5,331,275	5,331,275	5,331,275	5,331,275	63,975,305
3	Orlando Cogen Limited (ORLACOGL)	5,025,789	5,514,457	5,302,972	5,361,969	5,361,790	5,361,790	5,361,790	5,361,790	5,361,790	5,361,790	5,361,790	5,361,790	64,099,507
4	Pasco County Resource Recovery (PASCOUNT)	1,784,800	2,011,580	1,898,190	1,898,190	1,898,190	1,898,190	1,898,190	1,898,190	1,898,190	1,898,190	1,898,190	1,898,190	22,778,280
5	Pinellas County Resource Recovery (PINCOUNT)	4,248,600	4,788,435	4,518,518	4,518,518	4,518,518	4,518,518	4,518,518	4,518,518	4,518,518	4,518,518	4,518,518	4,518,518	54,222,210
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	6,965,675	7,676,459	7,321,066	7,321,066	7,321,066	7,321,066	7,321,066	7,321,066	7,321,066	7,321,066	7,321,066	7,321,066	87,852,794
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	765,872	790,760	798,927	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	9,564,071
8	US EcoGen	(93,000)	(93,000)	(84,000)	(93,000)	(90,000)	(93,000)	-	-	-	-	-	-	(546,000)
9	Subtotal - Base Level Capacity Costs	23,769,300	26,279,678	25,086,949	25,138,964	25,141,785	25,138,785	25,231,784	25,231,784	25,231,784	25,231,784	25,231,784	25,231,784	301,946,167
10	Base Production Jurisdictional Responsibility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
11	Base Level Jurisdictional Capacity Costs	22,078,114	24,409,879	23,302,013	23,350,326	23,352,947	23,350,161	23,436,543	23,436,543	23,436,543	23,436,543	23,436,543	23,436,543	280,462,697
12	**Intermediate Production Level Capacity Costs**													
13	Southern Franklin	4,609,957	4,467,756	2,685,103	2,663,030	2,934,373	4,811,161	6,293,135	6,293,135	4,631,783	2,693,539	2,693,539	3,524,215	48,300,723
14	Schedule H Capacity Sales - NSB & RCID	(208,753)	(31,799)	379,669	270	(27,441)	-	-	-	-	-	-	-	111,946
15	Subtotal - Intermediate Level Capacity Costs	4,401,204	4,435,957	3,064,772	2,663,300	2,906,932	4,811,161	6,293,135	6,293,135	4,631,783	2,693,539	2,693,539	3,524,215	48,412,669
16	Intermediate Production Jurisdictional Responsibility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
17	Intermediate Level Jurisdictional Capacity Costs	3,199,808	3,225,074	2,228,181	1,936,299	2,113,427	3,497,858	4,575,298	4,575,298	3,367,445	1,958,283	1,958,283	2,562,210	35,197,463
18	**Peaking Production Level Capacity Costs**													
19	Shady Hills	1,984,500	1,984,500	1,417,500	1,371,600	1,920,240	3,904,200	3,911,684	3,911,684	1,825,453	1,374,376	1,374,376	1,983,330	26,963,442
20	Vandolah (NSG)	2,926,756	2,888,311	1,965,274	1,943,845	2,795,467	5,725,022	5,539,623	5,495,150	2,629,977	1,937,310	1,981,783	2,788,227	38,616,745
21	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Subtotal - Peaking Level Capacity Costs	4,911,256	4,872,811	3,382,774	3,315,445	4,715,707	9,629,222	9,451,307	9,406,834	4,455,430	3,311,686	3,356,159	4,771,557	65,580,188
23	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
24	Peaking Level Jurisdictional Capacity Costs	4,711,073	4,674,196	3,244,893	3,180,307	4,523,495	9,236,735	9,066,072	9,023,412	4,273,827	3,176,702	3,219,362	4,577,068	62,907,139
25	**Other Capacity Costs**													
26	Retail Wheeling	[redacted]												
27	RRSSA Second Amendment [1]													
28	Total Other Capacity Costs													
29	**Total Capacity Costs (Line 11+17+24+28)**	31,537,913	33,933,287	30,392,188	30,081,704	31,569,791	37,695,859	38,691,081	38,651,525	32,683,005	30,171,375	30,222,229	32,184,839	397,814,797
30	**Nuclear Cost Recovery Clause**													
31	CR3 Uprate Costs	4,290,186	4,261,861	4,233,534	4,205,208	4,176,884	4,148,557	4,120,232	4,091,907	4,063,580	4,035,255	4,006,929	3,978,603	49,612,736
32	**Total Recoverable Nuclear Costs**	4,290,186	4,261,861	4,233,534	4,205,208	4,176,884	4,148,557	4,120,232	4,091,907	4,063,580	4,035,255	4,006,929	3,978,603	49,612,736
33	**ISFSI Revenue Requirement** [2]	677,047	628,287	579,175	555,717	573,770	573,765	573,765	573,765	573,765	573,765	573,765	573,765	7,030,351
34	**Total Recov Capacity & Nuclear Costs (Line 29+32+33)**	36,505,147	38,823,435	35,204,897	34,842,630	36,320,446	42,418,181	43,385,077	43,317,197	37,320,350	34,780,394	34,802,924	36,737,207	454,457,884
35	**Capacity Revenues**													
36	Capacity Cost Recovery Revenues (net of tax)	35,082,201	37,272,890	35,441,587	33,706,211	34,969,792	41,859,835	46,576,445	48,650,437	47,554,221	43,166,059	36,691,945	34,902,418	475,874,041
37	Prior Period True-Up Provision Over/(Under) Recovery	(426,778)	(426,778)	(426,778)	(426,778)	(426,778)	(426,778)	(426,778)	(426,778)	(426,778)	(426,778)	(426,778)	(426,778)	(5,121,339)
38	**Current Period Revenues (net of tax)**	34,655,423	36,846,111	35,014,809	33,279,433	34,543,014	41,433,057	46,149,667	48,223,659	47,127,442	42,739,281	36,265,167	34,475,639	470,752,702
39	**True-Up Provision**													
40	True-Up Provision - Over/(Under) Recov (Line 38-34)	(1,849,724)	(1,977,324)	(190,089)	(1,563,197)	(1,777,432)	(985,123)	2,764,590	4,906,462	9,807,092	7,958,887	1,462,243	(2,261,567)	16,294,818
41	Interest Provision for the Month	(6,952)	(8,935)	(11,087)	(12,566)	(14,513)	(16,532)	(5,949)	(1,687)	6,498	13,212	14,734	13,278	(30,499)
42	Current Cycle Balance - Over/(Under)	(1,856,676)	(3,842,934)	(4,044,110)	(5,619,874)	(7,411,819)	(8,413,473)	(5,654,833)	(750,058)	9,063,532	17,035,631	18,512,608	16,264,319	16,264,319
43	Prior Period Balance - Over/(Under) Recovered	(4,775,185)	(4,775,185)	(4,775,185)	(4,775,185)	(4,775,185)	(4,775,185)	(4,775,185)	(4,775,185)	(4,775,185)	(4,775,185)	(4,775,185)	(4,775,185)	(4,775,185)
44	Prior Period Cumulative True-Up Collected/(Refunded)	426,778	853,557	1,280,335	1,707,113	2,133,891	2,560,670	2,987,448	3,414,226	3,841,004	4,267,783	4,694,561	5,121,339	5,121,339
45	Prior Period True-up Balance - Over/(Under)	(4,348,407)	(3,921,628)	(3,494,850)	(3,068,072)	(2,641,294)	(2,214,515)	(1,787,737)	(1,360,959)	(934,181)	(507,402)	(80,624)	346,154	346,154
46	**Net Capacity True-up Over/(Under) (Line 42+45)**	(6,205,082)	(7,764,563)	(7,538,961)	(8,687,945)	(10,053,112)	(10,627,989)	(7,442,570)	(2,111,017)	8,129,352	16,528,229	18,431,984	16,610,473	16,610,473

[1] Approved in Commission Order No. PSC-16-0138-FOF-EI
[2] Approved in Commission Order No. PSC-15-0465-S-EI

Docket No. 20190001-EI
Witness: Menendez
Exhibit No. (CAM-3T)
Schedule A1-1
Sheet 1 of 9

DUKE ENERGY FLORIDA, LLC
FUEL AND PURCHASED POWER

DECEMBER 2018

		$				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	FUEL COST OF SYSTEM NET GENERATION (SCH A3)	114,722,501	105,646,287	9,076,214	8.6	2,729,652	2,996,859	(267,206)	(8.9)	4.2028	3.5252	0.6776	19.2
2	COAL CAR SALE	(82,225)	0	(82,225)	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3	ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	4,965,506	1,246,700	3,718,806	298.3	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4	TOTAL COST OF GENERATED POWER	119,605,782	106,892,987	12,712,795	11.9	2,729,652	2,996,859	(267,206)	(8.9)	4.3817	3.5668	0.8149	22.9
5	ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	8,196,254	269,187	7,927,067	2,944.8	119,633	6,298	113,335	1,799.5	6.8512	4.2742	2.5770	60.3
6	ENERGY COST OF SCH C,X ECONOMY PURCH - BROKER (SCH A9)	-	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
7	ENERGY COST OF ECONOMY PURCH - NON-BROKER (SCH A9)	866,974	120,872	746,102	617.3	21,895	3,007	18,887	628.1	3.9597	4.0193	(0.0596)	(1.5)
8	PAYMENTS TO QUALIFYING FACILITIES (SCH A8)	11,143,113	11,174,285	(31,172)	(0.3)	241,709	271,206	(29,497)	(10.9)	4.6101	4.1202	0.4899	11.9
9	TOTAL COST OF PURCHASED POWER	20,206,341	11,564,344	8,641,997	74.7	383,237	280,512	102,725	36.6	5.2725	4.1226	1.1499	27.9
10	TOTAL AVAILABLE MWH					3,112,889	3,277,370	(164,481)	(5.0)				
11	FUEL COST OF OTHER POWER SALES (SCH A6)	(40,550)	(387,492)	346,942	(89.5)	(614)	(12,587)	11,973	(95.1)	6.6064	3.0786	3.5278	114.6
11a	GAIN ON OTHER POWER SALES - 100% (SCH A6)	(26,968)	(107,785)	80,817	(75.0)	(614)	(12,587)	11,973	(95.1)	4.3936	0.8563	3.5373	413.1
11b	GAIN ON TOTAL POWER SALES - 20% (SCH A6)	5,392	21,557	(16,165)	(75.0)	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
12	FUEL COST OF STRATIFIED SALES	(3,079,988)	(1,424,393)	(1,655,594)	116.2	(125,508)	(95,861)	(29,647)	30.9	2.4540	1.4859	0.9681	65.2
13	TOTAL FUEL COST AND GAINS ON POWER SALES	(3,142,113)	(1,898,113)	(1,244,000)	65.5	(126,122)	(108,448)	(17,674)	16.3	2.4913	1.7503	0.7410	42.3
14	NET INADVERTENT AND WHEELED INTERCHANGE					33,377	0	33,377					
15	TOTAL FUEL AND NET POWER TRANSACTIONS	136,670,010	116,559,218	20,110,792	17.3	3,020,144	3,168,923	(148,778)	(4.7)	4.5253	3.6782	0.8471	23.0
16	NET UNBILLED	(403,413)	2,928,938	(3,332,351)	(113.8)	8,915	(79,630)	88,544	(111.2)	(0.0139)	0.1011	(0.1150)	(113.8)
17	COMPANY USE	1,271,809	654,504	617,305	94.3	(28,105)	(17,794)	(10,310)	57.9	0.0439	0.0226	0.0213	94.3
18	T & D LOSSES	4,746,868	6,405,701	(1,658,833)	(25.9)	(104,897)	(174,153)	69,257	(39.8)	0.1639	0.2211	(0.0572)	(25.9)
19	ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 2)	136,670,010	116,559,218	20,110,792	17.3	2,896,058	2,897,345	(1,288)	(0.0)	4.7192	4.0230	0.6962	17.3
20	WHOLESALE KWH SALES (EXCLUDING STRATIFIED SALES)	(820,020)	(711,011)	(109,009)	15.3	(17,355)	(17,608)	253	(1.4)	4.7249	4.0380	0.6869	17.0
21	JURISDICTIONAL KWH SALES	135,849,990	115,848,207	20,001,783	17.3	2,878,702	2,879,737	(1,035)	(0.0)	4.7191	4.0229	0.6962	17.3
22	JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.00112	135,892,103	115,884,120	20,007,984	17.3	2,878,702	2,879,737	(1,035)	(0.0)	4.7206	4.0241	0.6965	17.3
23	PRIOR PERIOD TRUE-UP	8,145,991	8,145,991	(0)	0.0	2,878,702	2,879,737	(1,035)	(0.0)	0.2830	0.2829	0.0001	0.0
24	TOTAL JURISDICTIONAL FUEL COST	144,038,094	124,030,111	20,007,983	16.1	2,878,702	2,879,737	(1,035)	(0.0)	5.0036	4.3070	0.6966	16.2
25	REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
26	FUEL COST ADJUSTED FOR TAXES									5.0072	4.3101	0.6971	16.2
27	GPIF	232,768	232,768			2,878,702	2,879,737			0.0081	0.0081	0.0000	0.0
28	TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									5.015	4.318	0.697	16.1

*Line 15a. MWH Data for Infomational Purposes Only

Docket No. 20190001-EI
Witness: Menendez
Exhibit No. (CAM-3T)
Schedule A1-2

DUKE ENERGY FLORIDA, LLC
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
YEAR TO DATE - DECEMBER 2018

		$				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	FUEL COST OF SYSTEM NET GENERATION (SCH A3)	1,322,472,390	1,322,046,314	426,075	0.0	37,225,085	37,640,386	(415,301)	(1.1)	3.5526	3.5123	0.0403	1.2
2	COAL CAR SALE	(2,149,074)	0	(2,149,074)	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3	ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	11,178,608	6,274,902	4,903,706	78.2	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4	TOTAL COST OF GENERATED POWER	1,331,501,923	1,328,321,216	3,180,707	0.2	37,225,085	37,640,386	(415,301)	(1.1)	3.5769	3.5290	0.0479	1.4
5	ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	163,859,893	104,791,544	59,068,349	56.4	3,456,477	2,405,479	1,050,998	43.7	4.7407	4.3564	0.3843	8.8
6	ENERGY COST OF SCH C,X ECONOMY PURCH - BROKER (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
7	ENERGY COST OF ECONOMY PURCH - NON-BROKER (SCH A9)	13,166,647	8,269,692	4,896,955	59.2	280,750	184,233	96,518	52.4	4.6898	4.4887	0.2011	4.5
8	PAYMENTS TO QUALIFYING FACILITIES (SCH A8)	137,425,176	140,729,302	(3,304,126)	(2.4)	3,065,228	3,176,824	(111,596)	(3.5)	4.4834	4.4299	0.0535	1.2
9	TOTAL COST OF PURCHASED POWER	314,451,717	253,790,538	60,661,178	23.9	6,802,455	5,766,535	1,035,920	18.0	4.6226	4.4011	0.2215	5.0
10	TOTAL AVAILABLE MWH					44,027,540	43,406,921	620,618	1.4				
11	FUEL COST OF OTHER POWER SALES (SCH A6)	(2,628,177)	(3,043,086)	414,909	(13.6)	(59,720)	(73,322)	13,602	(18.6)	4.4008	4.1503	0.2505	6.0
11a	GAIN ON OTHER POWER SALES - 100% (SCH A6)	(2,269,916)	(2,179,293)	(90,623)	4.2	(59,720)	(73,322)	13,602	(18.6)	3.8009	2.9722	0.8287	27.9
11b	GAIN ON TOTAL POWER SALES - 20% (SCH A6)	90,526	72,401	18,125	25.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
12	FUEL COST OF STRATIFIED SALES	(43,354,333)	(34,511,593)	(8,842,741)	25.6	(2,069,941)	(1,717,858)	(352,083)	20.5	2.0945	2.0090	0.0855	4.3
13	TOTAL FUEL COST AND GAINS ON POWER SALES	(48,161,901)	(39,661,571)	(8,500,330)	21.4	(2,129,661)	(1,791,180)	(338,481)	18.9	2.2615	2.2143	0.0472	2.1
14	NET INADVERTENT AND WHEELED INTERCHANGE					255,774	96,969	158,805					
15	TOTAL FUEL AND NET POWER TRANSACTIONS	1,597,791,739	1,542,450,184	55,341,555	3.6	42,153,653	41,712,710	440,943	1.1	3.7904	3.6978	0.0926	2.5
16	NET UNBILLED	1,137,950	(9,508,775)	10,646,725	(112.0)	(30,022)	276,694	(306,716)	(110.9)	0.0029	(0.0242)	0.0271	(112.0)
17	COMPANY USE	7,104,381	7,255,402	(151,021)	(2.1)	(187,431)	(195,876)	8,445	(4.3)	0.0180	0.0184	(0.0004)	(2.2)
18	T & D LOSSES	96,174,523	90,195,817	5,978,706	6.6	(2,537,319)	(2,439,804)	(97,516)	4.0	0.2441	0.2292	0.0149	6.5
19	ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 2)	1,597,791,739	1,542,450,184	55,341,555	3.6	39,398,881	39,353,725	45,156	0.1	4.0554	3.9195	0.1359	3.5
20	WHOLESALE KWH SALES (EXCLUDING STRATIFIED SALES)	(10,372,497)	(8,864,036)	(1,508,461)	17.0	(254,230)	(222,684)	(31,546)	14.2	4.0800	3.9805	0.0995	2.5
21	JURISDICTIONAL KWH SALES	1,587,419,241	1,533,586,147	53,833,094	3.5	39,144,651	39,131,041	13,610	0.0	4.0553	3.9191	0.1362	3.5
22	JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.00112	1,588,012,756	1,534,162,974	53,849,782	3.5	39,144,651	39,131,041	13,610	0.0	4.0568	3.9206	0.1362	3.5
23	PRIOR PERIOD TRUE-UP	97,751,887	97,751,892	(5)	0.0	39,144,651	39,131,041	13,610	0.0	0.2497	0.2498	(0.0001)	(0.0)
24	TOTAL JURISDICTIONAL FUEL COST	1,685,764,643	1,631,914,866	53,849,777	3.3	39,144,651	39,131,041	13,610	0.0	4.3065	4.1704	0.1361	3.3
25	REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
26	FUEL COST ADJUSTED FOR TAXES									4.3096	4.1734	0.1362	3.3
27	GPIF	2,793,216	2,793,216			39,144,651	39,131,041			0.0071	0.0071	0.0000	100.0
28	TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									4.317	4.181	0.136	3.3

*Line 15a. MWH Data for Infomational Purposes Only

DUKE ENERGY FLORIDA, LLC
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2018

		CURRENT MONTH				YEAR TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
A .	FUEL COSTS AND NET POWER TRANSACTIONS								
1 .	FUEL COST OF SYSTEM NET GENERATION	$114,722,501	105,646,287	$9,076,214	8.6	$1,322,472,390	$1,322,046,314	$426,075	0.0
1a.	COAL CAR SALE	(82,225)	0	(82,225)	0.0	(2,149,074)	0	(2,149,074)	0.0
2 .	FUEL COST OF POWER SOLD	(40,550)	(387,492)	346,942	(89.5)	(2,628,177)	(3,043,086)	414,909	(13.6)
2a.	GAIN ON POWER SALES	(21,576)	(107,785)	86,209	(80.0)	(2,179,391)	(2,179,293)	(98)	0.0
3 .	FUEL COST OF PURCHASED POWER	8,196,254	269,187	7,927,067	2,944.8	163,859,893	104,791,544	59,068,349	56.4
3a.	ENERGY PAYMENTS TO QUALIFYING FACILITIES	11,143,113	11,174,285	(31,172)	(0.3)	137,425,176	140,729,302	(3,304,126)	(2.4)
4 .	ENERGY COST OF ECONOMY PURCHASES	866,974	120,872	746,102	617.3	13,166,647	8,269,692	4,896,955	59.2
5 .	TOTAL FUEL & NET POWER TRANSACTIONS	134,784,491	116,715,354	18,069,137	15.5	1,629,967,464	1,570,614,474	59,352,990	3.8
6 .	ADJUSTMENTS TO FUEL COST:								
6a.	FUEL COST OF STRATIFIED SALES	(3,079,988)	(1,424,393)	(1,655,594)	116.2	(43,354,333)	(34,511,593)	(8,842,741)	25.6
6b.	OTHER- JURISDICTIONAL ADJUSTMENTS (see detail below)	4,965,506	1,246,700	3,718,806	298.3	11,178,608	6,274,902	4,903,706	78.2
6c.	OTHER - PRIOR PERIOD ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
7 .	ADJUSTED TOTAL FUEL & NET PWR TRNS	$136,670,010	$116,537,661	$20,132,349	17.3	$1,597,791,739	$1,542,377,783	$55,413,956	3.6

FOOTNOTE: DETAIL OF LINE 6b ABOVE

	CM ACTUAL	CM ESTIMATED	CM DIFFERENCE	YTD ACTUAL	YTD ESTIMATED	YTD DIFFERENCE
INSPECTION & FUEL ANALYSIS REPORTS {Wholesale Portion}	$0	$0	$0	$0	$0	$0
CITRUS CC INEFFICIENT USE	0	0	0	(1,502,363)	0	(1,502,363)
UNIVERSITY OF FLORIDA STEAM REVENUE ALLOCATION {Wholesale Portion}	600	0	600	7,620	0	7,620
FPD AGREEMENT TERMINATION	0	0	0	0	0	0
TANK BOTTOM ADJUSTMENT	0	0	0	(171,899)	0	(171,899)
AERIAL SURVEY ADJUSTMENT (Coal Pile)	3,719,710	0	3,719,710	5,415,075	0	5,415,075
FDP AGREEMENT TERMINATION	1,245,196	0	1,245,196	7,326,228	0	7,326,228
RAIL CAR SALE PROCEEDS	0	0	0	0	0	0
Gain/Loss on Disposition of Oil	0	0	0	0	0	0
NET METER SETTLEMENT	0	0	0	103,947	0	103,947
N/A - Not used	0	0	0	0	0	0
Derivative Collateral Interest	0	0	0	0	0	0
SUBTOTAL LINE 6b SHOWN ABOVE	$4,965,506	$0	$4,965,506	$11,178,608	$0	$11,178,608

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		CURRENT MONTH ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	YEAR TO DATE ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
B.	KWH SALES								
1 .	JURISDICTIONAL SALES	2,878,702,504	2,879,737,426	(1,034,922)	(0.0)	39,144,650,882	39,131,040,949	13,609,933	0.0
2 .	NON JURISDICTIONAL (WHOLESALE) SALES	17,355,384	17,608,000	(252,616)	(1.4)	254,173,334	222,684,074	31,489,260	14.1
3 .	TOTAL SALES	2,896,057,888	2,897,345,426	(1,287,538)	(0.0)	39,398,824,216	39,353,725,023	45,099,193	0.1
4 .	JURISDICTIONAL SALES % OF TOTAL SALES	99.40	99.39	0.01	0.0	99.35	99.43	(0.08)	(0.1)

DUKE ENERGY FLORIDA, LLC
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2018

		CURRENT MONTH				YEAR TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
C.	TRUE UP CALCULATION								
1 .	JURISDICTIONAL FUEL REVENUE	$115,795,394	$118,762,346	($2,966,953)	(2.5)	$1,603,480,385	$1,603,647,559	($167,174)	(0.0)
2 .	ADJUSTMENTS:	0	0	0	0.0	0	0	0	0.0
2a.	TRUE UP PROVISION	(8,145,991)	(8,145,991)	0	0.0	(97,751,887)	(97,751,892)	5	0.0
2b.	INCENTIVE PROVISION	(232,768)	(232,768)	0	0.0	(2,793,216)	(2,793,216)	0	0.0
3 .	TOTAL JURISDICTIONAL FUEL REVENUE	107,416,635	110,383,587	(2,966,952)	(2.7)	1,502,935,282	1,503,102,451	(167,169)	(0.0)
4 .	ADJ TOTAL FUEL & NET PWR TRNS (LINE A7)	136,670,010	116,537,661	20,132,349	17.3	1,597,791,739	1,542,377,783	55,413,956	3.6
5 .	JURISDICTIONAL SALES % OF TOT SALES (LINE B4)	99.40	99.39	0.01	0.0	99.35	99.43	(0.08)	(0.1)
6 .	JURISDICTIONAL FUEL & NET POWER TRANSACTIONS (LINE C4 * LINE C5 * 1.00112 LOSS MULTIPLIER)	135,892,103	115,884,120	20,007,984	17.3	1,588,012,756	1,534,162,974	53,849,782	3.5
7 .	TRUE UP PROVISION FOR THE MONTH OVER/(UNDER) COLLECTION (LINE C3 - C6)	(28,475,468)	(5,500,532)	(22,974,936)	417.7	(85,077,474)	(31,060,523)	(54,016,951)	173.9
8 .	INTEREST PROVISION FOR THE MONTH (LINE D10)	(378,902)	(239,187)	(139,715)	58.4	(3,954,025)	(3,542,306)	(411,719)	11.6
9 .	TRUE UP & INTEREST PROVISION BEG OF MONTH/PERIOD	(182,171,211)	(150,857,190)	(31,314,021)	20.8	(211,599,978)	(211,599,981)	3	0.0
10.	TRUE UP COLLECTED (REFUNDED)	8,145,991	8,145,991	(0)	0.0	97,751,887	97,751,892	(5)	0.0
11.	END OF PERIOD TOTAL NET TRUE UP (LINES C7 + C8 + C9 + C10)	(202,879,590)	(148,450,918)	(54,428,672)	36.7	(202,879,590)	(148,450,918)	(54,428,672)	36.7
12.	OTHER:	0				0		0	
13.	END OF PERIOD TOTAL NET TRUE UP (LINES C11 + C12)	($202,879,590)	(148,450,918)	(54,428,672)	36.7	($202,879,590)	(148,450,918)	(54,428,672)	36.7

		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
D.	INTEREST PROVISION				
1 .	BEGINNING TRUE UP (LINE C9)	($182,171,211)	N/A	--	--
2 .	ENDING TRUE UP (LINES C7 + C9 + C10 + C12)	(202,500,688)	N/A	--	--
3 .	TOTAL OF BEGINNING & ENDING TRUE UP	(384,671,899)	N/A	--	--
4 .	AVERAGE TRUE UP (50% OF LINE D3)	(192,335,949)	N/A	--	--
5 .	INTEREST RATE - FIRST DAY OF REPORTING MONTH	2.300	N/A	--	--
6 .	INTEREST RATE - FIRST DAY OF SUBSEQUENT MONTH	2.420	N/A	--	--
7 .	TOTAL (LINE D5 + LINE D6)	4.720	N/A		
8 .	AVERAGE INTEREST RATE (50% OF LINE D7)	2.360	N/A	--	--
9 .	MONTHLY AVERAGE INTEREST RATE (LINE D8/12)	0.197	N/A	--	--
10.	INTEREST PROVISION (LINE D4 * LINE D9)	($378,902)	N/A	--	--

NOT

A-3 Generating System Comparative Data Report

Docket No. 20190001-EI
Witness: Menendez
Exhibit No. (CAM-3T)
Schedule: A3-1
Sheet 5 of 9

Duke Energy Florida, LLC

FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
NET GENERATION ($)				
1 - HEAVY OIL	0	0	0	0.0 %
2 - LIGHT OIL	22,609,544	15,958,463	6,651,081	41.7 %
3 - COAL	276,175,645	320,893,530	(44,717,885)	(13.9 %)
4 - GAS	1,023,687,201	985,194,322	38,492,879	3.9 %
5 - NUCLEAR	0	0	0	0.0 %
6	0	0	0	0.0 %
7	0	0	0	0.0 %
8 - TOTAL ($)	1,322,472,390	1,322,046,315	426,075	0.0 %
SYSTEM NET GENERATION (MWH)				
9 - HEAVY OIL	0	0	0	0.0 %
10 - LIGHT OIL	90,434	60,434	30,000	49.6 %
11 - COAL	8,421,960	9,475,431	(1,053,471)	(11.1 %)
12 - GAS	28,686,945	28,068,215	618,730	2.2 %
13 - NUCLEAR	0	0	0	0.0 %
14 - SOLAR	25,744	36,310	(10,566)	(29.1 %)
15	0	0	0	0.0 %
16 - TOTAL (MWH)	37,225,084	37,640,390	(415,306)	(1.1 %)
UNITS OF FUEL BURNED				
17 - HEAVY OIL (BBL)	0	0	0	0.0 %
18 - LIGHT OIL (BBL)	198,094	135,384	62,710	46.3 %
19 - COAL (TON)	3,745,945	4,239,712	(493,767)	(11.6 %)
20 - GAS (MCF)	222,082,583	214,463,963	7,618,620	3.6 %
21 - NUCLEAR (MMBTU)	0	0	0	0.0 %
22	0	0	0	0.0 %
23	0	0	0	0.0 %
BTUS BURNED (MILLION BTU)				
24 - HEAVY OIL	0	0	0	0.0 %
25 - LIGHT OIL	1,141,753	783,756	357,997	45.7 %
26 - COAL	86,196,682	98,222,765	(12,026,083)	(12.2 %)
27 - GAS	226,705,787	216,580,572	10,125,215	4.7 %
28 - NUCLEAR	0	0	0	0.0 %
29	0	0	0	0.0 %
30	0	0	0	0.0 %
31 - TOTAL (MILLION BTU)	314,044,222	315,587,093	(1,542,871)	(0.5 %)

A-3 Generating System Comparative Data Report

Docket No. 20190001-EI
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Exhibit No. (CAM-3T)
Schedule: A3-1
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Duke Energy Florida, LLC

FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
GENERATION MIX (% MWH)				
32 - HEAVY OIL	0.0	0.00	0.0	0.0 %
33 - LIGHT OIL	0.2	0.16	0.1	51.3 %
34 - COAL	22.6	25.17	(2.5)	(10.1 %)
35 - GAS	77.1	74.57	2.5	3.3 %
36 - NUCLEAR	0.0	0.00	0.0	0.0 %
37 - SOLAR	0.07	0.10	(0.03)	(28.3 %)
38	0	0	0	0
39 - TOTAL (% MWH)	100	100	0.0	0.0 %
FUEL COST PER UNIT ($)				
40 - HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.0 %
41 - LIGHT OIL ($/BBL)	114.14	117.88	(3.74)	(3.2 %)
42 - COAL ($/TON)	73.73	75.69	(1.96)	(2.6 %)
43 - GAS ($/MCF)	4.61	4.59	0.02	0.3 %
44 - NUCLEAR ($/MBTU)	0.00	0.00	0.00	0.0 %
45	0.00	0.00	0.00	0.0 %
46	0.00	0.00	0.00	0.0 %
FUEL COST PER MILLION BTU ($/MILLION BTU)				
47 - HEAVY OIL	0.00	0.00	0.00	0.0 %
48 - LIGHT OIL	19.80	20.36	(0.56)	(2.7 %)
49 - COAL	3.20	3.27	(0.06)	(1.9 %)
50 - GAS	4.52	4.55	(0.03)	(0.7 %)
51 - NUCLEAR	0.00	0.00	0.00	0.0 %
52	0.00	0.00	0.00	0.0 %
53	0.00	0.00	0.00	0.0 %
54 - SYSTEM ($/MBTU)	4.21	4.19	0.02	52.4 %
BTU BURNED PER KWH (BTU/KWH)				
55 - HEAVY OIL	0	0	0	0.0 %
56 - LIGHT OIL	12,625	12,969	(344)	(2.6 %)
57 - COAL	10,235	10,366	(131)	(1.3 %)
58 - GAS	7,903	7,716	187	2.4 %
59 - NUCLEAR	0	0	0	0.0 %
60	0	0	0	0.0 %
61	0	0	0	0.0 %
62 - SYSTEM (BTU/KWH)	8,436	8,384	52	0.6 %

A-3 Generating System Comparative Data Report

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Schedule: A3-1
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Duke Energy Florida, LLC

FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
GENERATED FUEL COST PER KWH (CENTS/KWH)				
63 - HEAVY OIL	0.00	0.00	0.00	0.0 %
64 - LIGHT OIL	25.00	26.41	(1.41)	(5.3 %)
65 - COAL	3.28	3.39	(0.11)	(3.2 %)
66 - GAS	3.57	3.51	0.06	1.7 %
67 - NUCLEAR	0.00	0.00	0.00	0.0 %
68	0.00	0.00	0.00	0.0 %
69	0.00	0.00	0.00	0.0 %
70 - SYSTEM (CENTS/KWH)	3.55	3.51	0.04	1.1 %

Duke Energy Florida, LLC
Schedule A6
Power Sold for the Month of
December 2018

Docket No. 20190001-EI
Witness: Menendez
Exhibit No. (CAM-3T)
Schedule A6
Sheet 8 of 9

(1) Sold To	(2) Type & Schedule	(3) Total KWH Sold (000)	(4) KWH Wheeled from Other Systems (000)	(5) KWH from Own Generation (000)	(6a) Fuel Cost C/KWH	(6b) Total Cost C/KWH	(7) Fuel Adj Total $	(8) Total Cost $	(9) Gain on Sales $
ESTIMATED		12,587		12,587	3.079	3.935	387,492.00	495,277.00	107,785.00
ACTUAL									
Reedy Creek Improvement District	CR-1	670		670	3.041	2.638	20,373.40	17,677.60	(2,695.80)
The Energy Authority	Schedule OS	40		40	4.049	4.000	1,619.60	1,600.00	(19.60)
ADJUSTMENTS									
PJM Settlements							18,556.56	10,441.86	(8,114.70)
City of Tallahassee		(96)						37,797.92	37,797.92
Subtotal - Gain on Other Power Sales		614	0	710	6.606	11.000	40,549.56	67,517.38	26,967.82
CURRENT MONTH TOTAL		614		710	6.606	11.000	40,549.56	67,517.38	26,967.82
DIFFERENCE		(11,973)		(11,877)	3.527	7.065	(346,942.44)	(427,759.62)	(80,817.18)
DIFFERENCE %		(95)		(94)	114.562	179.542	(89.54)	(86.37)	(74.98)
CUMULATIVE ACTUAL		59,720		59,816	4.401	8.202	2,628,177.49	4,898,093.95	2,269,917.44
CUMULATIVE ESTIMATED		73,322		73,322	4.150	7.123	3,043,086.29	5,222,379.32	2,179,293.03
DIFFERENCE		(13,602)		(13,506)	0.251	1.079	(414,908.80)	(324,285.37)	90,624.41
DIFFERENCE %		(19)		(18)	6.037	15.153	(13.63)	(6.21)	4.16

	Counterparty	Type	MW	Start Date - End Date	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
1	Orange Cogen (ORANGECO)	QF	74.00	7/1/95 - 12/31/24	5,071,564	5,590,987	5,331,276	5,331,276	5,331,276	5,331,276	5,331,276	5,331,276	5,331,276	5,331,276	5,331,276	5,331,276	63,975,307
2	Orlando Cogen Limited (ORLACOGL)	QF	79.20	9/1/93 - 12/31/23	5,025,789	5,514,457	5,302,972	5,361,969	5,361,790	5,361,790	5,414,950	5,361,790	5,361,790	5,361,790	5,361,790	5,361,790	64,152,667
3	Pasco County Resource Recovery (PASCOUNT)	QF	23.00	1/1/95 - 12/31/24	1,784,800	2,011,580	1,898,190	1,898,190	1,898,190	1,898,190	1,898,190	1,898,190	1,898,190	1,898,190	1,898,190	1,898,190	22,778,280
4	Pinellas County Resource Recovery (PINCOUNT)	QF	54.75	1/1/95 - 12/31/24	4,248,600	4,788,435	4,518,518	4,518,518	4,518,518	4,518,518	4,518,518	4,518,518	4,518,518	4,518,518	4,518,518	4,518,518	54,222,210
5	Polk Power Partners, L.P. (MULBERRY)	QF	115.00	8/1/94 - 8/8/24	6,965,675	7,676,459	7,321,066	7,321,066	7,321,066	7,321,066	7,321,066	7,321,066	7,321,066	7,321,066	7,321,066	7,321,066	87,852,796
6	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	QF	39.60	8/1/94 - 12/31/23	765,872	790,760	798,927	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	9,564,071
7	Southern purchase - Franklin	Other	425	6/1/16 - 5/31/21	4,609,957	4,467,756	2,685,103	2,663,030	2,934,373	4,811,161	6,285,017	6,268,886	4,634,240	2,701,639	2,384,883	3,505,309	47,951,354
8	Retail Wheeling				(82,003)	(2,819)	(5,894)	(4,260)	(35,146)	0	0	(567)	(13,875)	(53,736)	(6,689)	0	(204,989)
9	CR-3 Projected Expense				4,290,186	4,261,861	4,233,534	4,205,208	4,176,884	4,148,557	4,120,232	4,091,907	4,063,580	4,035,255	4,006,929	3,978,603	49,612,736
10	ISFSI Return				677,047	628,287	579,175	555,717	573,770	573,765	573,771	573,769	573,883	573,769	573,545	573,320	7,029,819
	SUB-TOTAL				33,357,487	35,727,762	32,662,867	32,651,659	32,881,667	34,765,268	36,263,965	36,165,780	34,489,613	32,488,713	32,190,453	33,289,017	406,934,251

Confidential Capacity Contracts (Aggregated):

		MW	Contracts	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
Purchases/Sales (Net)		1176.25	4	6,240,425	6,374,971	5,301,439	4,841,747	6,213,334	11,147,327	11,401,479	11,227,238	6,132,129	4,856,595	5,168,636	6,506,218	85,411,537
TOTAL				39,597,912	42,102,733	37,964,306	37,493,405	39,095,001	45,912,595	47,665,445	47,393,018	40,621,742	37,345,307	37,359,089	39,795,235	492,345,789

Docket No. 20190001-EI
Witness: Menendez
Exh bit No. (CAM-4T)
Sheet 1 of 2

Duke Energy Florida, LLC
Capital Structure and Cost Rates Applied to Capital Projects
Estimated for the Period of : January 2018 through June 2018

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost	Pre-Tax Weighted Cost Rate
Common Equity	$ 4,711,485	44.73%	10.50%	4.70%	6.29%
Preferred Stock	0	0.00%	0.00%	0.00%	0.00%
Long Term Debt	3,931,532	37.33%	5.29%	1.97%	1.97%
Short Term Debt	102,875	0.98%	0.21%	0.00%	0.00%
Customer Deposits - Active	191,025	1.81%	2.26%	0.04%	0.04%
Customer Deposits - Inactive	1,455	0.01%	0.00%	0.00%	0.00%
Deferred Tax	1,772,933	16.83%	0.00%	0.00%	0.00%
Deferred Tax (FAS 109)	(180,391)	-1.71%	0.00%	0.00%	0.00%
ITC	1,968	0.02%	0.00%	0.00%	0.00%
	$10,532,883	100.00%		6.71%	8.31%
			Total Debt	2.02%	2.02%
			Total Equity	4.70%	6.29%

Above is the May 2017 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PSS-EU, Docket No. 120007-EI.

The May 2017 Pre-Tax Weighted Cost Rate for Common Equity above reflects the impact of the reduction in the federal corporate income tax rate as a result of the 2018 Tax Cuts and Jobs Act.

Duke Energy Florida, LLC
Capital Structure and Cost Rates Applied to Capital Projects
Estimated for the Period of : July 2018 through December 2018

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost	Pre-Tax Weighted Cost Rate
Common Equity	$ 5,022,459	44.29%	10.50%	4.65%	6.23%
Preferred Stock	0	0.00%	0.00%	0.00%	0.00%
Long Term Debt	4,497,052	39.66%	4.90%	1.94%	1.94%
Short Term Debt	(193,058)	-1.70%	0.88%	-0.01%	-0.01%
Customer Deposits - Active	179,649	1.58%	2.35%	0.04%	0.04%
Customer Deposits - Inactive	1,597	0.01%	0.00%	0.00%	0.00%
Deferred Tax	1,826,909	16.11%	0.00%	0.00%	0.00%
Deferred Tax (FAS 109)	0	0.00%	0.00%	0.00%	0.00%
ITC	5,239	0.05%	7.85%	0.00%	0.00%
	$11,339,847	100.00%		6.62%	8.20%
			Total Debt	1.97%	1.97%
			Total Equity	4.65%	6.23%

Above is the May 2018 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PSS-EU, Docket No. 120007-EI.

The May 2018 DEF Surveillance Report reflects the tax reform adjustments as set forth in Paragraph 16 of DEF's 2nd Revised and Restated Settlement Agreement.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

ARNOLD GARCIA

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 20190001-EI

MARCH 1, 2019

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

A. I am employed by Duke Energy Business Services, LLC ("DEBS"), a subsidiary of Duke Energy Corporation ("Duke Energy"), as Manager, Insurance. Duke Energy Florida, LLC ("DEF" or the "Company") is a wholly-owned subsidiary of Duke Energy and affiliate of DEBS.

Q. What are your responsibilities in that position?

A. I am responsible for placing insurance coverage for Duke Energy and its subsidiaries.

Q. Please describe your educational background and professional experience.

A. I earned a Master on Business Administration from Wake Forest University (Winston Salem, NC), and a Bachelors of Arts degree from Colgate University (Hamilton, NY). I also hold an Associate in Risk Management (ARM) designation. I have held similar positions to my current position for other organizations such as a utility, a diversified manufacturer and two consumer product companies (one of which was a Fortune 250 Company).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is twofold: first, I will describe the insurance protection that was in place at the Bartow Combined Cycle Power Plant ("Bartow CC") on February 9, 2017; and second, it was made apparent to DEF during the 2018 fuel clause docket that there were questions regarding whether or not DEF had, or should have had, insurance coverage covering replacement power costs, therefore I will provide an overview of the types of coverages that are, and are not, available (commercially or practically) to Duke Energy and the Company for its generating assets.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Exhibit NO. __ (AG-1), the Bartow CC Insurance Policy in effect on February 9, 2017. This exhibit is confidential.

Q. Please provide a summary of your testimony.

A. In summary, on February 9, 2017, the Bartow CC was covered by a Policy of All Risk Property Insurance Including Machinery Breakdown ("the Policy") issued by Associated Electric & Gas Insurance Services, Ltd ("AEGIS") that did not provide coverage for replacement power costs or other business interruption costs. Moreover, an Insurance Product that provided such coverage for generating units such as the Bartow CC was not available in a commercially viable form at that time; that is, the costs to the Company and its customers of any such policy would outweigh the benefit received.

Q. Please describe the Policy.

A. The Policy provides Duke Energy protection against loss occurring from damage to its generation fleet, including the Bartow CC, except under the named exclusions and subject to the limits described therein (subject to any applicable deductible).

Q. Did the Policy include an exclusion for replacement power costs?

A. Yes, it did. Section A provides the Coverage Declarations, and section A.2. is the Extra Expense declaration. Section A.2.c.(3) provides the exclusion for replacement power costs. See Ex. No.__ (AG-1). The exclusion is also shown in section 3 "Limit of Liability" on the Declarations Page, page 3 of 5, where it provides the limitation of liability for Extra Expenses as shown in that section.

Q. Was coverage for replacement power costs available for the Bartow CC during February of 2017?

A. From a practical standpoint, the answer is no cost-effective product was available in the market. Allow me to explain, Duke Energy routinely monitors developments in the insurance market and the results of those efforts have consistently shown the coverage is unavailable in the current market at a cost point that would make economic sense. Essentially, any product that would provide this sort of coverage would require a premium that would all but negate the value of the coverage being obtained (i.e., the premiums would be set equal to a high-end expected loss, plus the insurer's administrative fee).

Q. Does this conclude your testimony?

A. Yes.

Docket No. 20190001-EI
Duke Energy Florida
Witness: Garcia
Exhibit No. ___(AG-1)

REDACTED
In its entirety

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFFREY SWARTZ

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 20190001-EI

MARCH 1, 2019

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

A. I am employed by Duke Energy Florida ("DEF" or the "Company") as Vice President – Generation.

Q. What are your responsibilities in that position?

A. As Vice President of DEF's Generation organization, my responsibilities include overall leadership and strategic direction of DEF's power generation fleet. My major duties and responsibilities include strategic and tactical planning to operate and maintain DEF's non-nuclear generation fleet; generation fleet project and additions recommendations; major maintenance programs; outage and project management; retirement of generation facilities; asset allocation; workforce planning and staffing; organizational alignment and design; continuous business improvements; retention and inclusion; succession planning; and oversight of hundreds of employees and hundreds of millions of dollars in assets and capital and operating budgets.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science degree in Mechanical Engineering from the United States Naval Academy in 1985. I have 17 years of power plant and production experience in various managerial and executive positions within Duke Energy managing Fossil Steam Operations, Combustion Turbine Operations and Nuclear Plant Operations. While at Duke Energy I have managed new unit projects from construction to operation, and I have extensive contract negotiation and management experience. My prior experience also includes nuclear engineering and operations experience in the United States Navy and project management, engineering, supervisory and management experience with a pulp, paper and chemical manufacturing company.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with information related to the Bartow Steam Turbine (ST) forced outage that occurred from February 9, 2017 through April 8, 2017, including background information on the event that led to the outage, an explanation of DEF's responsive actions, a presentation of DEF's root cause analysis and findings, and an explanation of DEF's reasonable and prudent restoration actions.

Q. Please provide a summary of your testimony.

A. On February 9, 2017, the Bartow steam turbine was removed from service due to an indication of a sodium leak into the steam water cycle. During this shutdown, DEF discovered a failed LP turbine rupture disk. The disk had been breached by a foreign object that caused a hole in the rupture diaphragm. DEF performed an inspection of the Bartow Steam Turbine ("ST") and discovered damage to the ST's L-0 blades (and determined part of an L-0 blade ruptured the LP turbine rupture disk), resulting in a forced outage to the ST that lasted until April 8, 2017 (while the ST was off-line, the Bartow combustion turbines ("CTs") remained available to run in simple cycle mode). DEF performed a Root Cause Analysis ("RCA") that determined the failure of the Bartow ST's L-0 Blades was caused by events beyond DEF's control, and DEF could not have reasonably prevented the failure from occurring. The results of DEF's RCA were discussed in more detail in my March 1, 2018 testimony filed in Docket No. 20180001-EI, which I adopt and incorporate as if fully set forth herein. DEF's actions prior to and in the wake of the blade failure were reasonable and prudent.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the DEF RCA Report, attached as Exhibit No. __ (JS-1) to my March 1, 2018 testimony filed in Docket No. 20180001-EI.

Q: Is the RCA considered confidential by the Company?

A: Yes. Portions of the RCA's findings are considered proprietary and confidential by the blades' manufacturer. In order to protect the OEM's rights, this information has been treated by the Company as proprietary confidential business information and has not been made publicly available. As part of the stipulation reached on Issue 1B in Docket No. 20180001-EI, DEF committed to work with the OEM to revise the confidentiality request; DEF intends to fully comply with that stipulation.

Q. Please summarize the events leading up to the 2017 Bartow event.

A. Bartow is a 4x1 Combined Cycle ("CC") Station with a ST manufactured by Mitsubishi Hitachi Power Systems ("MHPS"). The ST was purchased from a company that intended to use it for a 3x1 CC with a gross output of 420MW. The ST was never delivered to that third party but instead remained with MHPS in a warehouse in Japan until DEF purchased the unit in 2006.

Before the ST was purchased, DEF contracted with MHPS to evaluate the ST design conditions and to update heat balances for a 4x1 CC configuration. CC units blend steam from the CTs as they start-up and/or shut-down with steam to the ST. These blending events result in brief periods of higher steam temperatures and flows into the condenser below the ST L-0 blades, a common occurrence for CC units.

Since commissioning of the Bartow ST in 2009, there have been five (5) events involving L-0 blade failures and/or replacements. The latest blade failure occurred when a "loss of mass" event resulted in a blade fragment traveling through the Low-Pressure Turbine rupture disk diaphragm.

Q. What actions did DEF take in response to the February 2017 failure?

A. The Company took three primary actions in the wake of the event: a root cause team was established to investigate the incident and prepare a root cause analysis; a restoration team was formed to bring the unit back on-line; and a team was formed to evaluate a long-term solution for Bartow.

Q. Please describe the process DEF followed to ascertain the root cause of the event.

A. DEF created a RCA Team consisting of internal experts to investigate and determine the root cause of the event. The RCA Team consisted of seven individuals with expertise in engineering, operations and process, and human performance.

Following industry standard procedures, the RCA Team employed specific tools used to determine potential root cause(s) including: interviews, event and causal factor review ("E&CF"), flawed barrier analysis, change analysis, component analysis, visual inspections of the equipment, photographs taken following the event, engineering calculations and measurements, and detailed review of outage reports and maintenance logs.

DEF's findings are fully set forth in the RCA identified as Exhibit No. __(JS-1) to my March 1, 2018 testimony in docket No. 20180001-EI and as summarized in my testimony of that date. To avoid unnecessary repetition, those findings will not be rehashed here.

Q. What restoration process did DEF follow to bring tl service?

A. It's important to recall that the four Bartow CTs were able to continue operation in simple cycle mode (i.e., without operation of the ST) notwithstanding the blade failure. DEF worked with the OEM to identify and implement an interim solution that would allow the ST to resume operation, ultimately resulting in the installation of a pressure plate in place of the L-0 blades on March 22, 2017. The plate allows the ST to operate increasing the energy output of Bartow above what was possible in simple cycle mode. As mentioned above, the ST returned to service on April 8, 2017.

Q. Could DEF have reasonably prevented the event and the ensuing outage at Bartow?

A. No, the outage was caused by circumstances beyond DEF's reasonable control, as demonstrated by the RCA. DEF was not at fault.

Q. Did DEF act reasonably and prudently to restore Bartow to service in a timely fashion?

A. Yes, DEF took reasonable and prudent steps to develop a restoration team and guiding processes to restore the Bartow ST to service. The restoration team followed those processes and the unit was successfully brought back on line in a timely manner.

Q. Did DEF's agreement with the OEM include a provision obligating for the OEM to contribute funds towards replacement power costs in the event of an outage caused by the OEM's product?

A. No; to the contrary, the agreement specifically disclaimed any liability for consequential damages.

Q. In your experience, do DEF's agreements with OEMs usually include a similar disclaimer of liability?

A. Yes. In my experience OEMs are not willing to accept the risk of agreeing to pay consequential damages (such as replacement power costs) given the uncertain and potentially open-ended liability. To my knowledge, this is the case throughout the industry.

Q. Have you or anyone under your supervision engaged in negotiations with a vendor that was willing to accept consequential damages as part of a component part purchase order?

A. No, in DEF's experience, vendors do not offer to accept consequential damages as part of the terms and conditions of their agreements. Further, when DEF has indicated that such a provision would be a required part of the agreement, vendors have indicated they would withdraw rather than agree to those terms. DEF simply has not found such a provision to be commercially available.

Q. Does that conclude your testimony?

A. Yes.

DEF incorporates Exhibit No. ___(JS-1) filed on March 2, 2018 in Docket No. 20180001-EI as if fully set forth herein.