DUKE ENERGY.
FLORIDA

Matthew R. Bernier
ASSOCIATE GENERAL COUNSEL

July 27, 2021

VIA ELECTRONIC FILING

Adam J. 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. 20210001-EI*

Dear Mr. Teitzman:

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

- DEF's Petition for Approval of Fuel Cost Recovery and Capacity Cost Recovery Actual/Estimated True-Up for the Period January 2021 Through December 2021;
- Direct Testimony of Gary P. Dean and Exhibit No. __ (GPD-2, Parts 1 and 2); and
- Direct Testimony of Joseph Simpson and Exhibit No ____(JS-1) and Exhibit No. ___(JS-2).

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
Attachments

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchase Power Cost Recovery Clause with Generating Performance Incentive Factor	: : :	DOCKET NO. 20210001-EI Filed: July 27, 2021

PETITION FOR APPROVAL OF FUEL COST RECOVERY AND CAPACITY COST RECOVERY ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2021 THROUGH DECEMBER 2021

Duke Energy Florida, LLC ("DEF") hereby petitions the Commission for approval of its actual/estimated Fuel and Purchased Power Cost Recovery True-Up of $169,535,467 under-recovery and approval of its actual/estimated Capacity Cost Recovery true-up of $9,797,053 over-recovery for the period January 2021 through December 2021. In support of this petition, DEF states the following:

1. By Order No. PSC-99-2512-FOF-EI, dated December 22, 1999, utilities are directed to file current year estimated true-up data at least 90 days prior to each annual Fuel and Capacity Cost Recovery hearing. The hearing in this docket is scheduled for November 2 through 4, 2021.

2. The actual/estimated under-recovery $169,535,467 in the fuel cost recovery for the period January 2021 through December 2021 was calculated in accordance with the methodology set forth in Schedule 1, attached to Order 10093, dated June 19, 1981. It is based on actual data for the period January 2021 through June 2021 and re-estimated data for the period July 2021 through December 2021. The supporting documentation is contained in the prepared direct testimony and exhibits of DEF witness Gary P. Dean which is being filed together with this Petition.

3. The actual/estimated $9,797,053 over-recovery for the period January 2021 through December 2021 was calculated in accordance with the methodology set forth in Order No. 25773 dated February 24, 1992. It is based on actual data for the period January 2021 through June 2021 and re-estimated data for the period July 2021 through December 2021. The supporting

documentation is contained in the prepared direct testimony and exhibits of DEF witness Gary P. Dean.

WHEREFORE, Duke Energy Florida, LLC respectfully requests the Commission:

1. Approve the $169,535,467 under-recovery as the actual/estimated fuel cost recovery true-up amount for the period January 2021 through December 2021.
2. Approve the $9,797,053 over-recovery as the actual/estimated capacity cost recovery true-up amount for the period January 2021 through December 2021.

Respectfully,

s/ Matthew R. Bernier

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Attorneys for Duke Energy Florida, LLC

CERTIFICATE OF SERVICE

Docket No. 20210001-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 27th day of July 2021.

s/ Matthew R. Bernier
Attorney

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DUKE ENERGY FLORIDA, LLC
DOCKET NO. 20210001-EI

Fuel and Capacity Cost Recovery
Actual/Estimated True-Up Amounts
January 2021 through December 2021

DIRECT TESTIMONY OF
GARY P. DEAN

July 27, 2021

Q. Please state your name and business address.

A. My name is Gary P. Dean. My business address is 299 1st Avenue North, St. Petersburg, Florida 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 20210001-EI?

A. Yes. I provided direct testimony on April 1, 2021.

Q: Has your job description, education, background and professional experience changed since that time?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the actual/estimated fuel and capacity cost recovery true-up amounts of Duke

Energy Florida, LLC ("DEF" or the "Company") for the period of January 2021 through December 2021.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared Exhibit No.__ (GPD-2), which is attached to my prepared testimony, consisting of two parts. Part 1 consists of Schedules E1-B through E9, which include the calculation of the 2021 actual/estimated fuel and purchased power true-up balance, and a schedule to support the capital structure components and cost rates relied upon to calculate the return requirements on all capital projects recovered through the fuel clause as required per Order No. PSC-2020-0165-PAA-EU. Part 2 consists of Schedules E12-A through E12-C, which include the calculation of the 2021 actual/estimated capacity true-up balance. The calculations in my exhibit are based on actual data from January through June 2021 and estimated data from July through December 2021.

FUEL COST RECOVERY

Q. What is the amount of DEF's 2021 estimated fuel true-up balance and how was it developed?

A. DEF's estimated fuel true-up balance is a $169,535,467 under-recovery. The calculation begins with the actual under-recovered balance of $105,928,013 taken from Schedule A2, page 2 of 2, line 13, for the month of June 2021. This balance plus the estimated July through

December 2021 monthly true-up calculations comprise the estimated $169,535,467 under-recovered balance at year-end. The increase in the currently projected 2021 under-recovery is primarily due to sizable increases in natural gas prices. DEF will continue to monitor natural gas prices and update its 2021 forecast and true-up balance in its 2022 projection filing. The projected December 2021 true-up balance includes interest which is estimated from July through December 2021 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.5% per month.

Q. DEF filed a Petition for a Mid-course Correction on July 9, 2021 in this Docket. Did DEF incorporate the proposed Mid-course Correction into the 2021 Actual/Estimated Filing?

A. Yes. The Total True-Up Balance of $169,535,467 shown on Exhibit GPD-2, Schedule E1-B, Line 13, Page 2 of 2, incorporates the recovery of the requested Midcourse Correction of $39,503,838, beginning in October 2021, as shown on Exhibit GPD-2, Schedule E1-B-1, Line 22. The $39,503,838 is the difference between the $61,083,424 and $21,579,587 on Exhibit GPD-1T, Sheet 1 of 6, in DEF's 2020 FAC True-Up filed on April 1, 2021 in the instant docket. If the Commission were to approve DEF's requested Midcourse adjustment to become effective with September 2021 billing, DEF will incorporate that impact into the Schedule E1-B to be filed with DEF's 2022 Projection Filing on September 3rd.

Q. How does the current forecast of fuel costs on Schedule E3 for July through December 2021 compare with the same period forecast used in the Company's 2021 Projection Filing approved in Order No. PSC-2021-0024-FOF-EI?

A. Light oil decreased $0.74/mmbtu (-4%). Coal and natural gas increased $0.13/mmbtu (5%) and $0.62/mmbtu (15%), respectively.

Q. Have any adjustments been made to estimated fuel costs for the period January through December 2021?

A. Yes. Consistent with Order No. PSC-2018-0240-PAA-EQ dated June 8, 2018, DEF included an adjustment of approximately $13.15 million (grossed up to approximately $13.20 million from retail to system) for the amortization of Florida Power Development, LLC qualifying facility regulatory asset from January 2021 through December 2021. This adjustment is included on Schedule E1-B, line A5, columns Jan Actual through Dec Estimated. DEF also included an adjustment of approximately $1.94 million to coal inventory attributable to the semi-annual aerial survey conducted on May 4, 2021 in accordance with Order No. PSC-1997-0359-FOF-EI in Docket No. 1997001-EI.

Q: Has DEF made an adjustment to remove the replacement power costs associated with the Spring 2021 unplanned outage at Crystal River Unit 4?

A: No. As detailed in the direct testimony of Joseph Simpson, DEF's actions were prudent and therefore no adjustment has been made.

Q. Does DEF expect to exceed the three-year rolling average gain on non-separated power sales in 2021?

A. No. DEF estimates the total gain on non-separated sales during 2021 will be $1,420,960 which does not exceed the three-year rolling average of $1,714,254.

CAPACITY COST RECOVERY

Q. What is DEF's 2021 estimated capacity true-up balance and how was it developed?

A. DEF's estimated capacity true-up balance is an $9,797,053 over-recovery. The estimated true-up calculation begins with the actual under-recovered balance of $16,368,856 as of June 2021. This balance plus the estimated July through December 2021 monthly true-up calculations comprise the estimated $9,797,053 over-recovered balance at year-end. The projected December 2021 true-up balance includes interest which is estimated from July through December 2021 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.5% per month.

Q. What are the primary drivers of the estimated year-end 2021 capacity over-recovery?

A. The $9.8 million over-recovery is primarily attributable to the $6.5 million 2020 Capacity Cost Recovery Clause net over-recovery filed on April 1, 2021 in the instant docket.

Q. Does this conclude your testimony?

A. Yes.

Docket No. 20210001-EI
Exhibit No. ____(GPD-2)
Part 1

Duke Energy Florida, LLC

Fuel Cost Recovery

Actual / Estimated True-Up

January through December 2021

Duke Energy Florida, LLC
Calculation of Estimated True-Up
6 Months Actual and 6 Months Estimated
January 2021 - December 2021

			Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	6 Month Sub-Total
A	1	Fuel Cost of System Generation	$ 91,130,395	$ 89,669,082	$ 92,086,502	$ 91,479,028	$ 116,809,348	$ 123,000,789	$ 604,175,144
	2	Fuel Cost of Power Sold	(6,980,349)	(2,343,139)	(2,503,060)	(3,313,839)	(8,802,456)	(8,990,972)	(32,933,814)
	3	Fuel Cost of Purchased Power	1,098,076	3,598,830	12,098,754	5,959,317	10,846,159	13,023,594	46,624,731
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	7,548,154	7,301,243	8,097,325	7,109,630	8,508,302	9,152,559	47,717,214
	4	Energy Cost of Economy Purchases	541,456	928,870	1,048,067	1,424,838	4,071,775	3,333,096	11,348,103
	5	Adjustments to Fuel Cost	1,287,414	1,129,037	1,088,154	1,105,338	1,102,029	3,040,212	8,752,184
	6	TOTAL FUEL & NET POWER TRANSACTIONS	94,625,147	100,283,924	111,915,742	103,764,312	132,535,158	142,559,279	685,683,562
		(Sum of Lines A1 Through A5)							
B	1	Jurisdictional mWh Sales	2,883,089	2,745,686	2,893,186	2,950,824	3,156,781	3,692,154	18,321,720
	2	Non-Jurisdictional mWh Sales	17	15,027	1,840	1,128	1,780	19,330	39,122
	3	TOTAL SALES (Lines B1 + B2)	2,883,105	2,760,713	2,895,026	2,951,952	3,158,561	3,711,484	18,360,842
	4	Jurisdictional % of Total Sales (Line B1/B3)	100.00%	99.46%	99.94%	99.96%	99 94%	99.48%	99.79%
C	1	Jurisdictional Fuel Recovery Revenue	87,983,471	83,155,269	87,192,862	89,476,925	96,745,142	114,558,977	559,112,646
		(Net of Revenue Taxes)							
	2	True-Up Provision	5,090,285	5,090,285	5,090,285	5,090,285	5,090,285	5,090,285	30,541,710
	2a	Incentive Provision	(367,309)	(367,309)	(367,309)	(367,309)	(367,309)	(367,309)	(2,203,854)
	3	FUEL REVENUE APPLICABLE TO PERIOD	92,706,447	87,878,245	91,915,838	94,199,901	101,468,118	119,281,953	587,450,502
		(Sum of Lines C1 Through C2a)							
	4	Fuel & Net Power Transactions (Line A6)	94,625,147	100,283,924	111,915,742	103,764,312	132,535,158	142,559,279	685,683,562
	5	Jurisdictional Total Fuel Costs & Net Power Transactions	94,654,481	99,770,319	111,879,910	103,751,849	132,492,725	141,857,680	684,406,963
		(Line A6 * Line B4 * Line Loss Multiplier)							
	6	Over/(Under) Recovery (Line C3 - Line C5)	(1,948,034)	(11,892,074)	(19,964,072)	(9,551,948)	(31,024,607)	(22,575,727)	(96,956,461)
	7	Interest Provision	1,625	545	(1,197)	(2,785)	(3,010)	(4,605)	(9,427)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(1,946,408)	(11,891,529)	(19,965,269)	(9,554,733)	(31,027,617)	(22,580,331)	(96,965,888)
	9	Plus: Prior Period Balance	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587
	10	Plus: Cumulative True-Up Provision	(5,090,285)	(10,180,570)	(15,270,855)	(20,361,140)	(25,451,425)	(30,541,710)	(30,541,710)
	11	Subtotal Prior Period True-up	16,489,302	11,399,017	6,308,732	1,218,447	(3,871,838)	(8,962,123)	(8,962,123)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	$14,542,893	(2,438,921)	($27,494,475)	($42,139,494)	($78,257,396)	($105,928,013)	(105,928,013)

Duke Energy Florida, LLC
Calculation of Estimated True-Up
6 Months Actual and 6 Months Estimated
January 2021 - December 2021

			Jul Estimated	Aug Estimated	Sep Estimated	Oct Estimated	Nov Estimated	Dec Estimated	12 Month Period
A	1	Fuel Cost of System Generation	$ 133,486,550	$ 143,190,572	$ 127,990,226	$ 111,384,392	$ 96,849,484	$ 102,109,663	$ 1,319,186,031
	2	Fuel Cost of Power Sold	(10,572,747)	(10,358,952)	(9,292,364)	(7,055,021)	(5,879,840)	(3,575,931)	(79,668,669)
	3	Fuel Cost of Purchased Power	6,072,483	10,823,277	2,250,881	869,664	1,101,345	44,981	67,787,362
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	9,763,058	9,797,946	9,371,619	9,289,938	9,245,904	9,687,120	104,872,798
	4	Energy Cost of Economy Purchases	501,507	810,800	289,767	261,448	217,100	272,348	13,701,073
	5	Adjustments to Fuel Cost	1,105,933	1,107,496	1,093,015	1,084,215	1,080,232	1,076,898	15,299,973
	6	TOTAL FUEL & NET POWER TRANSACTIONS	140,356,784	155,371,139	131,703,144	115,834,636	102,614,225	109,615,079	1,441,178,569
		(Sum of Lines A1 Through A5)							
B	1	Jurisdictional mWh Sales	3,826,726	3,928,784	3,863,471	3,601,707	2,990,539	2,830,489	39,363,435
	2	Non-Jurisdictional mWh Sales	41,049	60,583	20,825	2,186	692	1,255	165,711
	3	TOTAL SALES (Lines B1 + B2)	3,867,774	3,989,367	3,884,296	3,603,893	2,991,230	2,831,743	39,529,146
	4	Jurisdictional % of Total Sales (Line B1/B3)	98.94%	98.48%	99.46%	99.94%	99 98%	99.96%	99 58%
C	1	Jurisdictional Fuel Recovery Revenue	118,157,880	121,309,137	119,292,463	126,479,329	105,017,236	99,396,843	1,248,765,535
		(Net of Revenue Taxes)							
	2	True-Up Provision	5,090,285	5,090,285	5,090,285	(8,077,661)	(8,077,661)	(8,077,656)	21,579,592
	2a	Incentive Provision	(367,309)	(367,309)	(367,309)	(367,309)	(367,309)	(367,313)	(4,407,712)
	3	FUEL REVENUE APPLICABLE TO PERIOD	122,880,856	126,032,113	124,015,439	118,034,360	96,572,266	90,951,874	1,265,937,415
		(Sum of Lines C1 Through C2a)							
	4	Fuel & Net Power Transactions (Line A6)	140,356,784	155,371,139	131,703,144	115,834,636	102,614,225	109,615,079	1,441,178,569
	5	Jurisdictional Total Fuel Costs & Net Power Transactions	138,907,885	153,052,340	131,028,625	115,797,550	102,622,428	109,601,913	1,435,417,703
		(Line A6 * Line B4 * Line Loss Multiplier)							
	6	Over/(Under) Recovery (Line C3 - Line C5)	(16,027,029)	(27,020,228)	(7,013,185)	2,236,810	(6,050,162)	(18,650,039)	(169,480,294)
	7	Interest Provision	(5,822)	(7,153)	(8,259)	(8,304)	(7,996)	(8,210)	(55,171)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(16,032,852)	(27,027,381)	(7,021,444)	2,228,506	(6,058,158)	(18,658,249)	(169,535,465)
	9	Plus: Prior Period Balance	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587	21,579,587
	10	Plus: Cumulative True-Up Provision	(35,631,995)	(40,722,280)	(45,812,565)	(37,734,904)	(29,657,243)	(21,579,591)	(21,579,591)
	11	Subtotal Prior Period True-up	(14,052,408)	(19,142,693)	(24,232,978)	(16,155,318)	(8,077,657)	(5)	(5)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($127,051,152)	($159,168,817)	($171,280,547)	($160,974,380)	($158,954,877)	($169,535,467)	(169,535,467)

Duke Energy Florida, LLC
Comparison of Actual/Estimated vs. Projection Filing
of the Fuel and Purchased Power Cost Recovery Factor
Estimated for the Period of : January 2021 hrough December 2021

	DOLLARS				mWh				c/kWh			
	Actual/ Estimated	Projection Filing	Difference Amount	%	Actual/ Estimated	Projection Filing	Difference Amount	%	Actual/ Estimated	Projec ion Filing	Difference Amount	%
1 Fuel Cost of System Net Genera ion (E3)	1,319,186,031	1,194,993,335	124,192,696	10%	40,410,950	40,923,065	(512,115)	-1%	3.264	2.920	0.344	12%
2 Coal Car Investment	-	0	-	0%			-	0%	0.000	0.000	0.000	0%
3 Adjustment to Fuel Cost	15,299,973	13,261,552	2,038,422	0%			-	0%	0.000	0.000	0.000	0%
4 TOTAL COST OF GENERATED POWER	1,334,486,004	1,208,254,887	126,231,118	10%	40,410,950	40,923,065	(512,115)	-1%	3.302	2.953	0.350	12%
5 Energy Cost of Purchased Power	67,787,362	9,333,612	58,453,750	626%	1,139,593	199,674	939,918	471%	5.948	4.674	1.274	27%
(Excl. Econ & Cogens) (E7)												
6 Energy Cost of Economy Purchases (E9)	13,701,073	1,539,353	12,161,720	790%	273,467	38,203	235,264	616%	5.010	4.029	0.981	24%
7 Payments to Qualifying Facili ies (E8)	104,872,798	106,375,724	(1,502,925)	-1%	2,561,888	2,866,788	(304,900)	-11%	4.094	3.711	0.383	10%
8 TOTAL COST OF PURCHASED POWER	186,361,233	117,248,689	69,112,544	59%	3,974,947	3,104,665	870,282	28%	4.688	3.777	0.912	24%
9 TOTAL AVAILABLE mWh (LINE 4 + LINE 8)			-		44,385,897	44,027,729	358,167	1%	0.000	0.000	0.000	0%
10 Fuel Cost of Economy Sales (E6)	(5,497,162)	(7,572,236)	2,075,074	-27%	(213,902)	(213,680)	(222)	0%	2.570	3.544	-0.974	-27%
10a Gain on Economy Sales (E6)	(1,420,960)	(1,920,095)	499,135	-26%	(213,902)	(213,680)	(222)	0%	0.664	0.899	-0.234	-26%
10b Gain on Total Power Sales - 20% (E6)	0	47,511	(47,511)	100%			-	0%	0.000	0.000	0.000	0%
11 Fuel Cost of Stratified Sales (E6)	(72,750,547)	(36,852,618)	(35,897,929)	97%	(2,549,333)	(1,735,681)	(813,652)	47%	2.854	2.123	0.730	34%
12 TOTAL FUEL COST AND GAINS OF POWER SALES	(79,668,669)	(46,297,438)	(33,371,231)	72%	(2,763,234)	(1,949,360)	(813,874)	42%	2.883	2.375	0.508	21%
(LINES 10 + 10a + 10b + 11)												
13 Net Inadvertent Interchange					0	0	-					
14 TOTAL FUEL & NET POWER TRANSACTIONS	1,441,178,569	1,279,206,138	161,972,431	13%	41,622,662	42,078,369	(455,707)	-1%	3.462	3.040	0.422	14%
(LINES 4 + 8 + 12 + 13)												
15 Net Unbilled					338,944	230,366	108,578	47%	0.000	0.000	0.000	0%
16 Company Use					(162,608)	(179,646)	17,038	-9%	0.000	0.000	0.000	0%
17 T & D Losses					(2,377,363)	(2,523,902)	146,539	-6%	0.000	0.000	0.000	0%
18 SYSTEM mWh SALES	1,441,178,569	1,279,206,138	161,972,431	13%	39,529,146	39,605,188	(76,042)	0%	3.646	3.230	0.416	13%
19 Wholesale mWh Sales	(6,165,508)	(558,777)	(5,606,731)	1003%	(165,711)	(17,012)	(148,699)	874%	3.721	3.285	0.436	13%
20 Jurisdictional mWh Sales	1,435,013,061	1,278,647,361	156,365,700	12%	39,363,435	39,588,176	(224,741)	-1%	3.646	3.230	0.416	13%
20a Jurisdictional Loss Multiplier	1.00028	1 00031	-0.00003	0%	1.00028	1.00031	-0.00003	0%				
21 Jurisdictional Sales Adjusted for Line Losses	1,435,417,703	1,279,043,741	156,373,962	12%	39,363,435	39,588,176	(224,741)	-1%	3.647	3.231	0.416	13%
22 TRUE-UP	(21,579,587)	(61,083,424)	39,503,838	-65%	39,363,435	39,588,176	(224,741)	-1%	(0.055)	(0.154)	0.099	-64%
23 TOTAL JURISDICTIONAL FUEL COST	1,413,838,116	1,217,960,318	195,877,799	16%	39,363,435	39,588,176	(224,741)	-1%	3.592	3.077	0.515	17%
24 Revenue Tax Factor	1,017,963	876,931	141,032	16%								
25 Fuel Factor Adjusted for Taxes	1,414,856,080	1,218,837,249	196,018,831	16%	39,363,435	39,588,176	(224,741)	-1%	3.594	3.079	0.516	17%
26 GPIF **	4,407,708	4,407,712	(4)	0%	39,363,435	39,588,176	(224,741)	-1%	0.011	0.011	0.000	1%
27 Fuel Factor Adjusted for Taxes Including GPIF	1,419,263,793	1,223,244,961	196,018,832	16%	39,363,435	39,588,176	(224,741)	-1%	3.606	3.090	0.516	17%
28 FUEL FACTOR ROUNDED TO NEAREST .001 c/kWh									3.606	3.090	0.516	17%

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January 2021 through December 2021

			Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	TOTAL
1	Fuel Cost of System Net Generation		$91,130,395	$89,669,082	$92,086,502	$91,479,028	$116,809,348	$123,000,789	$133,486,550	$143,190,572	$127,990,226	$111,384,392	$96,849,484	$102,109,663	$1,319,186,031
1a	Adjustments to Fuel Cost		1,287,414	1,129,037	1,088,154	1,105,338	1,102,029	3,040,212	1,105,933	1,107,496	1,093,015	1,084,215	1,080,232	1,076,898	15,299,973
2	Fuel Cost of Power Sold		(534,601)	(461,648)	(623,136)	(500,046)	(536,009)	(651,376)	(363,837)	(323,391)	(578,757)	(616,522)	(922,238)	(806,561)	(6,918,122)
2a	Gain on Total Power Sales - 20%		0	0	0	0	0	0	0	0	0	0	0	0	0
2b	Fuel Cost of Stratified Sales		(6,445,748)	(1,881,490)	(1,879,924)	(2,813,792)	(8,266,447)	(8,339,596)	(10,208,910)	(10,035,561)	(8,713,607)	(6,438,499)	(4,957,602)	(2,769,370)	(72,750,547)
3	Fuel Cost of Purchased Power (Excl Economy)		1,098,076	3,598,830	12,098,754	5,959,317	10,846,159	13,023,594	6,072,483	10,823,277	2,250,881	869,664	1,101,345	44,981	67,787,362
3a	Energy Payments to Qualifying Facilities		7,548,154	7,301,243	8,097,325	7,109,630	8,508,302	9,152,559	9,763,058	9,797,946	9,371,619	9,289,938	9,245,904	9,687,120	104,872,798
4	Energy Cost of Economy Purchases		541,456	928,870	1,048,067	1,424,838	4,071,775	3,333,096	501,507	810,800	289,767	261,448	217,100	272,348	13,701,073
5	Total System Fuel & Net Power Transactions		$94,625,147	$100,283,924	$111,915,742	$103,764,312	$132,535,158	$142,559,279	$140,356,784	$155,371,139	$131,703,144	$115,834,636	$102,614,225	$109,615,079	$1,441,178,569
6	Jurisdictional MWH Sold		2,883,089	2,745,686	2,893,186	2,950,824	3,156,781	3,692,154	3,826,726	3,928,784	3,863,471	3,601,707	2,990,539	2,830,489	39,363,435
7	Jurisdictional % of Total Sales		100.00%	99.46%	99.94%	99.96%	99.94%	99.48%	98.94%	98.48%	99.46%	99.94%	99.98%	99.96%	99.58%
8	Jurisdicitonal Fuel & Net Power Transactions		94,625,147	99,742,391	111,848,592	103,722,807	132,455,637	141,817,971	138,869,002	153,009,497	130,991,947	115,765,135	102,593,702	109,571,233	1,435,013,061
9	Jurisdictional Loss Multiplier		1.00031	1.00028	1.00028	1.00028	1.00028	1.00028	1.00028	1.00028	1.00028	1.00028	1.00028	1.00028	1.00028
10	Jurisdictional Fuel & Net Power Transactions		94,654,481	99,770,319	111,879,910	103,751,849	132,492,725	141,857,680	138,907,885	153,052,340	131,028,625	115,797,550	102,622,428	109,601,913	1,435,417,703
11	Adjusted System Sales	MWH	2,883,105	2,760,713	2,895,026	2,951,952	3,158,561	3,711,484	3,867,774	3,989,367	3,884,296	3,603,893	2,991,230	2,831,743	39,529,146
12	System Cost per MWH Sold	c/kwh	3.2821	3.6325	3.8658	3.5151	4.1960	3.8411	3.6289	3.8946	3.3907	3.2142	3.4305	3.8709	3.6459
13	Jurisdictional Loss Multiplier	x	1.00031	1.00028	1.00028	1.00028	1.00028	1.00028	1.00028	1.00028	1.00028	1.00028	1.00028	1.00028	1.00028
14	Jurisdictional Cost per MWH Sold	c/kwh	3.2831	3.6337	3.8670	3.5160	4.1971	3.8421	3.6299	3.8957	3.3915	3.2151	3.4316	3.8722	3.6466
15	Prior Period True-Up	+	-0.0624	-0.0655	-0.0622	-0.0609	-0.0570	-0.0487	-0.0470	-0.0458	-0.0466	-0.0499	-0.0601	-0.0635	-0.0548
16	Total Jurisdictional Fuel Expense	c/kwh	3.2207	3.5682	3.8049	3.4551	4.1401	3.7934	3.5830	3.8499	3.3449	3.1651	3.3714	3.8087	3.5918
17	Revenue Tax Multiplier	x	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
18	Recovery Factor Adjusted for Taxes	c/kwh	3.2230	3.5708	3.8076	3.4576	4.1431	3.7962	3.5855	3.8527	3.3473	3.1674	3.3739	3.8114	3.5943
19	GPIF	+	0.0127	0.0134	0.0127	0.0124	0.0116	0.0099	0.0096	0.0093	0.0095	0.0102	0.0123	0.0130	0.0112
20	Total Recovery Factor (rounded .001)	c/kwh	3.236	3.584	3.820	3.470	4.155	3.806	3.595	3.862	3.357	3.178	3.386	3.824	3.606

Duke Energy Florida, LLC
Generating System Comparative Data by Fuel Type
Estimated for the Period of : January 2021 through December 2021

			Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	LIGHT OIL		1,263,812	6,290,454	1,343,139	1,392,329	2,327,880	1,794,206	14,411,819
2	COAL		8,532,371	13,079,895	12,645,483	20,184,047	19,920,683	18,794,594	93,157,074
3	GAS		81,334,212	70,298,733	78,097,880	69,902,652	94,560,786	102,411,989	496,606,251
4	OTHER		0	0	0	0	0	0	0
5	TOTAL	$	91,130,395	89,669,082	92,086,502	91,479,028	116,809,348	123,000,789	604,175,144
	SYSTEM NET GENERATION (MWH)								
6	LIGHT OIL		2,122	24,482	3,562	2,557	5,598	3,701	42,022
7	COAL		243,140	409,436	383,681	604,649	640,772	632,931	2,914,609
8	GAS		2,738,971	2,056,216	2,350,235	2,221,771	2,808,850	3,160,451	15,336,494
9	SOLAR		48,798	51,160	83,932	96,100	112,135	86,460	478,584
10	OTHER		0	0	0	0	0	0	0
11	TOTAL	MWH	3,033,030	2,541,294	2,821,411	2,925,077	3,567,355	3,883,543	18,771,709
	UNITS OF FUEL BURNED								
12	LIGHT OIL	BBL	9,404	57,675	13,345	11,997	19,082	14,642	126,145
13	COAL	TON	113,514	176,141	178,397	287,457	298,173	294,422	1,348,104
14	GAS	MCF	19,752,154	15,414,666	17,017,842	16,237,530	20,822,673	23,855,826	113,100,691
15	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
16	LIGHT OIL		53,874	331,281	76,577	68,528	109,512	83,960	723,732
17	COAL		2,537,265	3,918,080	3,972,188	6,351,075	6,627,193	6,611,540	30,017,341
18	GAS		20,262,820	15,828,205	17,448,387	16,592,729	21,342,629	24,445,185	115,919,956
19	OTHER		0	0	0	0	0	0	0
20	TOTAL	MMBTU	22,853,960	20,077,566	21,497,151	23,012,332	28,079,334	31,140,686	146,661,029
	GENERATION MIX (% MWH)								
21	LIGHT OIL		0.07%	0.96%	0.13%	0.09%	0.16%	0.10%	0.22%
22	COAL		8.02%	16.11%	13.60%	20.67%	17.96%	16.30%	15.53%
23	GAS		90.31%	80.91%	83.30%	75.96%	78.74%	81.38%	81.70%
24	SOLAR		1.61%	2.01%	2.98%	3.29%	3.14%	2.23%	2.55%
25	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
26	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
27	LIGHT OIL	$/BBL	134.39	109.07	100.65	116.06	121.99	122.54	114.25
28	COAL	$/TON	75.17	74.26	70.88	70.22	66.81	63.84	69.10
29	GAS	$/MCF	4.12	4.56	4.59	4.31	4.54	4.29	4.39
30	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
31	LIGHT OIL		23.46	18.99	17.54	20.32	21.26	21.37	19.91
32	COAL		3.36	3.34	3.18	3.18	3.01	2.84	3.10
33	GAS		4.01	4.44	4.48	4.21	4.43	4.19	4.28
34	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	TOTAL	$/MMBTU	3.99	4.47	4.28	3.98	4.16	3.95	4.12
	BTU BURNED PER KWH (BTU/KWH)								
36	LIGHT OIL		25,393	13,531	21,497	26,799	19,562	22,688	17,223
37	COAL		10,435	9,569	10,353	10,504	10,343	10,446	10,299
38	GAS		7,398	7,698	7,424	7,468	7,598	7,735	7,558
39	OTHER		0	0	0	0	0	0	0
40	TOTAL	BTU/KWH	7,535	7,901	7,619	7,867	7,871	8,019	7,813
	GENERATED FUEL COST PER KWH (C/KWH)								
41	LIGHT OIL		59.57	25.69	37.70	54.45	41.58	48.48	34.30
42	COAL		3.51	3.19	3.30	3.34	3.11	2.97	3.20
43	GAS		2.97	3.42	3.32	3.15	3.37	3.24	3.24
44	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
45	TOTAL	C/KWH	3.00	3.53	3.26	3.13	3.27	3.17	3.22

Duke Energy Florida, LLC
Generating System Comparative Data by Fuel Type
Estimated for the Period of : January 2021 through December 2021

			Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	LIGHT OIL		1,663,875	9,778,647	991,043	757,617	714,159	1,163,759	29,480,919
2	COAL		24,589,314	24,055,111	24,206,487	23,741,618	14,841,841	19,017,885	223,609,330
3	GAS		107,233,361	109,356,814	102,792,696	86,885,157	81,293,484	81,928,019	1,066,095,782
4	OTHER		0	0	0	0	0	0	0
5	TOTAL	$	133,486,550	143,190,572	127,990,226	111,384,392	96,849,484	102,109,663	1,319,186,031
	SYSTEM NET GENERATION (MWH)								
6	LIGHT OIL		6,108	39,054	4,309	2,856	3,115	4,956	102,419
7	COAL		879,851	853,591	845,338	822,432	504,587	659,086	7,479,494
8	GAS		3,156,648	3,257,883	3,055,637	2,510,384	2,252,427	2,198,472	31,767,946
9	SOLAR		110,810	105,000	95,251	100,338	85,549	85,559	1,061,091
10	OTHER		0	0	0	0	0	0	0
11	TOTAL	MWH	4,153,417	4,255,528	4,000,536	3,436,010	2,845,678	2,948,072	40,410,950
	UNITS OF FUEL BURNED								
12	LIGHT OIL	BBL	14,366	100,010	9,117	6,643	6,320	10,907	273,508
13	COAL	TON	385,452	374,663	374,186	365,159	218,055	284,203	3,349,822
14	GAS	MCF	23,651,535	24,581,580	22,587,329	18,565,889	16,333,854	15,211,569	234,032,447
15	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
16	LIGHT OIL		83,683	582,592	53,109	38,678	36,819	63,553	1,582,166
17	COAL		8,969,223	8,699,282	8,634,364	8,395,673	5,027,647	6,559,101	76,302,631
18	GAS		23,651,535	24,581,580	22,587,329	18,565,889	16,333,854	15,211,569	236,851,712
19	OTHER		0	0	0	0	0	0	0
20	TOTAL	MMBTU	32,704,441	33,863,454	31,274,802	27,000,240	21,398,320	21,834,223	314,736,509
	GENERATION MIX (% MWH)								
21	LIGHT OIL		0.15%	0.92%	0.11%	0.08%	0.11%	0.17%	0.25%
22	COAL		21.18%	20.06%	21.13%	23.94%	17.73%	22.36%	18.51%
23	GAS		76.00%	76.56%	76.38%	73.06%	79.15%	74.57%	78.61%
24	SOLAR		2.67%	2.47%	2.38%	2.92%	3.01%	2.90%	2.63%
25	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
26	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
27	LIGHT OIL	$/BBL	115.82	97.78	108.70	114.05	113.00	106.70	107.79
28	COAL	$/TON	63.79	64.20	64.69	65.02	68.06	66.92	66.75
29	GAS	$/MCF	4.53	4.45	4.55	4.68	4.98	5.39	4.56
30	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
31	LIGHT OIL		19.88	16.79	18.66	19.59	0.00	0.00	18.63
32	COAL		2.74	2.77	2.80	2.83	2.95	0.00	2.93
33	GAS		4.53	4.45	4.55	4.68	4.98	5.39	4.50
34	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	TOTAL	$/MMBTU	4.08	4.23	4.09	4.13	4.53	4.68	4.19
	BTU BURNED PER KWH (BTU/KWH)								
36	LIGHT OIL		13,701	14,918	12,324	13,545	11,821	12,824	15,448
37	COAL		10,194	10,191	10,214	10,208	9,964	9,952	10,202
38	GAS		7,493	7,545	7,392	7,396	7,252	6,919	7,456
39	OTHER		0	0	0	0	0	0	0
40	TOTAL	BTU/KWH	7,874	7,958	7,818	7,858	7,520	7,406	7,788
	GENERATED FUEL COST PER KWH (C/KWH)								
41	LIGHT OIL		27.24	25.04	23.00	26.53	22.93	23.48	28.78
42	COAL		2.79	2.82	2.86	2.89	2.94	2.89	2.99
43	GAS		3.40	3.36	3.36	3.46	3.61	3.73	3.36
44	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
45	TOTAL	C/KWH	3.21	3.36	3.20	3.24	3.40	3.46	3.26

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Jul-21

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	451,020	82 8	89 35	92.7	10,189	COAL	197,492 TONS	23.27	4,595,516	12,581,141	2.79
2	CRYSTAL RIVER	5	712	428,831	81 0	92 26	88.3	10,199	COAL	187,960 TONS	23.27	4,373,707	12,008,173	2.80
3	ANCLOTE	1	517	116,343	30 2	92 90	35.1	10,948	GAS	1,273,753 MCF	1.00	1,273,753	5,946,626	5.11
4	ANCLOTE	2	521	131,969	34 0	96.13	35.4	11,562	GAS	1,525,829 MCF	1.00	1,525,829	6,742,936	5.11
5	BARTOW	1-4	228	1,573	1 0	90 00	17.6	13,977	GAS	21,992 MCF	1.00	21,992	99,680	6.34
6	BARTOWCC	1	1279	338,389	35 6	93 55	38.0	7,472	GAS	2,528,448 MCF	1.00	2,528,448	11,460,604	3.39
7	CITRUS CC	1-2	1640	1,085,439	89 0	93 55	95.1	6,530	GAS	7,088,435 MCF	1.00	7,088,435	32,129,490	2.96
8	DEBARY	1-10	785	10,148	1 9	80.71	9.2	12,814	GAS	130,045 MCF	1.00	130,045	589,452	5.81
9	HINESCC	1-4	2,204	1,074,668	65 6	95.16	70.0	7,333	GAS	7,880,671 MCF	1.00	7,880,671	35,720,429	3.32
10	INT CITY	1-14	1,186	18,198	2.1	92 81	6.2	12,866	GAS	234,128 MCF	1.00	234,128	1,061,227	5.83
11	OSPREY	1	505	255,413	68 0	95 86	90.6	7,640	GAS	1,951,460 MCF	1.00	1,951,460	8,845,311	3.46
12	SUWANNEE CT	1-3	200	3,229	2 3	87 26	24.3	13,569	GAS	43,819 MCF	1.00	43,819	198,616	6.15
13	TIGER BAY	1	225	90,442	54 0	88 39	85.7	7,561	GAS	683,845 MCF	1.00	683,845	3,099,640	3.43
14	UNIV OF FLA.	1	47	30,835	88 2	94.19	93.6	9,376	GAS	289,110 MCF	1.00	289,110	1,339,350	4.34
15	BARTOW	1-4	228	196	1 0	90 00	17.6	15,841	LIGHT OIL	534 BBLS	5.81	3,105	50,911	25.97
16	BARTOW CC	1	1,279	0	35 6	93 55	38.0	0	LIGHT OIL	0 BBLS	5.81	0	0	0.00
17	BAYBORO	1-4	231	2,769	1 6	93.15	13.2	14,997	LIGHT OIL	7,128 BBLS	5.81	41,527	886,454	32.01
18	DEBARY	1-10	785	839	1 9	80.71	9.2	13,450	LIGHT OIL	1,937 BBLS	5.81	11,278	227,188	27.09
19	HINESCC	1-4	2,204	1,718	65 6	95.16	70.0	7,261	LIGHT OIL	2,141 BBLS	5.81	12,474	188,287	10.96
20	OTHER		0	0	0 0	0 00	0.0	0	LIGHT OIL	0 BBLS	5.81	0	0	0.00
21	INT CITY	1-14	1,186	415	2.1	92 81	6.2	14,331	LIGHT OIL	1,020 BBLS	5.81	5,943	105,802	25.51
22	SUWANNEE CT	1-3	200	171	2 3	87 26	24.3	13,423	LIGHT OIL	395 BBLS	5.81	2,301	37,485	21.87
23	OTHER - START UP	0	-	0	-	0 00	0.0	0	LIGHT OIL	1,211 BBLS	5.81	7,055	167,748	0.00
24	SOLAR	1	513	110,810	29 0	0 00	51.6	0	SOLAR	0 N/A		0	0	0.00
25	TOTAL			4,153,417								32,704,441	133,486,550	3.21

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Aug-21

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		(J)	(K)	(L)	(M)
	PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)		FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	436,832	80.2	87.10	93.1	10,187	COAL	191,655	TONS	23.22	4,450,026	12,288,766	2 81
2	CRYSTAL RIVER	5	712	416,759	78.7	88.39	89.0	10,196	COAL	183,008	TONS	23.22	4,249,256	11,766,345	2 82
3	ANCLOTE	1	517	122,435	31.8	90.97	36.2	10,934	GAS	1,338,726	MCF	1.00	1,338,726	6,055,954	4 95
4	ANCLOTE	2	521	129,529	33.4	93.23	35.8	11,567	GAS	1,498,291	MCF	1.00	1,498,291	6,561,777	5 07
5	BARTOW	1-4	1,279	2,641	0.3	89.52	3.3	14,075	GAS	37,177	MCF	1.00	37,177	165,344	6 26
6	BARTOWCC	1	1279	365,869	38.4	96.45	39.9	7,465	GAS	2,731,086	MCF	1.00	2,731,086	12,146,598	3 32
7	CITRUS CC	1-2	1640	1,088,742	89.2	93.71	95.2	6,531	GAS	7,110,327	MCF	1.00	7,110,327	31,623,420	2 90
8	DEBARY	1-10	785	22,704	4.0	80.61	9.5	12,836	GAS	291,432	MCF	1.00	291,432	1,296,152	5.71
9	HINESCC	1-4	2,204	1,091,531	66.7	95.16	70.2	7,324	GAS	7,994,779	MCF	1.00	7,994,779	35,557,055	3 26
10	INT CITY	1-14	1,186	34,669	4.0	93.09	6.1	12,896	GAS	447,077	MCF	1.00	447,077	1,988,394	5.74
11	OSPREY	1	505	250,263	66.6	96.25	91.3	7,647	GAS	1,913,722	MCF	1.00	1,913,722	8,511,344	3.40
12	SUWANNEE CT	1-3	200	5,436	3.8	82.58	24.2	13,598	GAS	73,918	MCF	1.00	73,918	328,753	6 05
13	TIGER BAY	1	225	112,701	67.3	91.94	85.5	7,552	GAS	851,091	MCF	1.00	851,091	3,785,258	3 36
14	UNIV OF FLA.	1	47	31,363	89.7	95.81	93.6	9,373	GAS	293,954	MCF	1.00	293,954	1,336,765	4 26
15	BARTOW	1-4	228	190	1.7	89.52	18.3	15,864	LIGHT OIL	518	BBLS	5.83	3,018	49,479	26 01
16	BARTOW CC	1	1,279	0	38.4	96.45	39.9	0	LIGHT OIL	0	BBLS	5.83	0	0	0 00
17	BAYBORO	1-4	231	35,107	20.4	92.34	13.1	15,050	LIGHT OIL	90,699	BBLS	5.83	528,357	8,794,705	25 05
18	DEBARY	1-10	785	790	4.0	80.61	9.5	13,387	LIGHT OIL	1,817	BBLS	5.83	10,577	213,408	27 01
19	HINESCC	1-4	2,204	1,718	66.7	95.16	70.2	7,263	LIGHT OIL	2,141	BBLS	5.83	12,474	188,287	10 96
20	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	5.83	0	0	0 00
21	INT CITY	1-14	1,186	1,065	4.0	93.09	6.1	14,393	LIGHT OIL	2,632	BBLS	5.83	15,329	262,106	24 61
22	SUWANNEE CT	1-3	200	184	3.8	82.58	24.2	13,386	LIGHT OIL	422	BBLS	5.83	2,462	40,028	21.76
23	OTHER - START UP	0	-	0	-	0.00	0.0	0	LIGHT OIL	1,781	BBLS	5.83	10,375	230,634	0 00
24	SOLAR	1	513	105,000	27.5	0.00	50.8	0	SOLAR	0	N/A		0	0	0 00
25	TOTAL			4,255,528									33,863,454	143,190,572	3 36

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Sep-21

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVA L FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	448,533	85.1	95.00	90 2	10,203	COAL	198,333	TONS	23.08	4,576,547	12,787,767	2.85
2	CRYSTAL RIVER	5	712	396,805	77.4	92.67	83 6	10,226	COAL	175,853	TONS	23.08	4,057,817	11,418,720	2.88
3	ANCLOTE	1	517	69,473	18.7	93.67	30.4	11,129	GAS	773,129	MCF	1.00	773,129	3,765,886	5.42
4	ANCLOTE	2	521	90,426	24.1	97.67	24.7	12,345	GAS	1,116,308	MCF	1.00	1,116,308	4,830,427	5.34
5	BARTOW	1-4	1,279	203	0.0	89.84	2 6	14,201	GAS	2,883	MCF	1.00	2,883	13,119	6.46
6	BARTOWCC	1	1279	545,185	59.2	96.33	61.4	7,401	GAS	4,034,868	MCF	1.00	4,034,868	18,357,314	3.37
7	CITRUS CC	1-2	1640	1,047,065	88.7	95.17	93.1	6,535	GAS	6,842,686	MCF	1.00	6,842,686	31,131,954	2.97
8	DEBARY	1-10	785	2,974	0.7	80.47	9.1	12,821	GAS	38,134	MCF	1.00	38,134	173,495	5.83
9	HINES CC	1-4	2,204	954,866	60.3	95.75	65 2	7,377	GAS	7,044,074	MCF	1.00	7,044,074	32,048,208	3.36
10	NT CITY	1-14	1,186	5,455	0.8	93.62	6 3	12,853	GAS	70,119	MCF	1.00	70,119	319,010	5.85
11	OSPREY	1	505	237,395	65.3	96.03	90.1	7,671	GAS	1,821,124	MCF	1.00	1,821,124	8,285,512	3.49
12	SUWANNEE CT	1-3	200	2,345	1.7	83.00	24 2	13,625	GAS	31,950	MCF	1.00	31,950	145,365	6.20
13	TIGER BAY	1	225	70,577	43.6	90.33	85 2	7,563	GAS	533,782	MCF	1.00	533,782	2,428,531	3.44
14	UNIV OF FLA.	1	47	29,674	87.7	93.67	93.7	9,378	GAS	278,272	MCF	1.00	278,272	1,293,875	4.36
15	BARTOW	1-4	228	203	0.2	89.84	14 8	15,890	LIGHT OIL	554	BBLS	5.82	3,227	52,717	25.96
16	BARTOW CC	1	1,279	0	59.2	96.33	61.4	0	LIGHT OIL	0	BBLS	5.82	0	0	0.00
17	BAYBORO	1-4	231	163	0.1	92.25	17 6	13,840	LIGHT OIL	386	BBLS	5.82	2,249	93,659	57.64
18	DEBARY	1-10	785	745	0.7	80.47	9.1	13,241	LIGHT OIL	1,695	BBLS	5.82	9,870	199,553	26.77
19	HINESCC	1-4	2,204	1,624	60.3	95.75	65 2	7,297	LIGHT OIL	2,034	BBLS	5.82	11,850	179,237	11.04
20	OTHER		0	0	0.0	0.00	0 0	0	LIGHT OIL	0	BBLS	5.82	0	0	0.00
21	NT CITY	1-14	1,186	1,456	0.8	93.62	6 3	12,992	LIGHT OIL	3,246	BBLS	5.82	18,914	320,570	22.02
22	SUWANNEE CT	1-3	200	119	1.7	83.00	24 2	13,525	LIGHT OIL	276	BBLS	5.82	1,604	26,483	22.33
23	OTHER - START UP	0	-	0	-	0.00	0 0	0	LIGHT OIL	926	BBLS	5.82	5,395	118,824	0.00
24	SOLAR	1	513	95,251	25.8	0.00	49 3	0	SOLAR	0	N/A		0	0	0.00
25	TOTAL			4,000,536									31,274,802	127,990,226	3.20

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Oct-21

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	424,461	77 9	86.77	91 0	10,200	COAL	188,312	TONS	22.99	4,329,640	12,221,280	2.88
2	CRYSTAL RIVER	5	712	397,971	75.1	88 39	85 6	10,217	COAL	176,847	TONS	22.99	4,066,033	11,520,338	2.89
3	ANCLOTE	1	517	25,356	6 6	93 87	23 5	11,677	GAS	296,092	MCF	1.00	296,092	1,631,211	6.43
4	ANCLOTE	2	521	46,248	11 9	96.45	21 3	12,781	GAS	591,100	MCF	1.00	591,100	2,520,070	5.45
5	BARTOW	1-4	1,279	103	0 0	89 68	2.4	14,273	GAS	1,464	MCF	1.00	1,464	6,851	6.68
6	BARTOWCC	1	1279	482,644	50.7	85 94	51 9	7,834	GAS	3,780,856	MCF	1.00	3,780,856	17,691,104	3.67
7	CITRUS CC	1-2	1640	814,116	66.7	70.16	71 3	6,557	GAS	5,338,160	MCF	1.00	5,338,160	24,977,929	3.07
8	DEBARY	1-10	785	1,266	0 3	66.40	8 3	13,022	GAS	16,483	MCF	1.00	16,483	77,125	6.09
9	HINES CC	1-4	2,204	870,637	53 2	87.74	66 0	7,362	GAS	6,409,200	MCF	1.00	6,409,200	29,989,457	3.44
10	INT CITY	1-14	1,186	2,849	0 3	84 95	5.7	13,175	GAS	37,540	MCF	1.00	37,540	175,656	6.16
11	OSPREY	1	505	199,224	53 0	96.15	71 9	7,769	GAS	1,547,818	MCF	1.00	1,547,818	7,242,436	3.64
12	SUWANNEE CT	1-3	200	1,151	0 9	84 68	21 9	14,006	GAS	16,117	MCF	1.00	16,117	75,418	6.55
13	TIGER BAY	1	225	52,958	31 6	90 00	84.7	7,572	GAS	400,986	MCF	1.00	400,986	1,876,264	3.54
14	UNIV OF FLA.	1	47	13,834	39 6	38.73	93.7	9,403	GAS	130,073	MCF	1.00	130,073	621,636	4.49
15	BARTOW	1-4	228	174	0 2	89 68	13 5	16,058	LIGHT OIL	481	BBLS	5.82	2,801	45,915	26.32
16	BARTOW CC	1	1,279	0	50.7	85 94	51 9	0	LIGHT OIL	0	BBLS	5.82	0	0	0.00
17	BAYBORO	1-4	231	154	0.1	92 50	16.7	13,844	LIGHT OIL	367	BBLS	5.82	2,132	91,683	59.53
18	DEBARY	1-10	785	616	0 3	66.40	8 3	13,435	LIGHT OIL	1,423	BBLS	5.82	8,281	168,420	27.33
19	HINESCC	1-4	2,204	1,790	53 2	87.74	66 0	7,265	LIGHT OIL	2,233	BBLS	5.82	13,005	195,996	10.95
20	OTHER		0	0	0 0	0 00	0 0	0	LIGHT OIL	0	BBLS	5.82	0	0	0.00
21	INT CITY	1-14	1,186	0	0 0	84 95	0 0	0	LIGHT OIL	0	BBLS	5.82	0	6,216	0.00
22	SUWANNEE CT	1-3	200	121	0 9	84 68	21 9	13,826	LIGHT OIL	287	BBLS	5.82	1,669	27,501	22.78
23	OTHER - START UP	0	-	0	-	0 00	0 0	0	LIGHT OIL	1,852	BBLS	5.82	10,790	221,886	0.00
24	SOLAR	1	513	100,338	26 3	0 00	52 6	0	SOLAR	0	N/A		0	0	0.00
25	TOTAL			3,436,010									27,000,240	111,384,392	3.24

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Nov-21

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		(J)	(K)	(L)	(M)
	PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)		FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	430,920	81.8	88.67	93.3	9,971	COAL	186,351	TONS	23 06	4,296,654	12,187,909	2.83
2	CRYSTAL RIVER	5	712	73,667	14.4	10.67	92.4	9,923	COAL	31,704	TONS	23 06	730,993	2,653,932	3.60
3	ANCLOTE	1	517	2,116	0.6	95.33	37.2	10,817	GAS	22,889	MCF	1 00	22,889	297,088	14.04
4	ANCLOTE	2	521	18,639	5.0	96.00	22.4	12,348	GAS	230,145	MCF	1 00	230,145	961,757	5.16
5	BARTOW	1-4	1,279	107	0.0	48.17	2.5	15,162	GAS	1,625	MCF	1 00	1,625	8,083	7.54
6	BARTOWCC	1	1279	294,925	32.0	67.32	32.8	9,011	GAS	2,657,505	MCF	1 00	2,657,505	13,221,070	4.48
7	CITRUS CC	1-2	1640	1,069,243	90.6	93.33	96.2	6,542	GAS	6,995,159	MCF	1 00	6,995,159	34,800,864	3.25
8	DEBARY	1-10	785	1,082	0.3	71.63	9.1	12,850	GAS	13,908	MCF	1 00	13,908	69,194	6.39
9	HINES	1-4	2,204	619,932	39.2	81.28	71.2	7,179	GAS	4,450,429	MCF	1 00	4,450,429	22,140,852	3.57
10	NT CITY	1-14	1,186	2,618	0.3	81.13	6.3	12,980	GAS	33,975	MCF	1 00	33,975	169,025	6.46
11	OSPREY	1	505	173,706	47.8	97.09	64.2	7,656	GAS	1,329,842	MCF	1 00	1,329,842	6,615,957	3.81
12	SUWANNEE CT	1-3	200	961	0.8	60.58	26.7	12,976	GAS	12,470	MCF	1 00	12,470	62,036	6.46
13	TIGER BAY	1	225	34,298	21.2	93.00	92.9	7,556	GAS	259,163	MCF	1 00	259,163	1,289,336	3.76
14	UNIV OF FLA.	1	47	34,800	102.8	96.67	106.4	9,389	GAS	326,744	MCF	1 00	326,744	1,658,222	4.77
15	BARTOW	1-4	228	209	0.2	48.17	13.9	15,696	LIGHT OIL	563	BBLS	5 82	3,276	53,371	25.57
16	BARTOW CC	1	1,279	0	32.0	67.32	32.8	0	LIGHT OIL	0	BBLS	5 82	0	0	0.00
17	BAYBORO	1-4	231	203	0.1	93.25	22.0	13,387	LIGHT OIL	467	BBLS	5 82	2,723	101,389	49.85
18	DEBARY	1-10	785	853	0.3	71.63	9.1	12,858	LIGHT OIL	1,883	BBLS	5 82	10,971	221,143	25.92
19	HINESCC	1-4	2,204	1,676	39.2	81.28	71.2	7,259	LIGHT OIL	2,088	BBLS	5 82	12,163	183,768	10.97
20	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	5 82	0	0	0.00
21	NT CITY	1-14	1,186	13	0.3	81.13	0.0	16,328	LIGHT OIL	36	BBLS	5 82	209	9,695	75.74
22	SUWANNEE CT	1-3	200	161	0.8	60.58	26.7	12,939	LIGHT OIL	357	BBLS	5 82	2,082	34,026	21.15
23	OTHER - START UP	0	-	0	-	0.00	0.0	0	LIGHT OIL	926	BBLS	5 82	5,395	110,767	0.00
24	SOLAR	1	513	85,549	23.2	0.00	51.0	0	SOLAR	0	N/A		0	0	0.00
25	TOTAL			2,845,678									21,398,320	96,849,484	3.40

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Dec-21

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	473,464	86.9	91.61	95.5	9,965	COAL	204,439 TONS	23 08	4,718,234	13,371,733	2.82
2	CRYSTAL RIVER	5	712	185,622	35.0	30.87	95.5	9,917	COAL	79,764 TONS	23 08	1,840,867	5,646,152	3.04
3	ANCLOTE	1	517	580	0.2	90.32	28.1	12,092	GAS	7,017 MCF	1 00	7,017	93,820	16.17
4	ANCLOTE	2	521	4,734	1.2	93.87	19.3	13,515	GAS	63,979 MCF	1 00	63,979	288,399	6.09
5	BARTOW	1-4	1,279	116	0.0	83.42	2.1	16,699	GAS	1,942 MCF	1 00	1,942	10,454	8.99
6	BARTOWCC	1	1279	558,813	58.7	94.52	62.1	7,159	GAS	4,000,358 MCF	1 00	4,000,358	21,536,647	3.85
7	CITRUS CC	1-2	1640	1,094,330	89.7	94.84	94.8	6,540	GAS	7,156,763 MCF	1 00	7,156,763	38,529,721	3.52
8	DEBARY	1-10	785	1,007	0.3	81.10	8.7	13,141	GAS	13,232 MCF	1 00	13,232	71,239	7.07
9	HINES CC	1-4	2,204	438,920	26.9	89.45	70.5	7,069	GAS	3,102,698 MCF	1 00	3,102,698	16,703,933	3.81
10	NT CITY	1-14	1,186	2,540	0.5	93.41	5.9	13,563	GAS	34,449 MCF	1 00	34,449	185,467	7.30
11	OSPREY	1	505	45,767	12.2	95.63	80.2	7,812	GAS	357,525 MCF	1 00	357,525	1,924,801	4.21
12	SUWANNEE CT	1-3	200	2,564	1.8	84.03	23.6	13,679	GAS	35,068 MCF	1 00	35,068	188,794	7.36
13	TIGER BAY	1	225	13,100	7.8	90.65	91.0	7,674	GAS	100,538 MCF	1 00	100,538	541,263	4.13
14	UNIV OF FLA.	1	47	36,000	103.0	96.77	106.4	9,389	GAS	338,000 MCF	1 00	338,000	1,853,481	5.15
15	BARTOW	1-4	228	103	0.1	83.42	12.0	15,867	LIGHT OIL	281 BBLS	5 82	1,636	27,457	26.63
16	BARTOW CC	1	1,279	0	58.7	94.52	62.1	0	LIGHT OIL	0 BBLS	5 82	0	0	0.00
17	BAYBORO	1-4	231	220	0.1	93.31	23.9	13,389	LIGHT OIL	507 BBLS	5 82	2,951	105,080	47.68
18	DEBARY	1-10	785	902	0.3	81.10	8.7	13,013	LIGHT OIL	2,014 BBLS	5 82	11,735	236,110	26.18
19	HINESCC	1-4	2,204	1,775	26.9	89.45	70.5	7,252	LIGHT OIL	2,209 BBLS	5 82	12,869	194,016	10.93
20	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	5 82	0	0	0.00
21	NT CITY	1-14	1,186	1,825	0.5	93.41	5.9	12,863	LIGHT OIL	4,027 BBLS	5 82	23,472	394,093	21.60
22	SUWANNEE CT	1-3	200	131	1.8	84.03	23.6	13,438	LIGHT OIL	302 BBLS	5 82	1,760	28,931	22.09
23	OTHER - START UP	0	-	0	-	0.00	0.0	0	LIGHT OIL	1,567 BBLS	5 82	9,130	178,072	0.00
24	SOLAR	1	588	85,559	19.6	0.00	42.9	0	SOLAR	0 N/A		0	0	0.00
25	TOTAL			2,948,072								21,834,223	102,109,663	3.46

Duke Energy Florida, LLC
Inventory Analysis

Estimated for the Period of : January 2021 through December 2021

			Act Jan-21	Act Feb-21	Act Mar-21	Act Apr-21	Act May-21	Act Jun-21	Subtotal
	LIGHT OIL								
1	PURCHASES:								
2	UNITS	BBL	2,860	4,279	(2,871)	4,783	18,847	5,841	33,739
3	UNIT COST	$/BBL	178.38	183.11	(62.49)	83.34	122.72	124.01	145.50
4	AMOUNT	$	510,177	783,541	179,397	398,634	2,312,897	724,328	4,908,975
5	BURNED:								
6	UNITS	BBL	9,404	57,675	13,345	11,997	19,082	14,642	126,145
7	UNIT COST	$/BBL	134.39	109.07	100 65	116.06	121.99	122.54	114.25
8	AMOUNT	$	1,263,812	6,290,454	1,343,139	1,392,329	2,327,880	1,794,206	14,411,819
9	ENDING INVENTORY:								
10	UNITS	BBL	524,848	471,453	457,070	449,780	449,606	440,805	
11	UNIT COST	$/BBL	108.85	109.50	110.40	109.98	109.98	109.75	
12	AMOUNT	$	57,129,004	51,622,091	50,458,349	49,464,655	49,449,672	48,379,795	
	COAL								
13	PURCHASES:								
14	UNITS	TON	169,077	112,534	189,268	244,250	247,397	245,639	1,208,165
15	UNIT COST	$/TON	84.59	69.34	61.15	68.69	59.73	58.23	65.83
16	AMOUNT	$	14,302,414	7,803,156	11,573,459	16,778,108	14,778,153	14,303,780	79,539,070
17	BURNED:								
18	UNITS	TON	113,514	176,141	178,397	287,457	298,173	294,422	1,348,104
19	UNIT COST	$/TON	75.17	74.26	70 88	70.22	66.81	63.84	69.10
20	AMOUNT	$	8,532,371	13,079,895	12,645,483	20,184,047	19,920,683	18,794,594	93,157,074
21	ADJUSTMENTS								
22	UNITS	TON						(26,652)	(26,652)
23	AMOUNT	$						(1,936,195)	(1,936,195)
24	ENDING INVENTORY:								
25	UNITS	TON	609,700	546,093	556,964	513,756	462,981	387,546	
26	UNIT COST	$/TON	75.17	74.26	70 88	70.22	66.81	63.23	
27	AMOUNT	$	45,828,567	40,551,828	39,479,804	36,073,865	30,931,335	24,504,326	
	GAS								
28	BURNED:								
29	UNITS	MCF	19,752,154	15,414,666	17,017,842	16,237,530	20,822,673	23,855,826	113,100,691
30	UNIT COST	$/MCF	4.12	4.56	4 59	4.31	4.54	4.29	4 39
31	AMOUNT	$	81,334,212	70,298,733	78,097,880	69,902,652	94,560,786	102,411,989	496,606,251

Duke Energy Florida, LLC
Inventory Analysis

Estimated for the Period of : January 2021 through December 2021

			Est	Est	Est	Est	Est	Est	
			Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
	LIGHT O L								
1	PURCHASES:								
2	UNITS	BBL	14,366	100,010	9,117	6,643	6,320	10,907	181,102
3	UNIT COST	$/BBL	115.82	97.78	108.70	114 05	113.00	106.70	110.31
4	AMOUNT	$	1,663,875	9,778,647	991,043	757,617	714,159	1,163,759	19,978,075
5	BURNED:								
6	UNITS	BBL	14,366	100,010	9,117	6,643	6,320	10,907	273,508
7	UNIT COST	$/BBL	115.82	97.78	108.70	114 05	113.00	106.70	107.79
8	AMOUNT	$	1,663,875	9,778,647	991,043	757,617	714,159	1,163,759	29,480,919
9	ENDING NVENTORY:								
10	UNITS	BBL	440,805	440,805	440,805	440,805	440,805	440,805	
11	UNIT COST	$/BBL	109.75	109.75	109.75	109.75	109.75	109.75	
12	AMOUNT	$	48,379,795	48,379,795	48,379,795	48,379,795	48,379,795	48,379,795	
	COAL								
13	PURCHASES:								
14	UNITS	TON	385,452	374,663	374,186	365,159	218,055	284,203	3,209,883
15	UNIT COST	$/TON	63.79	64 20	64.69	65 02	68.06	66 92	65.42
16	AMOUNT	$	24,589,314	24,055,111	24,206,487	23,741,618	14,841,841	19,017,885	209,991,326
17	BURNED:								
18	UNITS	TON	385,452	374,663	374,186	365,159	218,055	284,203	3,349,822
19	UNIT COST	$/TON	63.79	64 20	64.69	65 02	68.06	66 92	66.75
20	AMOUNT	$	24,589,314	24,055,111	24,206,487	23,741,618	14,841,841	19,017,885	223,609,330
21	ADJUSTMENTS								
22	UNITS	TON							(26,652)
23	AMOUNT	$							(1,936,195)
24	ENDING NVENTORY:								
25	UNITS	TON	387,546	387,546	387,546	387,546	387,546	387,546	
26	UNIT COST	$/TON	63.23	63 23	63.23	63 23	63.23	63 23	
27	AMOUNT	$	24,504,326	24,504,326	24,504,326	24,504,326	24,504,326	24,504,326	
	GAS								
28	BURNED:								
29	UNITS	MCF	23,651,535	24,581,580	22,587,329	18,565,889	16,333,854	15,211,569	234,032,447
30	UNIT COST	$/MCF	4.53	4.45	4.55	4 68	4.98	5 39	4.56
31	AMOUNT	$	107,233,361	109,356,814	102,792,696	86,885,157	81,293,484	81,928,019	1,066,095,782

Duke Energy Florida, LLC
Fuel Cost of Power Sold
Estimated for the Period of : January 2021 through December 2021

(1) MONTH	(2) SOLD TO	(3) TYPE & SCHED	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) C/KWH (A) FUEL COST	(7) C/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ (6) x (7)(A)	(9) TOTAL COST $ (6) x (7)(B)	(10) REFUNDABLE GAIN ON POWER SALES $
Jan-21	ECONSALE	--	20,955		20,955	1.845	2.551	386,674	534,601	147,927
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	208,965		208,965	3.085	3.085	6,445,748	6,445,748	0
	TOTAL		229,920		229,920	2.972	3.036	6,832,422	6,980,349	147,927
Feb-21	ECONSALE	--	10,254		10,254	3.707	4.502	380,148	461,648	81,500
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	64,252		64,252	2.928	2.928	1,881,490	1,881,490	0
	TOTAL		74,506		74,506	3.036	3.145	2,261,638	2,343,139	81,500
Mar-21	ECONSALE	--	28,341		28,341	1.716	2.199	486,390	623,136	136,746
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	84,579		84,579	2.223	2.223	1,879,924	1,879,924	0
	TOTAL		112,920		112,920	2.096	2.217	2,366,314	2,503,060	136,746
Apr-21	ECONSALE	--	20,020		20,020	1.940	2.498	388,396	500,046	111,650
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	133,751		133,751	2.104	2.104	2,813,792	2,813,792	0
	TOTAL		153,771		153,771	2.082	2.155	3,202,189	3,313,839	111,650
May-21	ECONSALE	--	24,815		24,815	1.807	2.160	448,330	536,009	87,679
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	277,496		277,496	2.979	2.979	8,266,447	8,266,447	0
	TOTAL		302,311		302,311	2.883	2.912	8,714,777	8,802,456	87,679
Jun-21	ECONSALE	--	27,210		27,210	2.104	2.394	572,616	651,376	78,760
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	364,612		364,612	2.287	2.287	8,339,596	8,339,596	0
	TOTAL		391,822		391,822	2.275	2.295	8,912,212	8,990,972	78,760
Jan-21	ECONSALE	--	131,595		131,595	2.023	2.513	2,662,554	3,306,816	644,262
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Jun-21	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	1,133,655		1,133,655	2.613	2.613	29,626,998	29,626,998	0
	TOTAL		1,265,250		1,265,250	2.552	2.603	32,289,552	32,933,814	644,262

Duke Energy Florida, LLC
Fuel Cost of Power Sold
Estimated for the Period of : January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	REFUNDABLE GAIN ON POWER SALES $
Jul-21	ECONSALE	--	7,772		7,772	3.675	4.682	285,585	363,837	78,252
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	343,352		343,352	2.973	2.973	10,208,910	10,208,910	0
	TOTAL		351,124		351,124	2.989	3.011	10,494,495	10,572,747	78,252
Aug-21	ECONSALE	--	6,114		6,114	4.152	5.289	253,838	323,391	69,553
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	338,754		338,754	2.962	2.962	10,035,561	10,035,561	0
	TOTAL		344,868		344,868	2.984	3.004	10,289,399	10,358,952	69,553
Sep-21	ECONSALE	--	13,161		13,161	3.452	4.398	454,281	578,757	124,476
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	284,920		284,920	3.058	3.058	8,713,607	8,713,607	0
	TOTAL		298,080		298,080	3.076	3.117	9,167,888	9,292,364	124,476
Oct-21	ECONSALE	--	13,965		13,965	3.465	4.415	483,924	616,522	132,598
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	213,200		213,200	3.020	3.020	6,438,499	6,438,499	0
	TOTAL		227,165		227,165	3.047	3.106	6,922,423	7,055,021	132,598
Nov-21	ECONSALE	--	20,783		20,783	3.483	4.437	723,889	922,238	198,349
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	149,221		149,221	3.322	3.322	4,957,602	4,957,602	0
	TOTAL		170,004		170,004	3.342	3.459	5,681,491	5,879,840	198,349
Dec-21	ECONSALE	--	20,512		20,512	3.086	3.932	633,091	806,561	173,470
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	86,231		86,231	3.212	3.212	2,769,370	2,769,370	0
	TOTAL		106,744		106,744	3.188	3.350	3,402,461	3,575,931	173,470
Jan-21	ECONSALE	--	213,902		213,902	2.570	3.234	5,497,162	6,918,122	1,420,960
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-21	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	2,549,333		2,549,333	2.854	2.854	72,750,547	72,750,547	0
	TOTAL		2,763,234		2,763,234	2.832	2.883	78,247,709	79,668,669	1,420,960

Duke Energy Florida, LLC
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH			C/KWH		TOTAL $
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UT LITIES	MWH FOR INTERRUPTIBLE	MWH FOR F RM	(A) FUEL COST	(B) TOTAL COST	FOR FUEL ADJ (7) x (8)(B)
Jan-21	OTHER	--	0			0	0 000	0.000	0
Act	SHADY HILLS	--	(303)			(303)	-4 841	-4.841	14,667
	SOCO Franklin	--	4,800			4,800	11 946	11.946	573,385
	Vandolah (NSG)	--	9,875			9,875	5.165	5.165	510,024
	TOTAL		14,372	0	0	14,372	7 640	7.640	1,098,076
Feb-21	OTHER	--	0			0	0 000	0.000	0
Act	SHADY HILLS	--	4,211			4,211	0 864	0.864	36,365
	SOCO Franklin	--	29,471			29,471	4.197	4.197	1,236,965
	Vandolah (NSG)	--	49,982			49,982	4 653	4.653	2,325,500
	TOTAL		83,664	0	0	83,664	4 302	4.302	3,598,830
Mar-21	OTHER	--	0			0	0 000	0.000	0
Act	SHADY HILLS	--	16,305			16,305	13 972	13.972	2,278,153
	SOCO Franklin	--	56,251			56,251	4.462	4.462	2,510,190
	Vandolah (NSG)	--	72,774			72,774	10 045	10.045	7,310,411
	TOTAL		145,330	0	0	145,330	8 325	8.325	12,098,754
Apr-21	OTHER	--	0			0	0 000	0.000	0
Act	SHADY HILLS	--	8,778			8,778	4 913	4.913	431,244
	SOCO Franklin	--	18,223			18,223	3 223	3.223	587,262
	Vandolah (NSG)	--	82,251			82,251	6 007	6.007	4,940,810
	TOTAL		109,252	0	0	109,252	5.455	5.455	5,959,317
May-21	OTHER	--	0			0	0 000	0.000	0
Act	SHADY HILLS	--	39,183			39,183	6 023	6.023	2,360,022
	SOCO Franklin	--	58,640			58,640	3 356	3.356	1,967,723
	Vandolah (NSG)	--	105,848			105,848	6.158	6.158	6,518,414
	TOTAL		203 671	0	0	203 671	5 325	5.325	10 846 159
Jun-21	OTHER	--	0			0	0 000	0.000	0
Act	SHADY HILLS	--	44,660			44,660	6 548	6.548	2,924,448
	SOCO Franklin	--	1,850			1,850	24 909	24.909	460,824
	Vandolah (NSG)	--	166,396			166,396	5.792	5.792	9,638,323
	TOTAL		212,906	0	0	212,906	6.117	6.117	13,023,594
Jan-21	OTHER	--	0			0	0 000	0.000	0
THRU	SHADY HILLS	--	112,834			112,834	7.130	7.130	8,044,899
Jun-21	SOCO Franklin	--	169,235			169,235	4 335	4.335	7,336,350
	Vandolah (NSG)	--	487,126			487,126	6.414	6.414	31,243,482
	TOTAL		769,195	0	0	769,195	6 061	6.061	46,624,731

Duke Energy Florida, LLC
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January 2021 through December 2021

(1) MONTH	(2) NAME OF PURCHASE	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUPTIBLE	(7) MWH FOR F RM	(8) C/KWH (A) FUEL COST	(8) C/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jul-21	OTHER	--	0			0	0.000	0.000	0
Est	SHADY HILLS	--	43,398			43,398	5.064	5.064	2,197,511
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	66,664			66,664	5.813	5.813	3,874,972
	TOTAL		110,061	0	0	110,061	5.517	5.517	6,072,483
Aug-21	OTHER	--	0			0	0.000	0.000	0
Est	SHADY HILLS	--	112,300			112,300	4.930	4.930	5,536,652
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	86,080			86,080	6.142	6.142	5,286,625
	TOTAL		198,380	0	0	198,380	5.456	5.456	10,823,277
Sep-21	OTHER	--	0			0	0.000	0.000	0
Est	SHADY HILLS	--	4,302			4,302	5.390	5.390	231,876
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	33,513			33,513	6.025	6.025	2,019,005
	TOTAL		37,815	0	0	37,815	5.952	5.952	2,250,881
Oct-21	OTHER	--	0			0	0.000	0.000	0
Est	SHADY HILLS	--	4,212			4,212	5.497	5.497	231,528
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	9,953			9,953	6.412	6.412	638,136
	TOTAL		14,165	0	0	14,165	6.140	6.140	869,664
Nov-21	OTHER	--	0			0	0.000	0.000	0
Est	SHADY HILLS	--	1,822			1,822	16.468	16.468	300,075
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	8,155			8,155	9.826	9.826	801,270
	TOTAL		9,977	0	0	9,977	11.039	11.039	1,101,345
Dec-21	OTHER	--	0			0	0.000	0.000	0
Est	SHADY HILLS	--	0			0	0.000	0.000	1,857
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	0			0	0.000	0.000	43,124
	TOTAL		0	0	0	0	0.000	0.000	44,981
Jan-21	OTHER	--	0			0	0.000	0.000	-
THRU	SHADY HILLS	--	278,867			278,867	5.933	5.933	16,544,398
Dec-21	SOCO Franklin	--	169,235			169,235	4.335	4.335	7,336,350
	Vandolah (NSG)	--	691,490			691,490	6.350	6.350	43,906,614
TOTAL			1,139,593	0	0	1,139,593	5.948	5.948	67,787,362

Duke Energy Florida, LLC
Energy Payments to Qualifying Facilities
Estimated for the Period of : January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILIT ES	MWH FOR INTERRUPTIBLE	MWH FOR F RM	C/KWH (A) ENERGY COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(A)
Jan-21 Act	QUAL. FAC LITIES	COGEN	207,778			207,778	3 633	17.411	7,548,154
Feb-21 Act	QUAL. FAC LITIES	COGEN	203,273			203,273	3 592	17.682	7,301,243
Mar-21 Act	QUAL. FAC LITIES	COGEN	181,241			181,241	4.468	20.267	8,097,325
Apr-21 Act	QUAL. FAC LITIES	COGEN	177,610			177,610	4 003	20.125	7,109,630
May-21 Act	QUAL. FAC LITIES	COGEN	219,951			219,951	3 868	16.887	8,508,302
Jun-21 Act	QUAL. FAC LITIES	COGEN	211,457			211,457	4 328	17.870	9,152,559
Jul-21 Est	QUAL. FAC LITIES	COGEN	229,907			229,907	4 247	16.702	9,763,058
Aug-21 Est	QUAL. FAC LITIES	COGEN	229,907			229,907	4 262	16.717	9,797,946
Sep-21 Est	QUAL. FAC LITIES	COGEN	222,491			222,491	4 212	17.082	9,371,619
Oct-21 Est	QUAL. FAC LITIES	COGEN	217,043			217,043	4 280	17.474	9,289,938
Nov-21 Est	QUAL. FAC LITIES	COGEN	224,068			224,068	4.126	16.906	9,245,904
Dec-21 Est	QUAL. FAC LITIES	COGEN	237,161			237,161	4 085	16.159	9,687,120
TOTAL	QUAL. FAC LITIES	COGEN	2 561 888			2 561 888	4 094	17.506	104 872 798

Duke Energy Florida, LLC
Economy Energy Purchases
Estimated for the Period of : January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jan-21	ECONPURCH	--	8,530	3.657	3.657	311,949	4.526	386,099	74,150
Act	SEPA	--	7,643	3.003	3.003	229,507	3.003	229,507	0
	TOTAL		16,173	3.348	3.348	541,456	3.806	615,606	74,150
Feb-21	ECONPURCH	--	17,707	4.880	4.880	864,136	6.679	1,182,584	318,448
Act	SEPA	--	1,877	3.448	3.448	64,734	3.448	64,734	0
	TOTAL		19,584	4.743	4.743	928,870	6.369	1,247,318	318,448
Mar-21	ECONPURCH	--	24,097	4.171	4.171	1,005,070	6.648	1,602,039	596,968
Act	SEPA	--	1,220	3.523	3.523	42,996	3.523	42,996	0
	TOTAL		25,317	4.140	4.140	1,048,067	6.498	1,645,035	596,968
Apr-21	ECONPURCH	--	31,516	4.075	4.075	1,284,388	3.719	1,171,923	(112,465)
Act	SEPA	--	4,503	3.119	3.119	140,450	3.119	140,450	0
	TOTAL		36,019	3.956	3.956	1,424,838	3.644	1,312,373	(112,465)
May-21	ECONPURCH	--	47,761	8.286	8.286	3,957,495	9.789	4,675,269	717,775
Act	SEPA	--	3,151	3.626	3.626	114,281	3.626	114,281	0
	TOTAL		50,912	7.998	7.998	4,071,775	9.407	4,789,550	717,775
Jun-21	ECONPURCH	--	73,240	4.366	4.366	3,197,432	6.570	4,811,609	1,614,177
Act	SEPA	--	3,763	3.605	3.605	135,664	3.605	135,664	(0)
	TOTAL		77,003	4.329	4.329	3,333,096	6.425	4,947,273	1,614,176
Jan-21	ECONPURCH	--	202,851	5.236	5.236	10,620,470	6.818	13,829,523	3,209,053
THRU	SEPA	--	22,158	3.284	3.284	727,633	3.284	727,632	(0)
Jun-21									
	TOTAL		225,009	5.043	5.043	11,348,103	6.470	14,557,155	3,209,052

Duke Energy Florida, LLC
Economy Energy Purchases
Estimated for the Period of : January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jul-21	ECONPURCH	--	9,902	5 065	5.065	501,507	5.760	570,385	68,878
Est	SEPA	--	0	0 000	0.000	0	0.000	0	-
	TOTAL		9,902	5 065	5.065	501,507	5.760	570,385	68,878
Aug-21	ECONPURCH	--	15,140	5 355	5.355	810,800	6.091	922,165	111,365
Est	SEPA	--	0	0 000	0.000	0	0.000	0	-
	TOTAL		15,140	5 355	5.355	810,800	6.091	922,165	111,365
Sep-21	ECONPURCH	--	5,694	5 089	5.089	289,767	5.788	329,568	39,801
Est	SEPA	--	0	0 000	0.000	0	0.000	0	-
	TOTAL		5,694	5 089	5.089	289,767	5.788	329,568	39,801
Oct-21	ECONPURCH	--	5,667	4.614	4.614	261,448	5.247	297,359	35,911
Est	SEPA	--	0	0 000	0.000	0	0.000	0	-
	TOTAL		5,667	4.614	4.614	261,448	5.247	297,359	35,911
Nov-21	ECONPURCH	--	5,316	4 084	4.084	217,100	4.645	246,919	29,819
Est	SEPA	--	0	0 000	0.000	0	0.000	0	-
	TOTAL		5,316	4 084	4.084	217,100	4.645	246,919	29,819
Dec-21	ECONPURCH	--	6,739	4 041	4.041	272,348	4.596	309,761	37,413
Est	SEPA	--	0	0 000	0.000	0	0.000	0	-
	TOTAL		6,739	4 041	4.041	272,348	4.596	309,761	37,413
Jan-21	ECONPURCH	--	251,309	5.162	5.162	12,973,440	6.568	16,505,680	3,532,240
THRU	SEPA	--	22,158	3 284	3.284	727,633	3.284	727,632	(0)
Dec-21									
	TOTAL		273,467	5 010	5.010	13,701,073	6.302	17,233,312	3,532,239

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Capital Structure and Cost Rates Applied to Capital Projects
Estimated for the Period of : January 2021 through December 2021

		(1) Jurisdictional Rate Base Adjusted Retail ($000s)	(2) Cap Ratio	(3) Cost Rate	(4) Weighted Cost	(5) Revenue Requirement Rate	(6) Monthly Revenue Requirement Rate
1	Common Equity	$ 6,564,170	43.08%	10.50%	4.523%	5.99%	0.4992%
2	Long Term Debt	5,970,469	39.18%	4.22%	1.655%	1.66%	0.1383%
3	Short Term Debt	141,506	0.93%	1.10%	0.010%	0.01%	0 0008%
4	Cust Dep Active	181,717	1.19%	2.36%	0.028%	0.03%	0 0025%
5	Cust Dep Inactive	1,883	0.01%			0.00%	0 0000%
6	Invest Tax Cr	176,535	1.16%	7.51%	0.087%	0.11%	0 0092%
7	Deferred Inc Tax	2,202,583	14.45%			0.00%	0 0000%
8	**Total**	**$ 15,238,864**	**100.00%**		**6.304%**	**7.80%**	**0.6500%**

	ITC split between Debt and Equity**:		Ratio	Cost Rate	Ratio	Ratio	Deferred Inc Tax	Weighted ITC	After Gross-up
9	Common Equity	6,564,170	52%	10.5%	5.50%	73.2%	0.09%	0.0637%	0.084%
10	Preferred Equity	-	0%				0.09%	0.0000%	0.000%
11	Long Term Debt	5,970,469	48%	4.22%	2.01%	26.8%	0.09%	0.0233%	0.023%
12		12,534,639	100%		7.51%			0.0870%	0.108%

	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:	
13	Total Equity Component (Lines 1 and 9)	6.07%
14	Total Debt Component (Lines 2, 3 , 4 , and 11)	1.72%
15	**Total Revenue Requirement Rate of Return**	**7.80%**

Effective Tax Rate: 24.522%

Column:

(1)	Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology
(2)	Column (1) / Total Column (1)
(3)	Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology
(4)	Column (2) x Column (3)
(5)	For equity components: Column (4) / (1-effective income tax rate/100)
*	For debt components: Column (4)
**	Line 6 is the pre-tax ITC components from Lines 9 and 11
(6)	Column (5) / 12

DUKE ENERGY FLORIDA, LLC

Capacity Cost Recovery

Actual / Estimated True-Up

January through December 2021

Schedule E12-A – Purchased Power Capacity Cost (Projected)

Schedule E12-B – Purchased Power Capacity Cost (Re-Projected)

Schedule E12-C – Variance Analysis (Re-projected vs. Projected)

Duke Energy Florida, LLC
Calculation of Projected Capacity Costs
For the Year 2021

Docket No. 20210001-EI
Exhibit__GPD-2, Part 2
Schedule E12-A

		EST Jan-21	EST Feb-21	EST Mar-21	EST Apr-21	EST May-21	EST Jun-21	EST Jul-21	EST Aug-21	EST Sep-21	EST Oct-21	EST Nov-21	EST Dec-21	TOTAL
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	74,266,522
3	Orlando Cogen Limited (ORLACOGL)	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	74,711,196
4	Pasco County Resource Recovery (PASCOUNT)	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	27,412,320
5	Pinellas County Resource Recovery (PINCOUNT)	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	65,253,240
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	101,978,670
7	Subtotal - Base Level Capacity Costs	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	343,621,948
8	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%	
9	Base Level Jurisdictional Capacity Costs	26,597,771	26,597,770	26,597,770	26,597,770	26,597,770	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	319,173,244
10	**Intermediate Production Level Capacity Costs**													
11	Southern Franklin	4,950,486	4,950,486	2,951,482	2,951,482	3,237,054	-	-	-	-	-	-	-	19,040,989
12	Schedule H Capacity Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Subtotal - Intermediate Level Capacity Costs	4,950,486	4,950,486	2,951,482	2,951,482	3,237,054	-	-	-	-	-	-	-	19,040,989
14	Intermediate Production Jurisdict. 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%	
15	Intermediate Level Jurisdict. Capacity Costs	3,599,152	3,599,152	2,145,816	2,145,816	2,353,436	-	-	-	-	-	-	-	13,843,372
16	**Peaking Production Level Capacity Costs**													
17	Shady Hills	1,971,891	1,971,891	1,408,494	1,366,449	1,913,029	3,889,124	3,889,124	3,889,124	1,814,925	1,366,449	1,366,449	1,971,891	26,818,842
18	Vandolah (NSG)	2,811,161	2,826,948	2,025,934	2,003,380	2,732,224	5,634,444	5,617,529	5,572,423	2,666,444	1,963,912	2,009,019	2,826,948	38,690,366
19	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Subtotal - Peaking Level Capacity Costs	4,783,052	4,798,839	3,434,427	3,369,830	4,645,253	9,523,569	9,506,654	9,461,547	4,481,369	3,330,362	3,375,468	4,798,839	65,509,208
21	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%	
22	Peaking Level Jurisdictional Capacity Costs	4,588,095	4,603,238	3,294,440	3,232,475	4,455,913	9,135,388	9,119,162	9,075,895	4,298,708	3,194,616	3,237,884	4,603,238	62,839,052
23	**Other Capacity Costs**													
24	Retail Wheeling	(77,693)	(43,096)	(23,969)	(10,778)	(29,249)	(35,507)	(47,172)	(42,531)	(40,483)	(18,724)	(22,824)	(22,452)	(414,476)
25	Ridge Generating Station L.P. Termination [1]	666,245	662,777	659,309	655,842	652,374	648,906	645,438	641,971	638,503	635,035	631,568	628,100	7,766,067
26	State Corporate Income Tax Change [2]	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(2,793,306)
27	CR1&2 NBV [3]	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	80,592,431
28	SoBRA True-Up - Columbia [4]	(133,589)	-	-	-	-	-	-	-	-	-	-	-	(133,589)
29	SoBRA True-Up - DeBary [4]	(77,810)	-	-	-	-	-	-	-	-	-	-	-	(77,810)
30	SoBRA True-Up - Lake Placid [4]	(213,688)	-	-	-	-	-	-	-	-	-	-	-	(213,688)
31	SoBRA True-Up - Trenton [4]	(597,927)	-	-	-	-	-	-	-	-	-	-	-	(597,927)
32	Total Other Capacity Costs	6,048,797	7,102,942	7,118,601	7,128,324	7,106,385	7,096,660	7,081,527	7,082,701	7,081,280	7,099,572	7,092,004	7,088,909	84,127,702
33	**Total Capacity Costs (line 9+15+22+32)**	40,833,814	41,903,102	39,156,627	39,104,385	40,513,504	42,829,818	42,798,460	42,756,366	37,977,759	36,891,958	36,927,658	38,289,918	479,983,370
34	Actual/Estimated True-Up Provision - Jan - Dec 2020													463,084
35	**Total Capacity Costs w/ True-Up**													480,446,455
36	Revenue Tax Multiplier													1.00072
37	**Total Recoverable Capacity Costs**													480,792,376
38	**ISFSI Revenue Requirement** [3]													6,879,837
39	Revenue Tax Multiplier													1.00072
40	**Total Recoverable ISFSI Costs**													6,884,791
41	**Total Recoverable Capacity & ISFSI Costs (line 37+40)**													487,677,167

[1] Approved in Commission Order No. PSC-2018-0532-PAA-EQ.
[2] As approved in Order No. PSC-2021-0024-FOF-EI.
[3] As set forth in DEF's 2017 Settlement Agreement approved in Commission Order No. PSC-2017-0451-PAA-EI.
[4] True-up of solar project costs as filed in Docket No. 20190072 and 20180149 (Columbia) in accordance with paragraph 15g of the 2017 Settlement Agreement.

Duke Energy Florida, LLC
Calculation of Projected Capacity Costs
For the Year 2021

Docket No. 20210001-EI
Exhibit__GPD-2, Part 2
Schedule E12-B

		ACT Jan-21	ACT Feb-21	ACT Mar-21	ACT Apr-21	ACT May-21	ACT Jun-21	EST Jul-21	EST Aug-21	EST Sep-21	EST Oct-21	EST Nov-21	EST Dec-21	TOTAL
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	6,181,528	6,196,226	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	74,266,524
3	Orlando Cogen Limited (ORLACOGL)	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	74,711,197
4	Pasco County Resource Recovery (PASCOUNT)	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	27,412,320
5	Pinellas County Resource Recovery (PINCOUNT)	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	65,253,240
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	101,978,672
7	Subtotal - Base Level Capacity Costs	28,627,814	28,642,512	28,635,163	28,635,163	28,635,163	28,635,163	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	343,621,953
8	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%	
9	Base Level Jurisdictional Capacity Costs	26,590,945	26,604,598	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	319,173,253
10	**Intermediate Production Level Capacity Costs**													
11	Southern Franklin	4,832,347	4,988,816	2,913,671	2,914,969	3,198,304	(755,104)	-	-	-	-	-	-	18,093,003
12	Capacity Sales and Purchases	(5,587)	-	-	-	-	225,736	-	-	-	-	-	-	220,149
13	Subtotal - Intermediate Level Capacity Costs	4,826,760	4,988,816	2,913,671	2,914,969	3,198,304	(529,369)	-	-	-	-	-	-	18,313,151
14	Intermediate Production Jurisdict. 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%	
15	Intermediate Level Jurisdict. Capacity Costs	3,509,199	3,627,019	2,118,327	2,119,270	2,325,263	(384,867)	-	-	-	-	-	-	13,314,211
16	**Peaking Production Level Capacity Costs**													
17	Shady Hills	1,976,940	1,976,940	1,976,940	804,060	1,916,460	3,896,100	3,901,540	3,901,540	1,820,718	1,370,811	1,370,811	1,978,186	26,891,046
18	Vandolah (NSG)	3,033,279	2,968,686	2,017,074	1,998,157	2,873,617	5,948,748	5,695,435	5,649,696	2,702,911	1,990,514	2,036,254	2,865,669	39,780,040
19	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Subtotal - Peaking Level Capacity Costs	5,010,219	4,945,626	3,994,014	2,802,217	4,790,077	9,844,848	9,596,975	9,551,235	4,523,630	3,361,326	3,407,065	4,843,855	66,671,086
21	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%	
22	Peaking Level Jurisdictional Capacity Costs	4,806,003	4,744,042	3,831,218	2,687,999	4,594,833	9,443,572	9,205,802	9,161,927	4,339,247	3,224,318	3,268,193	4,646,419	63,953,573
23	**Other Capacity Costs**													
24	Retail Wheeling	-	(19,418)	(4,147)	(1,634)	-	-	16,799	13,216	28,447	30,185	44,924	44,338	152,710
25	Ridge Generating Station L.P. Termination [1]	670,785	667,189	656,848	657,880	654,349	650,819	647,288	643,758	640,228	636,697	633,167	629,636	7,788,644
26	State Corporate Income Tax Change [2]	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(2,793,309)
27	CR1&2 NBV [3]	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	80,592,431
28	Total Other Capacity Costs	7,154,045	7,131,031	7,135,961	7,139,506	7,137,609	7,134,079	7,147,348	7,140,235	7,151,935	7,150,143	7,161,352	7,157,235	85,740,476
29	**Total Capacity Costs (line 9+15+22+28)**	42,060,192	42,106,690	39,683,277	38,544,546	40,655,476	42,790,555	42,950,921	42,899,933	38,088,953	36,972,232	37,027,316	38,401,425	482,181,513
30	**ISFSI Revenue Requirement** [3]	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	6,879,837
31	**Total Recoverable Capacity & ISFSI Costs (line 29+30)**	42,633,512	42,680,009	40,256,596	39,117,865	41,228,796	43,363,875	43,524,240	43,473,252	38,662,273	37,545,552	37,600,635	38,974,744	489,061,350
32	**Capacity Revenues**													
33	Capacity Cost Recovery Revenues (net of tax)	35,903,840	34,543,316	35,777,609	36,135,702	39,269,964	45,215,250	48,143,985	50,805,403	49,334,515	45,283,201	37,695,418	34,683,384	492,791,587
34	Prior Period True-Up Provision Over/(Under) Recovery	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(38,590)	(463,084)
35	**Current Period Revenues (net of tax)**	35,865,250	34,504,726	35,739,018	36,097,112	39,231,373	45,176,659	48,105,394	50,766,813	49,295,925	45,244,611	37,656,828	34,644,794	492,328,503
36	**True-Up Provision**													
37	True-Up Provision - Over/(Under) Recov (Line 35-31)	(6,768,262)	(8,175,284)	(4,517,578)	(3,020,753)	(1,997,422)	1,812,785	4,581,154	7,293,560	10,633,652	7,699,059	56,192	(4,329,950)	3,267,153
38	Interest Provision for the Month	249	(425)	(883)	(1,181)	(862)	(865)	(294)	(110)	156	350	352	245	(3,268)
39	Current Cycle Balance - Over/(Under)	(6,768,012)	(14,943,722)	(19,462,182)	(22,484,117)	(24,482,401)	(22,670,481)	(18,089,620)	(10,796,171)	(162,362)	7,537,047	7,593,591	3,263,886	3,263,885
40	Prior Period Balance - Over/(Under) Recovered	6,070,083	6,070,083	6,070,083	6,070,083	6,070,083	6,070,083	6,070,083	6,070,083	6,070,083	6,070,083	6,070,083	6,070,083	6,070,083
41	Prior Period Cumulative True-Up Collected/(Refunded)	38,590	77,181	115,771	154,361	192,952	231,542	270,133	308,723	347,313	385,904	424,494	463,084	463,084
42	Prior Period True-up Balance - Over/(Under)	6,108,673	6,147,264	6,185,854	6,224,445	6,263,035	6,301,625	6,340,216	6,378,806	6,417,396	6,455,987	6,494,577	6,533,167	6,533,167
43	**Net Capacity True-up Over/(Under) (Line 39+42)**	($659,339)	($8,796,458)	($13,276,329)	($16,259,673)	($18,219,367)	($16,368,856)	($11,749,405)	($4,417,365)	$6,255,034	$13,993,033	$14,088,168	$9,797,053	$9,797,053

[1] Approved in Commission Order No. PSC-2018-0532-PAA-EQ.
[2] As approved in Order No. PSC-2021-0024-FOF-EI.
[3] As set forth in DEF's 2017 Settlement Agreement approved in Commission Order No. PSC-2017-0451-PAA-EI.

Contract Data:

	Name	Start Date	Expiration Date	Type	Purchase/Sale	MW
1	Orlando Cogen Limited (ORLACOGL)	Sep-93	Dec-23	QF	Purch	115.00
2	Orange Cogen (ORANGECO)	Jul-95	Dec-25	QF	Purch	104.00
3	Pasco County Resource Recovery (PASCOUNT)	Jan-95	Dec-24	QF	Purch	23.00
4	Pinellas County Resource Recovery (PINCOUNT)	Jan-95	Dec-24	QF	Purch	54.75
5	Polk Power Partners, L. P. (MULBERY/ROYSTER)	Aug-94	Aug-24	QF	Purch	115.00
6	Southern - Franklin	Jun-16	May-21	Other	Purch	424.00
7	Vandolah (NSG)	Jun-12	May-27	Other	Purch	669.00
8	Shady Hills Tolling Agreement	Apr-07	Apr-24	Other	Purch	521.00

Duke Energy Florida, LLC
Variance Analysis
For the Year 2021

Docket No. 20210001-EI
Exhibit__GPD-2, Part 2
Schedule E12-C

Line		Re-Projection Total	Original Projection Total	Variance Total
1	**Capacity Revenues**			
2	Capacity Cost Recovery Revenues (net of tax)	$492,791,587	$487,326,292	$5,465,295
3	Prior Period True-Up Provision Over/(Under) Recovery	(463,084)	(463,084)	0
4	**Current Period Revenues (net of tax)**	492,328,503	486,863,207	5,465,295
5				
6	**Capacity Costs**			
7	**Base Production Level Capacity Costs**			
8	Orange Cogen (ORANGECO)	74,266,524	74,266,522	2
9	Orlando Cogen Limited (ORLACOGL)	74,711,197	74,711,196	1
10	Pasco County Resource Recovery (PASCOUNT)	27,412,320	27,412,320	0
11	Pinellas County Resource Recovery (PINCOUNT)	65,253,240	65,253,240	0
12	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	101,978,672	101,978,670	2
13	Subtotal - Base Level Capacity Costs	343,621,953	343,621,948	5
14	Base Production Jurisdictional Responsibility	92.885%	92.885%	0.000%
15	Base Level Jurisdictional Capacity Costs	319,173,253	319,173,244	9
16				
17	**Intermediate Production Level Capacity Costs**			
18	Southern - Franklin	18,093,003	19,040,989	(947,986)
19	Capacity Sales and Purchases	220,149	0	220,149
20	Subtotal - Intermediate Level Capacity Costs	18,313,151	19,040,989	(727,838)
21	Intermediate Production Jurisdictional Responsibility	72.703%	72.703%	0.000%
22	Intermediate Level Jurisdictional Capacity Costs	13,314,211	13,843,372	(529,161)
23				
24	**Peaking Production Level Capacity Costs**			
25	Shady Hills	26,891,046	26,818,842	72,204
26	Vandolah (NSG)	39,780,040	38,690,366	1,089,675
27	Subtotal - Peaking Level Capacity Costs	66,671,086	65,509,208	1,161,879
28	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	0.000%
29	Peaking Level Jurisdictional Capacity Costs	63,953,573	62,839,052	1,114,521
30				
31	**Other Capacity Costs**			
32	Retail Wheeling	152,710	(414,476)	567,186
33	Ridge Generating Station L.P. Termination [1]	7,788,644	7,766,067	22,577
34	State Corporate Income Tax Change [2]	(2,793,309)	(2,793,306)	(3)
35	CR1&2 NBV [3]	80,592,431	80,592,431	0
36	SoBRA True-Up - Columbia [4]		(133,589)	133,589
37	SoBRA True-Up - DeBary [4]		(77,810)	77,810
38	SoBRA True-Up - Lake Placid [4]		(213,688)	213,688
39	SoBRA True-Up - Trenton [4]		(597,927)	597,927
40	Other Jurisdictional Capacity Costs	85,740,476	84,127,702	1,612,774
41				
42	**Subtotal Jurisdictional Capacity Costs (Line 15+22+29+40)**	482,181,513	479,983,370	2,198,143
43				
44	**ISFSI Revenue Requirement** [3]	6,879,837	6,879,837	(0)
45				
46	**Total Jurisdictional Capacity Costs (Line 42+44)**	489,061,350	486,863,207	2,198,143
47				
48	**True-Up Provision**			
49	True-Up Provision - Over/(Under) Recovered	3,267,153	0	3,267,153
50	Interest Provision for the Month	(3,268)	0	(3,268)
51	Current Cycle Balance - Over/(Under)	3,263,885	0	3,263,885
52				
53	Prior Period Balance - Over/(Under) Recovered	6,070,083	(463,084)	6,533,167
54	Prior Period Cumulative True-Up Collected/(Refunded)	463,084	463,084	0
55	Prior Period True-up Balance - Over/(Under)	6,533,167	0	6,533,167
56				
57	**Net Capacity True-up Over/(Under) (Line 51+55)**	$9,797,053	$0	$9,797,053

[1] Approved in Commission Order No. PSC-2018-0532-PAA-EQ.
[2] As approved in Order No. PSC-2021-0024-FOF-EI.
[3] As set forth in DEF's 2017 Settlement Agreement approved in Commission Order No. PSC-2017-0451-PAA-EI.
[4] True-up of solar project costs as filed in Docket No. 20190072 and 20180149 (Columbia) in accordance with paragraph 15g of the 2017 Settlement Agreement.

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210001-EI

DIRECT TESTIMONY OF JOSEPH SIMPSON

July 27, 2021

Q. Please state your name and business address.

A. My name is Joseph Simpson. My business address is 8202 W. Venable St. Crystal River, FL 34429.

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

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company") as Manager, Generation Engineering. DEF is a wholly-owned subsidiary of Duke Energy Corporation ("Duke Energy").

Q. Describe your responsibilities as Manager of Generation Engineering.

A. As Manager of Generation Engineering, I lead the Regional Engineering Organization for the Florida Generating Fleet. The group specifically provides engineering and technical support for components and equipment in the areas of electrical, instrumentation, control systems, and protective relaying. This department provides day-to-day plant support for maintenance and operations for planned/emergent work as well as project support during upgrades/modifications.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science in Electrical Engineering from the University of South Florida in Tampa, FL. I am a licensed Professional Engineer in the State of Florida, and I have 15 years of experience in power generation. Initially employed at Progress Energy Crystal River Unit 3 ("CR3") Nuclear Facility as Instrumentation & Controls ("I&C") Design Engineer. I transitioned later into Electrical/I&C Maintenance Leadership, Nuclear Operations, and then back to Design Engineering Leadership. Following closure of CR3 in 2013, I transitioned to non-nuclear generation as a Project Manager/Project Engineer. In 2016, I transitioned from Project Manager/Project Engineer into my current position as Regional Engineering Manager.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to present to the Commission the cause of the Spring outage at the Company's Crystal River Unit 4 generating unit ("CR4") and to explain how the Company acted reasonably and prudently at all times.

Q: Do you have any exhibits?

A: Yes, I sponsor the following exhibits:

- Exhibit No. __ (JS-1), Root Cause Analysis; and
- Exhibit No. __ (JS-2), Repair Evaluation Report.

These exhibits are true and accurate.

Q: Can you please give a summary of the CR4 Spring outage along with a high-level description of what caused the outage?

A: Yes. As CR4 was being returned to service after a planned outage, the unit attempted to synchronize to the grid out of phase, resulting in damage to the generator rotor and an unplanned outage. By way of background, generator synchronization is the process of connecting the generator to the 230kV transmission or power system (in the case of CR4) by matching the generator and power system's electrical parameter. During synchronization, the generator voltage and frequency are adjusted to match the system voltage and frequency, and the angle is monitored to ensure the breaker close circuit is completed when the angle "matches." Closely matching these parameters ensures torques are minimized as the power system begins to govern the prime mover's rotating field. Standard Operating Procedure ("SOP") at CR4 is to synchronize the unit to the grid in the automatic mode, that is to say, the command to close the generator breaker is given by a breaker control relay when the synchronization parameters are met. At many plants, SOP is to sync the unit to the grid manually, and the CR4 Startup Procedure not only permits manual synchronization but that method of synchronization has been used at CR4 both before and since this particular event.

In this particular instance, the CR4 operator unsuccessfully attempted three times to synchronize the unit in the “automatic” mode; after those attempts were unsuccessful, the operator green flagged the breaker (issued an “open” command to the breaker) and placed the sync switch in manual mode. The operator then red flagged breaker 3233 (issued a “closed” command to the breaker) expecting a failed synchronization which would allow repositioning of the sync switch handle back to automatic. The operator expected nothing to happen until the automatic sync option was selected and the synchroscope rolled to the twelve o'clock position. Unknown to the operator, the manual sync check relay (25) had failed, allowing the breaker close circuit to be completed causing the turbine/generator to attempt to sync to the grid out of phase.

Q: Has the Company performed a Root Cause Analysis (RCA) to understand the cause of the outage?

A: Yes. The Company’s RCA is attached to my testimony as Exhibit No. __ (JS-1).

Q: What is the purpose of the RCA?

A: RCAs are a standard practice when there is an event in the utility industry; for DEF, RCAs are required for events that meet the Safety, Environmental, Asset damage, or Megawatt impact (SEAM) criteria. Their sole purpose is to identify the cause of the event with the intent of preventing future similar issues from occurring. When an event like the outage being discussed occurs, DEF will perform an analysis to determine the cause(s) of the event, including contributory cause(s), the extent of the condition at the impacted unit and elsewhere within the organization, and determine what corrective actions can be taken to mitigate against repeat occurrences moving forward. Corrective actions could include, for example, modification, revisions, or creation of new procedures and/or training. The RCA attached to my testimony was conducted consistent with the Corrective Action Program for the purpose described above and was not done to support any regulatory proceeding.

Q: How many people were included on the RCA team and what were their backgrounds?

A: In addition to myself, the RCA Team included four (4) employees: a Generator Specialist from our Turbine Generator Services (TGS) Organization with 35+ years of generation experience, a qualified Operations Team Supervisor (OTS) from another facility in our Florida Generating Fleet, an OTS from CR4 that was not on-shift during the night of the event, and an Operational Excellence Specialist responsible for adherence to the Corrective Action Program.

Q: Please describe the result of the Company's RCA.

A: As shown in Section V of the Report (page 4), the RCA concluded there were two Root Causes of the occurrence: Failure of a component, specifically the Beckwith Manual sync check relay; and the previous success in use of a rule reinforced continued use of the rule. The RCA also determined there were other contributing causes, which are outlined in Section VI of the document.

Q: Can you please provide further explanation regarding the two root causes identified in the RCA?

A: Yes. The first cause identified was the failure of the Beckwith Manual sync check relay. The purpose of the relay is to prevent the generator/unit from attempting to sync to the grid in an out of phase condition – that is, its purpose is to prevent exactly what occurred at CR4. The Beckwith Manual sync check relay is a highly reliable component with extremely low known incidents of failure, so its failure was unforeseen and unforeseeable prior to the event. The second cause identified, the previous success of a rule reinforcing continued use of the rule, is essentially another way of saying the operator had previously performed a task in a certain way with no adverse consequences, and therefore believed it was acceptable to continue to do so without adverse results.

Q: Regarding the second identified cause, why was the operator not able to follow the rule in this particular instance without the unit being damaged?

A: The operator believed the generating unit would not be permitted to attempt to synchronize to the grid even though it was "red flagged" (the breaker commanded to close) because of the manual relay sync check; that is, the operator believed synchronization would be prevented by the device, thereby allowing the operator to reset the unit to "automatic" and proceed with synchronization attempt in automatic configuration. . Had the sync check relay not failed, this is the chain of events that would have occurred. However, because the relay check had failed, when the unit was "red flagged" it synchronized while out of phase causing the damage and the resulting outage.

Q: Was the operator's actions a result of a failure to properly train the operator?

A: No, the operator was properly trained and had the supporting materials necessary to correctly and safely operate the unit. In this case, the operator simply made a physical error by red-flagging (closing) the breaker approximately one (1) second prior to the appropriate time in reliance on the relay. In fact, had the operator closed the breaker one second later, no damage would have occurred (and the failure of the relay would have gone unnoticed until the next scheduled test or potentially the next attempt at manual synchronization). Thus, the failure was not of training, but was rather a human performance error. An explanation of what occurred and what led the operator to believe his actions were correct is summarized in the "Five (5) Why Staircase" on page 7 of the RCA:

> 1. Why did Crystal River Unit 4 generator have an out of phase synchronization to the grid?
>
> 1a. The operator red flagged the breaker at the wrong point in the synchronization process.
>
> 2. Why did the operator red flag the breaker at the wrong point in the synchronization process?
>
> 2a. The operator thought that it didn't matter when you red flagged the breaker.

3. Why did the operator think that it didn't matter when you red flagged the breaker?

3a. The operator understood that the synchronizing relay would not allow an out of phase synchronization.

4. Why did the operator understand that the synchronizing relay would not allow an out of phase synchronization?

4a. The operators training and experience supported this position.

4b. The operator expected the synchronization check relay to perform as designed.

5. Why did the synchronization check relay not support the operators training and experience, and not perform as designed?

5a. The synchronization check relay had failed allowing an out of phase event.

In sum, the operator believed it did not matter when he red-flagged the breaker because the sync check relay would not allow it to attempt to sync out of phase; had the component, which is a very reliable component that was properly maintained and inspected, operated as designed the operator would have been correct.

Q: Would the damage and resulting outage have occurred if the manual relay check had performed properly?

A: No. Notwithstanding any other actions taken by the operator, had the relay check performed as designed and expected, the unit would not have been able to attempt to sync to the grid out of phase and the unit would not have been damaged.

Q: What caused the relay to fail and should DEF have anticipated that failure?

A: No, DEF could not have reasonably anticipated the failure. The component was regularly tested in conformity with DEF's established testing protocol; in fact, it was tested approximately 6 months prior to this incident and was operating properly. However, at some time between the testing and the incident, a soldered component of the relay failed. My Exhibit No. __ (JS-2) is the Repair Evaluation Report provided by the component's manufacturer. There was absolutely no way for the operator to be aware of the failure. Had the unit synced to the grid in the automatic setting, or had the operator red-flagged the breaker within the range that would have allowed synchronization, DEF would still be unaware of the failure and would have remained unaware until either the next component test was completed or an operator attempted to manually sync the unit to the grid following a later outage – but in the latter case, only then if the operator mis-timed the synchronization attempt. DEF has prudently operated and maintained the relay check; the failure was beyond DEF's reasonable ability to control.

Q. Based on your review of the RCA, did DEF act prudently with respect to its operation of CR4?

A. Yes, as explained in my testimony, the Company at all times acted prudently.

Q. Does this conclude your testimony?

A. Yes.

Root Cause Analysis Report

CRN U4 Generator Out of Phase Synchronization
12/18/2020

Revision # 2.0

PlantView Event Number: 1100300

Prepared By:	Barbara Martinuzzi	Date:	2/2/2021
Sponsor Approval:	Wayne Toms	Date:	2/24/2021

Regional Review Committee date: ______________________

This cause analysis evaluates important conditions adverse to quality through the use of a structured evaluation process. The information identified in this report was discovered using all the data available to the root cause evaluation team at the time of writing using the benefit of hindsight. Cause analyses performed after the fact for Duke Energy have been established as a responsive means to document and assure that conditions adverse to quality are promptly identified and corrected and, as required, to assure that actions are taken to reduce the risk of repetition of the event or condition adverse to quality.

As such, this cause analysis is not intended to make a determination as to whether any of the actions taken or the decisions made by management, vendors, internal organizations, or individual personnel prior to or at the time of the event were reasonable or prudent based on the information that was known or available at the time they took such actions or made such decisions. Any individual statement or conclusion included in the evaluation as to whether errors may have been made or improvements are warranted is based solely upon information the root cause team considered, including information and results learned after-the-fact. Nothing in this evaluation should be construed as an admission of negligence, liability, or imprudence.

Team Kick-Off Meeting Date:	1/21/2021
Date Report Completed:	2/16/2021
Root Cause Investigator(s):	Barbara Martinuzzi, Sr OE Specialist James C Winborne, Lead Engineer Joe Simpson, Manager Generation Engineering Doug Wood, Senior Engineer Gene Mullins, Interim Assignment - Leader Dana Christensen, Supervisor Operations

I. Problem Statement:

Crystal River Unit 4 generator failed to synchronize (sync) with the system when breaker closed, resulting in an out of phase event.

II. Description of Incident/Issue:

Crystal River Unit 4 had been in an extended outage returning to service on December 16, 2020. Unit 4 had been operating at near minimum load, having just completed the swapping from the standby boiler feed pump to the main boiler feed pump, when the turbine/generator tripped due to a boiler feed water pump control issue.

Unit 5 was in startup operations at the time of the unit 4 turbine/generator trip. The station only has one standby boiler feed pump that is shared by both units. Since unit 5 was still one day away from being online, the decision was made to put unit 5 on hold in a safe condition and recover unit 4.

Operations closed the exciter field breaker, turbine auto sync was selected, set generator output breaker 3233 to close, turbine speed was set at 3602 RPM, and generator voltage verified to be within 2KV of system voltage. When the synchroscope rolled to the twelve o'clock position, all conditions were met (sync slip frequency OK, sync volts OK, sync phase angle OK), amber lights were lit, but breaker 3233 did not close and unit 4 failed to sync to the grid. A walkdown was performed and Operations found permissive 86A&B lockout relays tripped. The permissive lockout relays were reset, and a second attempt to synchronize in auto was initiated.

On the second auto attempt, when the synchroscope rolled to the twelve o'clock position, all conditions were met (sync slip frequency OK, sync volts OK, sync phase angle OK), amber lights were lit, but breaker 3233 did not close and unit 4 failed to sync to the grid a second time. Another walkdown was performed and Operations found plant lines lockout relays 3AG & AB tripped. The plant line lockout relays were reset, and a third attempt to synchronize in auto was initiated.

On the third auto attempt, when the synchroscope rolled to the twelve o'clock position, all conditions were met (sync slip frequency OK, sync volts OK, sync phase angle OK), amber lights were lit, but breaker 3233 did not close and unit 4 failed to sync to the grid for the third time in auto.

The operator green flagged the breaker in auto and placed the sync switch in manual. The operator then red flagged breaker 3233 expecting a failed synchronization allowing reposition of the sync switch handle back to auto. The operator expected nothing to happen until the auto option was selected and the synchroscope rolled to the twelve o'clock position. The operator stated that they were not attempting to synchronize in manual rather attempting to reset the synchronization circuit to permit auto synchronization. Through interviews it was noted that the auto sync option has been used since 2017 and use of the manual option would be rare. Unknown to Operations was that the manual sync check relay 25A1 had failed. The circuit was completed when breaker 3233 was red flagged causing the turbine/generator to attempt to sync to the grid out of phase at a 160-degree angle. This resulted in significant damage to the generator rotor. The event also caused enough grid instability on the 230KV to trip Citrus Combined Cycle PB1 station offline (reference Plantview event #1100460).

The Beckwith Manual sync check relay model M-0359 (25A1) failed to pass bench testing. The failure mode allowed the closing contact to latch closed as far out as fifty degrees from zero. The setpoint is fifteen degrees. This relay monitors the slip frequency, voltage, and phase angle. When all three conditions are satisfied, the relay closes permitting synchronization to the grid. The relay was sent for failure analysis and a spare relay was removed from Crystal River Unit 2, bench tested and installed.

No damage was initially found to the machine during inspection, all electrical tests were satisfied, and the station went into a forced outage. During attempted start-up on January 7, a low speed centrifugal ground was found on the main generator field and the unit was placed in forced outage.

Timeline

December 16, 2020	22:53	Unit 4 returned to service
December 17, 2020	19:10	Turbine/generator tripped (boiler feed water pump control issue)
December 17, 2020	22:00:12.608	First attempt to auto sync (permissive 86A&B lockouts tripped)
December 17, 2020	22:00:16.924	Second attempt to auto sync (plant line 3AG & 3BG lockout relays tripped)
December 17, 2020	22:00:20.132	Third attempt to auto sync (cause for failed auto sync unknown)
December 17, 2020	22:11:44.7340	Citrus Combined Cycle PB1 tripped (breaker open)
December 17, 2020	22:11:47.7080	Fourth attempt (red flagged the breaker - breaker closed)
December 17, 2020	22:11:47.7106	Unit 4 breaker 3233 tripped open (U4 placed in forced outage)
December 18, 2020		Meeting with Turbine Generator Services
December 21, 2020		Review of substation drawings, relay operational data
December 23, 2020		Beckwith manual sync check relay replaced
January 7, 2021		Unit 4 start attempt (ground on the main field)
January 20, 2021		Beckwith manual sync check relay model M-0359 (25A1) sent for failure analysis
February 8, 2021		Beckwith completed repair evaluation report (confirmed onsite findings)

III. Extent of Condition:

The Beckwith Manual Sync Check Relay model M-0359 (25A1) is typically a very solid device with little to no history of failure in decades of operation. Relay 25A1, serial #1711 was originally procured on February 28, 2002, and then relocated from the retired 230KV Crystal River substation and reinstalled in the new 230KV substation terminal house as part of the 2017-2019 fiber optic communication upgrades. The relay was last functionally tested in April 2020. The relay was sent for failure analysis following the event. The sync check relay was verified with component failure that led to mis-operation of the device. The report is included as Attachment 2.

The Beckwith model M-0193 and M-0189 auto sync check relays were tested and passed.

The plant line lockout (3AG & AB) relay panels were modified during 2017 and completed in 2019 as part of Transmission substation upgrade project, making units 4 and 5 panel light sequence and visual cues identical. Before this project, the plant line relay panel light sequence, which indicates a unit trip, was different for both units. The Operations Team Supervisor (OTS) was aware of this modification, but several operators on shift were not and did not check the plant line relay panels on initial walkdown. Detailed information on relay trip schedules along with the lockout relay reset procedure would have assisted Operations during the multiple attempts to synchronize.

Prior to the 2017-2019 fiber optic outage, the preferred method to sync unit 4 was in manual when syncing to the grid. Following the outage, the preferred method was modified to auto. It has been verified that no changes to the wiring or sync selector switch occurred during this outage. There have been no changes to the synchronization hard panel since original panel construction in 2002.

IV. Analysis:

The team utilized interviews, shift logs, shift turnover documents and the pre-job brief. Status updates and correspondence from Transmission and TGS, developed immediately after the event were examined as part of the analysis. Station electrical drawings, digital fault recorder, relay event files and substation relay schemes were reviewed along with projects and configuration changes occurring between 2017 and 2020. The Start-up procedure and Emergency Operating Procedure (EOP) were reviewed along with the generator synchronizing guide instructions and the General Electric (GE) contact table for breaker 3233/3234 control switch. Unit 5 breaker control switches were also evaluated. The Beckwith Electric Company repair evaluation report was reviewed.

V. Summary of Root Cause(s):

Note: Not necessarily listed in order of significance.

A2B6C01 – Damaged, Defective or failed part

The Beckwith Manual sync check relay model M-0359 (25A1) failed in the closed position which left the circuit armed on manual operation.

A3B2C04 – Previous successes in use of rule reinforced continued use of rule

(Successful use of a rule in the past led to the wrong use of the rule or the rule being incorrectly applied.)

The operator red flagged breaker 3233 expecting a failed synchronization allowing reposition of the sync switch handle back to auto. Proper operational procedure would be to green flag the breaker placing the unit in a safe condition prior to repositioning the synchronization switch handle.

VI. Summary of Contributing Cause(s):

Note: Not necessarily listed in order of significance.

A3B3C04 – LTA review based on assumption that process will not change

(Individual believed that no variability existed in the process and thus overlooked the fact that a change had occurred, leading to different results than normally realized).

After initial voltage adjustment and verifying generator speed of 3602 RPM, no other adjustments were made to the frequency or voltage angle. Adjusting the turbine speed may have allowed the generator voltage and system voltage to align and the unit to sync to the grid in auto.

A3B3C06 – Individual underestimated the problem by using past events as basis

(Based on stored knowledge of past events, the individual underestimated problems with the existing event and planned for fewer contingencies than would be needed.)

During the 17-minute time frame of the event, the operations crew attempted unsuccessfully to synchronize to the grid four times without a questioning attitude and without consulting the Operations Superintendent and/or Station Manager.

A6B2C01 – Practice or "hands-on" experience LTA

(The on-the-job training did not provide opportunities to learn skills necessary to perform the job. There was not enough practice, or hands-on, time allotted.)

Additional training resources are needed to fully train the shifts for the newly restructured organization.

A5B1C01 – Format deficiencies

(The layout of the written communication made it difficult to follow. The steps of the procedure were not logically grouped.)

The unit 4 and unit 5 steps are intertwined even though the start-up process and unit configuration are different. CRN Startup Procedure #CRNOP/00/TBD/0004 is included as Attachment 3.

A5B2C08 – Incomplete/situation not covered

(*Details of the written communication were incomplete. Insufficient information was presented. The written communication did not address situations likely to occur during the completion of the procedure.)*

Page 75 of the Start-up procedure notes 'two methods of generator synchronization on Unit 4: Auto sync mode and Manual mode. Automatic is the normal mode'.
Page 76, section 13.2.2 states 'If Auto synchronization is inoperable on unit 4, then use manual sync listed in Enclosure 5'. Enclosure 5 instructions are incomplete, stopping mid step.

A5B2C01 – Limit inaccuracies

(*Limits were not expressed clearly and concisely.)*

A generator synchronizing guide (operator aid) for unit 5 is laminated and attached to the generator synchronization panel. The guide states 'Ensure the turbine speed is at least 3600 RPM (3602 is recommended)." Quite often, turbine speed needs to be adjusted up and down for synchronization. 3602 RPM should be a target, and not a specific setpoint.

A4B5C09 – Change-related documents not developed or revised
(Changes to processes resulted in the need for new forms of written communication, which were not created.)
Laminated generator synchronizing guidance (operator aid) did not exist for unit 4.

VII. Extent of Cause:

Cases where the plant line breakers also serve as the Generator Synchronizing Breakers should be reviewed for output contact supervision with 25A1/A2 elements. Modifying SEL-351S Breaker 3233/3234 logic to supervise output contact equation 102 with 25A1/A2 synchronizing checks will provide a fail-safe mechanism that allows performance only one way.

VIII. Repeat Event Review:

There have been no similar generator events at Crystal River or in the Florida fleet within the last three years.

Corrective Actions:

Immediate & Interim Corrective Actions *A4B5C09 – Change-related documents not developed or revised*		
Corrective Action Describe specific actions taken or required.	**Assignee** Evaluator **SHALL** obtain concurrence from assignee or supervisor	**Due/Completion Date**
Develop a generator synchronizing guide (operator aid) for unit 4, laminate and attach to the generator output breaker.	Jamie Long	Complete

Corrective action for Extent of Condition		
Corrective Action Describe specific actions taken or required	**Assignee** Evaluator **SHALL** obtain concurrence from assignee or supervisor	**Due/Completion Date**
Create PMs to check synchronizing relays on a six-year period based on industry standard.	Heath McDonald	Complete
Share technical document on lessons learned with peers.	Joe Simpson	5/1/2021

Action(s) to Correct the Root Cause(s)		
Root Cause(s):	*A2B6C01 – Damaged, Defective or failed part* *A3B2C04 – Previous successes in use of rule reinforced continued use of rule*	
Corrective Action Describe specific actions taken or required	**Assignee** Evaluator **SHALL** obtain concurrence from assignee or supervisor	**Due/Completion Date**
CAPR 1: Replace the Beckwith Manual Sync Check Relay model M-0359 (25A1) with a new device.	Heath McDonald	5/1/2021
CAPR 2: Revise Crystal River Start-Up Procedure to include detailed information on resetting relays.	TJ Snodgrass	4/1/2021
CAPR 3: Performance manage employees involved in the event as appropriate.	Jamie Long	3/15/2021
CAPR 4: Share this Root Cause Analysis with all employees at the station.	Wayne Toms	3/31/2021

Action to Correct the Contributing Cause(s)		
Contributing Cause(s):	*A3B3C04 – LTA review based on assumption that process will not change* *A4B2C04 – Resources not provided to assure adequate training was provided/ maintained* *A3B3C06 – Individual underestimated the problem by using past events as basis* *A6B2C01 – Practice or "hands-on" experience LTA*	
Corrective Action Describe specific actions taken or required	**Assignee** Evaluator **SHALL** obtain concurrence from assignee or supervisor	**Due/Completion Date**
Ensure that there is a specific lesson plan around generator synchronization and implement.	TJ Snodgrass	5/1/2021
Ensure that the lesson plan includes methodical problem-solving techniques with unfamiliar situations.	TJ Snodgrass	6/1/2021
Provide instructor led training for Operations and OTSs upon completion of the Start-up procedure and synchronizing guide revisions.	TJ Snodgrass	5/1/2021
Issue Standing Order "maximum of two attempts at synchronization in start-up procedure" until identified procedural changes are complete.	Jamie Long	3/15/2021
Evaluate OTS training (technical, command and control) and consider increased shadowing time and rotation to improve proficiency.	Jamie Long	5/1/2021

Action(s) to Correct the Contributing Cause(s)		
Contributing Cause (s):	*A5B1C01 – Format deficiencies* *A5B2C08 – Incomplete/situation not covered* *A5B2C01 – Limit inaccuracies*	
Corrective Action Describe specific actions taken or required	**Assignee** Evaluator **SHALL** obtain concurrence from assignee or supervisor	**Due/Completion Date**
Revise Crystal River Start-Up Procedure to add enclosures for unit specific activities.	TJ Snodgrass	4/1/2021
Revise Crystal River Start-Up Procedure to reference the EOP ensuring EOP steps have been satisfied.	TJ Snodgrass	4/1/2021
Update generator synchronizing guides (operator aids) on both units to reference 3602 RPM should be a target, and not a specific setpoint.	TJ Snodgrass	4/1/2021

Corrective action for Extent of Cause		
Corrective Action Describe specific actions taken or required	**Assignee** Evaluator **SHALL** obtain concurrence from assignee or supervisor	**Due/Completion Date**
Modify SEL-351S Breaker 3233/3234 logic to supervise output contact equation 102 with 25A1/A2 synchronizing checks.	Jezzel Martinez (Transmission)	3/15/2021
Review existing facilities in Florida for extent of cause.	Joe Simpson	4/1/2021

Effectiveness Review Action Insert rows for additional EREV such as interim effectiveness review		
Corrective Action Describe specific actions required	**Assignee** Evaluator **SHALL** obtain concurrence from assignee or supervisor	**Due Date** 6 months or earlier after all actions have been completed
EREV: Perform effectiveness review on event #1100300. Document no repeat events, procedures revised as described in the corrective actions, training completed, and Transmission corrective actions complete.	Barbara Martinuzzi	10/18/2021

Attachments

Attachment 1: Five (5) Why Staircase

Problem Statement: Crystal River Unit 4 generator failed to synchronize (sync) with the system when breaker closed, resulting in an out of phase event.

1. Why did Crystal River Unit 4 generator have an out of phase synchronization to the grid?
1a. The operator red flagged the breaker at the wrong point in the synchronization process.

2. Why did the operator red flag the breaker at the wrong point in the synchronization process?
2a. The operator thought that it didn't matter when you red flagged the breaker.

3. Why did the operator think that it didn't matter when you red flagged the breaker?
3a. The operator understood that the synchronizing relay would not allow an out of phase synchronization.

4. Why did the operator understand that the synchronizing relay would not allow an out of phase synchronization?
4a. The operators training and experience supported this position.
4b. The operator expected the synchronization check relay to perform as designed.

5. Why did the synchronization check relay not support the operators training and experience, and not perform as designed?
5a. The synchronization check relay had failed allowing an out of phase event.

Attachment 2: Beckwith Electric Company Repair Evaluation Report

PDF
RMA 21184 DUKE ENERGY EVALUATION

Attachment 3: CRN Startup Procedure #CRNOP/00/TBD/0004

PDF
CR Unit Start-Up Procedure OI-1 CRNC

Attachment 4: Barrier(s) that should have precluded or reduced the likelihood or significance of the incident

BARRIER(s) THAT SHOULD HAVE PRECLUDED, OR REDUCED THE LIKELIHOOD OR SIGNIFICANCE OF, THE INCIDENT (Barriers that should have precluded the incident may be part of the Root Causal Train. Barriers that should have reduced the incident may be part of a Contributing Causal Train.)	**BARRIER ASSESSMENT (HOW THE BARRIER FAILED)** (Identify whether, and in what specific manner, the barrier was missing, weak, or ineffective. Note that a barrier may fail in several different ways in the same incident. Each failure of the barrier should be considered separately.)	**CONSEQUENCES OF BARRIER FAILURE** (Careful consideration of **actual** consequences of specific barrier failure is needed to help determine whether a specific failure is part of the Root Causal Train or a Contributing Causal Train.) Indicate if Barrier Failure directly led to or contributed to the Event.	**REASON(s) for BARRIER FAILURE** (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented this Barrier failure. Apply "WHY STAIRCASE" as appropriate.
The Beckwith Manual sync check relay model M-0359 (25A1)	Relay failed in the closed position.	The relay failure armed the circuit on manual operation (directly led).	Damaged, defective or failed part
Operator red flagged the breaker at the 9 o'clock position on the synchroscope	Synchronization to the grid should occur as close to 12 o'clock as possible, but within the zone of 11 to 1 on the synchronization scope.	The operator expected a failed synchronization allowing reposition of the sync switch handle back to auto. Operator was unaware that the sync check relay failed (directly led).	Previous successes in use of rule reinforced continued use of the rule
Turbine speed of 3602 RPM was considered a setpoint and not a target.	After initial voltage adjustment and verifying generator speed of 3602 RPM, no other adjustments were made to the turbine speed.	Adjusting the turbine speed greater than 3602 RPM may have allowed the generator voltage and system voltage to align and the unit to sync in auto (contributed to).	Less than adequate review based on assumption that process will not change

BARRIER(s) THAT SHOULD HAVE PRECLUDED, OR REDUCED THE LIKELIHOOD OR SIGNIFICANCE OF, THE INCIDENT (Barriers that should have precluded the incident may be part of the Root Causal Train. Barriers that should have reduced the incident may be part of a Contributing Causal Train.)	**BARRIER ASSESSMENT (HOW THE BARRIER FAILED)** (Identify whether, and in what specific manner, the barrier was missing, weak, or ineffective. Note that a barrier may fail in several different ways in the same incident. Each failure of the barrier should be considered separately.)	**CONSEQUENCES OF BARRIER FAILURE** (Careful consideration of **actual** consequences of specific barrier failure is needed to help determine whether a specific failure is part of the Root Causal Train or a Contributing Causal Train.) Indicate if Barrier Failure directly led to or contributed to the Event.	**REASON(s) for BARRIER FAILURE** (Identify immediate cause(s) of Barrier failure.) As appropriate, identify additional barrier(s) that should have prevented this Barrier failure. Apply "WHY STAIRCASE" as appropriate.
On the job training	The amount of training did not adequately address normal, abnormal, and emergency working conditions.	Operations team supervisor experience consisted of shadowing for approximately three months. Shadowing only provides training on conditions that exist during the shadowing. (contributed to).	Practice or "hands-on" experience less than adequate
Procedure was not of adequate quality and did not provide clear instructions.	The unit steps are intertwined even though the start-up process and unit configuration are different. Enclosure instructions are incomplete, and limits should be a target and not setpoints.	Operator and Operations team supervisor could not rely on the procedure for guidance during the event (contributed to).	Format deficiencies Incomplete/situation not covered Limit inaccuracies Change related documents not developed or revised

BECKWITH ELECTRIC CO.INC.

Repair Evaluation Report

RMA Number:	21184	**RMA Line Number:**	1
Customer:	DUKE ENERGY FL, LLC	**Customer Contact :**	JOE 352-601-1461
Model Number:	M-0359#4801	**Serial Number:**	1711
Date Returned:	01/20/21	**Original Ship Date:**	02/28/02
Failure Code:	2	**Cost:**	

Reason for return:

CUSTOMER STATES: A/B CONTACT LATCHED

Initial Evaluation:

Visually inspected the older M-0359 SN-1711 Syncrocloser and found no damage. Powered up the unit and upon further testing CTS verified the A/B breaker close out contacts were intermittent in operation and would latch. The customer was contacted with the cost to repair relay

SW/FW Version:	N/A	Reviewed By:	CTS / Brian Holt	Date:	2/5/21
Complaint Verified ? (Y/N)	Yes	If **Yes** skip to Repair section:	If N complete Customer Communication section		

Customer Communication

Customer contacted: Joe

On 2/3/21 the customer was contacted with the evaluation and cost to repair the unit.
On 2/3/21 the customer declined the repair and asked to have the unit returned as is.

Customer Contacted By:	Dave Jones	Date:	2/3/21

Probable Cause:

A Tantalum 2.2 uf capacitor C 57 failed on the older main Phase Board Breaker Close Circuit. This capacitor is part of a RC Timer circuit input to U6 comparator which operates a transistor array single-shot output This is a discrete component failure type with no failure trends.

Repair/Corrective Actions Taken:

No repairs were made to the M-0359. The customer asked to have the unit returned as is.

RMA Technician:	Dave Peterson	**Date:**	2/5/2021
QA Director:	Roger Mogler	**Date:**	2/8/2021