Matthew R. Bernier
Associate General Counsel

March 2, 2018

VIA ELECTRONIC FILING

Ms. Carlotta Stauffer, 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. 20180001-EI*

Dear Ms. Stauffer:

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 2017;
- Direct Testimony of Christopher Menendez with Exhibit No. ___ (CAM-1T), Redacted Exhibit No. ___ (CAM-2T), Redacted Exhibit No. ___ (CAM-3T) and Exhibit No. ___ (CAM-4T); and
- Redacted Direct Testimony of Jeffrey Swartz with Redacted Exhibit No. ___(JS-1)

Thank you for your assistance in this matter. Please feel free to call me at (850) 521-1428 should you have any questions concerning this filing.

Respectfully,

s/ Matthew R. Bernier
Matthew R. Bernier

MRB/mw
Enclosures

106 East College Avenue, Suite 800 ▪ Tallahassee, Florida 32301
Phone: 850.521.1428 ▪ Fax: 727.820.5041 ▪ Email: matthew.bernier@duke-energy.com

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchase Power Cost Recovery Clause with Generating Performance Incentive Factor	)))	Docket No. 20180001-EI Filed: March 2, 2018

PETITION FOR APPROVAL OF FUEL COST RECOVERY AND CAPACITY COST RECOVERY ACTUAL TRUE-UPS FOR THE PERIOD ENDING DECEMBER 2017

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 $211,599,981 under-recovery and actual Capacity Cost Recovery ("CCR") true-up amount of $4,775,185 under-recovery for the period ending December 2017. In support of this Petition, DEF states as follows:

1. The actual $211,599,981 FCR under-recovery for the period January 2017 through December 2017 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 2018 rates. By Order No. PSC-2018-0028-FOF-EI, the Commission approved a

levelized FCR Factor of 4.127 cents/kWh for the 12-month period commencing January 2018. This FCR Factor reflects an actual/estimated under-recovery including interest for the period January 2017 through December 2017 of $97,751,887. The actual FAC under-recovery including interest for the period January 2017 through December 2017 is $211,599,981. The $211,599,981 actual under-recovery, less the actual/estimated under-recovery of $195,503,774 results in a total under-recovery of $16,096,208.

3. The actual $4,775,185 CCR under-recovery for the period January 2017 through December 2017 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-2018-0028-FOF-EI, the Commission approved CCR Factors for the 12-month period commencing January 2018. These factors reflected an actual/estimated under-recovery, including interest, for the period January 2017 through December 2017 of $5,121,339. The actual under-recovery, including interest, for the period January 2017 through December 2017 is $4,775,185. The $4,775,185 actual under-recovery, less the actual/estimated under-recovery of $5,121,339 which is currently reflected in charges for the period beginning January 2018 results in a total over-recovery of $346,154.

WHEREFORE, DEF respectfully requests the Commission to approve the net $16,096,208 FCR under-recovery as the actual true-up amount for the period ending

December 2017; and to approve the net $346,154 CCR over-recovery as the actual true-up amount for the period ending December 2017.

Respectfully submitted,

*s/Matthew R. Bernier*_____

DIANNE M. TRIPLETT
Deputy General Counsel
299 First Avenue North
St. Petersburg, FL 33701
T: 727-820-4692
F: 727-820-5041
Email: Dianne.Triplett@duke-energy.com

MATTHEW R. BERNIER
Associate General Counsel
106 East College Avenue, Suite 800
Tallahassee, Florida 32301
T: 850-521-1428
F: 727-820-5519
Email: Matthew.Bernier@duke-energy.com

Attorneys for Duke Energy Florida, LLC

Duke Energy Florida, LLC
CERTIFICATE OF SERVICE
Docket No. 20180001-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via email this 2nd day of March, 2018 to all parties of record as indicated below.

*s/Matthew R. Bernier*_____
Attorney

Suzanne Brownless Office of General Counsel FL Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 sbrownle@psc.state.fl.us James Beasley / J. Jeffry Wahlen Ausley McMullen P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com Russell Badders / Steven Griffin Beggs & Lane P.O. Box 12950 Pensacola, FL 32591 rab@beggslane.com srg@beggslane.com Kenneth A. Hoffman Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken.hoffman@fpl.com Rhonda J. Alexander / Jeffrey A. Stone Gulf Power Company One Energy Place Pensacola, FL 32520 rjalexad@southernco.com jastone@southernco.com	Charles Rehwinkel / Erik Sayler/ J.R. Kelly / Patricia Christensen Office of Public Counsel c/o The Florida Legislature 111 W. Madison St., Room 812 Tallahassee, FL 32399-1400 kelly.jr@leg.state.fl.us sayler.erik@leg.state.fl.us christensen.patty@leg.state.fl.us rehwinkel.charles@leg.state.fl.us Ms. Paula K. Brown Regulatory Affairs Tampa Electric Company P.O. Box 111 Tampa, FL 33601-0111 regdept@tecoenergy.com John Butler / Maria Moncada Florida Power & Light Company 700 Universe Blvd (LAW/JB) Juno Beach, FL 33408-0420 john.butler@fpl.com maria.moncada@fpl.com James Brew / Laura Wynn Stone Law Firm 1025 Thomas Jefferson St., N.W. Suite 800 West Washington, DC 20007 jbrew@smxblaw.com law@smxblaw.com	Beth Keating Gunster, Yoakley & Stewart, P.A. 215 South Monroe Street, Suite 601 Tallahassee, FL 32301 bkeating@gunster.com Mike Cassel Florida Public Utilities Company 1750 S. 14th Street, Suite 200 Fernandina Beach, FL 32034 mcassel@fpuc.com Robert Scheffel Wright / John T. LaVia, III c/o Gardner Law Firm 1300 Thomaswood Drive Tallahassee, FL 32308 schef@gbwlegal.com jlavia@gbwlegal.com Jon C. Moyle, Jr. Moyle Law Firm, P.A. 118 North Gadsden Street Tallahassee, FL 32301 jmoyle@moylelaw.com

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20180001-EI

Fuel and Capacity Cost Recovery
Actual True-Up for the Period
January 2017 - December 2017

DIRECT TESTIMONY OF
Christopher A. Menendez

March 2, 2018

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 2017 through December 2017, 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 2017, year-to-date; and Exhibit No. __(CAM-4T), a schedule outlining the 2017 capital structure and cost rates applied to capital projects. Exhibit No. __(CAM-4T) is included for informational purposes only, as DEF's 2017 Actual True-Up Filing does not include a capital return component. Schedules A1 through A9, and A12 for the year ended December 31, 2017, were filed with the Commission on January 19, 2018.

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-2018-0028-FOF-EI, the estimated 2017 fuel adjustment true-up amount was an under-recovery of $195.5 million. The actual under-recovery for 2017 was $211.6 million resulting in a final fuel adjustment true-up under-recovery amount of $16.1 million. Exhibit No. __(CAM-1T).

The estimated 2017 capacity cost recovery true-up amount was an under-recovery of $5.1 million. The actual amount for 2017 was an under-recovery of $4.8 million resulting in a final capacity true-up over-recovery amount of $0.3 million. Exhibit No. __(CAM-2T).

FUEL COST RECOVERY

Q. What is DEF's jurisdictional ending balance as of December 31, 2017 for fuel cost recovery?

A. The actual ending balance as of December 31, 2017 for true-up purposes is an under-recovery of $211,599,981.

Q. How does this amount compare to DEF's estimated 2017 ending balance included in the Company's Actual/Estimated Filing?

A. The actual true-up amount attributable to the January 2017 - December

2017 period is an under-recovery of $211,599,981 which is $16,096,208 higher than the re-projected year end under-recovery balance of $195,503,774.

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 $16,096,208 shown on your Exhibit No. __(CAM-1T)?

A. The $16.1 million primarily consists of approximately $11.1 million in replacement power costs associated with the Bartow Combined Cycle Plant which is discussed below, and an approximate $3.5 million adjustment coal inventory from the semi-annual aerial surveys.

Q. Please explain the components shown on Exhibit No. __(CAM-1T), sheet 6 of 6, which helps to explain the $4.2 million favorable 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 <u>amount</u> (MWH's) of energy required; (2) changes in the <u>heat rate</u> of generated energy (BTU's per kWh); and (3) changes in the <u>unit price</u> of either fuel consumed for generation ($ per million BTU) or energy purchases and sales (cents per kWh). The $4.2 million favorable system variance is mainly attributable to a shift from coal to natural gas generation driven primarily by favorable natural gas pricing.

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.

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

A. Yes. DEF included an adjustment of approximately $3.5 million to coal inventory attributable to the semi-annual aerial surveys conducted on May 26, 2017 and October 31, 2017 in accordance with Docket No. 19970001-EI, Order No. PSC-1997-0359-FOF-EI. This adjustment represents 1.13% of the total coal consumed at the Crystal River facility in 2017.

Q. On February 9, 2017, an outage occurred at the Bartow Combined Cycle Plant. Did DEF incur any replacement power costs as a result of this outage?

A. Yes. DEF incurred retail replacement power costs of approximately $11.0 million (approximately $11.1 million system). Consistent with the Stipulated Resolution to Issue 1B in Docket No. 20170001-EI, DEF excluded these costs for ratemaking purposes in the 2017 Actual/Estimated Filing. DEF has included these costs in its Final 2017 True-Up balance.

Q. Did DEF exceed the economy sales threshold in 2017?

A. No. DEF did not exceed the gain on economy sales threshold of $3.0 million in 2017. As reported on Schedule A1-2, Line 11a, the gain for the year-to-date period through December 2017 was $0.9 million. This entire amount was returned to customers through a reduction of total fuel and net purchased power expense recovered through the fuel clause.

Q. Has the three-year rolling average gain on economy sales included in the Company's filing for the October 2017 hearings been updated to incorporate actual data for all of year 2017?

A. Yes. DEF has calculated its three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2015 through 2017, as follows:

Year	Actual Gain
2015	$3,720,655
2016	$ 843,842
2017	$ 887,370

Three-Year Average $1,817,289

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 2017 for capacity cost recovery?

A. The actual ending balance as of December 31, 2017 for true-up purposes is an under-recovery of $4,775,185.

Q. How does this amount compare to the estimated 2017 ending balance included in the Company's Actual/estimated Filing?

A. When the estimated 2017 under-recovery of $5,121,339 is compared to the $4,775,185 actual under-recovery, the final capacity true-up for the twelve month period ended December 2017 is an over-recovery of $346,154.

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 over-recovery of $0.3 million?

A. Exhibit No. __(CAM-2T, sheet 1 of 3) compares actual results to the original projection for the period. The $0.3 million over-recovery is primarily due to lower than estimated costs.

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

A. Yes.

Docket No.	20180001-EI
Witness:	Menendez
Exh bit No.	(CAM-1T)
	Sheet 1 of 6

Duke Energy Florida, LLC
Fuel Adjustment Clause
Summary of Actual True-Up Amount
January 2017 - December 2017

Line No.	Description	Contribution to Over/(Under) Recovery Period to Date
	KWH Sales:	
1	Jurisdictional kWh Sales - Difference	(1,190,023,086)
2	Non-Jurisdictional kWh Sales - Difference	45,719,405
3	Total System kWh Sales - Difference Schedule A2, pg 1 of 2, line B3	(1,144,303,681)
	System:	
4	Fuel and Net Purchased Power Costs - Difference Schedule A2, page 2 of 2, line C4	$ 99,801,251
	Jurisdictional:	
5	Fuel Revenues - Difference Schedule A2, page 2 of 2, line C3	($52,856,450)
6	Fuel and Net Purchased Power Costs - Difference Schedule A2, page 2 of 2, line C6 - C12 - C7	98,137,882
7	True-Up Amount for the Period	(150,994,332)
8	True-Up for the Prior Period Schedule A2, page 2 of 2, line C9	(58,893,511)
9	Interest Provision Schedule A2, page 2 of 2, line C8	(1,712,138)
10	Actual True-Up Ending Balance for the Period January 2017 through December 2017 Schedule A2, page 2 of 2, line C13	(211,599,981)
11	Estimated True-Up Ending Balance for the Period included in the Filing of Levelized Fuel Cost Factors per DEF's 2017 Settlement as approved in Order No. PSC-2017-0451-AS-EU	(195,503,774)
12	Total True-Up for the Period January 2017 through December 2017	$ (16,096,208)

Docket No. 20180001-EI
Witness: Menendez
Exhibit No. (CAM-1T)
Sheet 2 of 6

Duke Energy Florida, LLC
Fuel Adjustment Clause
Calculation of Actual True-up
January 2017 - December 2017

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 98,838,811	$ 84,184,731	$ 90,419,035	$ 100,319,245	$ 117,216,767	$ 115,354,960	$ 606,333,548
	2	Fuel Cost of Power Sold	(1,882,944)	(1,085,989)	(1,485,156)	(2,599,179)	(5,577,691)	(3,537,241)	(16,168,199)
	3	Fuel Cost of Purchased Power	2,642,216	2,786,384	9,274,000	16,392,106	16,766,208	13,971,663	61,832,577
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	13,627,016	12,466,965	10,563,523	8,178,273	13,530,431	12,874,239	71,240,448
	4	Energy Cost of Economy Purchases	199,213	441,004	1,462,753	2,688,774	396,680	407,730	5,596,154
	5	Adjustments to Fuel Cost	(559,468)	510	790	590	720	740	(556,118)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	112,864,845	98,793,605	110,234,944	124,979,810	142,333,115	139,072,092	728,278,410
B	1	Jurisdictional MWH Sales	2,574,798	2,691,028	2,573,592	2,850,311	3,163,946	3,525,452	17,379,127
	2	Non-Jurisdictional MWH Sales	24,148	13,668	20,372	16,964	25,999	26,298	127,450
	3	TOTAL SALES (Lines B1 + B2)	2,598,947	2,704,696	2,593,964	2,867,275	3,189,945	3,551,751	17,506,577
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.07%	99.49%	99.21%	99.41%	99.18%	99.26%	99.27%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	92,072,964	95,990,883	91,338,422	102,241,284	115,189,445	129,207,442	626,040,440
	2	True-Up Provision	(2,184,805)	(2,184,805)	(2,184,805)	(2,184,805)	(2,184,805)	(2,184,805)	(13,108,830)
	2a	Incentive Provision	(187,952)	(187,952)	(187,952)	(187,952)	(187,952)	(187,952)	(1,127,712)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	89,700,207	93,618,126	88,965,665	99,868,527	112,816,688	126,834,685	611,803,898
	4	Fuel & Net Power Transactions (Line A6)	112,864,845	98,793,605	110,234,944	124,979,810	142,333,115	139,072,092	728,278,410
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	111,859,928	98,399,842	109,486,576	124,381,581	141,324,089	138,197,566	723,649,581
	6	Over/(Under) Recovery (Line 3 - Line 5)	(22,159,722)	(4,781,716)	(20,520,911)	(24,513,054)	(28,507,401)	(11,362,882)	(111,845,684)
	7	Interest Provision	(58,010)	(61,737)	(77,201)	(103,035)	(121,356)	(152,728)	(574,067)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(22,217,732)	(4,843,452)	(20,598,111)	(24,616,089)	(28,628,757)	(11,515,610)	(112,419,751)
	9	Plus: Prior Period Balance	(85,111,174)	(85,111,174)	(85,111,174)	(85,111,174)	(85,111,174)	(85,111,174)	(85,111,174)
	10	Plus: Cumulative True-Up Provision	2,184,805	4,369,611	6,554,416	8,739,221	10,924,025	13,108,830	13,108,830
	11	Subtotal Prior Period True-up	(82,926,369)	(80,741,564)	(78,556,758)	(76,371,954)	(74,187,149)	(72,002,344)	(72,002,344)
	12	Regulatory Accounting Adjustment	0	0	0	0	0	0	-
	13	TOTAL TRUE-UP BALANCE	($105,144,101)	(107,802,748)	($126,216,054)	($148,647,338)	($175,091,291)	($184,422,095)	(184,422,095)

Docket No. 20180001-EI
Witness: Menendez
Exhibit No. (CAM-1T)
Sheet 3 of 6

Duke Energy Florida, LLC
Fuel Adjustment Clause
Calculation of Actual True-up
January 2017 - December 2017

			JUL ACTUAL	AUG ACTUAL	SEPT ACTUAL	OCT ACTUAL	NOV ACTUAL	DEC ACTUAL	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 124,162,571	$ 127,338,432	$ 110,420,006	$ 119,206,550	$ 81,876,751	$ 86,219,596	$ 1,255,557,454
	2	Fuel Cost of Power Sold	(4,863,580)	(6,365,135)	(5,032,752)	(3,845,835)	(1,885,545)	(1,994,681)	(40,155,727)
	3	Fuel Cost of Purchased Power	16,350,234	16,171,544	20,289,746	9,357,230	9,602,906	6,228,677	139,832,913
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	13,609,946	13,564,330	9,337,870	12,499,847	13,049,646	12,600,939	145,903,025
	4	Energy Cost of Economy Purchases	445,625	314,515	1,436,881	348,553	1,020,859	258,603	9,421,190
	5	Adjustments to Fuel Cost	3,974,796	690	630	670	480	(448,969)	2,972,180
	6	TOTAL FUEL & NET POWER TRANSACTIONS	153,679,592	151,024,376	136,452,380	137,567,014	103,665,097	102,864,166	1,513,531,035
		(Sum of Lines A1 Through A5)							
B	1	Jurisdictional MWH Sales	3,794,213	3,816,545	3,808,830	3,339,022	3,119,978	2,766,298	38,024,013
	2	Non-Jurisdictional MWH Sales	20,630	26,450	24,001	22,482	15,043	20,112	256,168
	3	TOTAL SALES (Lines B1 + B2)	3,814,843	3,842,995	3,832,831	3,361,503	3,135,022	2,786,410	38,280,181
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.46%	99.31%	99.37%	99.33%	99.52%	99.28%	99.33%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	140,134,644	141,043,490	140,647,336	122,137,865	112,589,658	99,770,028	1,382,363,462
	2	True-Up Provision	(2,184,805)	(2,184,805)	(2,184,805)	(2,184,805)	(2,184,805)	(2,184,805)	(26,217,661)
	2a	Incentive Provision	(187,952)	(187,952)	(187,952)	(187,952)	(187,952)	(187,952)	(2,255,422)
	3	FUEL REVENUE APPLICABLE TO PERIOD	137,761,887	138,670,733	138,274,579	119,765,108	110,216,901	97,397,271	1,353,890,379
		(Sum of Lines C1 Through C2a)							
	4	Fuel & Net Power Transactions (Line A6)	153,679,592	151,024,376	136,452,380	137,567,014	103,665,097	102,864,166	1,513,531,033
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	153,020,913	150,150,287	135,744,594	136,798,358	103,283,052	102,237,922	1,504,884,707
	6	Over/(Under) Recovery (Line 3 - Line 5)	(15,259,026)	(11,479,554)	2,529,986	(17,033,250)	6,933,849	(4,840,652)	(150,994,328)
	7	Interest Provision	(175,682)	(184,111)	(153,595)	(163,811)	(213,043)	(247,829)	(1,712,138)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(15,434,708)	(11,663,665)	2,376,390	(17,197,061)	6,720,807	(5,088,480)	(152,706,466)
	9	Plus: Prior Period Balance	(85,111,174)	(85,111,174)	(85,111,174)	(85,111,174)	(85,111,174)	(85,111,174)	(85,111,174)
	10	Plus: Cumulative True-Up Provision	15,293,635	17,478,440	19,663,245	21,848,051	24,032,856	26,217,661	26,217,661
	11	Subtotal Prior Period True-up	(69,817,539)	(67,632,734)	(65,447,929)	(63,263,124)	(61,078,318)	(58,893,513)	(58,893,513)
	12	Regulatory Accounting Adjustment	0	0	0	0	0	0	-
	13	TOTAL TRUE-UP BALANCE	($197,671,999)	($207,150,859)	($202,589,663)	($217,601,919)	($208,696,307)	($211,599,981)	(211,599,981)

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

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 98,838,811	$ 84,184,731	$ 90,419,035	$ 100,319,245	$ 117,216,767	$ 115,354,960	$ 606,333,548
	2	Fuel Cost of Power Sold	(1,882,943)	(1,085,989)	(1,485,156)	(2,599,179)	(5,577,691)	(3,537,241)	(16,168,199)
	3	Fuel Cost of Purchased Power	2,642,216	2,786,384	9,274,000	16,392,106	16,766,208	13,971,663	61,832,577
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	13,627,016	12,466,965	10,563,523	8,178,273	13,530,431	12,874,239	71,240,448
	4	Energy Cost of Economy Purchases	199,213	441,004	1,462,753	2,688,774	396,680	407,730	5,596,154
	5	Adjustments to Fuel Cost	(559,468)	510	790	590	720	740	(556,118)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	112,864,845	98,793,605	110,234,944	124,979,810	142,333,115	139,072,092	728,278,410
B	1	Jurisdictional MWH Sales	2,574,799	2,691,028	2,573,592	2,850,311	3,163,946	3,525,452	17,379,127
	2	Non-Jurisdictional MWH Sales	24,148	13,668	20,372	16,964	25,999	26,298	127,450
	3	TOTAL SALES (Lines B1 + B2)	2,598,947	2,704,696	2,593,964	2,867,275	3,189,945	3,551,751	17,506,577
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.07%	99.49%	99.21%	99.41%	99.18%	99.26%	99.27%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	92,072,964	95,990,883	91,338,422	102,241,284	115,189,445	129,207,442	626,040,440
	2	True-Up Provision	(2,184,805)	(2,184,805)	(2,184,805)	(2,184,805)	(2,184,805)	(2,184,805)	(13,108,830)
	2a	Incentive Provision	(187,952)	(187,952)	(187,952)	(187,952)	(187,952)	(187,952)	(1,127,712)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	89,700,207	93,618,126	88,965,665	99,868,527	112,816,688	126,834,685	611,803,898
	4	Fuel & Net Power Transactions (Line A6)	112,864,845	98,793,605	110,234,944	124,979,810	142,333,115	139,072,092	728,278,410
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	111,859,928	98,399,842	109,486,576	124,381,581	141,324,089	138,197,566	723,649,581
	6	Over/(Under) Recovery (Line 3 - Line 5)	(22,159,721)	(4,781,715)	(20,520,910)	(24,513,054)	(28,507,401)	(11,362,882)	(111,845,683)
	7	Interest Provision	(58,010)	(61,737)	(77,201)	(103,035)	(121,356)	(152,728)	(574,067)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(22,217,731)	(4,843,452)	(20,598,111)	(24,616,089)	(28,628,757)	(11,515,610)	(112,419,750)
	9	Plus: Prior Period Balance	(85,111,174)	(85,111,174)	(85,111,174)	(85,111,174)	(85,111,174)	(85,111,174)	(85,111,174)
	10	Plus: Cumulative True-Up Provision	2,184,805	4,369,610	6,554,415	8,739,220	10,924,025	13,108,830	13,108,830
	11	Subtotal Prior Period True-up	(82,926,369)	(80,741,564)	(78,556,759)	(76,371,954)	(74,187,149)	(72,002,344)	(72,002,344)
	12	Regulatory Accounting Adjustment	0	0	0	0	0	0	-
	13	TOTAL TRUE-UP BALANCE	($105,144,101)	($107,802,748)	($126,216,054)	($148,647,338)	($175,091,291)	($184,422,095)	(184,422,095)

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

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 122,167,999	$ 123,430,300	$ 115,546,389	$ 110,831,232	$ 97,938,315	$ 104,930,710	$ 1,281,178,493
	2	Fuel Cost of Power Sold	(3,267,945)	(3,214,844)	(2,358,978)	(1,872,394)	(1,400,106)	(1,847,163)	(30,129,628)
	3	Fuel Cost of Purchased Power	10,540,983	9,783,222	8,926,178	10,176,086	5,986,568	1,345,450	108,591,064
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	13,947,559	13,779,054	13,202,773	11,422,607	11,236,172	13,571,718	148,400,332
	4	Energy Cost of Economy Purchases	144,049	187,883	167,214	290,334	176,634	113,827	6,676,095
	5	Adjustments to Fuel Cost	(11,038,768)	0	0	0	0	0	(11,594,886)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	132,493,877	143,965,614	135,483,577	130,847,866	113,937,583	118,114,542	1,503,121,470
B	1	Jurisdictional MWH Sales	3,748,227	3,925,489	3,834,611	3,532,857	2,973,199	2,815,326	38,208,836
	2	Non-Jurisdictional MWH Sales	22,314	24,303	21,286	18,065	12,988	17,475	243,881
	3	TOTAL SALES (Lines B1 + B2)	3,770,541	3,949,792	3,855,897	3,550,922	2,986,187	2,832,801	38,452,717
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.41%	99.38%	99.45%	99.49%	99.57%	99.38%	99.37%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	137,183,799	143,671,512	140,345,419	129,301,319	108,818,046	103,039,931	1,388,400,466
	2	True-Up Provision	(2,184,805)	(2,184,805)	(2,184,805)	(2,184,805)	(2,184,805)	(2,184,805)	(26,217,660)
	2a	Incentive Provision	(187,952)	(187,952)	(187,952)	(187,952)	(187,952)	(187,949)	(2,255,421)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	134,811,042	141,298,755	137,972,662	126,928,562	106,445,289	100,667,177	1,359,927,385
	4	Fuel & Net Power Transactions (Line A6)	132,493,877	143,965,614	135,483,577	130,847,866	113,937,583	118,114,542	1,503,121,470
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	131,859,681	143,233,269	134,889,324	130,326,344	113,574,713	117,513,700	1,495,046,613
	6	Over/(Under) Recovery (Line 3 - Line 5)	2,951,361	(1,934,514)	3,083,338	(3,397,782)	(7,129,424)	(16,846,523)	(135,119,228)
	7	Interest Provision	(154,576)	(152,418)	(150,202)	(148,607)	(151,350)	(159,811)	(1,491,031)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	2,796,785	(2,086,932)	2,933,136	(3,546,388)	(7,280,774)	(17,006,335)	(136,610,260)
	9	Plus: Prior Period Balance	(85,111,174)	(85,111,174)	(85,111,174)	(85,111,174)	(85,111,174)	(85,111,174)	(85,111,174)
	10	Plus: Cumulative True-Up Provision	15,293,635	17,478,440	19,663,245	21,848,050	24,032,855	26,217,660	26,217,660
	11	Subtotal Prior Period True-up	(69,817,539)	(67,632,734)	(65,447,929)	(63,263,124)	(61,078,319)	(58,893,514)	(58,893,514)
	12	Regulatory Accounting Adjustment	0	0	0	0	0	0	-
	13	TOTAL TRUE-UP BALANCE	($179,440,505)	($179,342,633)	($174,224,692)	($175,586,275)	($180,682,244)	($195,503,774)	(195,503,774)

Duke Energy Florida, LLC
Fuel Adjustment Clause
Fuel and Net Power Cost Variance Analysis
January 2017 - December 2017

	(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	10,290,533	(1,964,485)	(1,772,687)	6,553,361
3	Coal	(52,403,376)	1,860,169	10,654,436	(39,888,772)
4	Gas	41,682,846	13,652,158	(47,620,632)	7,714,372
5	Nuclear	0	0	0	0
6	Other Fuel	0	0	0	0
7	Total Generation	(429,997)	13,547,842	(38,738,884)	(25,621,039)
8	Firm Purchases	30,685,242	0	556,607	31,241,849
9	Economy Purchases	2,755,970	0	(10,876)	2,745,095
10	Schedule E Purchases	0	0	0	0
11	Qualifying Facilities	(4,665,339)	0	2,168,033	(2,497,307)
12	Total Purchases	28,775,873	0	2,713,764	31,489,637
13	Economy Sales	0	0	0	0
14	Other Power Sales	(2,280)	0	(12,013)	(14,293)
15	Supplemental Sales	(6,402,809)	0	(3,608,995)	(10,011,804)
16	Total Sales	(6,405,089)	0	(3,621,008)	(10,026,097)
17	Total Fuel and Net Power Cost Variance	21,940,788	13,547,842	(39,646,129)	(4,157,500)

Duke Energy Florida, LLC
Capacity Cost Recovery Clause
Summary of Actual True-Up Amount
January 2017 - December 2017

Line No.	Description	Actual	Actual/Estimated Filing	Variance
	Jurisdictional:			
1	Capacity Cost Recovery Revenues Sheet 2 of 3, Line 42	$ 433,168,496	$ 433,744,489	$ (575,993)
2	Capacity Cost Recovery Expenses Sheet 2 of 3, Line 38	440,123,535	441,059,303	(935,768)
3	Plus/(Minus) Interest Provision Sheet 2 of 3, Line 45	(23,204)	(9,582)	(13,622)
4	Sub-Total Current Period Over/(Under) Recovery Sheet 2 of 3, Line 46	$ (6,978,242)	$ (7,324,397)	$ 346,154
5	Prior Period True-up - January through December 2016 - Over/(Under) Recovery Sheet 2 of 3, Line 47	16,868,292	16,868,292	-
6	Prior Period True-up - January through December 2016 - (Refunded)/Collected Sheet 2 of 3, Line 48	(14,665,234)	(14,665,234)	-
7	Actual True-Up Ending Balance Over/(Under) Recovery for the Period January through December 2017 Sheet 2 of 3, Line 50	$ (4,775,185)	$ (5,121,339)	$ 346,154
8	Estimated True-Up Ending Balance for the Period Included in the Filing of Levelized Fuel Cost Factors January through December 2018 per Order No. PSC-2018-0028-FOF-EI (Sheet 3 of 3, Line 50)	(5,121,339)		
9	Total Over/(Under) Recovery for the Period January through December 2017 (Line 7 - Line 8)	346,154		

REDACTED

Docket No.	20180001-EI
Witness:	Menendez
Exhibit No.	(CAM-2T)
	Sheet 2 of 3

Duke Energy Florida, LLC
Capacity Cost Recovery Clause
Calculation of Actual True-Up
January 2017 - December 2017

		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	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	60,858,765
3	Orlando Cogen Limited (ORLACOGL)	5,102,804	5,102,804	5,102,804	5,102,804	5,089,383	5,094,138	5,096,530	5,099,746	5,097,899	4,988,662	5,015,745	5,023,523	60,916,840
4	Pasco County Resource Recovery (PASCOUNT)	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	21,417,600
5	Pinellas County Resource Recovery (PINCOUNT)	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	50,983,200
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	6,733,888	6,656,139	6,675,150	6,669,159	6,662,563	6,900,122	6,965,675	6,965,675	6,965,675	6,965,675	6,965,675	6,965,675	82,091,070
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	1,097,143	646,573	648,924	678,961	684,116	705,834	719,623	750,224	765,134	751,969	754,931	755,868	8,959,300
8	US EcoGen	0	0	0	(3,000)	(90,000)	(93,000)	(90,000)	(93,000)	(93,000)	(90,000)	(93,000)	(90,000)	(735,000)
9	Calpine Osprey	92,394	0	0	0	0	0	0	0	0	0	0	0	92,394
10	Subtotal - Base Level Capacity Costs	24,131,193	23,510,479	23,531,842	23,552,887	23,451,026	23,712,058	23,796,792	23,827,608	23,840,671	23,721,270	23,748,315	23,760,029	284,584,168
11	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%	
12	Base Level Jurisdictional Capacity Costs	22,414,258	21,837,709	21,857,551	21,877,099	21,782,485	22,024,945	22,103,650	22,132,273	22,144,407	22,033,501	22,058,622	22,069,503	264,336,004
13	**Intermediate Production Level Capacity Costs**													
14	Southern Franklin	4,485,507	4,630,269	2,673,583	2,669,458	2,955,813	6,057,918	6,236,165	6,252,703	4,638,320	2,750,085	2,698,716	3,488,522	49,537,060
15	Schedule H Capacity Sales - NSB, RCID & Tallahassee	0	0	0	0	0	0	(73,253)	0	0	(75,671)	(6,305)	(37,835)	(193,065)
16	Subtotal - Intermediate Level Capacity Costs	4,485,507	4,630,269	2,673,583	2,669,458	2,955,813	6,057,918	6,162,912	6,252,703	4,638,320	2,674,414	2,692,410	3,450,687	49,343,995
17	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%	
18	Intermediate Level Jurisdictional Capacity Costs	3,261,098	3,366,345	1,943,775	1,940,776	2,148,965	4,404,288	4,480,622	4,545,903	3,372,198	1,944,379	1,957,463	2,508,753	35,874,565
19	**Peaking Production Level Capacity Costs**													
20	Shady Hills	1,954,260	1,954,260	1,395,900	1,374,300	1,924,020	3,912,300	3,912,300	3,912,300	1,825,740	1,149,734	1,374,300	1,984,500	26,673,914
21	Vandolah (NSG)	2,924,309	2,889,528	1,965,274	1,943,845	2,795,467	5,785,430	5,768,280	5,707,232	2,712,726	1,918,109	2,015,348	2,943,834	39,369,382
22	Other	-	-	-	-	-	-	-	-	-	-	-	-	
23	Subtotal - Peaking Level Capacity Costs	4,878,569	4,843,788	3,361,174	3,318,145	4,719,487	9,697,729.55	9,680,580	9,619,532	4,538,466	3,067,843	3,389,648	4,928,334	66,043,296
24	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%	
25	Peaking Level Jurisdictional Capacity Costs	4,679,718	4,646,355	3,224,173	3,182,897	4,527,121	9,302,450	9,286,000	9,227,440	4,353,478	2,942,798	3,251,486	4,727,455	63,351,371
26	**Other Capacity Costs**													
27	Retail Wheeling	(23,615)	(2,605)	(13,552)	(1,023)	(49,903)	(27)	(9,282)	(6,007)	(3,342)	(4,243)	0	(1,766)	(115,365)
28	RRSSA Second Amendment [1]	[redacted]												
29	Batch-19 Nuclear Fuel [2]													
30	ASC Servicing Fees [3]	-	-	-	-	-	-	(296,269)	-	(160,182)	-	-	-	(456,451)
31	Total Other Capacity Costs	1,768,743	1,785,790	1,770,879	1,779,445	1,726,601	1,772,514	1,463,027	1,758,607	1,597,128	1,752,444	1,638,849	1,633,119	20,447,145
32	**Total Capacity Costs (Line 12+18+25+31)**	32,123,817	31,636,198	28,796,378	28,780,217	30,185,172	37,504,197	37,333,298	37,664,224	31,467,211	28,673,122	28,906,420	30,938,830	384,009,086
33	**Nuclear Cost Recovery Clause**													
34	CR3 Uprate Costs	4,459,192	4,431,769	4,404,346	4,376,920	4,349,497	4,322,073	4,294,649	4,267,226	4,239,801	4,212,377	4,184,953	4,157,530	51,700,333
35	**Total Recoverable Nuclear Costs**	4,459,192	4,431,769	4,404,346	4,376,920	4,349,497	4,322,073	4,294,649	4,267,226	4,239,801	4,212,377	4,184,953	4,157,530	51,700,333
36														
37	**ISFSI Revenue Requirement** [4]	-	-	-	-	-	-	724,926	726,807	728,105	735,486	747,111	751,681	4,414,116
38	**Total Recov Capacity & Nuclear Costs (Line 32+35+37)**	36,583,010	36,067,968	33,200,724	33,157,137	34,534,669	41,826,271	42,352,873	42,658,257	36,435,117	33,620,985	33,838,484	35,848,041	440,123,535
39	**Capacity Revenues:**													
40	Capacity Cost Recovery Revenues (net of tax)	28,519,282	29,627,699	28,061,262	31,308,667	35,187,257	38,498,070	41,592,488	41,953,532	41,807,961	36,803,224	34,335,381	30,808,440	418,503,263
41	Prior Period True-Up Provision Over/(Under) Recovery	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	14,665,233
42	Current Period CCR Revenues (net of tax)	29,741,384	30,849,802	29,283,365	32,530,770	36,409,359	39,720,172	42,814,591	43,175,635	43,030,063	38,025,327	35,557,484	32,030,543	433,168,496
43	**True-Up Provision**													
44	True-Up Provision - Over/(Under) Recov (Line 42-38)	(6,841,625)	(5,218,166)	(3,917,359)	(626,367)	1,874,691	(2,106,098)	461,718	517,378	6,594,946	4,404,342	1,719,000	(3,817,498)	(6,955,039)
45	Interest Provision for the Month	7,805	3,244	(128)	(2,766)	(3,217)	(4,786)	(7,065)	(7,661)	(4,569)	(1,419)	19	(2,658)	(23,204)
46	Current Cycle Balance - Over/(Under)	(6,833,820)	(12,048,743)	(15,966,230)	(16,595,364)	(14,723,890)	(16,834,773)	(16,380,120)	(15,870,403)	(9,280,027)	(4,877,104)	(3,158,085)	(6,978,242)	(6,978,242)
47	Prior Period Balance - Over/(Under) Recovered	16,868,292	15,646,189	14,424,086	13,201,983	11,979,880	10,757,777	9,535,675	8,313,572	7,091,469	5,869,366	4,647,263	3,425,160	16,868,292
48	Prior Period Cumulative True-Up Collected/(Refunded)	(1,222,103)	(1,222,103)	(1,222,103)	(1,222,103)	(1,222,103)	(1,222,103)	(1,222,103)	(1,222,103)	(1,222,103)	(1,222,103)	(1,222,103)	(1,222,103)	(14,665,234)
49	Prior Period True-up Balance - Over/(Under)	15,646,189	14,424,086	13,201,983	11,979,880	10,757,777	9,535,675	8,313,572	7,091,469	5,869,366	4,647,263	3,425,160	2,203,058	2,203,058
50	**Net Capacity True-up Over/(Under) (Line 46+49)**	$8,812,368	$2,375,343	($2,764,247)	($4,615,483)	($3,966,112)	($7,299,099)	($8,066,548)	($8,778,934)	($3,410,661)	($229,841)	$267,075	($4,775,185)	($4,775,185)

[1] Approved in Commission Order No. PSC-16-0138-FOF-EI
[2] Approved in Commission Order No. PSC-15-0465-S-EI
[3] Approved in Commission Order No. PSC-15-0537-FOF-EI
[4] Approved in Commission Order No. PSC-16-0425-PAA-EI

REDACTED

Docket No. 20180001-EI
Witness: Menendez
Exhibit No. (CAM-2T)

Duke Energy Florida, LLC
Capacity Cost Recovery Clause
Calculation of Actual/Estimated True-Up
January 2017 - December 2017 (Filed July 27, 2017)

		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	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	60,858,764
3	Orlando Cogen Limited (ORLACOGL)	5,102,804	5,102,804	5,102,804	5,102,804	5,089,383	5,094,138	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	61,211,555
4	Pasco County Resource Recovery (PASCOUNT)	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	21,417,600
5	Pinellas County Resource Recovery (PINCOUNT)	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	50,983,200
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	6,733,888	6,656,139	6,675,150	6,669,159	6,662,563	6,900,122	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	82,091,068
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	1,097,143	646,573	648,924	678,961	684,116	705,834	800,946	800,946	800,946	800,946	800,946	800,946	9,267,226
8	US EcoGen	-	-	-	(3,000)	(90,000)	(93,000)	-	-	-	-	-	-	(186,000)
9	Calpine Osprey	92,394	-	-	-	-	-	-	-	-	-	-	-	92,394
10	Subtotal - Base Level Capacity Costs	24,131,193	23,510,479	23,531,842	23,552,887	23,451,026	23,712,058	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	285,735,807
11	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%	
12	Base Level Jurisdictional Capacity Costs	22,414,258	21,837,709	21,857,551	21,877,099	21,782,485	22,024,945	22,268,609	22,268,609	22,268,609	22,268,609	22,268,609	22,268,609	265,405,704
13	**Intermediate Production Level Capacity Costs**													
14	Southern Franklin	4,485,507	4,630,269	2,673,583	2,669,458	2,955,813	6,057,918	6,260,918	6,260,918	4,623,002	2,712,100	2,712,100	3,531,058	49,572,645
15	Schedule H Capacity Sales - NSB & RCID	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Subtotal - Intermediate Level Capacity Costs	4,485,507	4,630,269	2,673,583	2,669,458	2,955,813	6,057,918	6,260,918	6,260,918	4,623,002	2,712,100	2,712,100	3,531,058	49,572,645
17	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%	
18	Intermediate Level Jurisdictional Capacity Costs	3,261,098	3,366,345	1,943,775	1,940,776	2,148,965	4,404,288	4,551,875	4,551,875	3,361,061	1,971,778	1,971,778	2,567,185	36,040,800
19	**Peaking Production Level Capacity Costs**													
20	Shady Hills	1,954,260	1,954,260	1,395,900	1,374,300	1,924,020	3,912,300	3,856,015	3,856,015	1,799,474	1,354,816	1,354,816	1,955,104	26,691,280
21	Vandolah (NSG)	2,924,309	2,889,528	1,965,274	1,943,845	2,795,467	5,785,430	5,539,623	5,495,150	2,629,977	1,937,310	1,981,783	2,788,227	38,675,923
22	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Subtotal - Peaking Level Capacity Costs	4,878,569	4,843,788	3,361,174	3,318,145	4,719,487	9,697,730	9,395,638	9,351,165	4,429,451	3,292,126	3,336,599	4,743,331	65,367,203
24	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%	
25	Peaking Level Jurisdictional Capacity Costs	4,679,718	4,646,355	3,224,173	3,182,897	4,527,121	9,302,450	9,012,672	8,970,012	4,248,907	3,157,939	3,200,600	4,549,993	62,702,836
26	**Other Capacity Costs**													
27	Retail Wheeling	(23,615)	(2,605)	(13,552)	(1,023)	(49,903)	(27)	(24,689)	(20,202)	(4,376)	(2,342)	(12,596)	(17,124)	(172,054)
28	RRSSA Second Amendment [1]	[redacted]												
29	Batch-19 Nuclear Fuel [2]													
30	ASC Servicing Fees [3]							(296,269)						(296,269)
31	Total Other Capacity Costs	1,768,743	1,785,790	1,770,879	1,779,445	1,726,601	1,772,514	1,447,620	1,744,413	1,756,275	1,754,346	1,740,128	1,674,699	20,721,452
32	**Total Capacity Costs (Line 12+18+25+31)**	32,123,817	31,636,198	28,796,378	28,780,217	30,185,172	37,504,198	37,280,776	37,534,909	31,634,852	29,152,673	29,181,116	31,060,484	384,870,792
33	**Nuclear Cost Recovery Clause**													
34	CR3 Uprate Costs	4,459,192	4,431,769	4,404,346	4,376,920	4,349,497	4,322,073	4,294,649	4,267,226	4,239,801	4,212,377	4,184,953	4,157,530	51,700,333
35	**Total Recoverable Nuclear Costs**	4,459,192	4,431,769	4,404,346	4,376,920	4,349,497	4,322,073	4,294,649	4,267,226	4,239,801	4,212,377	4,184,953	4,157,530	51,700,333
36														
37	**ISFSI Revenue Requirement [4]**	-	-	-	-	-	-	697,042	710,787	766,141	770,260	771,297	772,653	4,488,180
38	**Total Recov Capacity & Nuclear Costs (Line 32+35+37)**	36,583,010	36,067,967	33,200,724	33,157,137	34,534,669	41,826,271	42,272,467	42,512,921	36,640,795	34,135,309	34,137,366	35,990,667	441,059,303
39	**Capacity Revenues**													
40	Capacity Cost Recovery Revenues (net of tax)	28,519,282	29,627,699	28,061,262	31,308,667	35,187,257	38,498,070	41,005,606	42,944,849	41,950,646	38,649,455	32,526,800	30,799,664	419,079,255
41	Prior Period True-Up Provision Over/(Under) Recovery	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	1,222,103	14,665,234
42	**Current Period Revenues (net of tax)**	29,741,384	30,849,802	29,283,365	32,530,770	36,409,359	39,720,172	42,227,709	44,166,952	43,172,749	39,871,557	33,748,903	32,021,766	433,744,489
43	**True-Up Provision**													
44	True-Up Provision - Over/(Under) Recov (Line 42-38)	(6,841,625)	(5,218,166)	(3,917,359)	(626,366)	1,874,691	(2,106,099)	(44,758)	1,654,030	6,531,954	5,736,248	(388,463)	(3,968,902)	(7,314,815)
45	Interest Provision for the Month	7,805	3,244	(128)	(2,766)	(3,217)	(4,786)	(3,641)	(3,459)	(1,203)	715	31	(2,176)	(9,582)
46	Current Cycle Balance - Over/(Under)	(6,833,820)	(12,048,743)	(15,966,230)	(16,595,363)	(14,723,889)	(16,834,773)	(16,883,172)	(15,232,600)	(8,701,850)	(2,964,887)	(3,353,319)	(7,324,397)	(7,324,397)
47	Prior Period Balance - Over/(Under) Recovered	16,868,292	16,868,292	16,868,292	16,868,292	16,868,292	16,868,292	16,868,292	16,868,292	16,868,292	16,868,292	16,868,292	16,868,292	16,868,292
48	Prior Period Cumulative True-Up Collected/(Refunded)	(1,222,103)	(2,444,206)	(3,666,309)	(4,888,411)	(6,110,514)	(7,332,617)	(8,554,720)	(9,776,823)	(10,998,926)	(12,221,028)	(13,443,131)	(14,665,234)	(14,665,234)
49	Prior Period True-up Balance - Over/(Under)	15,646,189	14,424,086	13,201,983	11,979,880	10,757,777	9,535,675	8,313,572	7,091,469	5,869,366	4,647,263	3,425,160	2,203,058	2,203,058
50	**Net Capacity True-up Over/(Under) (Line 46+49)**	8,812,368	2,375,343	(2,764,247)	(4,615,482)	(3,966,111)	(7,299,099)	(8,569,600)	(8,141,131)	(2,832,483)	1,682,376	71,841	(5,121,339)	(5,121,339)

[1] Approved in Commission Order No. PSC-16-0138-FOF-EI
[2] Approved in Commission Order No. PSC-15-0465-S-EI
[3] Approved in Commission Order No. PSC-15-0537-FOF-EI
[4] Approved in Commission Order No. PSC-16-0425-PAA-EI

DUKE ENERGY FLORIDA, LLC
FUEL AND PURCHASED POWER

DECEMBER 2017

		$				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	FUEL COST OF SYSTEM NET GENERATION (SCH A3)	86,219,596	103,562,549	(17,342,953)	(16.8)	2,656,189	2,873,853	(217,664)	(7.6)	3.2460	3.6036	(0.3576)	(9.9)
2	COAL CAR SALE	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3	ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	(448,969)	0	(448,969)	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4	TOTAL COST OF GENERATED POWER	85,770,627	103,562,549	(17,791,922)	(17.2)	2,656,189	2,873,853	(217,664)	(7.6)	3.2291	3.6036	(0.3745)	(10.4)
5	ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	6,228,677	1,323,796	4,904,881	370.5	170,174	22,509	147,665	656.0	3.6602	5.8813	(2.2211)	(37.8)
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)	258,603	271,115	(12,512)	(4.6)	8,851	6,462	2,389	37.0	2.9217	4.1958	(1.2741)	(30.4)
8	PAYMENTS TO QUALIFYING FACILITIES (SCH A8)	12,600,939	12,408,768	192,172	1.6	284,147	296,037	(11,890)	(4.0)	4.4347	4.1916	0.2431	5.8
9	TOTAL COST OF PURCHASED POWER	19,088,219	14,003,679	5,084,541	36.3	463,172	325,007	138,165	42.5	4.1212	4.3087	(0.1875)	(4.4)
10	TOTAL AVAILABLE MWH					3,119,361	3,198,860	(79,499)	(2.5)				
11	FUEL COST OF OTHER POWER SALES (SCH A6)	(17,395)	(153,818)	136,423	(88.7)	(450)	(5,981)	5,531	(92.5)	3.8656	2.5716	1.2940	50.3
11a	GAIN ON OTHER POWER SALES - 100% (SCH A6)	(222)	(37,441)	37,219	(99.4)	(450)	(5,981)	5,531	(92.5)	0.0493	0.6260	(0.5767)	(92.1)
11b	GAIN ON TOTAL POWER SALES - 20% (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
12	FUEL COST OF STRATIFIED SALES	(1,977,064)	(1,607,290)	(369,774)	23.0	(116,809)	(60,437)	(56,372)	93.3	1.6926	2.6594	(0.9668)	(36.4)
13	TOTAL FUEL COST AND GAINS ON POWER SALES	(1,994,681)	(1,798,549)	(196,132)	10.9	(117,259)	(66,418)	(50,841)	76.6	1.7011	2.7079	(1.0068)	(37.2)
14	NET INADVERTENT AND WHEELED INTERCHANGE					10,729	0	10,729					
15	TOTAL FUEL AND NET POWER TRANSACTIONS	102,864,166	115,767,679	(12,903,513)	(11.2)	3,012,831	3,132,441	(119,611)	(3.8)	3.4142	3.6958	(0.2816)	(7.6)
16	NET UNBILLED	4,517,719	819,600	3,698,119	451.2	(132,321)	(22,177)	(110,145)	496.7	0.1621	0.0279	0.1342	481.0
17	COMPANY USE	695,006	564,890	130,116	23.0	(20,356)	(15,285)	(5,072)	33.2	0.0249	0.0192	0.0057	29.7
18	T & D LOSSES	2,517,725	5,768,700	(3,250,975)	(56.4)	(73,743)	(156,089)	82,347	(52.8)	0.0904	0.1963	(0.1059)	(54.0)
19	ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 2)	102,864,166	115,767,679	(12,903,513)	(11.2)	2,786,410	2,938,890	(152,480)	(5.2)	3.6916	3.9392	(0.2476)	(6.3)
20	WHOLESALE KWH SALES (EXCLUDING STRATIFIED SALES)	(740,622)	(683,029)	(57,593)	8.4	(20,112)	(17,436)	(2,676)	15.4	3.6825	3.9174	(0.2349)	(6.0)
21	JURISDICTIONAL KWH SALES	102,123,544	115,084,650	(12,961,106)	(11.3)	2,766,298	2,921,454	(155,156)	(5.3)	3.6917	3.9393	(0.2476)	(6.3)
22	JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.00112	102,237,922	115,130,684	(12,892,761)	(11.2)	2,766,298	2,921,454	(155,156)	(5.3)	3.6958	3.9409	(0.2451)	(6.2)
23	PRIOR PERIOD TRUE-UP	2,184,805	2,184,808	(3)	0.0	2,766,298	2,921,454	(155,156)	(5.3)	0.0790	0.0748	0.0042	5.6
24	TOTAL JURISDICTIONAL FUEL COST	104,422,727	117,315,492	(12,892,764)	(11.0)	2,766,298	2,921,454	(155,156)	(5.3)	3.7748	4.0157	(0.2409)	(6.0)
25	REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
26	FUEL COST ADJUSTED FOR TAXES									3.7775	4.0186	(0.2411)	(6.0)
27	GPIF	187,952	187,949			2,766,298	2,921,454			0.0068	0.0064	0.0004	6.3
28	TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									3.784	4.025	(0.241)	(6.0)

*Line 15a. MWH Data for Infomational Purposes Only

Docket No.	20180001-EI
Witness:	Menendez
Exhibit No.	(CAM-3T)
Schedule	A1-2
	Sheet 2 of 9

DUKE ENERGY FLORIDA, LLC
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
YEAR TO DATE - DECEMBER 2017

		$				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	FUEL COST OF SYSTEM NET GENERATION (SCH A3)	1,255,557,454	1,221,838,538	33,718,916	2.8	36,107,656	37,020,131	(912,475)	(2.5)	3.4773	3.3005	0.1768	5.4
2	COAL CAR SALE	(42,303)	0	(42,303)	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3	ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	3,014,483	0	3,014,483	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4	TOTAL COST OF GENERATED POWER	1,258,529,634	1,221,838,538	36,691,096	3.0	36,107,656	37,020,131	(912,475)	(2.5)	3.4855	3.3005	0.1850	5.6
5	ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	139,832,913	73,811,326	66,021,587	89.5	3,145,889	1,760,693	1,385,196	78.7	4.4449	4.1922	0.2527	6.0
6	ENERGY COST OF SCH C,X ECONOMY PURCH - BROKER (SCH A9)	32,448	0	32,448	0.0	1,242	0	1,242	0.0	2.6126	0.0000	2.6126	0.0
7	ENERGY COST OF ECONOMY PURCH - NON-BROKER (SCH A9)	9,388,742	4,417,649	4,971,093	112.5	244,911	97,274	147,637	151.8	3.8335	4.5415	(0.7080)	(15.6)
8	PAYMENTS TO QUALIFYING FACILITIES (SCH A8)	145,903,025	140,596,014	5,307,011	3.8	3,235,494	3,329,832	(94,338)	(2.8)	4.5095	4.2223	0.2872	6.8
9	TOTAL COST OF PURCHASED POWER	295,157,127	218,824,989	76,332,138	34.9	6,627,536	5,187,798	1,439,737	27.8	4.4535	4.2181	0.2354	5.6
10	TOTAL AVAILABLE MWH					42,735,191	42,207,929	527,263	1.3				
11	FUEL COST OF OTHER POWER SALES (SCH A6)	(2,729,825)	(2,516,281)	(213,544)	8.5	(70,215)	(82,705)	12,490	(15.1)	3.8878	3.0425	0.8453	27.8
11a	GAIN ON OTHER POWER SALES - 100% (SCH A6)	(887,370)	(612,488)	(274,882)	44.9	(70,215)	(82,705)	12,490	(15.1)	1.2638	0.7406	0.5232	70.7
11b	GAIN ON TOTAL POWER SALES - 20% (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
12	FUEL COST OF STRATIFIED SALES	(36,538,531)	(23,804,974)	(12,733,557)	53.5	(1,939,897)	(956,306)	(983,591)	102.9	1.8835	2.4893	(0.6058)	(24.3)
13	TOTAL FUEL COST AND GAINS ON POWER SALES	(40,155,726)	(26,933,743)	(13,221,983)	49.1	(2,010,112)	(1,039,011)	(971,102)	93.5	1.9977	2.5922	(0.5945)	(22.9)
14	NET INADVERTENT AND WHEELED INTERCHANGE					219,667	0	219,667					
15	TOTAL FUEL AND NET POWER TRANSACTIONS	1,513,531,036	1,413,729,784	99,801,251	7.1	40,944,746	41,168,918	(224,172)	(0.5)	3.6965	3.4340	0.2625	7.6
16	NET UNBILLED	11,138,428	(18,203,083)	29,341,511	(161.2)	(301,322)	465,894	(767,216)	(164.7)	0.0291	(0.0462)	0.0753	(163.0)
17	COMPANY USE	6,137,373	5,388,849	748,524	13.9	(166,031)	(156,000)	(10,031)	6.4	0.0160	0.0137	0.0023	16.8
18	T & D LOSSES	81,220,436	70,543,902	10,676,534	15.1	(2,197,213)	(2,054,328)	(142,886)	7.0	0.2122	0.1789	0.0333	18.6
19	ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 2)	1,513,531,036	1,413,729,784	99,801,251	7.1	38,280,180	39,424,485	(1,144,305)	(2.9)	3.9538	3.5859	0.3679	10.3
20	WHOLESALE KWH SALES (EXCLUDING STRATIFIED SALES)	(10,249,494)	(7,543,808)	(2,705,686)	35.9	(256,168)	(210,449)	(45,719)	21.7	4.0011	3.5846	0.4165	11.6
21	JURISDICTIONAL KWH SALES	1,503,281,542	1,406,185,977	97,095,565	6.9	38,024,012	39,214,036	(1,190,024)	(3.0)	3.9535	3.5859	0.3676	10.3
22	JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.00112	1,504,884,710	1,406,748,451	98,136,259	7.0	38,024,012	39,214,036	(1,190,024)	(3.0)	3.9577	3.5874	0.3703	10.3
23	PRIOR PERIOD TRUE-UP	26,217,663	26,217,663	0	0.0	38,024,012	39,214,036	(1,190,024)	(3.0)	0.0690	0.0669	0.0021	3.1
24	TOTAL JURISDICTIONAL FUEL COST	1,531,102,373	1,432,966,114	98,136,259	6.9	38,024,012	39,214,036	(1,190,024)	(3.0)	4.0267	3.6543	0.3724	10.2
25	REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
26	FUEL COST ADJUSTED FOR TAXES									4.0296	3.6569	0.3727	10.2
27	GPIF	2,255,421	2,255,421			38,024,012	39,214,036			0.0059	0.0058	0.0001	98.3
28	TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									4.036	3.663	0.373	10.2

*Line 15a. MWH Data for Infomational Purposes Only

DUKE ENERGY FLORIDA, LLC
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2017

		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	$86,219,596	103,562,549	($17,342,953)	(16.8)	$1,255,557,454	$1,221,838,538	$33,718,916	2.8
1a.	COAL CAR SALE	-	0	0	0.0	(42,303)	0	(42,303)	0.0
2 .	FUEL COST OF POWER SOLD	(17,395)	(153,818)	136,423	(88.7)	(2,729,825)	(2,516,281)	(213,544)	8.5
2a.	GAIN ON POWER SALES	(222)	(37,441)	37,219	(99.4)	(887,370)	(612,488)	(274,882)	44.9
3 .	FUEL COST OF PURCHASED POWER	6,228,677	1,323,796	4,904,881	370.5	139,832,913	73,811,326	66,021,587	89.5
3a.	ENERGY PAYMENTS TO QUALIFYING FACILITIES	12,600,939	12,408,768	192,172	1.6	145,903,025	140,596,014	5,307,011	3.8
4 .	ENERGY COST OF ECONOMY PURCHASES	258,603	271,115	(12,512)	(4.6)	9,421,190	4,417,649	5,003,541	113.3
5 .	TOTAL FUEL & NET POWER TRANSACTIONS	105,290,198	117,374,969	(12,084,770)	(10.3)	1,547,055,084	1,437,534,758	109,520,326	7.6
6 .	ADJUSTMENTS TO FUEL COST:								
6a.	FUEL COST OF STRATIFIED SALES	(1,977,064)	(1,607,290)	(369,774)	23.0	(36,538,531)	(23,804,974)	(12,733,557)	53.5
6b.	OTHER- JURISDICTIONAL ADJUSTMENTS (see detail below)	(448,969)	0	(448,969)	0.0	3,014,483	0	3,014,483	0.0
6c.	OTHER - PRIOR PERIOD ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
7 .	ADJUSTED TOTAL FUEL & NET PWR TRNS	$102,864,166	$115,767,679	($12,903,513)	(11.2)	$1,513,531,036	$1,413,729,784	$99,801,251	7.1

FOOTNOTE: DETAIL OF LINE 6b ABOVE

INSPECTION & FUEL ANALYSIS REPORTS {Wholesale Portion}	$0	$0	$0	$0	$0	$0
N/A - Not used	0	0	0	0	0	0
UNIVERSITY OF FLORIDA STEAM REVENUE ALLOCATION {Wholesale Portion}	720	0	720	8,110	0	8,110
N/A - Not used	0	0	0	0	0	0
TANK BOTTOM ADJUSTMENT	0	0	0	(574,531)	0	(574,531)
AERIAL SURVEY ADJUSTMENT (Coal Pile)	(449,689)	0	(449,689)	3,524,567	0	3,524,567
N/A - Not used	0	0	0	0	0	0
N/A - Not used	0	0	0	0	0	0
Gain/Loss on Disposition of Oil	0	0	0	0	0	0
N/A - Not used	0	0	0	0	0	0
NET METER SETTLEMENT	0	0	0	56,336	0	56,336
N/A - Not used	0	0	0	0	0	0
Derivative Collateral Interest	0	0	0	0	0	0
SUBTOTAL LINE 6b SHOWN ABOVE	($448,969)	$0	($448,969)	$3,014,483	$0	$3,014,483

`

		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
B.	KWH SALES								
1 .	JURISDICTIONAL SALES	2,766,298,556	2,921,454,337	(155,155,781)	(5.3)	38,024,012,860	39,214,035,946	(1,190,023,086)	(3.0)
2 .	NON JURISDICTIONAL (WHOLESALE) SALES	20,112,154	17,436,000	2,676,154	15.4	256,168,405	210,449,000	45,719,405	21.7
3 .	TOTAL SALES	2,786,410,710	2,938,890,337	(152,479,627)	(5.2)	38,280,181,265	39,424,484,946	(1,144,303,681)	(2.9)
4 .	JURISDICTIONAL SALES % OF TOTAL SALES	99.28	99.41	(0.13)	(0.1)	99.33	99.47	(0.14)	(0.1)

DUKE ENERGY FLORIDA, LLC
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2017

		CURRENT MONTH				YEAR TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
C.	TRUE UP CALCULATION								
1 .	JURISDICTIONAL FUEL REVENUE	$99,770,028	$106,924,200	($7,154,173)	(6.7)	$1,382,363,462	$1,435,219,912	($52,856,450)	(3.7)
2 .	ADJUSTMENTS:	0	0	0	0.0	0	0	0	0.0
2a.	TRUE UP PROVISION	(2,184,805)	(2,184,808)	3	0.0	(26,217,663)	(26,217,663)	0	0.0
2b.	INCENTIVE PROVISION	(187,952)	(187,949)	(3)	0.0	(2,255,421)	(2,255,421)	0	0.0
3 .	TOTAL JURISDICTIONAL FUEL REVENUE	97,397,271	104,551,443	(7,154,173)	(6.8)	1,353,890,378	1,406,746,828	(52,856,450)	(3.8)
4 .	ADJ TOTAL FUEL & NET PWR TRNS (LINE A7)	102,864,166	115,767,679	(12,903,513)	(11.2)	1,513,531,036	1,413,729,784	99,801,251	7.1
5 .	JURISDICTIONAL SALES % OF TOT SALES (LINE B4)	99.28	99.41	(0.13)	(0.1)	0.00	99.47	(99.47)	(100.0)
6 .	JURISDICTIONAL FUEL & NET POWER TRANSACTIONS (LINE C4 * LINE C5 * 1.00112 LOSS MULTIPLIER)	102,237,922	115,130,684	(12,892,761)	(11.2)	1,504,884,710	1,406,748,451	98,136,259	7.0
7 .	TRUE UP PROVISION FOR THE MONTH OVER/(UNDER) COLLECTION (LINE C3 - C6)	(4,840,652)	(10,579,240)	5,738,589	(54.2)	(150,994,332)	(1,623)	(150,992,710)	9,304,830.0
8 .	INTEREST PROVISION FOR THE MONTH (LINE D10)	(247,829)	1,299	(249,127)	(19,185.7)	(1,712,138)	(44,060)	(1,668,077)	3,785.9
9 .	TRUE UP & INTEREST PROVISION BEG OF MONTH/PERIOD	(208,696,306)	8,347,451	(217,043,757)	(2,600.1)	(85,111,174)	(26,217,663)	(58,893,511)	224.6
10.	TRUE UP COLLECTED (REFUNDED)	2,184,805	2,184,808	(3)	0.0	26,217,663	26,217,663	0	0.0
11.	END OF PERIOD TOTAL NET TRUE UP (LINES C7 + C8 + C9 + C10)	(211,599,981)	(45,683)	(211,554,298)	463,091.7	(211,599,981)	(45,683)	(211,554,298)	463,091.7
12.	OTHER:	0				0		0	
13.	END OF PERIOD TOTAL NET TRUE UP (LINES C11 + C12)	($211,599,981)	(45,683)	(211,554,298)	463,091.7	($211,599,981)	(45,683)	(211,554,298)	463,091.7

D.	INTEREST PROVISION				
1 .	BEGINNING TRUE UP (LINE C9)	($208,696,306)	N/A	--	--
2 .	ENDING TRUE UP (LINES C7 + C9 + C10 + C12)	(211,352,153)	N/A	--	--
3 .	TOTAL OF BEGINNING & ENDING TRUE UP	(420,048,459)	N/A	--	--
4 .	AVERAGE TRUE UP (50% OF LINE D3)	(210,024,229)	N/A	--	--
5 .	INTEREST RATE - FIRST DAY OF REPORTING MONTH	1.250	N/A	--	--
6 .	INTEREST RATE - FIRST DAY OF SUBSEQUENT MONTH	1.580	N/A	--	--
7 .	TOTAL (LINE D5 + LINE D6)	2.830	N/A		
8 .	AVERAGE INTEREST RATE (50% OF LINE D7)	1.415	N/A	--	--
9 .	MONTHLY AVERAGE INTEREST RATE (LINE D8/12)	0.118	N/A	--	--
10.	INTEREST PROVISION (LINE D4 * LINE D9)	($247,829)	N/A	--	--

N O T

A-3 Generating System Comparative Data Report

Duke Energy Florida, LLC

Docket No.	20180001-EI
Witness:	Menendez
Exhibit No.	(CAM-3T)
Schedule:	A3-1
	Sheet 5 of 9

FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
NET GENERATION ($)				
1 - HEAVY OIL	0	0	0	0.0%
2 - LIGHT OIL	13,616,153	4,039,261	9,576,892	237.1%
3 - COAL	313,055,107	310,853,337	2,201,770	0.7%
4 - GAS	928,886,194	906,945,940	21,940,254	2.4%
5 - NUCLEAR	0	0	0	0.0%
6	0	0	0	0.0%
7	0	0	0	0.0%
8 - TOTAL ($)	1,255,557,454	1,221,838,538	33,718,916	2.8%
SYSTEM NET GENERATION (MWH)				
9 - HEAVY OIL	0	0	0	0.0%
10 - LIGHT OIL	62,216	529	61,687	11,661.0%
11 - COAL	8,722,203	10,286,213	(1,564,010)	(15.2%)
12 - GAS	27,307,533	26,700,835	606,698	2.3%
13 - NUCLEAR	0	0	0	0.0%
14 - SOLAR	15,705	32,556	(16,851.00)	(51.8)%
15	0	0	0	0.0%
16 - TOTAL (MWH)	36,107,657	37,020,133	(912,476)	(2.5%)
UNITS OF FUEL BURNED				
17 - HEAVY OIL (BBL)	0	0	0	0.0%
18 - LIGHT OIL (BBL)	136,260	25,422	110,838	436.0%
19 - COAL (TON)	4,023,166	4,707,761	(684,595)	(14.5%)
20 - GAS (MCF)	213,729,336	201,883,140	11,846,196	5.9%
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	828,727	148,078	680,649	459.7%
26 - COAL	90,926,387	106,890,768	(15,964,381)	(14.9%)
27 - GAS	218,296,120	201,883,140	16,412,980	8.1%
28 - NUCLEAR	0	0	0	0.0%
29	0	0	0	0.0%
30	0	0	0	0.0%
31 - TOTAL (MILLION BTU)	310,051,234	308,921,986	1,129,248	0.4%

A-3 Generating System Comparative Data Report

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	0.00	0.2	11958.2%
34 - COAL	24.2	27.79	(3.6)	(13.1%)
35 - GAS	75.6	72.13	3.5	4.9%
36 - NUCLEAR	0.0	0.00	0.0	0.0%
37 - SOLAR	0.04	0.09	(0.04)	(50.54)%
38	0.0	0.00	0.0	0.0%
39 - TOTAL (% MWH)	100.0	100.0	0.0	0.0%
FUEL COST PER UNIT ($)				
40 - HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.0%
41 - LIGHT OIL ($/BBL)	99.93	158.89	(58.96)	(37.1%)
42 - COAL ($/TON)	77.81	66.03	11.78	17.8%
43 - GAS ($/MCF)	4.35	4.49	(0.15)	(3.3%)
44 - NUCLEAR ($/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 ($/MILLION BTU)				
47 - HEAVY OIL	0.00	0.00	0.00	0.0%
48 - LIGHT OIL	16.43	27.28	(10.85)	(39.8%)
49 - COAL	3.44	2.91	0.53	18.4%
50 - GAS	4.26	4.49	(0.24)	(5.3%)
51 - NUCLEAR	0.00	0.00	0.00	0.0%
52	0.00	0.00	0.00	0.0%
53	0.00	0.00	0.00	0.0%
54 - SYSTEM ($/MBTU)	4.05	3.96	0.09	2.4%
BTU BURNED PER KWH (BTU/KWH)				
55 - HEAVY OIL	0	0	0	0.0%
56 - LIGHT OIL	13,320	279,921	(266,600)	(95.2%)
57 - COAL	10,425	10,392	33	0.3%
58 - GAS	7,994	7,561	433	5.7%
59 - NUCLEAR	0	0	0	0.0%
60	0	0	0	0.0%
61	0	0	0	0.0%
62 - SYSTEM (BTU/KWH)	8,587	8,345	242	2.8%

A-3 Generating System Comparative Data Report

Duke Energy Florida, LLC

Docket No. 20180001-EI
Witness: Menendez
Exhibit No. (CAM-3T)
Schedule: A3-3
Sheet 7 of 9

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	21.89	763.57	(741.68)	(97.1%)
65 - COAL	3.59	3.02	0.57	18.8%
66 - GAS	3.40	3.40	0.00	0.1%
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)	3.48	3.30	0.18	5.4%

Duke Energy Florida, LLC
Schedule A6
Power Sold for the Month of
December 2017

(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		5,981		5,981	2.572	3.198	153,818.00	191,259.00	37,441.00
ACTUAL									
Tampa Electric Company	CR-1	450	0	450	3.866	5.071	17,395.22	22,821.50	5,426.28
PJM Settlements	MR-1	0	0	0	0.000	0.000	0.00	23.11	23.11
Tampa Electric Company		0	0	0	0.000	0.000	0.00	(5,227.60)	(5,227.60)
Subtotal - Gain on Other Power Sales		450	0	450	3.866	3.915	17,395.22	17,617.01	221.79
CURRENT MONTH TOTAL		450		450	3.866	3.915	17,395.22	17,617.01	221.79
DIFFERENCE		(5,531)		(5,531)	1.294	0.717	(136,422.78)	(173,641.99)	(37,219.21)
DIFFERENCE %		(92)		(92)	50.296	22.417	(88.69)	(90.79)	(99.41)
CUMULATIVE ACTUAL		70,215		70,215	3.888	5.152	2,729,823.98	3,617,194.63	887,370.65
CUMULATIVE ESTIMATED		82,704		82,704	3.043	3.783	2,516,281.00	3,128,769.00	612,488.00
DIFFERENCE		(12,489)		(12,489)	0.845	1.369	213,542.98	488,425.63	274,882.65
DIFFERENCE %		(15)		(15)	27.783	36.174	8.49	15.61	44.88

REDACTED

Duke Energy Florida, LLC
Schedule A12 - Capacity Costs
For the Period January - December 2017

Docket No. 20180001-EI
Witness: Menendez
Exhibit No. (CAM-3T)
Schedule A12
Sheet 9 of 9

	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	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	5,071,564	60,858,765
2	Orlando Cogen Limited (ORLACOGL)	QF	79.20	9/1/93 - 12/31/23	5,102,804	5,102,804	5,102,804	5,102,804	5,089,383	5,094,138	5,096,530	5,099,746	5,097,899	4,988,662	5,015,745	5,023,523	60,916,840
3	Pasco County Resource Recovery (PASCOUNT)	QF	23.00	1/1/95 - 12/31/24	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	1,784,800	21,417,600
4	Pinellas County Resource Recovery (PINCOUNT)	QF	54.75	1/1/95 - 12/31/24	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	4,248,600	50,983,200
5	Polk Power Partners, L.P. (MULBERRY)	QF	115.00	8/1/94 - 8/8/24	6,733,888	6,656,139	6,675,150	6,669,159	6,662,563	6,900,122	6,965,675	6,965,675	6,965,675	6,965,675	6,965,675	6,965,675	82,091,070
6	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	QF	39.60	8/1/94 - 12/31/23	1,097,143	646,573	648,924	678,961	684,116	705,834	719,623	750,224	765,134	751,969	754,931	755,868	8,959,300
7	Southern purchase - Franklin	Other	425	6/1/16 - 5/31/21	4,485,507	4,630,269	2,673,583	2,669,458	2,955,813	6,057,918	6,236,165	6,252,703	4,638,320	2,750,085	2,698,716	3,488,522	49,537,060
8	Retail Wheeling				(23,615)	(2,605)	(13,552)	(1,023)	(49,903)	(27)	(9,282)	(6,007)	(3,342)	(4,243)	0	(1,766)	(115,365)
9	CR-3 Projected Expense				4,459,192	4,431,769	4,404,346	4,376,920	4,349,497	4,322,073	4,294,649	4,267,226	4,239,801	4,212,377	4,184,953	4,157,530	51,700,333
10	ISFSI Return				0	0	0	0	0	0	724,926	726,807	728,105	735,486	747,111	751,681	4,414,116
11	ASC Servicing Fee				0	0	0	0	0	0	(296,269)	0	(160,182)	0	0	0	(456,451)
	SUBTOTAL				32,959,883	32,569,913	30,596,218	30,601,242	30,796,432	34,185,023	34,836,981	35,161,337	33,376,374	31,504,974	31,472,095	32,245,996	390,306,468

Confidential Capacity Contracts (Aggregated):

Purchases/Sales (Net)	MW	Contracts	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
Vandolah Capacity - Northern Star		6/1/12-5/31/27	2,924,309	2,889,528	1,965,274	1,943,845	2,795,467	5,785,430	5,768,280	5,707,232	2,712,726	1,918,109	2,015,348	2,943,834	39,369,382
Schedule H Capacity Sales-City of Tallahassee	-1	on-going no term date	0	0	0	0	0	0	(73,253)	0	0	(75,671)	(6,305)	(37,835)	(193,065)
Shady Hills Tolling	517	4/1/07-4/30/24	1,954,260	1,954,260	1,395,900	1,374,300	1,924,020	3,912,300	3,912,300	3,912,300	1,825,740	1,149,734	1,374,300	1,984,500	26,673,914
EcoGen			0	0	0	(3,000)	(90,000)	(93,000)	(90,000)	(93,000)	(93,000)	(90,000)	(93,000)	(90,000)	(735,000)
Calpine Osprey	515	Oct-14 to Jan-17	92,394	0	0	0	0	0	0	0	0	0	0	0	92,394
RRSSA Second Amendment [1]			[redacted]												
Batch-19 Nuclear Fuel [2]															
	1031														
Total			39,723,203	39,202,095	35,741,824	35,696,855	37,202,424	45,562,294	46,122,885	46,452,483	39,582,491	36,163,833	36,401,286	38,681,380	476,533,054

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

Docket No.	20180001-EI
Witness:	Menendez
Exhibit 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 2017 through June 2017

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost
Common Equity	$4,664,905	46.35%	10.50%	4.87%
Preferred Stock	0	0.00%	0.00%	0.00%
Long Term Debt	3,327,189	33.06%	5.47%	1.81%
Short Term Debt	373,704	3.71%	0.58%	0.02%
Customer Deposits - Active	182,948	1.82%	2.30%	0.04%
Customer Deposits - Inactive	1,367	0.01%	0.00%	0.00%
Deferred Tax	1,674,675	16.64%	0.00%	0.00%
Deferred Tax (FAS 109)	(161,369)	-1.60%	0.00%	0.00%
ITC	223	0.00%	0.00%	0.00%
	$10,063,642	100.00%		6.74%

Total Debt	1.87%
Total Equity	4.87%

* May 2016 DEF Surveillance Report capital structure and cost rates.
Reference: Docket Nos. 120001-EG, 120002-EI, 120007-EI, PSC Order No. 12-0425-PAA-EU, page 8.
Included for Informational purposes only. DEF 2017 True-Up Filing does not currently include a capital return component.

Duke Energy Florida, LLC
Capital Structure and Cost Rates Applied to Capital Projects
Estimated for the Period of : July 2017 through December 2017

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

Total Debt	2.02%
Total Equity	4.70%

* May 2017 DEF Surveillance Report capital structure and cost rates.
Reference: Docket Nos. 120001-EG, 120002-EI, 120007-EI, PSC Order No. 12-0425-PAA-EU, page 8.
Included for Informational purposes only. DEF 2017 True-Up Filing does not currently include a capital return component.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFFREY SWARTZ

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 20180001-EI

MARCH 2, 2018

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 cause of the L-0 blade failure is [redacted]. After investigation, the RCA Team determined that [redacted] both in the remainder of Duke Energy Corporation's ("Duke Energy") ST fleet and elsewhere in the industry. Therefore, 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. 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).

Q: Is the RCA considered confidential by the Company?

A: Yes. The RCA and portions of my testimony discussing the RCA's findings are confidential due to the ongoing claims process with the blades' manufacturer and the potential for insurance claims. In order to protect these rights, this information has been treated by the Company as proprietary confidential business information and has not been made publicly available.

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.

REDACTED

Q. Please describe the RCA Team's conclusio

A. The DEF RCA Team determined that the root cause of the failures in the ST L-0 40" blades is [redacted]

Notwithstanding the alternative causes hypothesized by the OEM, [redacted]

Q. Did the RCA Team consider alternative potential root causes?

A. Yes, DEF evaluated potential factors in the operation of the unit as well as specific design factors unique to these blades, each of which was ultimately rejected as the cause of the fifth failure and as the overall cause of all five failures. [redacted]

Q. Why did the RCA Team reject these theories?

A. The detailed rationale for rejecting these competing theories are contained in the RCA, but in general (and with the exception of the [redacted] DEF was unable to find a correlation between any of the individual factors and the blades' failures. However, it should be noted that DEF [redacted]

Q. What restoration process did DEF follow to bring the Bartow ST back into 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. DEF is currently in the process of evaluating potential long-term solutions to the L-0 blade issue.

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. Does that conclude your testimony?

A. Yes.

REDACTED

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

REDACTED

February 6, 2018

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

REDACTED

February 6, 2018

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

REDACTED

February 6, 2018

[redacted]

REDACTED

February 6, 2018

[redacted]

REDACTED

[redacted]

REDACTED

February 6, 2018

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

REDACTED

February 6, 2018

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

REDACTED

February 6, 2018

[redacted]

REDACTED

February 6, 2018

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

REDACTED

[redacted]

[redacted]

[redacted]

[redacted]

REDACTED

[redacted]

REDACTED

February 6, 2018

[redacted]

[redacted]

[redacted]

[redacted]

REDACTED

February 6, 2018

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

REDACTED

February 6, 2018

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

REDACTED

February 6, 2018

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

[redacted]